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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2021

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: 001-32678

DCP MIDSTREAM, LP

(Exact name of registrant as specified in its charter)

Delaware	**03-0567133**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6900 E. Layton Ave, Suite 900 Denver, Colorado	**80237**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (303) 595-3331

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

Title of Each Class:	Trading Symbol(s)	Name of Each Exchange on Which Registered:
Common Units Representing Limited Partner Interests	DCP	New York Stock Exchange
7.875% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	DCP PRB	New York Stock Exchange
7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	DCP PRC	New York Stock Exchange

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

None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1934, or the Act. Yes ☒ No☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Act 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 and 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report ☒

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

The aggregate market value of common units held by non-affiliates of the registrant on June 30, 2021, was approximately $2,780,516,000. The aggregate market value was computed by reference to the last sale price of the registrant's common units on the New York Stock Exchange on June 30, 2021.

As of February 16, 2022, there were 208,378,739 common units representing limited partner interests outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None

DCP MIDSTREAM, LP
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2021

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following is a list of terms used in the industry and throughout this report:

ASU	accounting standards update
Bbl	barrel
Bbls/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Btu	British thermal unit, a measurement of energy
Credit Agreement	Credit Agreement governing our $1.4 billion unsecured revolving credit facility, maturing December 9, 2024
Fractionation	the process by which natural gas liquids are separated into individual components
GAAP	generally accepted accounting principles in the United States of America
GP	DCP Midstream GP, LP the general partner of DCP Midstream, LP
IDR	incentive distribution right
LIBOR	London Interbank Offered Rate
MBbls	thousand barrels
MBbls/d	thousand barrels per day
MMBtu	million Btus
MMBtu/d	million Btus per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NGLs	natural gas liquids
OPEC	Organization of the Petroleum Exporting Countries
OPEC+	OPEC members plus ten other oil producing countries
OPIS	Oil Price Information Service
Railroad Commission	the Railroad Commission of Texas
SEC	U.S. Securities and Exchange Commission
Securitization Facility	$350 million Accounts Receivable Securitization Facility, maturing August 12, 2024
TBtu/d	trillion Btus per day
Throughput	the volume of product transported or passing through a pipeline or other facility

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Our 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" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "should," "intend," "assume," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including, but not limited to, 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 risks set forth in Item 1A. "Risk Factors" in this Annual Report on Form 10-K for the year ended December 31, 2021, including the following risks and uncertainties:

- the impact resulting from the COVID-19 pandemic and disruption to economies around the world including the oil, gas and NGL industry in which we operate and the resulting adverse impact on our business, liquidity, commodity prices, workforce, third-party and counterparty effects and resulting federal, state and local actions;
- the extent of changes in commodity prices and the demand for our products and services, our ability to effectively limit a portion of the adverse impact of potential changes in commodity prices through derivative financial instruments, and the potential impact of price, and of producers' access to capital on natural gas drilling, demand for our services, and the volume of NGLs and condensate extracted;
- the demand for crude oil, residue gas and NGL products;
- the level and success of drilling and quality of production volumes around our assets and our ability to connect supplies to our gathering and processing systems, as well as our residue gas and NGL infrastructure;
- new, additions to, and changes in, laws and regulations, particularly with regard to taxes, safety, regulatory and protection of the environment, including, but not limited to, climate change legislation, regulation of over-the-counter derivatives markets and entities, and hydraulic fracturing regulations, or the increased regulation of our industry, including additional local control over such activities, and their impact on producers and customers served by our systems;
- volatility in the price of our common units and preferred units;
- general economic, market and business conditions;
- the amount of natural gas we gather, compress, treat, process, transport, store and sell, or the NGLs we produce, fractionate, transport, store and sell, may be reduced if the pipelines, storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the natural gas or NGLs or we may be required to find alternative markets and arrangements for our natural gas and NGLs;
- our ability to continue the safe and reliable operation of our assets;
- our ability to grow through organic growth projects, or acquisitions, and the successful integration and future performance of such assets;
- our ability to access the debt and equity markets and the resulting cost of capital, which will depend on general market conditions, our financial and operating results, inflation rates, interest rates, our ability to comply with the covenants in our Credit Agreement or other credit facilities, and the indentures governing our notes, as well as our ability to maintain our credit ratings;
- the creditworthiness of our customers and the counterparties to our transactions, including the impact of bankruptcies;
- the amount of collateral we may be required to post from time to time in our transactions;
- industry changes, including consolidations, alternative energy sources, technological advances, infrastructure constraints and changes in competition;
- our ability to construct and start up facilities on budget and in a timely fashion, which is partially dependent on obtaining required construction, environmental and other permits issued by federal, state and municipal governments, or agencies thereof, the availability of specialized contractors and laborers, and the price of and demand for materials;
- our ability to hire, train, and retain qualified personnel and key management to execute our business strategy;
- weather, weather-related conditions and other natural phenomena, including, but not limited to, their potential impact on demand for the commodities we sell and the operation of company-owned and third party-owned infrastructure;
- security threats such as terrorist attacks, and cybersecurity attacks and breaches, against, or otherwise impacting, our facilities and systems; and
- our ability to obtain insurance on commercially reasonable terms, if at all, as well as the adequacy of insurance to cover our losses.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. The forward-looking statements in this report speak as of the filing date of this report. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable securities laws.

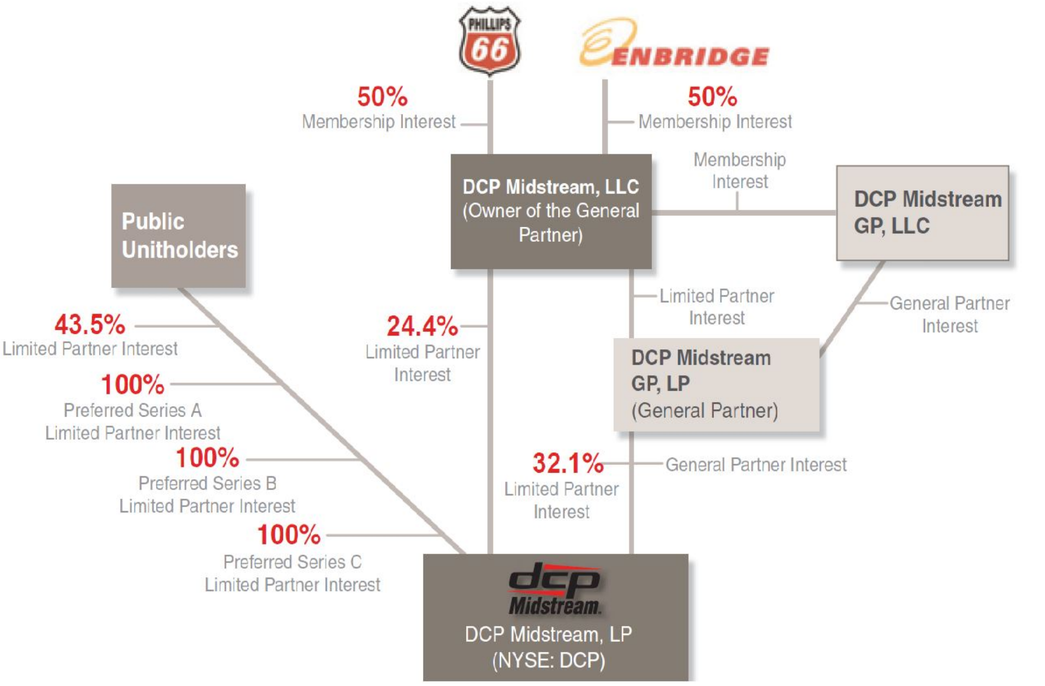
PART I

Item 1. ***Business***

OVERVIEW

DCP Midstream, LP (together with its consolidated subsidiaries, “we,” “our,” “us,” the “registrant,” or the “Partnership”) is a Delaware limited Partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC is owned 50% by Phillips 66 and 50% by Enbridge Inc. and its affiliates, or Enbridge.

The diagram below depicts our organizational structure as of December 31, 2021.



Our operations are organized into two reportable segments: (i) Logistics and Marketing and (ii) Gathering and Processing. Our Logistics and Marketing segment includes transporting, trading, marketing, and storing natural gas and NGLs, and fractionating NGLs. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering condensate. The remainder of our business operations are presented as “Other,” and consist of unallocated corporate costs.

OUR BUSINESS STRATEGY

Our primary business objectives are to achieve sustained company profitability, a strong balance sheet and profitable growth, thereby sustaining and ultimately growing our cash distribution per unit. We intend to accomplish these objectives by prudently executing the following business strategies:

Operational Performance. We believe our operating efficiency and reliability enhance our ability to attract new natural gas supplies by enabling us to offer more competitive terms, services and service flexibility to producers. Our logistics assets and gathering and processing systems consist of high-quality, well-maintained facilities, resulting in low-cost, efficient operations. Our goal is to establish a reputation in the midstream industry as a reliable, safe and low cost supplier of services to our customers. We will continue to pursue incremental revenue, cost efficiencies and operating improvements of our assets through process and technology improvements. We seek to increase the utilization of our existing facilities by providing additional services to our existing customers, by establishing relationships with new customers and by strategically rationalizing assets. In addition, we maximize efficiency by coordinating the completion of new facilities in a manner that is consistent with the expected production that supports them.

Organic Growth. We intend to use our strategic asset base in the United States and our position as one of the largest processors of natural gas, and as one of the largest producers and marketers of NGLs in the United States, as a platform for future growth. We plan to grow our business by leveraging our diverse and strategic asset base to increase supply across our fully integrated value chain. We will also make selective and capital efficient investments in our assets and energy transition.

Strategic Partnerships and Acquisitions. We intend to pursue economically attractive and strategic partnership and acquisition opportunities within the midstream energy industry, both in new and existing lines of business, and areas of operation.

OUR COMPETITIVE STRENGTHS

We are one of the largest processors of natural gas and one of the largest producers and marketers of NGLs in the United States with a diversified portfolio of integrated assets across our value chain. In 2021, our total wellhead volume was approximately 4.2 Bcf/d of natural gas and we produced an average of approximately 398 MBbls/d of NGLs. We provide natural gas gathering services to the wellhead, and leverage our strategic footprint to extend the value chain through our integrated NGL and natural gas pipelines and marketing infrastructure. We believe our ability to provide all of these services gives us an advantage in competing for new supplies of natural gas because we can provide substantially all services to move natural gas and NGLs from wellhead to market, and creates value for our customers. We believe that we are well positioned to execute our business strategies and achieve one of our primary business objectives of sustaining our cash distribution per unit because of the following competitive strengths:

Integrated Logistics and Marketing Operations. We believe the strategic location of our assets coupled with their geographic diversity and our reputation for running our business reliably and effectively, presents us with continuing opportunities to provide competitive services to our customers and attract new natural gas production to our gathering and processing operations. We have connected our gathering and processing operations to key markets with NGL pipelines that we own or operate to offer our customers a competitive, integrated midstream service. We have strategically located NGL transportation pipelines that provide takeaway capabilities for our gathering and processing operations in the Permian Basin, the Denver-Julesburg Basin (“DJ Basin”), the Midcontinent, East Texas, the Gulf Coast, South Texas, and Central Texas. Our NGL pipelines connect to various natural gas processing plants and transport the NGLs to fractionation facilities, a petrochemical plant, a third party underground NGL storage facility and other markets along the Gulf Coast. Our Logistics and Marketing operations also consists of multiple downstream assets including NGL fractionation facilities, an NGL storage facility and a residue gas storage facility.

Strategically Located Gas Gathering and Processing Operations. Our assets are strategically located in areas with the potential for increasing our wellhead volumes and cash flow generation. We have operations in some of the largest producing regions in the United States including the DJ Basin, Midcontinent, Permian Basin, and Eagle Ford. In addition, we operate one of the largest portfolios of natural gas processing plants in the United States. Our gathering systems and processing plants are connected to numerous key natural gas pipeline systems that provide producers with access to a variety of natural gas market hubs.

Stable Cash Flows. Our operations consist of a mix of fee-based and commodity-based services, which together with our commodity hedging program, are intended to generate relatively stable cash flows. The long term growth in our fee-based earnings will reduce the impact of unhedged margins. Additionally, while certain of our gathering and processing contracts subject us to commodity price risk, we have mitigated a portion of our currently anticipated commodity price risk associated with the equity volumes from our gathering and processing operations with fixed price commodity swaps. As of December 31, 2021, we were approximately 70% fee-based.

Established Relationships with Oil, Natural Gas and Petrochemical Companies. We have long-term relationships with many of our suppliers and customers, and we expect that we will continue to benefit from these relationships.

Digital Transformation. We are driving workforce efficiencies through automation, improving safety and decreasing emissions via real-time monitoring and predictive analytics and optimizing margins while increasing cost efficiencies.

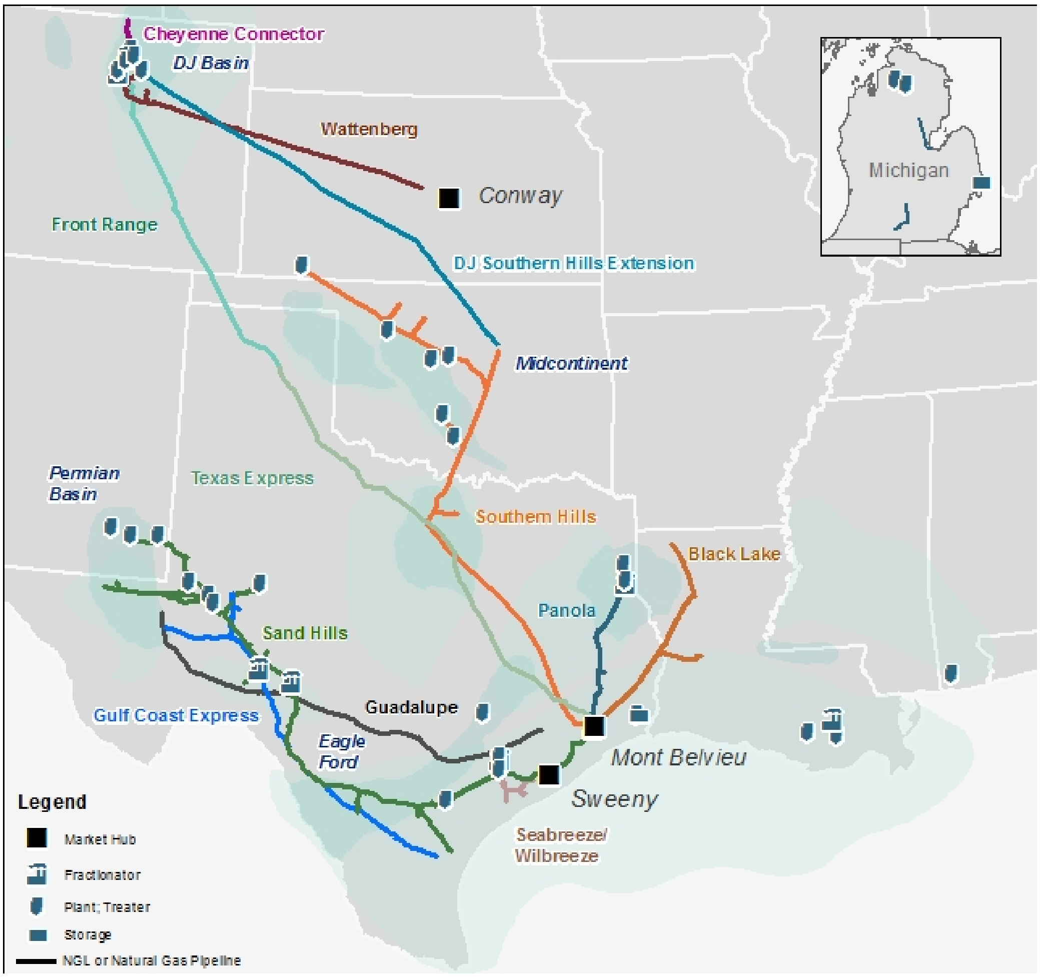
Experienced Management Team. Our senior management team and the board of directors of our General Partner have extensive experience in the midstream industry. We believe our management team has a proven track record of enhancing value through organic growth and the acquisition, optimization and integration of midstream assets.

Affiliation with DCP Midstream, LLC and its owners. Our relationship with DCP Midstream, LLC and its owners, Phillips 66 and Enbridge, should continue to provide us with significant business opportunities. Through our relationship with DCP Midstream, LLC and its owners, we believe our strong commercial relationships throughout the energy industry, including with major producers of natural gas and NGLs in the United States, will help facilitate the implementation of our strategies.

DCP Midstream, LLC has a significant interest in us through its ownership, together with our general partner, of an approximately 57% limited partner interest.

OUR OPERATING SEGMENTS

Logistics and Marketing Segment



General

We market our NGLs, residue gas and condensate and provide logistics and marketing services to third-party NGL producers and sales customers in significant NGL production and market centers in the United States. This includes purchasing NGLs on behalf of third-party NGL producers for shipment on our NGL pipelines and resale in key markets.

Our NGL services include plant tailgate purchases, transportation, fractionation, flexible pricing options and price risk management. Our primary NGL operations are located in close proximity to our Gathering and Processing assets in each of the operating regions.

Our NGL pipelines transport NGLs from natural gas processing plants to fractionation facilities, petrochemical plants and a third party underground NGL storage facility. Our pipelines provide transportation services to customers primarily on a fee basis. Therefore, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to recover NGLs from natural gas because of the higher value of natural gas compared to the value of NGLs. As a result, we have experienced periods, and will likely experience periods in the future, when higher relative natural gas prices reduce the volume of NGLs produced at plants connected to our NGL pipelines.

Our natural gas systems have the ability to deliver gas into numerous downstream transportation pipelines and markets. We sell residue gas on behalf of our producer customers and residue gas which we earn under our gas supply agreements, supplying the residue gas demands of end-use customers physically attached to our pipeline systems and managing excess capacity of our owned storage and transportation assets. End-users include large industrial companies, natural gas distribution companies and electric utilities. We are focused on extracting the highest possible value for the residue gas that results from our processing and transportation operations. We sell the residue gas at market-based prices.

The following is operating data for our Logistics and Marketing segment:

Operating Data

					Year Ended December 31, 2021		
System	**Approximate System Length (Miles)**	**Fractionators**	**Approximate Throughput Capacity (MBbls/d) (a)**	**Approximate Gas Throughput Capacity (TBtus/d) (a)**	**Pipeline Throughput (MBbls/d) (a)**	**Pipeline Throughput (TBtus/d) (a)(b)**	**Fractionator Throughput (MBbls/d) (a)**
Sand Hills pipeline	1,400	—	333	—	272	—	—
Southern Hills pipeline	980	—	128	—	114	—	—
Front Range pipeline	450	—	87	—	63	—	—
Texas Express pipeline	600	—	37	—	20	—	—
Other NGL pipelines (a)	1,100	—	310	—	183	—	—
Gulf Coast Express pipeline	500	—	—	0.50	—	0.48	—
Guadalupe pipeline	600	—	—	0.25	—	0.25	—
Cheyenne Connector	70	—	—	0.30	—	0.30	—
Mont Belvieu fractionators	—	2	—	—	—	—	52
Pipelines total	5,700	2	895	1.05	652	1.03	52

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.
(b) Represents average throughput for full year 2021.

NGL Pipelines

DCP Sand Hills Pipeline, LLC, or the Sand Hills pipeline, an interstate NGL pipeline which is owned 66.67% by us and 33.33% by Phillips 66, is a common carrier pipeline that provides takeaway service from plants in the Permian and the Eagle Ford basins to fractionation facilities along the Texas Gulf Coast and at the Mont Belvieu, Texas market hub.

DCP Southern Hills Pipeline, LLC, or the Southern Hills pipeline, an interstate NGL pipeline which is owned 66.67% by us and 33.33% by Phillips 66, provides takeaway service from the North and Midcontinent regions to fractionation facilities at the Mont Belvieu, Texas market hub.

Front Range Pipeline LLC, or the Front Range pipeline, an interstate NGL pipeline in which we own a 33.33% interest, originates in the DJ Basin and extends to Skellytown, Texas. The Front Range pipeline connects to our O'Connor plants, Lucerne 1, Lucerne 2, and Mewbourn plants, as well as third party plants in the DJ Basin. Enterprise Products Partners L.P., or Enterprise, is the operator of the pipeline.

Texas Express Pipeline LLC, or the Texas Express pipeline, an intrastate NGL pipeline in which we own a 10% interest, originates near Skellytown in Carson County, Texas, and extends to Enterprise's natural gas liquids fractionation and storage complex at Mont Belvieu, Texas. The pipeline also provides access to other third party facilities in the area. Enterprise is the operator of the pipeline.

The Southern Hills, Sand Hills, Texas Express, and Front Range pipelines have in place long-term, fee-based transportation agreements, a portion of which are ship-or-pay, with us as well as third party shippers. These NGL pipelines collect fee-based transportation revenue under regulated tariffs.

Natural Gas Pipelines

Gulf Coast Express LLC, or the Gulf Coast Express pipeline, an intrastate natural gas pipeline in which we own a 25% interest, originates from the Waha area in West Texas to Agua Dulce, in Nueces County, Texas. Kinder Morgan is the operator of the pipeline. The Gulf Coast Express pipeline is fully subscribed under long-term transportation contracts with us and third party shippers.

The Guadalupe pipeline is an intrastate natural gas pipeline that provides us access to market centers/hubs including Waha, Texas, Katy, Texas and the Houston Ship Channel and is used primarily in our natural gas asset based trading activities. We may transport volumes for third party shippers using our available capacity in the future.

Cheyenne Connector, LLC, or the Cheyenne Connector is an interstate natural gas pipeline in which we own a 50% interest, which provides residue gas takeaway from the DJ Basin to the Rockies Express Cheyenne Hub, just south of the Colorado-Wyoming border. Tallgrass Energy is the operator of the Cheyenne Connector.

NGL Fractionation Facilities

We own a 12.5% interest in the Enterprise fractionator operated by Enterprise and a 20% interest in the Mont Belvieu 1 fractionator operated by ONEOK Partners, both located in Mont Belvieu, Texas. The fractionation facilities separate NGLs received from processing plants into their individual components. These fractionation services are provided on a fee basis. The results of operations for this business are generally dependent upon the volume of NGLs fractionated and the level of fees charged to customers.

Storage Facilities

Our Marysville NGL storage facility, which stores ethane, propane and butane, is located in Michigan and has strategic access to Marcellus, Utica and Canadian NGLs. Our facility includes 11 underground salt caverns with approximately 8 MMBbls of storage capacity. Our facility serves regional refining and petrochemical demand, and helps to balance the seasonality of propane distribution in the Midwestern and Northeastern United States and in Sarnia, Canada. We provide services to customers primarily on a fee basis under multi-year storage agreements. The results of operations for this business are generally dependent upon the volume stored and the level of fees charged to customers.

Our Spindletop natural gas storage facility is located in Texas and plays an important role in our ability to act as a full-service natural gas marketer. The facility has capacity for residue gas of approximately 12 Bcf. We may lease a portion of the facility's capacity to third-party customers, and use the balance to manage relatively constant natural gas supply volumes with uneven demand levels, provide "backup" service to our customers and support our asset-based trading activities. Our asset based trading activities are designed to realize margins related to fluctuations in commodity prices, time spreads and basis differentials and to maximize the value of our storage facility.

Trading and Marketing

Our energy trading operations are exposed to market variables and commodity price risk. We manage commodity price risk related to our natural gas storage and pipeline assets by engaging in natural gas asset based trading and marketing. We may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. Our energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

We may execute a time spread transaction when the difference between the current price of natural gas (cash or futures) and the futures market price for natural gas exceeds our cost of storing physical gas in our owned and/or leased storage facilities. The time spread transaction allows us to lock in a margin when this market condition exists. A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time.

We may execute basis spread transactions when the market price differential between locations on a pipeline asset exceeds our cost of transporting physical gas through our owned and/or leased pipeline assets. When this market condition exists, we may execute derivative instruments around this differential at the market price. The basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas.

Customers and Contracts

We sell our commodities to a variety of customers ranging from large, multi-national petrochemical and refining companies to small regional retail propane distributors. Substantially all of our NGL sales are made at market-based prices.

Competition

The Logistics and Marketing business is highly competitive in our markets and includes interstate and intrastate pipelines, integrated oil and gas companies that produce, fractionate, transport, store and sell natural gas and NGLs, and underground storage facilities. Competition is often the greatest in geographic areas experiencing robust drilling by producers and strong petrochemical demand and during periods of high NGL prices relative to natural gas. Competition is also increased in those geographic areas where our contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Competition in the NGLs marketing area comes from other midstream NGL marketing companies, international producers/traders, chemical companies, refineries and other asset owners. Along with numerous marketing competitors, we offer price risk management and other services. We believe it is important that we tailor our services to the end-use customer to remain competitive.

Gathering and Processing Segment

General

Our Gathering and Processing segment consists of a geographically diverse complement of assets and ownership interests that provide a varied array of wellhead to market services for our producer customers in Alabama, Colorado, Kansas, Louisiana, Michigan, New Mexico, Oklahoma, Texas and Wyoming. These services include gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering condensate. Our Gathering and Processing segment's operations are organized into four regions: North, Permian, Midcontinent and South. Our geographic diversity helps to mitigate our natural gas supply risk in that we are not tied to one natural gas resource type or producing area. We believe our current geographic mix of assets is an important factor for the maintenance and long term growth of overall volumes and cash flow for this segment. Our assets are positioned in certain areas with active drilling programs and opportunities for organic growth.

We provide our producer customers with gathering and processing services that allow them to move their raw (unprocessed) natural gas to market. Raw natural gas is gathered, compressed and transported through pipelines to our processing facilities. In order for the raw natural gas to be accepted by the downstream market, we remove water, nitrogen and carbon dioxide and separate NGLs for further processing. Processed natural gas, usually referred to as residue natural gas, is then recompressed and delivered to natural gas pipelines and end users. The separated NGLs are in a mixed, unfractionated form and are sold and delivered through natural gas liquids pipelines to fractionation facilities for further separation.

We own or operate 35 active natural gas processing plants, including an interest in a plant through our 40% equity interest in Discovery Producer Services, LLC, or Discovery. At some of these facilities, we fractionate NGLs into individual components (ethane, propane, butane and natural gasoline).

We receive natural gas from a diverse group of producers under contracts with varying durations, and we receive fees or commodities from the producers to transport the natural gas from the wellhead to the processing plant. We receive fees or commodities as payment for our natural gas processing services, depending on the types of contracts we enter into with each supplier. We purchase or take custody of substantially all of our natural gas from producers, principally under fee-based or percent-of-proceeds/index processing contracts.

We actively seek new producing customers of natural gas on all of our systems to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been directly received or released from other gathering systems.

Our contracts with our producing customers in our Gathering and Processing segment are a mix of non-commodity sensitive fee-based contracts and commodity sensitive percent-of-proceeds and percent-of-liquids contracts. Percent-of-proceeds contracts are directly related to the price of natural gas, NGLs and condensate and percent-of-liquids contracts are directly related to the price of NGLs and condensate. Additionally, these contracts may include fee-based components. Generally, the initial term of these purchase agreements is three to five years and in some cases, the life of the lease. As we negotiate new agreements and renegotiate existing agreements, this may result in a change in contract mix period over period.

We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges.

During 2021, total wellhead volume on our assets was approximately 4.2 Bcf/d, originating from a diversified mix of customers. Our systems each have significant customer acreage dedications that we expect will continue to provide opportunities for growth as those customers execute their drilling plans over time. Our gathering systems also attract new natural gas volumes through numerous smaller acreage dedications and by contracting with undedicated producers who are operating in or around our gathering footprint. During 2021, the combined NGL production from our processing facilities was approximately 398 MBbls/d and was delivered and sold into various NGL takeaway pipelines.

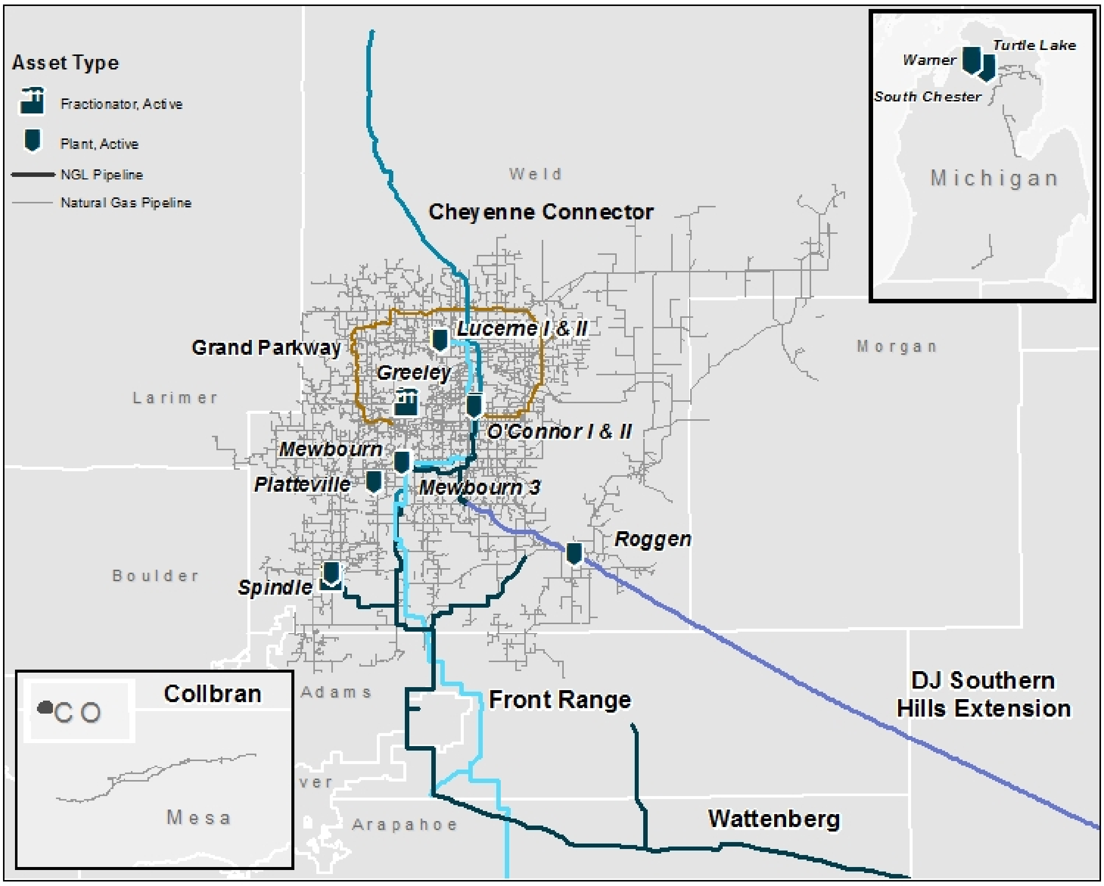
The following is operating data for our Gathering and Processing segment by region:

Operating Data

				Year ended December 31, 2021	
Regions	**Plants**	**Approximate Gathering and Transmission Systems (Miles)**	**Approximate Net Nameplate Plant Capacity (MMcf/d) (a)**	**Natural Gas Wellhead Volume (MMcf/d) (a)**	**NGL Production (MBbls/d) (a)**
North	13	3,500	1,580	1,545	144
Midcontinent	6	24,000	1,110	832	71
Permian	9	15,500	1,100	936	112
South	7	7,000	1,630	883	71
Total	35	50,000	5,420	4,196	398

(a) Represents total capacity or total volumes allocated to our proportionate ownership share.

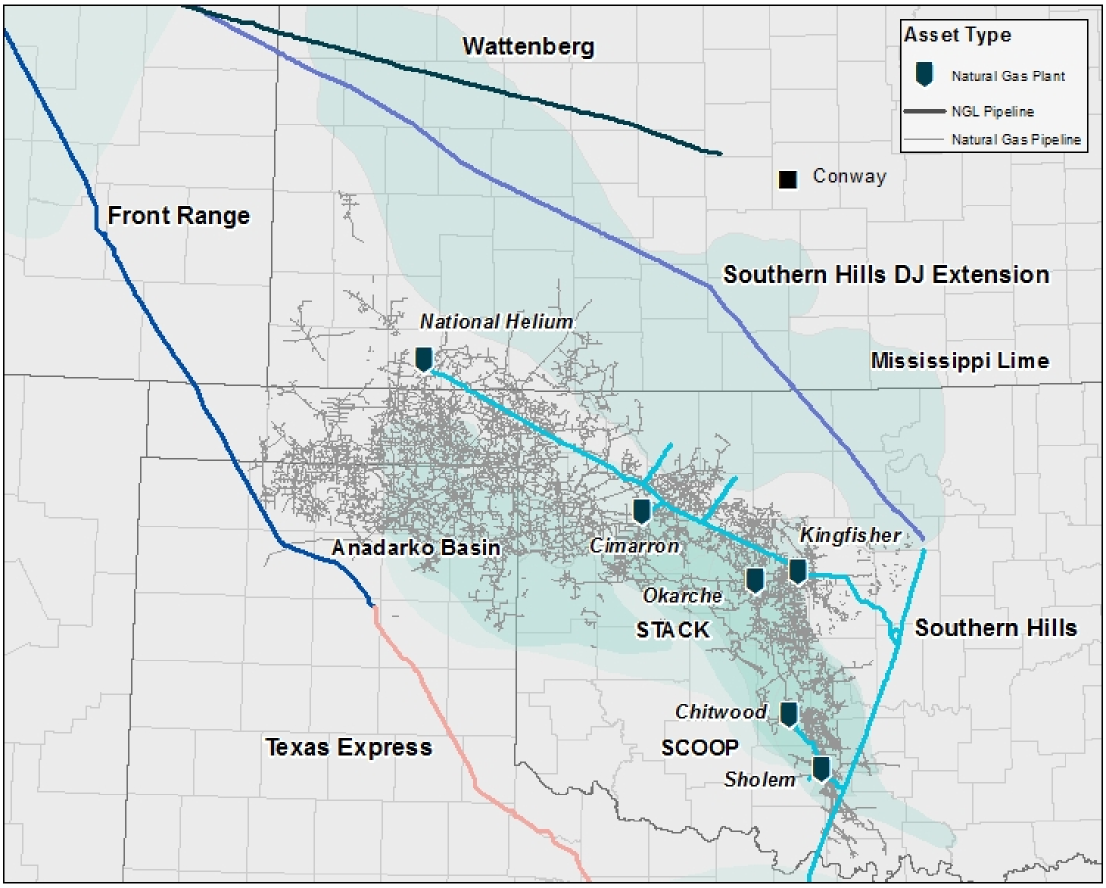
North Region



Our North region primarily consists of our DJ Basin system. We have a broad network of gathering, compression, treating, and processing facilities in Weld County, Colorado that provide significant optionality and flexibility.

Our DJ Basin system delivers to the Mont Belvieu hub in Mont Belvieu, Texas via the Southern Hills, Front Range and Texas Express pipelines, and to the Conway hub in Bushton, Kansas via our Wattenberg pipeline. We have added additional NGL takeaway for our producer customers through the DJ Southern Hills extension, and the expansions of the Texas Express and Front Range pipelines. We have also added additional gas takeaway through the Cheyenne Connector.

Midcontinent Region

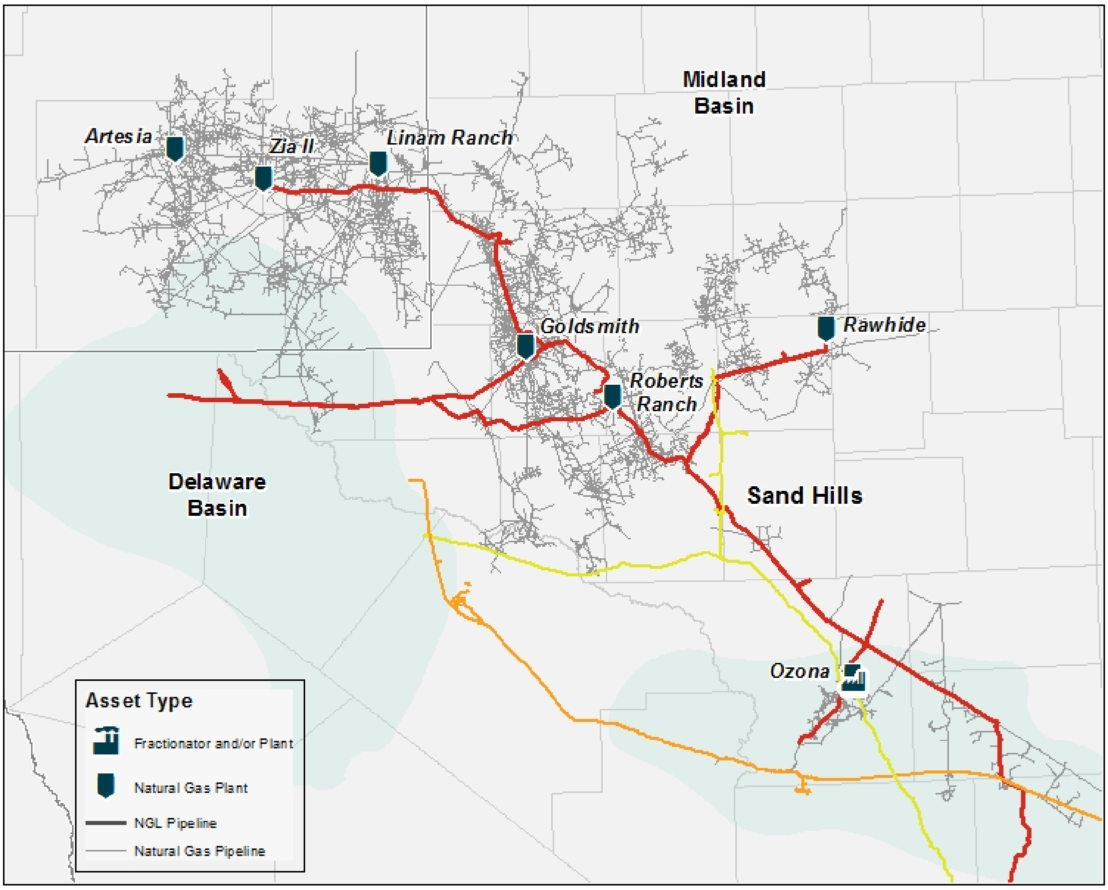


Our Midcontinent region primarily includes our Liberal system and South Central Oklahoma system. We gather and process raw natural gas primarily from the Ardmore and Anadarko Basins, including the South Central Oklahoma Oil Province ("SCOOP") play and the Sooner Trend Anadarko Basin Canadian and Kingfisher ("STACK") play.

Our gathering system footprint in the eastern Midcontinent region, which includes our South Central Oklahoma system, serves the SCOOP and STACK plays. Existing production in the western Midcontinent region, which includes our Liberal system in the Hugoton Basin, is typically from mature fields with shallow decline profiles that we expect will provide our plants with a dependable source of raw natural gas over a long term. We believe the infrastructure of our plants and gathering facilities is uniquely positioned to pursue our consolidation strategy in the western Midcontinent region.

Our gathering and processing assets in the Midcontinent region deliver NGLs primarily to the Gulf Coast and Mont Belvieu via our Southern Hills pipeline.

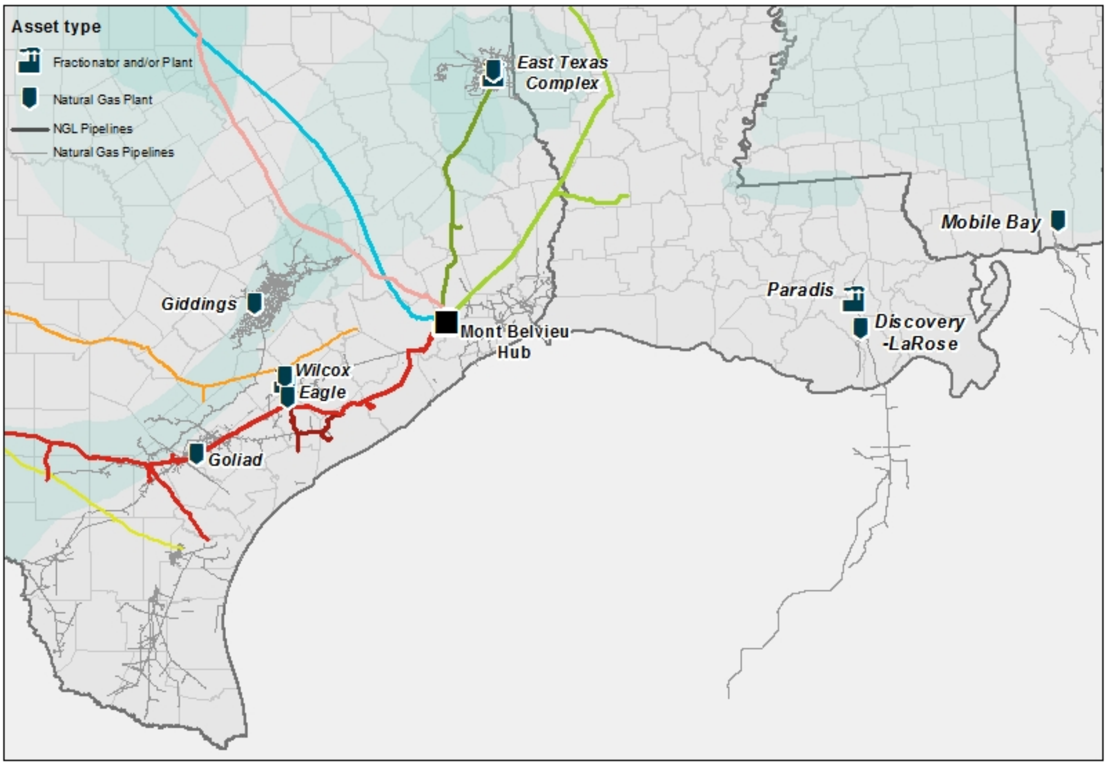
Permian Region



Our Permian region primarily includes our West Texas system in the Midland Basin and our Southeast New Mexico system in the Delaware Basin. Producers continue to focus drilling activity on the most attractive acreage in the Midland and Delaware Basins.

Our gathering and processing assets in the Permian region provide NGL takeaway service via our Sand Hills pipeline, to fractionation facilities along the Gulf Coast and to the Mont Belvieu hub. The Guadalupe pipeline provides gas takeaway from Waha to Katy, Texas. Through our ownership interest in the Gulf Coast Express pipeline we provide additional gas takeaway in the region.

South Region



Our South region primarily includes our Eagle Ford system, East Texas system, and our 40% interest in the Discovery system. We are pursuing cost efficiencies and increasing the utilization of our existing assets.

Our Eagle Ford system delivers NGLs to the Gulf Coast petrochemical markets and to Mont Belvieu through our Sand Hills pipeline and other third party NGL pipelines. Our East Texas system provides NGL takeaway service through the Panola pipeline, owned 15% by us, and delivers gas primarily through its Carthage Hub which delivers residue gas to multiple interstate and intrastate pipelines.

The Discovery system is operated by Williams Partners L.P., which owns a 60% interest, and offers a full range of wellhead-to-market services to both onshore and offshore natural gas producers. The assets are primarily located in the eastern Gulf of Mexico and Louisiana, and have access to downstream pipelines and markets.

Competition

We face strong competition in acquiring raw natural gas supplies. Our competitors in obtaining additional gas supplies and in gathering and processing raw natural gas include major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

We have no revenue attributable to international activities.

REGULATORY AND ENVIRONMENTAL MATTERS

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA and implementing regulations apply to interstate and intrastate pipeline facilities and the pipeline transportation of liquid petroleum and petroleum products, including NGLs and condensate, and require any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines in high-consequence areas within 10 years. DOT, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011(the Pipeline Safety and Job Creations Act) reauthorized funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules promulgated by DOT’s PHMSA address many areas of this legislation, as described below. We currently estimate we will incur approximately $121 million between 2022 and 2026 to implement integrity management program testing along certain segments of our natural gas transmission and NGL pipelines under Parts 192 and 195. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, nor is it inclusive of estimated costs to implement the Final Gathering Rule (as defined and discussed in further detail below).

The Pipeline Safety and Job Creation Act requires more stringent oversight of pipelines and increased civil penalties for violations of pipeline safety rules. The legislation gave PHMSA civil penalty authority up to $213,268 per day per violation, with a maximum of $2,132,679 for any related series of violations. Any material penalties or fines under these or other statutes, rules, regulations or orders could have a material adverse impact on our business, financial condition, results of operation and cash flows.

On December 21, 2020, the U.S. Congress passed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (the 2020 Act). The Act reauthorizes the federal pipeline safety program through September 30, 2023, and establishes annual funding levels through 2023. The 2020 Act also requires PHMSA to issue new rules for gas pipeline leak detection and repair programs and idle pipelines, and issue final rulemakings for gas gathering lines, class location changes, and the definition of unusually sensitive areas. The 2020 Act establishes additional due process requirements applicable to PHMSA enforcement actions, authorizes a new declaratory order proceeding, and obligates PHMSA to consider an operator's self-report in assessing a civil penalty.

On January 11, 2021, PHMSA published a Final Rule amending certain gas pipeline safety regulations at 49 C.F.R. Parts 191 and 192 (the "Final Rule"). Although the effective date of the Final Rule is March 12, 2021, PHMSA provided a deferred compliance date of October 1, 2021. Among other changes, these Part 192 changes include provisions allowing operators to remotely monitor cathodic protection rectifier stations, provided that they perform annual testing by physical inspection of the rectifier. The Final Rule also adjusts the monetary property damage threshold in the definition of an "incident" from $50,000 to $122,000 to account for inflation, with a commitment to update the threshold annually using a defined formula. The Final Rule incorporates certain industry standards for construction of plastic pipes and changes test factors for pressure vessels.

On November 15, 2021, PHMSA published a Final Rule amending the gas pipeline safety regulations at 49 CFR Parts 191 and 192 to extend regulation over larger diameter gas gathering pipelines located in rural (Class 1) locations (the "Final Gathering Rule"). The Final Gathering Rule imposes Part 191 or Part 192 requirements on such rural gathering pipelines. All rural gathering pipelines will be subject to annual and incident reporting under Part 191, while those pipelines over 8.625 inches in diameter that are operated at a maximum allowable operating pressure ("MAOP") of more than 20% of specified minimum yield strength ("SMYS") or, where SMYS is not known, where the MAOP exceeds 125 psig, must also comply with certain Part 192 requirements. The applicable Part 192 requirements increase with increased diameter and with proximity to buildings intended for human occupancy or impacted sites. For gathering pipelines between 8.625 inches and 16 inches in diameter, the new regulations require annual and incident reporting, as well as design and construction standards, damage prevention, and emergency planning on new pipelines or those that are repaired or replaced or otherwise substantially changed. If the potential impact radius of the pipeline segment includes a building intended for human occupancy or an impacted site, corrosion control, line markers, public awareness and leakage survey and repair for pipelines of less than 12.75 inches in diameter are also added, and MAOP requirements and standards for plastic pipelines for lines are added for pipelines between 12.75 inches and 16 inches in diameter. Pipelines of more than 16 inches in diameter are subject to all of the above, whether or not the potential impact radius includes any structures intended for human occupancy or impacted sites. The Part 191 reporting requirements of the Final Gathering Rule take effect on May 16, 2022, with the remaining Part 192 requirements taking effect on November 15, 2022 or May 16, 2023.

We are currently evaluating the impact of the Final Gathering Rule on our operations and compliance programs, including the identification of our gathering pipelines that are subject to the Final Gathering Rule, and to determine the specific compliance requirements applicable to these pipelines. We are also evaluating opportunities to reduce the number of miles of pipeline that will be subject to the Final Gathering Rule, including changes in operating pressures and system reconfiguration or optimization.

Finally, DCP is evaluating the cost impact of the Final Gathering Rule, which depends on the results of our analysis of pipeline data. We currently estimate that we will incur costs of approximately $100 million to implement the requirements of the Final Gathering Rule, and we will refine that number as we complete our analysis. We believe that we will be able to meet the requirements of the Final Gathering Rule in all material respects by the dates set forth in the Final Gathering Rule. Certain industry groups such as API and GPA Midstream Association, in which we are a member, have asked PHMSA to reconsider aspects of the Final Gathering Rule, including the timeframe for compliance, the outcome of which will further impact our cost estimates and the timing of incurring such costs.

We believe that we are in compliance in all material respects with the NGPSA and the Pipeline Safety Improvement Act of 2002 and the Pipeline Safety and Job Creation Act, and to the extent we make changes to our program to reflect the 2020 Act, we expect to be in material compliance by the effective dates of the new regulations promulgated under the 2020 Act.

States are largely preempted by federal law from regulating pipeline safety, but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations in those states in which we or the entities in which we own an interest operate. Our natural gas transmission and regulated gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency, or EPA, community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management and EPA Risk Management Program regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The OSHA regulations apply to any process that involves a chemical at or above specified thresholds, or any process that involves flammable liquid or gas, pressurized tanks, caverns and wells holding or handling these materials in quantities in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks at temperatures below the normal boiling point of the liquids without the benefit of chilling or refrigeration are exempt from these standards. The EPA regulations have similar applicability thresholds. We implement these safety programs, and we have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to worker health and safety.

FERC and State Regulation of Operations

Federal Energy Regulatory Commission ("FERC") regulation of interstate natural gas pipelines, the marketing and sale of natural gas in interstate commerce and the transportation of NGLs in interstate commerce may affect certain aspects of our business and the market for our products and services. Regulation of gathering systems and intrastate transportation of natural gas and NGLs by state agencies may also affect our business.

Interstate Natural Gas Pipeline Regulation

Our Cimarron River, Discovery, Cheyenne Connector, and Dauphin Island Gathering Partners systems, or portions thereof, are some of our natural gas pipeline assets that are subject to regulation by FERC, under the Natural Gas Act of 1938, as amended, or NGA. Natural gas companies subject to the NGA may only charge rates that have been determined to be just and reasonable. In addition, FERC authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of transportation services;
- terms and conditions of transportation services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

Generally, the maximum filed recourse rates for an interstate natural gas pipeline's transportation services are based on the pipeline's cost of service including recovery of and a return on the pipeline's actual prudent investment cost. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The allocation of costs to various pipeline services and the manner in which rates are designed also can impact a pipeline's profitability. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline's FERC-approved gas tariff. FERC-regulated natural gas pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the minimum rate or variable cost of performing service, provided they do not "unduly discriminate."

Tariff changes can only be implemented upon approval by FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If FERC determines, as required by the NGA, that a proposed change is just and reasonable, FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if FERC determines that a proposed change may not be just and reasonable as required by NGA, then FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, FERC may, on its own motion or based on a complaint, initiate a proceeding to compel the company to change or justify its rates, terms and/or conditions of service. If FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by FERC and Congress, especially in light of potential market power abuse by marketing companies engaged in interstate commerce. In the Energy Policy Act of 2005, or EPACT 2005, Congress amended the NGA and Federal Power Act to add anti-fraud and anti-manipulation requirements. EPACT 2005 prohibits the use of any “manipulative or deceptive device or contrivance” in connection with the purchase or sale of natural gas, electric energy or transportation subject to FERC jurisdiction. FERC adopted market manipulation and market behavior rules to implement the authority granted under EPACT 2005. These rules, which prohibit fraud and manipulation in wholesale energy markets, are subject to broad interpretation. Given FERC's broad mandate granted in EPACT 2005, if energy prices are high, or exhibit what FERC deems to be “unusual” trading patterns, FERC may investigate energy markets to determine if behavior unduly impacted or “manipulated” energy prices.

In addition, EPACT 2005 gave FERC increased penalty authority for violations of the NGA and FERC's rules and regulations thereunder. FERC may issue civil penalties of up to $1 million per day per violation, and violators may be subject to criminal penalties of up to $1 million per violation and five years in prison. FERC may also order disgorgement of profits obtained in violation of FERC rules. FERC relies on its enforcement authority in issuing a number of natural gas enforcement actions. Failure to comply with the NGA and FERC's rules and regulations thereunder could result in the imposition of civil penalties and disgorgement of profits.

Under the NGA and the National Environmental Policy Act of 1969, FERC has broad authority to approve the construction of new interstate natural gas pipeline facilities, including imposing environmental conditions on certificates of public convenience and necessity. New pipeline infrastructure projects could face increased scrutiny and enhanced regulatory reviews by federal, state and/or environmental regulators due to an increased focus on climate change policies and the fossil fuel industry. While we do not currently have projects pending that are subject to material risk, any governmental or regulatory actions that place additional burdens and/or costs on future projects, could adversely impact our ability to develop new infrastructure.

Intrastate Natural Gas Pipeline Regulation

Intrastate natural gas pipeline operations are not generally subject to rate regulation by FERC, but they are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate gas pipelines to provide service that is not unduly discriminatory and to file and/or seek approval of their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. For example, our Guadalupe system and Gulf Coast Express pipeline are intrastate pipelines regulated as a gas utility by the Railroad Commission. To the extent that an intrastate pipeline system transports natural gas in interstate commerce, the rates and terms and conditions of such interstate transportation service are subject to FERC rules and regulations under Section 311 of the Natural Gas Policy Act, or NGPA. Certain of our systems are subject to FERC jurisdiction under Section 311 of the NGPA for their interstate transportation services. Section 311 regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline on behalf of a local distribution company or an interstate natural gas pipeline. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest. Rates for service pursuant to Section 311 of the NGPA are generally subject to review and approval by FERC at least once every five years. Additionally, the terms and conditions of service set forth in the intrastate pipeline’s Statement of Operating Conditions are subject to FERC approval. Non-compliance with FERC's rules and regulations established under Section 311 of the NGPA, including failure to observe the service limitations applicable to transportation services provided under Section 311, failure to comply with the rates approved by FERC for Section 311 service, and failure to comply with the terms and conditions of service established in the pipeline's FERC-approved Statement of Operating Conditions could result in the imposition of civil and criminal penalties. Among other matters, EPACT 2005 also amended the NGPA to give FERC authority to impose civil penalties for violations of the NGPA up to $1 million for any one violation and violators may be subject to criminal penalties of up to $1 million per violation and five years in prison.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We believe that our natural gas gathering facilities meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services continues to be a current issue in various FERC proceedings with respect to facilities that interconnect gathering and processing plants with nearby interstate pipelines, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC and the courts. State regulation of gathering facilities generally includes various safety, environmental, and, in many circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

Our purchasing, gathering and intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which they operate. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels where FERC has recognized a jurisdictional exemption for the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other Laws - Texas Weather Emergencies

In 2021, in response to Winter Storm Uri in February 2021, the State of Texas implemented new laws related to preparing for, preventing and responding to weather emergencies and power outages. Under the new law, several state agencies, including the Railroad Commission, the Public Utilities Commission of Texas ("TPUC"), and the Energy Reliability Council of Texas ("ERCOT") are required to coordinate and implement new rules and processes related to weather emergencies impacting gas-fired electric generation and the natural gas production and supply chain. The Railroad Commission and TPUC implemented rules related to the critical designation of natural gas infrastructure and electric service to such critical infrastructure during an emergency. The Railroad Commission designated natural gas processing plants, natural gas pipelines and related facilities, and natural gas storage, in addition gas production and distribution facilities, as critical. We are obligated to develop a listing of our critical natural gas facilities and update it semi-annually. Electric utilities are obligated to review our critically designated facility listings and establish priorities during load shed events. The law further requires the agencies to "map" the supply chain of natural gas to electric generation facilities; natural gas facilities that are deemed critical to the supply of electricity will be required to implement measures to prepare to operate during a winter weather emergency ("weatherize"). The agencies are still in the process of identifying such facilities and developing the weatherization rules. Our facilities may be subject to further physical and operational weatherization requirements if such facilities are deemed critical to the supply of electric generation. We cannot anticipate at this time what facilities, if any, will be required to weatherize and the economic costs of additional weatherization. We are actively engaged in industry associations and the rulemaking processes as the agencies implement their obligations and new rules pursuant to the new law.

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our interstate purchases and sales of natural gas, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or CFTC. Should we violate the anti-market manipulation laws and regulations, in additional to civil and criminal penalties, we could be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Interstate NGL Pipeline Regulation

Certain of our pipelines, including Sand Hills and Southern Hills, are common carriers that provide interstate NGL transportation services subject to FERC regulation. FERC regulates interstate common carriers under its Oil Pipeline Regulations, the Interstate Commerce Act of 1887, as amended, or ICA, and the Elkins Act of 1903, as amended. FERC requires that common carriers file tariffs containing all the rates, charges and other terms for services provided by such pipelines. The ICA requires that tariffs apply to the interstate movement of NGLs, as is the case with the Sand Hills, Southern Hills, Black Lake, Wattenberg and Front Range pipelines. Pursuant to the ICA, rates must be just, reasonable, and nondiscriminatory, and can be challenged at FERC either by protest when they are initially filed or increased or by complaint at any time they remain on file with FERC.

In October 1992, Congress passed EPACT, which among other things, required FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for pipelines regulated by FERC pursuant to the ICA. FERC responded to this mandate by issuing several orders, including Order No. 561 that enables common carrier pipelines to charge rates up to their ceiling levels, which are adjusted annually based on an inflation index. Specifically, the indexing methodology requires a pipeline to adjust the ceiling level for its rates annually by the inflation index established by the FERC. FERC reviews the indexing methodology every five years, and in 2020, the indexing methodology for the five years beginning July 1, 2021 was changed to be the Producer Price Index for Finished Goods plus 0.78%; however, after considering rehearing requests, the FERC revised its decision and adjusted the five-year index to the Producer Price Index minus 0.21%. The new ceiling levels and revised tariff rates implementing the revised index are required to be filed with FERC effective March 1, 2022. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, the pipeline is required to reduce its rate to comply with the lower ceiling unless doing so would reduce a rate "grandfathered" under EPACT below the grandfathered level. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. FERC, however, retained cost-of-service ratemaking, market-based rates, and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances. The ceiling levels calculated for our interstate NGL pipelines are typically increased each year pursuant to the indexing methodology, but may be subject to decrease, which occurred in 2016 and 2021 and resulted in the decrease in many of the tariff rates for such pipelines. The ceiling levels for our interstate NGL pipelines will be further decreased effective March 1, 2022, as a result of the revised 2021 index; however, many of the tariff rates are below the ceiling level and will remain unchanged. The index effective July 1, 2022, is expected to be positive based on estimates of the Producer's Price Index for Finished Goods.

Intrastate NGL Pipeline Regulation

NGL and other common carrier petroleum pipelines that provide intrastate transportation services are subject to regulation by various agencies in the respective states where they are located. While the regulatory regime varies from state to state, state agencies typically require intrastate petroleum pipelines to file tariffs and their rates with the agencies and permit shippers to challenge existing rates or proposed rate increases. For example, certain of our pipelines have tariffs filed with the Railroad Commission for their intrastate NGL transportation services. The intrastate tarriffs for many of our intrastate NGL pipelines rely on the FERC indexing methodology for annual adjustments to rates when the index is positive and remain unchanged when the index is negative.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, compressing, treating, processing, transporting, fractionating, storing or selling natural gas, NGLs and other products is subject to stringent and complex federal, state and local laws and regulations governing the emission or discharge of materials into the environment or otherwise relating to the protection of the environment.

As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the acquisition of permits or authorizations to conduct regulated activities and imposing obligations in those permits, potentially including capital expenditures or operational requirements, that reduce or limit impacts to the environment;
- requiring changes or additions to our equipment or facilities, or changes to our operations, pursuant to government-promulgated regulations to protect the environment, including air quality and reduction of greenhouse gases;
- restricting the ways that we can handle or dispose of our wastes;
- limiting or prohibiting construction or operational activities in sensitive areas such as wetlands, coastal regions or areas inhabited by threatened and endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining, or compelling changes to, the operations of facilities deemed not to be in compliance with environmental regulations or with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil, or potentially criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, potential citizen lawsuits, and the issuance of orders enjoining or affecting current or future operations. Certain environmental statutes impose strict liability or joint and several liability for costs required to clean up and restore sites where hazardous substances, or in some cases hydrocarbons, have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for property damage or personal injury allegedly caused by the release of substances or other waste products into the environment.

The overall trend in federal and state environmental programs is to expand regulatory requirements, placing more restrictions and limitations on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations, participate as applicable in the public process to ensure such new requirements are well-founded and reasonable or seek to revise them if they are not, and to manage the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. Below is a discussion of the more significant environmental laws and regulations that relate to our business.

Impact of Air Quality Standards and Climate Change

A number of states have adopted or considered programs to reduce greenhouse gases, or GHGs, which includes methane. Depending on the particular program or jurisdiction, we could be required to purchase and surrender allowances, either for GHG emissions resulting from our operations (e.g., compressor units) or from downstream combustion of fuels (*e.g.*, NGLs or natural gas) that we process, or we may otherwise be required by regulation to take steps to reduce emissions of GHGs.

At the federal level, the EPA has taken several actions to regulate emissions of GHGs. In 2010, the EPA found that certain GHGs “endanger” public health and welfare and that GHG vehicle emissions contribute to the GHG pollution threatening public health and welfare, thus triggering regulation of GHG emissions from mobile sources such as cars and trucks. The EPA's 2010 action on the GHG vehicle emission rule triggered regulation of carbon dioxide and other GHG emissions from stationary sources under certain Clean Air Act programs at both the federal and state levels, including the Prevention of Significant Deterioration (“PSD”) program and Title V permitting. Most recently, in 2016, the EPA proposed PSD and Title V permitting regulations that would address control of GHG emissions if certain thresholds are met. While EPA has not finalized the rule, states such as Colorado have adopted similar requirements. The EPA also has issued various rules relating to the mandatory reporting of GHG emissions, including mandatory reporting requirements of GHGs from petroleum and natural gas systems, which encompasses all segments of the oil and gas sector.

The EPA has adopted federal new source performance standards ("NSPS") for new and modified oil and gas sector sources that regulate emissions of VOCs and methane from these sources. EPA promulgated the NSPS for VOCs in 2012 and the NSPS for VOCs and methane in 2016. The regulations, contained in 40 CFR Part 60, Subpart OOOO and OOOOa, require, among other things, control of VOC and methane emissions from subject sources through ensuring adequate design, requiring installation of emission controls, and institution of leak detection and repair programs. In November 2021, EPA proposed regulations that expand the scope and breadth of the existing regulations. The 2021 proposed rules include provisions that: 1) extend emission control and reduction requirements under this part of the Clean Air Act to existing sources, which is a first; and 2) expand and tighten the existing emission reduction requirements for new or modified sources adopted in 2012 and 2016. EPA has also requested information for a supplemental proposal in 2022 that may expand or modify the 2021 proposed rules.

States' efforts to comply with the National Ambient Air Quality Standard ("NAAQS") for ozone, which is set by the EPA, also may have an impact on our operations. States or areas of a state that are not in attainment with the ozone NAAQS are required to approve implementation plans that reduce emissions of ozone precursors in order to achieve compliance with the NAAQS, which plans can impose emissions control requirements and associated costs on us or on our customers. In October 2015, the EPA finalized a reduction of the ambient ozone standard from 75 parts per billion to 70 parts per billion under the Clean Air Act, and in December 2018 EPA published a final rule "Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area State Implementation Plan Requirements." The EPA in October 2016 issued Control Techniques Guidelines ("CTGs") for emissions of volatile organic compounds from oil and gas sector sources that were to be implemented or utilized by states in ozone nonattainment areas. Under the Trump Administration, the EPA on December 31, 2020, issued a final rule retaining the 2015 standard at 70 parts per billion. However, in late 2021, the EPA communicated that it would reconsider the 2020 decision to retain the ozone NAAQS with the intention of completing the reconsideration by the end of 2023. If the ozone NAAQS is lowered, it may result in additional actions by states requiring further emission controls and associated costs.

In relation to addressing the ozone NAAQS but more specifically greenhouse gas emissions, on January 29, 2019, the New Mexico governor issued an executive order establishing an interagency Climate Change Task Force and directing the Energy, Minerals and Natural Resources Department ("EMNRD") and the New Mexico Environment Department ("NMED") to develop a statewide, enforceable regulatory framework to reduce methane emissions from new and existing sources in the oil and gas sector. The Oil Conservation Division ("OCD") adopted the EMNRD rules in mid-2021, which institute gas capture requirements for both upstream and midstream operators, prohibit routine flaring, and require operation plans for operators of gas gathering systems. The NMED proposed draft regulations to the Environmental Improvement Board ("EIB") in May 2021 crafted with the intention of preventing the state falling into non-attainment with the ozone NAAQS by controlling ozone precursor pollutants, including volatile organic compounds ("VOCs") and nitrogen oxides ("NOx"), from the oil and gas industry, which regulations are also anticipated to control or reduce methane emissions. The evidentiary hearing before the EIB was completed October 1, 2021, with the final rules anticipated in spring 2022. Although the EIB has yet to finalize the rule, we anticipate that the NMED rule will impose additional operational costs and potential regulatory compliance and enforcement risks.

Similarly, Colorado has undertaken various rulemakings to address compliance with and attainment of the ozone NAAQS, including regulations in 2019 and 2020 to reduce emissions of NOx and VOCs from the oil and gas sector. These regulations, as an example, impose emissions standards on our compressor engines in the Ozone Non-Attainment Area, which, in turn, requires the installation of emissions control technologies and work practice standards to manage emissions. Further, in 2019 the Colorado legislature enacted HB19-1261 establishing statewide greenhouse gas emission reduction goals and included agency authorities and mandates to promulgate regulations to achieve greenhouse gas reduction goals. In January 2021 the governor issued the "Greenhouse Gas Pollution Reduction Roadmap," which describes state actions and the regulatory pathway to achieve the HB19-1261 greenhouse gas reduction goals. The Greenhouse Gas Reduction Roadmap specifies, among other things, intended reductions by economic sector, including the oil and gas sector as well as the "residential, commercial and industrial" sector that includes emissions from the combustion of fuels. In 2021, Governor Polis signed HB21-1266 into law, which includes environmental justice provisions and requirements for adoption of rules for reduction of greenhouse gas ("GHG") emissions from "oil and gas exploration, production, processing, transmission, and storage operations" by at least 36% by 2025 and 60% by 2030 below a 2005 baseline. These administrative and regulatory actions have been and will be pursued by various state agencies, including the Colorado Energy Office and the Colorado Air Quality Control Commission ("AQCC"). In December 2021, the AQCC adopted regulations to reduce GHGs from the oil and gas sector through myriad requirements to address emissions and control requirements, including emissions reduction requirements for production well sites, and capture requirements for pigging activities and capture and control requirements for equipment blowdowns. The AQCC also adopted requirements for a Steering Committee to assess methods and feasibility to reduce GHG emissions from industrial combustion of hydrocarbon fuels, specifically including oil and gas sector compression equipment to gather and transport natural gas, ultimately resulting in plans and regulations for oil and gas sector industrial combustion equipment to achieve the HB21-1266 reduction goals.

The regulations in New Mexico and Colorado collectively are anticipated to impose near- and longer-term obligations and costs on our producer customers as well as on our own midstream equipment and facilities. These rulemaking proceedings to reduce greenhouse gas emissions could increase costs on or inhibit or adversely influence the ability of our producer customers to develop and operate production wells. These rulemaking proceedings could increase costs for us to operate our compressor stations or gas plants in the respective states, and they could affect the types of equipment or the manner in which we operate our midstream equipment. These rulemaking proceedings, or future related rulemaking proceedings, have the potential to result in some manner of greenhouse gas emissions caps in the state, or greenhouse gas sector-specific performance standards, either of which could result in increased costs on our producer customers or increased costs on us to operate our facilities, and could affect the types of equipment that we operate or the manner in which it is operated. These rulemaking proceedings have the potential to affect the operations and production of our customers, which can in turn affect our operations, and they also have the potential to affect our costs and facility operations, either of which could adversely affect our financial results or have such an effect on our operations.

The Clean Air Act imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of air pollution also provide varying administrative, civil and potentially criminal penalties and liabilities. The permitting, regulatory compliance and reporting programs, including those detailed above, taken as a whole, increase the costs and complexity of oil and gas operations with potential to adversely affect the cost of doing business for our customers resulting in reduced demand for our gas processing and transportation services, and which may also require us to incur certain capital and operating expenditures in the future to meet regulatory requirements or for air pollution control equipment, for example, in connection with obtaining and maintaining operating permits and approvals for air emissions associated with our facilities and operations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, or solid or hazardous wastes, or petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict liability or joint and several liability for the investigation and remediation of areas at a facility where hazardous substances, or in some cases hydrocarbons, may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and companies that disposed or arranged for the disposal of, or transported the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to public health or the environment and to seek to recover from the responsible parties the costs that the agency incurs. Despite the "petroleum exclusion" of CERCLA Section 101(14), which encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum and natural gas production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, may in the future be designated by the EPA as hazardous wastes and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our sustaining capital expenditures and operating expenses.

We currently own or lease properties where petroleum hydrocarbons are being or have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under the other locations where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and wastes disposed or released thereon may be subject to CERCLA, RCRA and analogous state laws, or separate state laws that address hydrocarbon releases. Under these laws, we could be required to remove or remediate releases of hydrocarbon materials, or previously disposed wastes (including wastes disposed of or released by prior owners or operators), or to clean up contaminated property (including contaminated groundwater) or to contribute to or perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our financial condition or results of operations.

Water

The Federal Water Pollution Control Act of 1972, as amended, also referred to as the Clean Water Act, or CWA, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state and federal waters. The CWA also requires implementation of spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of threshold quantities of oil or certain other materials. The CWA imposes substantial potential civil and criminal penalties for non-compliance. State laws for the control of water pollution also provide varying administrative, civil and potentially criminal penalties and liabilities. In addition, some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater. The EPA has also promulgated regulations that require us to have permits in order to discharge certain storm water. The EPA has entered into agreements with certain states in which we operate whereby the permits are issued and administered by the respective states. These permits may require us to monitor and sample the storm water discharges. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our financial condition or results of operations.

The Oil Pollution Act of 1990, or OPA, which is part of the Clean Water Act, addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities, including natural gas gathering and processing facilities, terminals, pipelines, and transfer facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages, and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in government penalties and civil liability. We are not currently aware of any facts, events or conditions relating to the application of such requirements that could reasonably have a material impact on our financial condition or results of operations.

Anti-Terrorism Measures

The United States Department of Homeland Security regulates the security of chemical and industrial facilities pursuant to regulations known as the Chemical Facility Anti-Terrorism Standards. These regulations apply to oil and gas facilities, among others, that are deemed to present "high levels of security risk." Pursuant to these regulations, certain of our facilities are required to comply with certain regulatory provisions, including requirements regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

Human Capital Management

We recognize that our continued ability to attract and retain highly skilled employees, while maintaining an industry-leading corporate culture, helps to ensure our long-term competitive advantage and our ability to create value for our unitholders. We take pride in our dedicated efforts to create and support a vibrant and safe culture that provides opportunities for our employees to thrive professionally and in their communities. We are committed to promoting an organizational culture that encourages the highest ethical standards of personal, professional, and business conduct.

Our commitment to our purpose of building connections to enable better lives; our vision of being the safest, most reliable, low-cost midstream service provider; and our cultural hallmarks of trust, connection, inspiration, problem-solving, and achievement guide our actions and behaviors. Dedication to our cultural hallmarks are weighted equally to the performance metrics utilized in each leader’s and employee’s annual review process, ensuring that what we do matters as much as how we do it.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which is managed by its general partner, DCP Midstream GP, LLC, (the “General Partner”), which is 100% owned by DCP Midstream, LLC. We do not have any employees. As of December 31, 2021, 1,788 employees of DCP Services, LLC, a wholly-owned subsidiary of DCP Midstream, LLC, provided support for our operations pursuant to the Services and Employee Secondment Agreement between DCP Services, LLC and us (the “Services Agreement”). For additional information, refer to Item 10. “Directors, Executive Officers and Corporate Governance” and Item 13. “Certain Relationships and Related Transactions, and Director Independence” in this Annual Report on Form 10-K.

Benefits and compensation

Our compensation program is designed to attract and reward talented individuals who possess the skills necessary to support our business objectives, assist in the achievement of our goals and create long term value for our unitholders. We incentivize our employees by providing market competitive total compensation packages, including salaries, bonuses, opportunities for equity ownership, and benefits, including comprehensive medical plan options; dental, vision and life insurance; 401(k) savings matches and retirement contributions; vacation, sick, personal and wellness days; tuition and gym membership reimbursement, voluntary insurance, an employee-matching charitable gifts program, an employee assistance program and additional programs through DCP Perks. We use voluntary turnover as a key measure to track and reduce the turnover of key and critical employees, which was 7.9% in 2021.

Training and development

We believe that the high performance of our employees is a byproduct of our employees honing the skills and tools necessary to manage change and prepare for the future, and we are dedicated to the continual growth of our employees through training and development programs. We provide growth opportunities to all employees through programs ranging from individual development plans, rotational programs, tuition reimbursement, and a focused effort on succession planning tailored to each employee’s unique vision of success. Our performance review and talent development process is one in which managers provide regular feedback and coaching to assist with the development of our employees, including the use of individual development plans to assist with individual career development.

Safety, Health and Wellness

Safety is the first tenet of our vision to be the safest, most reliable, low-cost midstream service provider, and is our highest value. The importance of the safety of our employees and contractors is exemplified in our compensation structure, as every executive and employee has been directly incentivized to achieve industry-leading safety performance since 2007. Our Start SAFE Finish SAFE (“SSFS”) program provides a framework to ensure employees and contractors are starting and finishing each task or job safely. In conjunction with our SSFS program, we also have an environmental, health and safety management system database that is used to track and communicate safety related activities and events, such as audits, injuries, incidents, and near misses, including incident investigation observations and responsive actions. The Company uses the employee Total Recordable Incident Rate (“TRIR”) which is the number of Occupational Safety and Health Administration (OSHA) recordable injuries per 200,000 hours worked as an indicator of its performance. DCP is consistently a leader in the midstream industry for safety performance. In 2021 the company had a TRIR of 0.33.

Our COVID-19 pandemic response focused on increased cleaning procedures, social distancing guidelines, symptom check stations, limiting outside visitors, increased personal protection equipment, modified work schedules to limit employees in the offices, and remote working for all corporate employees.

We provide our employees with access to a variety of innovative, flexible and convenient health and wellness programs. These programs are designed to support employees' physical and mental health through tools and resources to help them improve their health and encourage engagement in healthy behaviors.

Inclusion and Diversity

We are committed to advancing inclusion and diversity ("I&D") in our workplace and driving accountability for progress throughout the Company. Our leadership is dedicated to maintaining an inclusive workplace that is free from harassment and discrimination and providing advancement opportunities for all employees. In 2020, we established an internal I&D committee that is comprised of over 100 volunteers, and sponsored by our Chief Executive Officer ("CEO") and Chief Human Resources Officer ("CHRO"), the purpose of which is "to create equity and belonging for everyone, everywhere". To inform the recommended actions of the I&D committee, we conducted a voluntary, company-wide inclusion survey with a 76% response rate, an employee satisfaction score of 80, and a belonging score of 75, both higher than external benchmarks. Additionally, we support a variety of internal employee resource groups, including our Leadership Development Network, and the Business Women's Network. Notably, in the fourth quarter of 2020, we appointed the first female director to the board of directors of our General Partner.

The Company demonstrated corporate leadership on inclusion and diversity by setting the following forward-looking goals during 2021. Our Inclusion and Diversity strategy consists of a 2028 target to ensure our workforce and leadership fully represents the gender and racial demographics of the industry within the communities in which we operate. A 2031 target to ensure that our internal leadership succession pipeline reflects the gender and racial demographics of the industry within the communities where we operate. Ensure representation of our veteran communities aligns with national demographics. As well as, maintain employee satisfaction and belonging scores above industry benchmark.

As part of our work to meet these goals, we piloted immersive, virtual reality experiences across our organization. As a result, we have partnered with Moth+Flame and the National Urban League to create and roll-out field-focused content to further our employees' understanding and engagement in our I&D efforts. Finally, our CEO became a member of "CEO in Action" in June of 2021, joining over 2,000 CEOs in the commitment to making I&D a business imperative through clear strategy, deliberate focus and sustained action.

General

We make certain filings with the SEC, including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports, which are available free of charge on the internet at www.sec.gov or through our website, *www.dcpmidstream.com*, as soon as reasonably practicable after they are filed with the SEC. Our annual reports to unitholders, press releases and recent analyst presentations are also available free of charge on our website. Information regarding our ESG, corporate responsibility and sustainability initiatives is also available on our website at www.dcpmidstream.com/sustainability. We have also posted our Code of Business Ethics, board committee charters and other corporate governance documents on our website. Our website and the information contained on that site, or connected to that site, are not incorporated by reference into this report.

Item 1A. *Risk Factors*

Risk Factors Summary
The following is a summary of the principal risk factors that could adversely affect our business, operations and financial results. These risks include, but are not limited to, the following:

Risks Related to Our Business and Industry

Risks Related to Our Operations
- We face numerous risks related to the COVID-19 pandemic, which could have a material adverse effect on our business, financial condition, liquidity, results of operations and prospects.
- Market conditions, including commodity prices, may impact our earnings, financial condition and cash flows.
- We could incur losses due to impairment in the carrying value of our long-lived assets.
- A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our results of operations and financial condition.
- We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs.
- Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs.
- Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport, process or produce natural gas and NGLs.
- We may incur significant costs and liabilities resulting from implementing and administering pipeline and asset integrity programs and related repairs.
- Our assets and operations, and related upstream and downstream operations, can be affected by weather, weather-related conditions and other natural phenomena.
- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to continue to make cash distributions to our unitholders.
- We have partial ownership interests in various joint ventures, which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.
- Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Risks Related to Our Strategy
- We may not be able to grow or effectively manage our growth.

Legal, Regulatory and Technology Risks
- Federal executive, legislative, and regulatory initiatives relating to oil and gas operations could adversely affect our operations and those of our third-party customers.
- State and local legislative and regulatory initiatives relating to oil and gas operations including legislative and regulatory initiatives in New Mexico and Colorado could adversely affect our third-party customers’ production and, therefore, adversely impact our midstream operations.
- We may incur significant costs and liabilities in the future resulting from a failure to comply with existing or new environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.
- Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.
- We may incur significant costs in the future associated with proposed climate change regulation and legislation.
- Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas and natural gas liquids that we gather, process and transport.
- Our increasing dependence on digital technology puts us at risk for a cyber incident that could result in information theft, data corruption, operational disruption or financial loss.
- Our business could be negatively impacted by security threats, including cybersecurity threats, terrorist attacks, the threat of terrorist attacks and related disruptions.

Risks Related to Our Indebtedness
- A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

- Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.
- Restrictions in our debt agreements may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.
- Our significant indebtedness and the restrictions in our debt agreements may adversely affect our future financial and operating flexibility.
- It is unclear how changes in the regulation of LIBOR or the discontinuation of LIBOR all together may affect our financing costs in the future.

Risks Inherent in an Investment in Our Units

- Conflicts of interest may exist between our individual unitholders and DCP Midstream, LLC, the owner of our general partner, which has sole responsibility for conducting our business and managing our operations.
- DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.
- Our Partnership Agreement limits our general partner's fiduciary duties to holders of our units.
- Our Partnership Agreement restricts the remedies available to holders of our units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.
- Holders of our units have limited voting rights and are not entitled to elect our general partner or its directors.
- Our units may experience price volatility.
- Our Partnership Agreement restricts the voting rights of our unitholders owning 20% or more of any class of our units.
- We may generally issue additional units, including units that are senior to our common units, without our unitholders' approval, which would dilute our unitholders' existing ownership interests.
- Our general partner including its affiliates may sell units in the public or private markets, which could reduce the market price of our outstanding common units.

Tax Risks to Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.
- The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.
- Unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.

Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may impair our business, financial condition, results of operations and cash flows.

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this Annual Report on Form 10-K for the year ended December 31, 2021 in evaluating an investment in our common units.

If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially affected. In that case, we might not be able to pay distributions on our units, the trading price of our units could decline and you could lose all or part of your investment.

Risks Related to Our Business and Industry

Risks Related to Our Operations

We face numerous risks related to the COVID-19 pandemic, which could have a material adverse effect on our business, financial condition, liquidity, results of operations and prospects.

Since the beginning of 2020, the COVID-19 pandemic has disrupted economies around the world, including the oil, gas and NGL industry in which we operate. The rapid spread of the virus has led to the implementation of various responses, including federal, state and local government-imposed quarantines, shelter-in-place mandates, sweeping restrictions on travel, and other public health and safety measures. The extent to which the COVID-19 pandemic impacts our operations will depend on future developments, which are highly uncertain and cannot be predicted with confidence, including the duration of the pandemic, additional or modified government actions, new information that may emerge concerning the severity of COVID-19, the actions taken to contain the spread of COVID-19 and treat its impact, and the availability and acceptance of vaccines to mitigate the spread of COVID-19, among others.

Some factors from the COVID-19 pandemic that could have an adverse effect on our business, financial condition, liquidity and results of operations, include:

- third-party effects, including contractual and counterparty risk;
- supply/demand market and macro-economic forces;
- lower commodity prices;
- unavailable storage capacity and operational effects, including curtailments and shut-ins;
- decreased utilization and rates for our assets and services
- impact on liquidity and access to capital markets;
- workforce reductions and furloughs; and
- federal, state and local actions.

The COVID-19 pandemic continues to evolve, and the extent to which the pandemic may impact our business, financial condition, liquidity, results of operations and prospects will depend highly on future developments, which are very uncertain and cannot be predicted with confidence. Additionally, the extent and duration of the impact of COVID-19 pandemic on our unit price is uncertain and may make us look less attractive to investors and, as a result, there may be a less active trading market for our units, our unit prices may be more volatile, and our ability to raise capital could be impaired.

Our cash flow is affected by natural gas, NGL and crude oil prices.

Our business is affected by natural gas, NGL and crude oil prices. The prices of natural gas, NGLs and crude oil have historically been volatile, and we expect this volatility to continue.

The level of drilling activity is dependent on economic and business factors beyond our control. Among the factors that impact drilling decisions are commodity prices, the liquids content of the natural gas production, drilling requirements for producers to hold leases, the cost of finding and producing natural gas and crude oil and the general condition of the financial markets. Commodity prices experienced volatility during 2021, as illustrated by the following table:

	Year Ended December 31, 2021		
	Daily High	Daily Low	December 31, 202
Commodity:			
NYMEX Natural Gas ($/MMBtu)	$ 6.31	$ 2.45	$ 3.
NGLs ($/Gallon)	$ 1.14	$ 0.59	$ 0.
Crude Oil ($/Bbl)	$ 84.65	$ 47.62	$ 75.

Market conditions, including commodity prices, may impact our earnings, financial condition and cash flows.

The markets and prices for natural gas, NGLs, condensate and crude oil depend upon factors beyond our control and may not always have a close relationship. These factors include supply of, and demand for, these commodities, which fluctuate with changes in domestic and export markets and economic conditions and other factors, including:

- the level of domestic and offshore production;
- the availability of natural gas, NGLs and crude oil and the demand in the U.S. and globally for these commodities;
- a general downturn in economic conditions;
- the impact of weather, including abnormally mild or extreme winter or summer weather that cause lower or higher energy usage for heating or cooling purposes, respectively, or extreme weather that may disrupt our operations or related upstream or downstream operations;
- actions taken by foreign oil and gas producing and importing nations, including the ability or willingness of OPEC and OPEC+ to set and maintain pricing and production levels for oil, which, for example, had a pronounced effect on global oil prices and the volatility thereof in 2020 during the onset and spread of the COVID-19 pandemic;
- the availability of local, intrastate and interstate transportation systems and condensate and NGL export facilities;

- the availability and marketing of competitive fuels; and
- the extent of governmental regulation and taxation.

The primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under percent-of-proceeds arrangements, we generally purchase natural gas from producers for an agreed percentage of the proceeds from the sale of residue gas and/or NGLs resulting from our processing activities, and then sell the resulting residue gas and NGLs at market prices. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the price of natural gas and NGLs fluctuate.

The amount of natural gas we gather, compress, treat, process, transport, store and sell, or the NGLs we produce, fractionate, transport, store and sell, may be reduced if the pipelines, storage and fractionation facilities to which we deliver the natural gas or NGLs are capacity constrained and cannot, or will not, accept the natural gas or NGLs or we may be required to find alternative markets and arrangements for our natural gas and NGLs.

The natural gas we gather, compress, treat, process, transport, sell and store, or the NGLs we produce, fractionate, transport, sell and store, are delivered into pipelines for further delivery to end-users, including fractionation facilities. If these pipelines, storage and fractionation facilities cannot, or will not, accept delivery of the gas or NGLs due to capacity constraints or changes in interstate pipeline gas quality specifications, we may be forced to limit or stop the flow of gas or NGLs through our pipelines and processing, treating, and fractionation facilities. We have long and short-term arrangements with facilities to fractionate our NGL production; however, additional fractionation capacity may be limited to the extent current and planned fractionation facilities experience delays in construction, significant mechanical or other problems arise at existing facilities, or such facilities otherwise become unavailable to us due to unforeseen circumstances. As a result, we may be required to find alternative markets and arrangements for our production and for fractionation, and such alternative markets and arrangements may not be available on favorable terms, or at all. Additionally, capacity constraints may impact production volumes from our producer customers and/or transportation volumes from our third-party NGL customers if there is insufficient fractionation or storage capacity to handle all of their projected volumes. Any number of factors beyond our control could cause such interruptions or constraints, including fully utilized capacity, necessary and scheduled maintenance, or unexpected damage to the pipelines. Because our revenues and net operating margins depend upon (i) the volumes of natural gas we process, gather and transmit, (ii) the throughput of NGLs through our transportation, fractionation and storage facilities and (iii) the volume of natural gas we gather and transport, any reduction of volumes could adversely affect our operations and cash flows available for distribution to our unitholders.

Our NGL pipelines could be adversely affected by any decrease in NGL prices relative to the price of natural gas.

The profitability of our NGL pipelines is dependent on the level of production of NGLs from processing plants. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost (principally that of natural gas as a feedstock and fuel) of separating the NGLs from the natural gas. As a result, we may experience periods in which higher natural gas prices relative to NGL prices reduce the volume of natural gas processed at plants connected to our NGL pipelines, and reduce the amount of NGL extraction, which would decrease the volumes and gross margins attributable to our NGL pipelines and NGL storage facilities.

Our hedging activities and the application of fair value measurements may have a material adverse effect on our earnings, profitability, cash flows, liquidity and financial condition.

We are exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. To mitigate a portion of our cash flow exposure to fluctuations in the price of natural gas and NGLs, we have entered into derivative financial instruments relating to the future price of natural gas and NGLs, as well as crude oil. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the portion not covered by derivative transactions. Our actual future production may be significantly higher or lower than we estimate at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimate, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, reducing our liquidity.

We record all of our derivative financial instruments at fair value on our balance sheet primarily using information readily observable within the marketplace. In situations where market observable information is not available, we may use a variety of data points that are market observable, or in certain instances, develop our own expectation of fair value. We will continue to use market observable information as the basis for our fair value calculations; however, there is no assurance that such information will continue to be available in the future. In such instances, we may be required to exercise a higher level of judgment in developing our own expectation of fair value, which may be significantly different from the historical fair values, and may increase the volatility of our earnings.

We will continue to evaluate whether to enter into any new derivative arrangements, but there can be no assurance that we will enter into any new derivative arrangement or that our future derivative arrangements will be on terms similar to our existing derivative arrangements. Additionally, although we enter into derivative instruments to mitigate a portion of our commodity price risk, we also forego the benefits we would otherwise experience if commodity prices were to change in our favor.

Our derivative instruments may require us to post collateral based on predetermined collateral thresholds. Depending on the movement in commodity prices, the amount of posted collateral required may increase, reducing our liquidity.

Our hedging activities may not be as effective as we intend and may actually increase the volatility of our earnings and cash flows. In addition, even though our management monitors our hedging activities, these activities can result in material losses. Such losses could occur under various circumstances, including if a counterparty does not or is unable to perform its obligations under the applicable derivative arrangement, the derivative arrangement is imperfect or ineffective, or our risk management policies and procedures are not properly followed or do not work as planned.

We could incur losses due to impairment in the carrying value of our long-lived assets.

We periodically evaluate long-lived assets for impairment. Our impairment analyses for long-lived assets require management to apply judgment in evaluating whether events and circumstances are present that indicate an impairment may have occurred. If we believe an impairment may have occurred judgments are then applied in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, and selecting the discount rate that reflects the risk inherent in future cash flows. In estimating cash flows, we incorporate current market information (including forecasted volumes and commodity prices), as well as historical and other factors. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to impairment charges. Adverse changes in our business or the overall operating environment, such as lower commodity prices, may affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services.

Volumes of natural gas dedicated to our systems in the future may be less than we anticipate.

If the reserves connected to our gathering systems are less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas on our systems in the future could be less than we anticipate.

We depend on certain natural gas producer customers for a significant portion of our supply of natural gas and NGLs.

We identify as primary natural gas suppliers those suppliers individually representing 10% or more of our total natural gas and NGLs supply. In 2021, our two largest suppliers of natural gas accounted for 27% of our total natural gas supply. While some of these customers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas and NGL volumes supplied by these customers, as a result of competition or otherwise, could have a material adverse effect on our business.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs.

Our gathering and transportation pipeline systems are connected to, or dependent, on the level of production from natural gas and crude wells, from which production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our gathering and transportation pipeline systems and NGL pipelines and the asset utilization rates at our natural gas processing plants, we must continually obtain new supplies. The primary factors affecting our ability to obtain new supplies of natural gas and NGLs, and to attract new customers to our assets include the level of successful drilling activity near these assets, the demand for natural gas, crude oil and NGLs, producers' desire and ability to obtain necessary permits in an efficient manner, natural gas field characteristics and production performance, surface access and infrastructure issues, and our ability to compete for volumes from successful new wells. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells or because of competition, throughput on our pipelines and the utilization rates of our treating and processing facilities would decline, which could have a material adverse effect on our business, results of operations, financial position and cash flows, and our ability to make cash distributions.

Third party pipelines and other facilities interconnected to our natural gas and NGL pipelines and facilities may become unavailable to transport, process or produce natural gas and NGLs.

We depend upon third party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Since we do not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within our control and may become unavailable to transport, process or produce natural gas and NGLs. If any of these third parties do not continue operation of these facilities or they become unavailable to us, and we are not able to obtain new facilities to transport, process or produce natural gas and NGLs, it could have a material adverse effect on our business, results of operations, financial position and cash flows, and our ability to make cash distributions.

We may not successfully balance our purchases and sales of natural gas.

We purchase from producers and other customers a substantial amount of the natural gas that flows through our natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. We may not be successful in balancing our purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause our purchases and sales to be unbalanced. While we attempt to balance our purchases and sales, if our purchases and sales are unbalanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income and cash flows.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

The partnership is a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We do not have significant assets other than equity in our subsidiaries and equity method investments. As a result, our ability to make required payments on our notes depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit instruments, applicable state business organization laws and other laws and regulations. If our subsidiaries are prevented from distributing funds to us, we may be unable to pay all the principal and interest on the notes when due.

We may incur significant costs and liabilities resulting from implementing and administering pipeline and asset integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in "high consequence areas." The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify threats to pipeline segments that could impact a high consequence area and assess the risks that such threats pose to pipeline integrity;
- collect, integrate, and analyze data regarding threats and risks posed to the pipeline;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Pipeline safety legislation enacted in 2012, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, or the Pipeline Safety and Job Creations Act, reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. New rules proposed by PHMSA address many areas of this legislation and PHMSA has indicated that it expects to publish these final rules this year. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material cost to our operations.

Although many of our natural gas facilities currently are not subject to pipeline integrity requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipelines. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, or new requirements that may be imposed as a result of the Pipeline Safety and Job Creation Act, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, we may be affected by the testing, maintenance and repair of pipeline facilities downstream from our own facilities. With the exception of our Wattenberg pipeline, our NGL pipelines are also subject to integrity management and other safety regulations imposed by the Railroad Commission.

We currently estimate that we will incur costs of approximately $121 million between 2022 and 2026 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, nor is it inclusive of estimated costs to implement the Final Gathering Rule (as defined and discussed in further detail below).

We currently transport NGLs produced at our processing plants on our owned and third party NGL pipelines. Accordingly, in the event that an owned or third party NGL pipeline becomes inoperable due to any necessary repairs resulting from integrity testing programs or for any other reason for any significant period of time, we would need to transport NGLs by other means. There can be no assurance that we will be able to enter into alternative transportation arrangements under comparable terms, if at all.

Any new or expanded pipeline integrity requirements or the adoption of other asset integrity requirements could also increase our cost of operation and impair our ability to provide service during the period in which assessments and repairs take place, adversely affecting our business. Further, execution of and compliance with such integrity programs may cause us to incur greater than expected capital and operating expenditures for repairs and upgrades that are necessary to ensure the continued safe and reliable operation of our assets.

We are exposed to the credit risks of our producer customers and counterparties, and any material nonpayment or nonperformance by our producer customers or counterparties could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our producer customers and counterparties. Any material nonpayment or nonperformance by our producer customers or counterparties could reduce our ability to make distributions to our unitholders. Furthermore, some of our producer customers or counterparties may be highly leveraged and subject to their own operating and regulatory risks, which could increase the risk that they may default on their obligations to us. Additionally, a decline in the availability of credit to producers in and surrounding our geographic footprint could decrease the level of capital investment and growth that would otherwise bring new volumes to our existing assets and facilities. Our customers or counterparties may experience rapid deterioration of their financial condition as a result of changing market conditions, commodity prices, or financial difficulties that could impact their creditworthiness and ability to perform their contractual obligations, including their ability to pay us.

Our assets and operations, and related upstream and downstream operations, can be affected by weather, weather-related conditions and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, tornadoes, wind, lightning, cold weather and other natural phenomena, which could impact our results of operations and make it more difficult for us to realize historic rates of return. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss and in some instances, we have been unable to obtain insurance on some of our assets on commercially reasonable terms, if at all. Extreme weather conditions and temperature changes may adversely impact the mechanical abilities of equipment and the volumes of natural gas gathered and processed and NGL volumes produced, transported, and fractionated. Any power interruptions and inaccessible well sites as a result of extreme weather or severe storms or freeze-offs, a phenomenon where produced water freezes at the wellhead or within the gathering system, may interrupt the flow of natural gas and NGLs. If we incur a significant disruption in our operations, or there is a significant disruption in related upstream or downstream operations, or a significant liability for which we were not fully insured, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to continue to make cash distributions to our unitholders.

The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, level of production of, and demand for natural gas, condensate, and NGLs;
- the success of our commodity and interest rate hedging programs in mitigating fluctuations in commodity prices and interest rates;
- the volume and quality of natural gas we gather, compress, treat, process, transport and sell, and the volume of NGLs we process, transport, sell and store;
- the operational performance and efficiency of our assets, including our plants and equipment;
- the operational performance and efficiency of third party assets that provide services to us;
- the relationship between natural gas, NGL and crude oil prices;
- the level of competition from other energy companies;
- the impact of weather conditions on the demand for natural gas and NGLs;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost and form of payment for acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets at reasonable rates;
- restrictions contained in our Credit Agreement and the indentures governing our notes;
- the timing of our producers' obligations to make volume deficiency payments to us;
- the amount of cash distributions we receive from our equity interests;
- the amount of cost reimbursements to our general partner;
- the amount of cash reserves established by our general partner; and
- new, additions to and changes in laws and regulations.

We have partial ownership interests in various joint ventures, which could adversely affect our ability to operate and control these entities. In addition, we may be unable to control the amount of cash we will receive from the operation of these entities and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Our inability, or limited ability, to control the operations and management of joint ventures in which we have a partial ownership interest may mean that we will not receive the amount of cash we expect to be distributed to us. In addition, for joint ventures in which we have a minority ownership interest, we will be unable to control ongoing operational decisions, including the incurrence of capital expenditures that we may be required to fund. Specifically,

- we have limited ability to control decisions with respect to the operations of these joint ventures, including decisions with respect to incurrence of expenses and distributions to us;
- these joint ventures may establish reserves for working capital, capital projects, environmental matters and legal proceedings which would reduce cash available for distribution to us;
- these joint ventures may incur additional indebtedness, and principal and interest made on such indebtedness may reduce cash otherwise available for distribution to us; and
- these joint ventures may require us to make additional capital contributions to fund working capital and capital expenditures, our funding of which could reduce the amount of cash otherwise available for distribution.

All of these items could significantly and adversely impact our ability to distribute cash to our unitholders.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow and not solely on profitability.

Profitability may be significantly affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

We do not own some of the land on which our pipelines and facilities are located, which may subject us to increased costs or disruptions to our operations.

Our pipelines and facilities are located either on land that we own in fee, or on land in which our right to use such land for our operations is derived from leases, easements, rights of way, permits, or licenses from landowners or governmental authorities either in perpetuity or for a specific period of time. We may become subject to more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or if such rights of way lapse or terminate. Certain of our leases contain renewal provisions that allow for our continued use and access of the subject land and, although we review and renew our leases as a routine business matter, there may be instances where we may not be able to renew our contract leases on commercially reasonable terms or may have to commence eminent domain proceedings to establish our right to continue to use the land. Any loss of rights with respect to land on which we operate, could disrupt our ability to continue operations thereon and adversely affect our business, results of operations, and financial position.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.

Our operations, and the operations of third parties, are subject to many hazards inherent in the gathering, compressing, treating, processing, storing, transporting and fractionating, as applicable, of natural gas and NGLs, including:

- damage to pipelines, plants, terminals, storage facilities and related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons from our pipelines, plants, terminals, or storage facilities, or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;
- contaminants in the pipeline system;
- fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks inherent to our business, including offshore wind. We insure our underground pipeline systems against property damage, although coverage on certain of our small diameter gathering pipelines is subject to usual and customary sublimits. We are not insured against all environmental accidents that might occur, which may include toxic tort claims, other than those considered to be sudden and accidental. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage, or may become prohibitively expensive, and we may elect not to carry such a policy.

Risks Related to Our Strategy

If we do not make acquisitions on economically acceptable terms, our future growth could be limited.

Our ability to make acquisitions that are accretive to our cash generated from operations per unit is based upon our ability to identify attractive acquisition candidates, negotiate acceptable purchase contracts and obtain financing for these acquisitions on economically acceptable terms. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit. Additionally, net assets contributed by DCP Midstream, LLC represent a transfer of net assets between entities under common control, and are recognized at DCP Midstream, LLC's basis in the net assets transferred. The amount of the purchase price in excess of DCP Midstream, LLC's basis in the net assets, if any, is recognized as a reduction to partners' equity. Conversely, the amount of the purchase price less than DCP Midstream's basis in the net assets, if any, is recognized as an increase to partners' equity.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, future contract terms with customers, revenues and costs, including synergies;
- an inability to successfully integrate the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- change in competitive landscape;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

In addition, any limitations on our access to substantial new capital to finance strategic acquisitions will impair our ability to execute this component of our growth strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates or underwriting discounts.

We may not be able to grow or effectively manage our growth.

Our future growth will depend upon a number of factors, some of which we can control and some of which we cannot. These factors include our ability to:

- complete construction projects and consummate accretive acquisitions or joint ventures;
- identify businesses engaged in managing, operating or owning pipelines, processing and storage assets or other midstream assets for acquisitions, joint ventures and construction projects;
- appropriately identify liabilities associated with acquired businesses or assets;
- integrate acquired or constructed businesses or assets successfully with our existing operations and into our operating and financial systems and controls;
- hire, train and retain qualified personnel to manage and operate our growing business; and
- obtain required financing for our existing and new operations at reasonable rates.

A deficiency in any of these factors could adversely affect our ability to sustain the level of our cash flows or realize benefits from acquisitions, joint ventures or construction projects. In addition, competition from other buyers could reduce our acquisition opportunities. DCP Midstream, LLC and its affiliates are not restricted from competing with us. DCP Midstream, LLC and its affiliates may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets. Furthermore, in recent years we have grown through organic projects, dropdowns and acquisitions. If we fail to properly integrate these assets successfully with our existing operations, if the future performance of these assets does not meet our expectations, if we did not properly value the assets, or if we did not identify significant liabilities associated with acquired assets, the anticipated benefits from these transactions may not be fully realized.

Acquisitions may not be beneficial to us.

Acquisitions involve numerous risks, including:

- the failure to realize expected profitability, growth or accretion;
- an increase in indebtedness and borrowing costs;
- potential environmental or regulatory compliance matters or liabilities;
- potential title issues;
- the incurrence of unanticipated liabilities and costs; and
- the temporary diversion of management’s attention from managing the remainder of our assets to the process of integrating the acquired businesses.

Assets recently acquired will also be subject to many of the same risks as our existing assets. If any of these risks or unanticipated liabilities or costs were to materialize, any desired benefits of these acquisitions may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

Legal, Regulatory and Technology Risks

Federal executive, legislative, and regulatory initiatives relating to oil and gas operations could adversely affect our operations and those of our third-party customers.

The Biden Administration has signaled an intention to take a more rigorous approach to environmental regulations as well as permitting reviews, particularly as they related to air quality and climate issues. It is expected that enforcement under the Biden EPA will be more common and EPA will seek greater penalties and injunctive relief requirements than under the Trump EPA. President Biden issued Executive Order 13990 in January 2021, which directed executive departments and agencies to review all existing regulations, orders, guidance documents, policies and any other similar action taken during the previous Administration that are inconsistent with President Biden’s plan to elevate climate issues and, as appropriate, suspend, revise, or rescind those that are inconsistent with that plan. Those initial actions included the revocation of certain prior Executive Orders concerning federal regulation executed by the previous Administration, as well as new Executive Orders directing a focused regulatory freeze and review of rulemaking actions taken by the prior Administration. In addition, in January 2021, President Biden issued Executive Order 14088 which imposed a moratorium on new oil and gas leases on public lands and offshore waters, pending a comprehensive review and reconsideration of oil and gas permitting and leasing practices, prompting the Bureau of Land Management to cancel all first and second quarter lease sales in 2021. That same Order directed a government-wide effort to address climate change by reducing greenhouse gas emissions and achieving net-zero global carbon emissions by mid-century or before. That effort is designed to infuse climate policy in all aspects of federal decision-making, including specific directives that touch for example on foreign policy, national security, financial regulation, federal procurement, infrastructure, and environmental justice.

The moratorium on new oil and gas leases has been challenged in court, including in Louisiana federal district court in a lawsuit filed in March 2021 by officials representing 13 states and in Wyoming federal district court in a similar lawsuit by officials representing the State of Wyoming and various trade organizations. In June 2021, the court ordered that plans be resumed for oil and gas lease sales for the Gulf of Mexico and Alaska. The Bureau of Land Management proceeded with an oil and gas lease sale on approximately eighty million acres of the Gulf of Mexico in November 2021. Meanwhile, the Biden Administration has appealed the Louisiana federal district court’s ruling to the 5th Circuit Court of Appeals. Other judicial challenges are ongoing. For example, North Dakota filed a lawsuit in federal district court in North Dakota in July 2021, seeking to compel the Biden Administration to reschedule two lease sales that were canceled in North Dakota and to restrain the Administration from revoking other sales in the future.

In November 2021, the U.S. Department of the Interior published a report in response to Executive Order 14088 that proposed reforms to the federal oil and gas leasing program that would increase royalties, rental rates, bonus bids and minimum bond amounts for oil and gas leases on public lands. Some of the proposed changes can be made through future lease sale notices, such as royalty increases, while other policies will require an act of Congress. The report stopped short of recommending a permanent ban on leasing public lands, and includes a number of proposed reforms that, if pursued administratively, might draw legal challenge as exceeding the agency's statutory authority. Nonetheless, it is expected that climate and environmental justice considerations may well become part of future federal oil and gas lease permitting decisions.

On November 15, 2021, PHMSA published a Final Rule amending the gas pipeline safety regulations at 49 CFR Parts 191 and 192 to extend regulation over larger diameter gas gathering pipelines located in rural (Class 1) locations (the "Final Gathering Rule"). The Final Gathering Rule imposes Part 191 or Part 192 requirements on such rural gathering pipelines. All rural gathering pipelines will be subject to annual and incident reporting under Part 191, while those pipelines over 8.625 inches in diameter that are operated at a maximum allowable operating pressure ("MAOP") of more than 20% of specified minimum yield strength ("SMYS") or, where SMYS is not known, where the MAOP exceeds 125 psig, must also comply with certain Part 192 requirements. The applicable Part 192 requirements increase with increased diameter and with proximity to buildings intended for human occupancy or impacted sites. For gathering pipelines between 8.625 inches and 16 inches in diameter, the new regulations require annual and incident reporting, as well as design and construction standards, damage prevention, and emergency planning on new pipelines or those that are repaired or replaced or otherwise substantially changed. If the potential impact radius of the pipeline segment includes a building intended for human occupancy or an impacted site, corrosion control, line markers, public awareness and leakage survey and repair for pipelines of less than 12.75 inches in diameter are also added, and MAOP requirements and standards for plastic pipelines for lines are added for pipelines between 12.75 inches and 16 inches in diameter. Pipelines of more than 16 inches in diameter are subject to all of the above, whether or not the potential impact radius includes any structures intended for human occupancy or impacted sites. The Part 191 reporting requirements of the Final Gathering Rule take effect on May 16, 2022, with the remaining Part 192 requirements taking effect on November 15, 2022 or May 16, 2023.

In November 2021, EPA proposed the expansion of the federal new source performance standards ("NSPS") for new and modified, and existing, oil and gas sector sources that regulate emissions of VOCs and methane from these sources. EPA had promulgated enhanced NSPS regulations for VOCs in 2012 and the NSPS for VOCs and methane in 2016. The regulations, contained in 40 CFR Part 60, Subpart OOOO and OOOOa, among other things, require control of VOC and methane emissions from subject sources through ensuring adequate design, requiring installation of emission controls, and institution of leak detection and repair programs. EPA's November 2021 proposed regulations would expand the scope and breadth of the existing regulations. The 2021 proposed rules include provisions that: 1) extend emission control and reduction requirements under this part of the Clean Air Act to existing oil and gas sources, which is a first; and 2) expand and tighten the existing emission reduction requirements for new or modified oil and gas sources adopted in 2012 and 2016. EPA has also requested information for a supplemental proposal in 2022 that may expand or modify the 2021 proposed rules.

The Biden Administration is also pursuing the enactment of sweeping legislative policy and spending priorities, including the Build Back Better Act, which as passed by the House in November includes a number of provisions that could impact oil and gas development generally while also incentivizing investment in certain renewable energy projects. At present, the legislation is pending in the Senate.

In the event federal executive or legislative initiatives result in increased federal lease costs or requirements, restrictions or prohibitions that apply to our areas of operations, our customers may incur increased compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells. Any adverse impact on our customers' activities could have a corresponding negative impact on our throughput volumes. In addition, certain administrative rules and legislative proposals specifically target existing law and direct future federal rulemaking activity that may, if adopted, directly impact our ability to competitively locate, construct, maintain, and operate our own assets. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows and ability to make distributions to our unitholders.

State agency rulemakings in New Mexico could increase our operational costs, and potentially impact new oil and gas development activity by our producer customers.

On January 29, 2019, the New Mexico governor issued an executive order establishing an interagency Climate Change Task Force and directing the Energy, Minerals and Natural Resources Department ("EMNRD") and the New Mexico Environment Department ("NMED") to develop a statewide, enforceable regulatory framework to reduce methane emissions from new and existing sources in the oil and gas sector. Following a year-long stakeholder process by both agencies, the Oil Conservation Division ("OCD") adopted the EMNRD rules in mid-2021, which institute gas capture requirements for both upstream and midstream operators, prohibit routine flaring, and require operation plans for operators of gas gathering systems.

NMED proposed draft regulations to the Environmental Improvement Board (“EIB”) in May 2021 regarding regulations and control of ozone precursor pollutants, including volatile organic compounds (“VOCs”) and nitrogen oxides (“NOx”), from the oil and gas industry, which are also anticipated to control or reduce methane emissions. The evidentiary hearing before the EIB was completed October 1, 2021, with the final rules anticipated in spring 2022. The EMNRD rules impose additional operational requirements and costs, and potential regulatory compliance and enforcement risk, on our facilities and operations. Although the EIB has yet to finalize the rule, we anticipate that the NMED rule will impose additional operational costs and potential regulatory compliance and enforcement risks. Similarly, our customers are expected to incur compliance costs of their own under these rules and may, if out of compliance, experience delays or curtailment in the pursuit of their exploration, development, or production activities. Any adverse impact on our customers’ activities could have a corresponding negative impact on our throughput volumes. Accordingly, such restrictions or prohibitions could have an adverse effect on our business, prospects, results of operations, financial condition, cash flows and ability to make distributions to our unitholders.

State and local legislative and regulatory initiatives relating to oil and gas operations could adversely affect our third-party customers’ production and, therefore, adversely impact our midstream operations.

Certain states in which we operate have adopted or are considering adopting measures that could impose new or more stringent requirements on oil and gas exploration and production activities. For example, the potential for adverse impacts to our business is present where local governments have enacted ordinances directly regulating pipeline assets and operations, and private individuals have sponsored and may in the future sponsor citizen initiatives to limit hydraulic fracturing, increase mandatory setbacks of oil and gas operations from occupied structures, and achieve more restrictive state or local control over such activities.

In the event state or local restrictions or prohibitions are adopted in our areas of operations, our customers may incur significant compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells altogether. Any adverse impact on our customers’ activities would have a corresponding negative impact on our throughput volumes. In addition, while the general focus of debate is on upstream development activities, certain proposals may, if adopted, directly impact our ability to competitively locate, construct, maintain, and operate our own assets. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows and ability to make distributions to our unitholders.

Laws and corresponding rulemakings in Colorado could have a material adverse impact on new oil and gas development in the state and could reduce the demand for our services in the state.

On April 16, 2019, the Colorado governor signed into law Senate Bill 19-181 (“SB-181”), which amended existing laws and enacted new laws concerning the conduct of oil and gas operations in Colorado. The bill changed the mandate of the Colorado Oil and Gas Conservation Commission (the “COGCC”) to regulate oil and gas development in a manner that protects the public health, safety, welfare, and the environment and wildlife, from the previous mandate to foster the development and production of oil and gas. Other key elements of SB-181 include granting local governments ability to regulate facility siting and surface impacts of oil and gas operations as well as the ability to inspect and impose fines for leaks, spills, and emissions, and requiring the Colorado Department of Public Health and Environment (the “CDPHE”) to adopt additional rules that call for the minimization and continual monitoring of emissions at oil and gas facilities. SB-181 also requires the COGCC to conduct rulemakings concerning the cumulative impacts of oil and gas development, additional flowline regulations, as well as other matters.

The COGCC completed the most significant rulemaking to implement SB-181 in late 2020, with a final SB-181 rulemaking concerning financial assurance to be completed in early 2022. These new rules are focused on upstream oil and gas development, and as a whole touch on nearly every aspect of oil and gas development activity. Due to the scope and complexity of the rules, the COGCC has issued guidance materials that will be central to achieving successful rule implementation. Although our customers have expressed confidence in their ability to conform to the rules and move forward with predictable development plans, the number of drilling permits issued by the COGCC slowed considerably in 2021 as staff began reviewing permit applications in accordance with the new rules. We expect the approval of well permit applications to improve as operators and COGCC staff both gain experience with the new regulatory regime, and because our customers are increasingly focused on permitting comprehensive area plans that will allow for the approval of a larger number of wells as part of larger long-term development plans.

While much of our oil and gas infrastructure in Colorado is not located near populous areas, the population in Colorado continues to grow, which may result in populated areas coming closer to existing and proposed oil and gas development. Notably, Weld County has exercised the authority granted under SB-181 to enact its own local siting and permitting regulatory framework, in a manner that is intended to and has allowed for continued oil and gas development in the jurisdiction where the majority of our assets are located. However, local regulations enacted under SB-181 do not supplant the COGCC's authority over well permitting and approval, and thus even in Weld County our customers may experience additional costs or delays associated with obtaining those state permits. Any such impact on new oil and gas development, would, as production from existing and previously permitted wells depletes, lead to a reduction in demand for our gathering, processing, and transportation services in the state, which reduction, over time, may be material.

In addition, in 2019 the Colorado legislature enacted HB19-1261 establishing statewide greenhouse gas emission reduction goals and included agency authorities and mandates to promulgate regulations to achieve greenhouse gas reduction goals. In January 2021 the governor issued the "Greenhouse Gas Pollution Reduction Roadmap," which describes state actions and the regulatory pathway to achieve the HB19-1261 greenhouse gas reduction goals. The Greenhouse Gas Reduction Roadmap specifies, among other things, intended reductions by economic sector, including the oil and gas sector as well as the "residential, commercial and industrial" sector that includes emissions from the combustion of fuels. In 2021, the governor signed HB21-1266 into law, which includes environmental justice provisions and requirements for adoption of rules for reduction of greenhouse gas ("GHG") emissions from "oil and gas exploration, production, processing, transmission, and storage operations" by at least 36% by 2025 and 60% by 2030 below a 2005 baseline. These administrative and regulatory actions have been and will be pursued by various state agencies, including the Colorado Energy Office and the Colorado Air Quality Control Commission ("AQCC"). In December 2021, the AQCC adopted regulations to reduce GHGs from the oil and gas sector through myriad requirements to address emissions and control requirements, including emissions reduction requirements for production well sites, and capture requirements for pigging activities and capture and control requirements for equipment blowdowns. The AQCC also adopted requirements for a Steering Committee to assess methods and feasibility to reduce GHG emissions from industrial combustion of hyrdrocarbon fuels, specifically including oil and gas sector compression equipment to gather and transport natural gas, ultimately resulting in plans and regulations for oil and gas sector industrial combustion equipment to achieve the HB21-1266 reduction goals. These regulations collectively are anticipated to impose near- and longer-term obligations and costs on our producer customers as well as on our own midstream equipment and facilities. These rulemaking proceedings to reduce greenhouse gas emissions could increase costs on or inhibit or adversely influence the ability of our producer customers to develop and operate production wells. These rulemaking proceedings could increase costs for us to operate our compressor stations or gas plants in the state, and they could affect the types of equipment or the manner in which we operate our midstream equipment. These rulemaking proceedings, or future related rulemaking proceedings, have the potential to result in some manner of greenhouse gas emissions caps in the state, or greenhouse gas sector-specific performance standards, either of which could result in increased costs on our producer customers or increased costs on us to operate our facilities, and could affect the types of equipment that we operate or the manner in which it is operated. These rulemaking proceedings have the potential to affect the operations and production of our customers, which can in turn affect our operations, and they also have the potential to affect our costs and facility operations, either of which could adversely affect our financial results or have such an effect on our operations.

We may incur significant costs and liabilities in the future resulting from a failure to comply with existing or new environmental regulations or an accidental release of hazardous substances or hydrocarbons into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example: (i) the federal Clean Air Act and comparable state laws and regulations, including federal and state air permits, that impose obligations related to air emissions; (ii) RCRA, and comparable state laws that impose requirements for the management, storage and disposal of solid and hazardous waste from our facilities; (iii) CERCLA, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal; (iv) the Clean Water Act and the Oil Pollution Act, and comparable state laws and regulations that impose requirements on discharges to waters as well as requirements to prevent and respond to releases of hydrocarbons to waters of the United States and regulated state waters; and (v) state laws that impose requirements on the response to and remediation of hydrocarbon releases to soil or groundwater and managing related wastes. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining or affecting current or future operations. Certain environmental laws and regulations, including CERCLA and analogous state laws and regulations, impose strict liability and joint and several liability for costs required to clean up and restore sites where hazardous substances, and in some cases hydrocarbons, have been disposed or otherwise released.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas, NGLs and other petroleum products, air emissions related to our operations, and historical industry operations and waste management and disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, governmental claims for natural resource damages or imposing fines or penalties for related violations of environmental laws, permits or regulations. In addition, it is possible that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance or third-party indemnification.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets.

The majority of our natural gas gathering and intrastate transportation operations are exempt from FERC regulation under the NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines, however there can be no assurance that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transportation services and federally unregulated gathering services has been the subject of regular litigation, so the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on any reassessment by us of the jurisdictional status of our facilities or on future determinations by FERC and the courts.

In addition, the rates, terms and conditions of some of the transportation services we provide on certain of our pipeline systems are subject to FERC regulation under Section 311 of the NGPA. Under Section 311, rates charged for transportation must be fair and equitable, and amounts collected in excess of fair and equitable rates are subject to refund with interest.

Several of our pipelines are interstate transporters of NGLs and are subject to FERC jurisdiction under the Interstate Commerce Act and the Elkins Act. The base interstate tariff rates for our NGL pipelines are determined either by a FERC cost-of-service proceeding or by agreement with an unaffiliated party, and adjusted annually through the FERC's indexing methodology. The NGL pipelines may also provide incentive rates, which offer tariff rates below the base tariff rates for high volume shipments.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and disgorgement of profits. Under EPACT 2005, FERC has civil penalty authority under the NGA to impose penalties of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation and five years in prison. Under the NGPA, FERC may impose civil penalties of up to $1 million for any one violation and may impose criminal penalties of up to $1 million and five years in prison.

Other state and local regulations also affect our business. Our non-proprietary gathering lines are subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our proprietary gathering lines are currently subject to limited state regulation, there is a risk that state laws will change, which may give producers a stronger basis to challenge the proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

The interstate tariff rates of certain of our pipelines are subject to review and possible adjustment by federal regulators.

FERC, pursuant to the NGA, regulates many aspects of our interstate natural gas pipeline transportation service, including the rates our pipelines are permitted to charge for such service. Under the NGA, interstate transportation rates must be just and reasonable and not unduly discriminatory. If FERC fails to permit our requested tariff rate increases, or if FERC lowers the tariff rates we are permitted to charge, on its own initiative, or as a result of challenges raised by customers or third parties, our tariff rates may be insufficient to recover the full cost of providing interstate transportation service. In certain circumstances, FERC also has the power to order refunds.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and the disgorgement of profits. Under EPACT 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation and five years in prison.

The transportation rates for our NGL pipelines that provide interstate transportation services, our interstate natural gas pipelines, and our intrastate pipelines that provide interstate services under Section 311 of the NGPA could be adversely impacted by FERC's revised income tax allowance policy for partnership pipelines and the federal law reducing the corporate income tax rate.

Effective January 1, 2018, the federal corporate tax rate was reduced to 21%, and in March 2018, FERC issued a revised policy statement disallowing an income tax allowance in the cost-of-service rates for partnership-owned pipelines. Previously, FERC's policy generally permitted partnership pipelines to recover an income tax allowance in a cost-of-service proceeding before FERC if the pipeline's ultimate owners had income tax liability. The maximum cost-based rates for our interstate natural gas pipelines and intrastate pipelines that provide interstate transportation services could be adversely affected in future rate proceedings as a result of the change in policy and law. For interstate oil and NGL pipelines, FERC considered the impacts of the tax policy and law changes on an industry-wide basis during the 2020 calendar year through its indexing methodology review. Additionally, any new cost-based rates for our pipelines regulated by the FERC will be affected by the new policy and tax law.

Recently proposed or finalized rules imposing more stringent requirements on the oil and gas industry could cause our customers and us to incur increased capital expenditures and operating costs as well as reduce the demand for our services.

EPA had promulgated enhanced New Source Performance Standards ("NSPS") regulations for the oil and gas sector to control volatile organic compounds ("VOCs") in 2012, and an NSPS for VOCs and methane in the oil and gas sector in 2016. The regulations, contained in 40 CFR Part 60, Subpart OOOO and OOOOa, among other things, require control of VOC and methane emissions from subject sources through ensuring adequate design, requiring installation of emission controls, and institution of leak detection and repair programs. EPA's 2016 regulatory action imposed leak detection and repair requirements for VOCs and methane on producer well site equipment and on midstream equipment such as compressor and booster stations, imposed additional emission reduction requirements on specific pieces of oil and gas equipment, and was a regulatory pre-condition to the EPA acting to regulate existing oil and gas methane sources in the future under Section 111(d) of the Clean Air Act. In November 2021, EPA proposed revisions of the federal NSPS for oil and gas sector sources that regulate emissions of VOCs and methane. EPA's November 2021 proposed regulations would expand the scope and breadth of the existing regulations, including: 1) the extension of emission control and reduction requirements under this part of the Clean Air Act to existing oil and gas sources, which is a first; and 2) expansion and tightening of the existing emission reduction requirements for new or modified oil and gas sources adopted in 2012 and 2016. EPA has also requested information for a supplemental proposal in 2022 that may expand or modify the 2021 proposed rules.

States' efforts to comply with the National Ambient Air Quality Standard ("NAAQS") for ozone, which is set by the EPA, also may have an impact on our operations. States or areas of a state that are not in attainment with the ozone NAAQS are required to approve implementation plans that reduce emissions of ozone precursors in order to achieve compliance with the NAAQS, which plans can impose emissions control requirements and associated costs on us or on our customers. The EPA revised and lowered the ozone NAAQS from 75 to 70 parts per billion in 2015, and on December 31, 2020, the EPA issued a final rule retaining the 2015 standard. In late 2021, the EPA communicated that it would reconsider the 2020 decision to retain the ozone NAAQS with the intention of completing the reconsideration by the end of 2023. If the ozone NAAQS is lowered, it may result in additional actions by states requiring further emission controls and associated costs. States are required to evaluate compliance with 70 parts per billion standard and, if not met, to adopt implementation plans to reduce emissions of ozone-forming pollutants, like VOCs and nitrogen oxides ("NOx"), that are emitted from, among others, the oil and gas industry. Persistent non-attainment status, such as for ozone, can result in lower major source permitting thresholds (making it more costly and complex to site and permit major new or modified facilities) and additional emissions control requirements. In October 2016, the EPA also finalized Control Techniques Guidelines ("CTGs") for VOC emissions from existing oil and natural gas equipment and processes in moderate ozone non-attainment areas. These CTGs provide recommendations for states and local air agencies to consider when determining what emissions control requirements apply to sources in the non-attainment areas.

In Colorado, including Weld County, EPA has classified the Denver Metro/North Front Range as "serious" nonattainment for the 2008 ozone standard and "marginal" nonattainment for the 2015/2020 ozone standard. Based on recent ambient air data, it is expected that the area will be classified as “severe” nonattainment for the 2008 ozone standard sometime in 2022. The nonattainment status of this area has resulted in reduction of the major source threshold and adoptions of regulations designed to reduce ozone precursor emissions, including regulations adopting provisions of the CTGs and other regulations focused on reducing VOC and NOx emissions from the oil and gas industry. Further rulemakings from the Colorado Air Quality Control Commission are expected to reduce emissions of VOCs and NOx from the oil and gas sector as part of the State’s Implementation Plan to come into compliance with the ozone standards.

New Mexico instituted a rulemaking in 2021 with the intention of preventing the state from falling into non-attainment with the ozone NAAQS by controlling ozone precursor pollutants, VOCs and NOx, from the oil and gas industry, which regulations are also anticipated to control or reduce methane emissions. The evidentiary hearing before the New Mexico Environmental Improvement Board was completed October 1, 2021, with the final rules anticipated in spring 2022. Although the Environmental Improvement Board has yet to finalize the rule, we anticipate that the rule will impose additional operational costs and potential regulatory compliance and enforcement risks.

States can initiate and promulgate regulations affecting oil and gas operations and associated emissions, either as a matter of their own statutory authority and programs or when implementing federal programs, such as the federal ozone ambient air quality standard or the federal Regional Haze regulation. Judicial challenges to new regulatory measures can occur, and we cannot predict the outcome of such challenges. New regulatory suspensions, revisions, or rescissions, as well as new regulations, and conflicting state and federal regulatory mandates may inhibit our ability to accurately forecast the costs associated with future regulatory compliance. Collectively, implementation of more stringent regulations could require modifications to the operations of our exploration and production customers, as well as our operations, including the installation of new equipment and new emissions management practices, which could result in significant additional costs, both increased capital expenditures and operating costs. These regulations could also affect the permitting of, or the emissions control requirements in permits for our customers’ facilities and equipment, or our facilities and equipment. The incurrence of such expenditures and costs by our customers could also result in reduced production by those customers and thus translate into reduced demand for our services, which could in turn have an adverse effect on our business and cash available for distributions.

We may incur significant costs in the future associated with proposed climate change regulation and legislation.

The United States Congress and some states where we have operations may consider legislation or regulations related to greenhouse gas emissions, including methane emissions, which may compel reductions of such emissions. In addition, there have been international conventions and efforts to establish standards for the reduction of greenhouse gases globally, including the Paris accords in December 2015. The conditions for entry into force of the Paris accords were met on October 5, 2016 and the Agreement went into force 30 days later on November 4, 2016. More recently, at the United Nations Climate Change Conference in Glasgow (COP26) in 2021, the United States and the European Union announced the Global Methane Pledge that aims to limit methane emissions by 30% compared with 2020 levels.

At the federal level, legislative proposals have included or could include limitations, or caps, on the amount of greenhouse gas that can be emitted, as well as a system of emissions allowances. For example, legislation passed by the U.S. House of Representatives in 2010, which was not taken up by the Senate, would have placed the entire burden of obtaining allowances for the carbon content of NGLs on the owners of NGLs at the point of fractionation. Most recently with respect to legislation, in 2021 the Biden Administration proposed the Build Back Better Act, which as passed by the House in November includes a number of provisions that could impact oil and gas development generally with respect to climate change and costs and requirements associated with greenhouse gas emissions, while also incentivizing investment in certain renewable energy projects. At present, the legislation is pending in the Senate. In 2011, EPA proposed greenhouse gas permitting requirements for stationary sources under certain Clean Air Act programs at both the federal and state levels, including the Prevention of Significant Deterioration (“PSD”) program and Title V permitting, although that rule was challenged. Following from that challenge, in 2016 the EPA proposed PSD and Title V permitting regulations that would address control of GHG emissions if certain thresholds are met. While EPA has not finalized the rule, states such as Colorado have adopted similar requirements. Separately, in 2011 EPA issued rules requiring reporting of greenhouse gases, on an annual basis, for certain onshore natural gas and oil production facilities, and in October 2015, EPA amended and expanded those greenhouse gas reporting requirements to all segments of the oil and gas industry effective January 1, 2016. In June 2013, President Obama announced a climate action plan that targeted methane emissions from the oil and gas industry as part of a comprehensive interagency methane reduction strategy, and in June 2016, the EPA expanded the NSPS regulations for new or modified oil and gas sources of VOCs to include methane emissions, which, among other things, imposes leak detection and repair requirements for VOCs and methane on producer well site equipment and on midstream equipment such as compressor and booster stations, imposes additional emission reduction requirements on specific pieces of oil and gas equipment, and is a regulatory pre-condition to the EPA acting to regulate existing oil and gas methane sources in the future under Section 111(d) of the Clean Air Act. In November 2021, EPA proposed revisions to the federal NSPS for oil and gas sector sources that regulate emissions of VOCs and methane. EPA's November 2021 proposed regulations would expand the scope and breadth of the existing regulations, including: 1) the extension of emission control and reduction requirements under this part of the Clean Air Act to existing oil and gas sources, which is a first; and 2) expansion and tightening of the existing emission reduction requirements for new or modified oil and gas sources adopted in 2012 and 2016. EPA has also requested information for a supplemental proposal in 2022 that may expand or modify the 2021 proposed rules.

Similarly, some states can initiate and promulgate regulations affecting oil and gas operations and associated greenhouse gas emissions as a matter of their own statutory authority and programs. For example, in 2019, the Colorado legislature passed House Bill 19-1261, the "Climate Action Plan to Reduce Pollution" that sets greenhouse gas emission reduction targets for the state, and included agency authorities and mandates to promulgate regulations to achieve greenhouse gas reduction goals. In January 2021 the governor issued the "Greenhouse Gas Pollution Reduction Roadmap," which describes state actions and the regulatory pathway to achieve the HB19-1261 greenhouse gas reduction goals. The Greenhouse Gas Reduction Roadmap specifies, among other things, intended reductions by economic sector, including the oil and gas sector as well as the "residential, commercial and industrial" sector that includes emissions from the combustion of fuels. In 2021, Governor Polis signed HB21-1266 into law, which includes environmental justice provisions and requirements for adoption of rules for reduction of greenhouse gas ("GHG") emissions from "oil and gas exploration, production, processing, transmission, and storage operations" by at least 36% by 2025 and 60% by 2030 below a 2005 baseline. These administrative and regulatory actions have been and will be pursued by various state agencies, including the Colorado Energy Office and the Colorado Air Quality Control Commission ("AQCC"). In December 2021, the AQCC adopted regulations to reduce GHGs from the oil and gas sector through myriad requirements to address emissions and control requirements, including emissions reduction requirements for production well sites, and capture requirements for pigging activities and capture and control requirements for equipment blowdowns. The AQCC also adopted requirements for a Steering Committee to assess methods and feasibility to reduce GHG emissions from industrial combustion of hydrocarbon fuels, specifically including oil and gas sector compression equipment to gather and transport natural gas, ultimately resulting in plans and regulations for oil and gas sector industrial combustion equipment to achieve the HB21-1266 reduction goals.

New regulations, as well as new regulatory suspensions, revisions, or rescissions, and conflicting state and federal regulatory mandates may inhibit our ability to accurately forecast the costs associated with future regulatory compliance. To the extent legislation is enacted or additional regulations are promulgated that regulate greenhouse gas emissions, it could significantly increase our costs to (i) acquire allowances; (ii) design, permit and construct new large facilities; (iii) operate and maintain our facilities; (iv) install new emission controls or institute emission reduction measures; and (v) manage a greenhouse gas emissions program. If such legislation becomes law or additional rules are promulgated in the United States or any states in which we have operations and we are unable to pass these costs through as part of our services, it could have an adverse effect on our business and cash available for distributions.

Increased regulation of hydraulic fracturing could result in reductions, delays or increased costs in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas and natural gas liquids that we gather, process and transport.

Certain of our customers' natural gas is developed from formations requiring hydraulic fracturing as part of the completion process. Fracturing is a process where water, sand, and chemicals are injected under pressure into subsurface formations to stimulate hydrocarbon production. While the underground injection of fluids is regulated by the EPA under the Safe Drinking Water Act, or SDWA, hydraulic fracturing is excluded from regulation except where the injection fluid is diesel fuel. The EPA has published an interpretive memorandum and permitting guidance related to regulation of fracturing fluids using this regulatory authority. Over the past several years, the EPA has finalized various regulatory programs directed at hydraulic fracturing. For example, in June 2016, the EPA issued regulations under the federal Clean Water Act to further regulate wastewater discharges from hydraulic fracturing and other natural gas production to publicly-owned treatment works. States can propose or promulgate regulations or enact initiatives or legislation imposing conditions or restrictions on hydraulic fracturing practices or oil and gas well development using hydraulic fracturing or horizontal drilling techniques. The adoption of new laws or regulations imposing reporting obligations on, or otherwise limiting or regulating, the hydraulic fracturing process could make it more difficult for our customers to complete oil and natural gas wells in shale formations and increase their costs of compliance. Several states in which our customers operate have also adopted regulations requiring disclosure of fracturing fluid components or otherwise regulate their use more closely. In Oklahoma, induced seismicity from injection of fluids in wastewater disposal wells has resulted in regulatory limitations on wastewater disposal into such wells. The implementation of rules relating to hydraulic fracturing could result in increased expenditures for our exploration and production customers, which could cause them to reduce their production and thereby result in reduced demand for our services by these customers.

President Biden has taken action to roll back many of the policies and regulations that the Trump administration had put in place to ease burdens on the development or use of domestically produced energy resources. President Biden issued Executive Order 13990 on January 20, 2021, directing executive departments and agencies to review all existing regulations, orders, guidance documents, policies and any other similar action taken during the Trump administration that are inconsistent with President Biden's plan to elevate climate issues and, as appropriate, suspend, revise, or rescind those that are inconsistent with that plan. Our customers will continue to be subject to uncertainty associated with new regulatory measures as well as new regulatory suspensions, revisions, or rescissions and conflicting state and federal regulatory mandates, which could adversely affect their production and thereby result in reduced demand for our services by these customers.

Construction of new assets is subject to regulatory, environmental, political, legal, economic, civil protest, and other risks that may adversely affect our financial results.

The construction of new midstream facilities or additions or modifications to our existing midstream asset systems involves numerous regulatory, environmental, political, legal, and economic uncertainties beyond our control and may require the expenditure of significant amounts of capital. For example, public participation in review and permitting processes can introduce uncertainty and additional costs associated with project timing and completion. Relatedly, civil protests regarding environmental and social issues, including construction of infrastructure associated with fossil fuels, may lead to increased legislative and regulatory initiatives and review at federal, state, and local levels of government that could prevent or delay the construction of such infrastructure and realization of associated revenues. Construction expenditures may occur over an extended period of time, yet we will not receive any material increases in cash flow until the project is completed and fully operational. Moreover, our cash flow from a project may be delayed or may not meet our expectations. These projects may not be completed on schedule or within budgeted cost, or at all. We may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for, and development of, natural gas and oil reserves, we often do not have access to third party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct new systems or additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, these facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. The construction of new systems or additions to our existing gathering and transportation assets may require us to obtain new rights-of-way prior to constructing these facilities. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. The construction of new systems or additions to our existing gathering and transportation assets may also require us to obtain various regulatory approvals. For example, under the NGA and the National Environmental Policy Act of 1969, FERC has broad authority to approve the construction of new interstate natural gas pipeline facilities, including imposing environmental conditions on certificates of public convenience and necessity. New pipeline infrastructure projects could face increased scrutiny and enhanced regulatory reviews by federal, state and/or environmental regulators due to an increased focus on climate change policies and the fossil fuel industry. While we do not currently have projects pending that are subject to material risk, any governmental or regulatory actions that place additional burdens and/or costs on future projects, could adversely impact our ability to develop new infrastructure. The construction of new systems or additions to our existing gathering and transportation assets may require us to rely on third parties downstream of our facilities to have available capacity for our delivered natural gas and NGLs. If such third-party facilities are not constructed or operational at the time that the addition to our facilities is completed, we may experience adverse effects on our results of operations and financial condition. The construction of additional systems may require greater capital investment if the commodity prices of certain supplies, such as steel, increase. Construction also subjects us to risks related to the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control that could adversely affect results of operations, financial position or cash flows.

Our increasing dependence on digital technology puts us at risk for a cyber incident that could result in information theft, data corruption, operational disruption or financial loss.

We are increasingly reliant on digital technology to run our business and operate our assets. Our DCP 2.0 digital transformation includes a focus on increasing the use of digital technology in all aspects of our business. We use digital technology to conduct certain of our plant operations, to monitor pipelines, compressors, pumps, meters, and other operating assets, to record financial and operating data, and to maintain various information databases relating our business. Our service providers are also increasingly reliant on digital technology. Our and their reliance on this technology increasingly puts us at risk for technology system failures, telecommunication, data, and network disruptions, and cyberattacks and other breaches in cybersecurity, which could significantly impair our ability to conduct our business. Any such events could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability. As these cyber-risks continue to evolve and our dependence on digital technology grows, we may be required to expend significant additional resources to continue to modify or enhance our protective measures and remediate cyber vulnerabilities.

Our business could be negatively impacted by security threats, including cybersecurity threats, terrorist attacks, the threat of terrorist attacks and related disruptions.

We face a variety of security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable. Cybersecurity threats are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

We face the threat of future terrorist attacks on both our industry in general and on us, including the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. The increased security measures we have taken as a precaution against possible terrorist attacks have resulted in increased costs to our business. Any physical damage to facilities or cyber incidents resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our business and cash flows. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Risk Related to Our Indebtedness

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

A downgrade of our credit rating could increase our cost of borrowing under our Credit Agreement and could require us to post collateral with third parties, including our hedging arrangements, which could negatively impact our available liquidity and increase our cost of debt.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold our securities, although such credit ratings may affect the market value of our debt instruments. Ratings are subject to revision or withdrawal at any time by the ratings agencies.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We continue to have the ability to incur additional debt, subject to limitations within our Credit Agreement. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- an increased amount of cash flow will be required to make interest payments on our debt;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to obtain new debt funding or service our existing debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, in addition to market interest rates. If our operating results are not sufficient to service our current or future indebtedness, we may take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

Restrictions in our debt agreements may limit our ability to make distributions to unitholders and may limit our ability to capitalize on acquisitions and other business opportunities.

Our debt agreements contain covenants limiting our ability to make distributions, incur indebtedness, grant liens, make acquisitions, investments or dispositions and engage in transactions with affiliates. Furthermore, our Credit Agreement contains covenants requiring us to maintain a certain leverage ratio and meet certain other tests. Any subsequent replacement of our debt agreements or any new indebtedness could have similar or greater restrictions. If our covenants are not met, whether as a result of reduced production levels of natural gas and NGLs as described above or otherwise, our financial condition, results of operations and ability to make distributions to our unitholders could be materially adversely affected.

Changes in interest rates may adversely impact our ability to issue additional equity or incur debt, as well as the ability of exploration and production companies to finance new drilling programs around our systems.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could impair our ability to issue additional equity or incur debt to make acquisitions, and for other purposes. Increased interest costs could also inhibit the financing of new capital drilling programs by exploration and production companies served by our systems.

It is unclear how changes in the regulation of LIBOR or the discontinuation of LIBOR altogether may affect our financing costs in the future.

The Credit Agreement and the Securitization Facility both bear interest based on pricing grids tied to the London Interbank Offered Rate (“LIBOR”). Additionally, our three series of preferred limited partner units convert from fixed percentage distributions to distributions that accumulate an annual floating rate of the three-month LIBOR plus a spread of 5.148% (Series A starting in December 2022), 4.919% (Series B starting in June 2023), and 4.882% (Series C starting in October 2023), respectively. In May 2023, our 5.85% Fixed-to-Floating Rate Junior Subordinated Notes due 2043 (our "Subordinated Notes") are to convert from a fixed percentage of interest to interest based on an annual floating rate of the three-month LIBOR plus a spread of 3.85%. On December 31, 2021, however, ICE Benchmark Administration Limited (the “IBA”), the administrator for LIBOR, permanently ceased publishing LIBOR with respect to one-week and two-month U.S. dollar LIBOR settings, and will permanently cease publishing LIBOR with respect to all other U.S. dollar LIBOR settings (overnight, one-month, three-month, six-month and 12-month U.S. dollar LIBOR settings) on June 30, 2023. Accordingly, in the near future, LIBOR will cease being a widely used benchmark interest rate. The current and any future reforms will cause LIBOR to be replaced with a new benchmark or and may cause LIBOR to perform differently than in the past during the transition period. The Credit Agreement contemplates a process for transitioning from LIBOR, and the Securitization Facility has been amended to provide for the transition from LIBOR, but the consequences of these market developments cannot be entirely predicted and a transition from LIBOR, even if administered consistent with the Credit Agreement and the Securitization Facility, could increase the cost of our variable rate indebtedness.

In addition, any other legal or regulatory changes made by the United Kingdom's Financial Conduct Authority (the "FCA"), the IBA, the European Money Markets Institute (formerly Euribor-EBF), the European Commission or any other successor governance or oversight body, or future changes adopted by such body, in the method by which LIBOR is determined or the transition from LIBOR to a successor benchmark may result in, among other things, a sudden or prolonged increase or decrease in LIBOR, a delay in the publication of LIBOR, and changes in the rules or methodologies in LIBOR, which may discourage market participants from continuing to administer or to participate in LIBOR’s determination. This could result in LIBOR no longer being determined and published. Because one-week and two-month U.S. dollar LIBOR rates become unavailable on December 31, 2021, and all other U.S. dollar LIBOR rates will be unavailable after June 30, 2023, after such times, the interest rate on our Credit Agreement and Securitization Facility will need to be determined using alternative methods, which may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on any outstanding debt under the Credit Agreement or the Securitization Facility if U.S. dollar LIBOR were available in its current form. Further, the same costs and risks that led to the discontinuation or unavailability of U.S. dollar LIBOR may make one or more alternative methods of calculating interest impossible or impracticable to determine. As a result, any of these consequences may have an adverse effect on our financing costs.

Finally, our Subordinated Notes are to convert from a fixed percentage of interest to interest based on an annual floating rate of three-month LIBOR plus a spread of 3.85% in May 2023. The Subordinated Notes have no fallback provisions providing for an alternative interest rate when LIBOR becomes unavailable after June 30, 2023. In April 2021, the State of New

York approved legislation covering contracts that are governed by New York law and have no fallback provisions for determination of interest rates upon LIBOR becoming unavailable. That legislation provides a statutory framework to replace LIBOR with a benchmark rate based on the Secured Overnight Financing Rate ("SOFR"). In December 2021, the United States House of Representatives passed HR 4616, which also provides such a statutory framework that, for the most part, parallels the New York legislation. For the federal legislation to become law, it must be passed by the United States Senate and signed by the President. There can be no assurance that the Senate will pass such legislation, that the President will sign such legislation, or as to the final form of any federal legislation. Because the Subordinated Notes are governed by New York law, the New York legislation will apply to the determination of the replacement rate for LIBOR under the Subordinated Notes, unless federal legislation is passed that preempts the New York legislation. There can be no assurance about how the legislation that is adopted will be implemented, or as to the ultimate replacement interest rate that will apply to our Subordinated Notes when LIBOR becomes unavailable.

The outstanding senior notes and junior subordinated notes, or notes, are unsecured obligations of our operating subsidiary, DCP Midstream Operating, LP, or DCP Operating, and are not guaranteed by any of our subsidiaries. As a result, our notes are effectively junior to DCP Operating's existing and future secured debt and to all debt and other liabilities of its subsidiaries.

The outstanding senior notes and junior subordinated notes, or notes, are unsecured obligations of our operating subsidiary, DCP Midstream Operating, LP, or DCP Operating, and are not guaranteed by any of our subsidiaries. As a result, our notes are effectively junior to DCP Operating's existing and future secured debt and to all debt and other liabilities of its subsidiaries.

The 3.875% Senior Notes due 2023, 5.375% Senior Notes due 2025, 5.625% Senior Notes due 2027, 5.125% Senior Notes due 2029, 8.125% Senior Notes due 2030, 3.25% Senior Notes due 2032, 6.450% Senior Notes due 2036, 6.750% Senior Notes due 2037, and 5.60% Senior Notes due 2044, or the Senior Notes, are senior unsecured obligations of DCP Operating and rank equally in right of payment with all of its other existing and future senior unsecured debt and effectively junior to any of its future secured indebtedness to the extent of the collateral securing such indebtedness. The 5.85% Fixed-to-Floating Rate Junior Subordinated Notes due 2043 are junior subordinated obligations of DCP Operating and rank junior in right of payment with all of its other existing and future senior unsecured debt. All of our operating assets are owned by our subsidiaries, and none of these subsidiaries guarantee DCP Operating's obligations with respect to the notes. Creditors of DCP Operating's subsidiaries may have claims with respect to the assets of those subsidiaries that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or bankruptcy proceeding, the claims of those creditors would be satisfied prior to making any such distribution or payment to DCP Operating in respect of its direct or indirect equity interests in such subsidiaries. Consequently, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of our notes. As of December 31, 2021, DCP Operating's subsidiaries had no debt for borrowed money owing to any unaffiliated third parties, other than the amounts borrowed under the Securitization Facility. Such subsidiaries are not prohibited under the indentures governing the notes from incurring indebtedness in the future.

In addition, because our notes and our guarantees of our notes are unsecured, holders of any secured indebtedness of us would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of our notes. Currently, we do not have any secured indebtedness, with the exception of our Securitization Facility. Although our debt agreements place some limitations on our ability to create liens securing debt, there are significant exceptions to these limitations that will allow us to secure significant amounts of indebtedness without equally and ratably securing the notes. If we incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, our assets would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on our notes. Consequently, any such secured indebtedness would effectively be senior to our notes and our guarantee of our notes, to the extent of the value of the collateral securing the secured indebtedness. In that event, our noteholders may not be able to recover all the principal or interest due under our notes.

Our significant indebtedness and the restrictions in our debt agreements may adversely affect our future financial and operating flexibility.

As of December 31, 2021, our consolidated principal indebtedness was $5,435 million. Our significant indebtedness and any additional debt we may incur in the future may adversely affect our liquidity and therefore our ability to make interest payments on our notes and distributions on our units.

Debt service obligations and restrictive covenants in our Credit Agreement, and the indentures governing our notes may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs as well as our ability to make distributions to our unitholders. In addition, this leverage may make our results of operations more susceptible to adverse economic or operating conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

If we incur any additional indebtedness, including trade payables, that ranks equally with our notes, the holders of that debt will be entitled to share ratably with the holders of our notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of us or DCP Operating. This may have the effect of reducing the amount of proceeds paid to our noteholders. If new debt is added to our current debt levels, the related risks that we now face could intensify.

Risks Inherent in an Investment in Our Common Units

Conflicts of interest may exist between our individual unitholders and DCP Midstream, LLC, the owner of our general partner, which has sole responsibility for conducting our business and managing our operations.

DCP Midstream, LLC owns and controls our general partner. Some of our general partner's directors and all of its executive officers are directors or executive officers of DCP Midstream, LLC or its owners. Therefore, conflicts of interest may arise between DCP Midstream, LLC and its affiliates and our unitholders. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our Partnership Agreement nor any other agreement requires DCP Midstream, LLC to pursue a business strategy that favors us. DCP Midstream, LLC's directors and officers have a fiduciary duty to make these decisions in the best interests of the owners of DCP Midstream, LLC, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as DCP Midstream, LLC and its affiliates, including Phillips 66 and Enbridge, in resolving conflicts of interest;
- DCP Midstream, LLC and its affiliates, including Phillips 66 and Enbridge, are not limited in their ability to compete with us. Please read "DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us" below;
- our general partner has limited its liability and reduced its fiduciary duties, and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a sustaining capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our Partnership Agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

DCP Midstream, LLC and its affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses, which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our Partnership Agreement nor the Services Agreement between us and DCP Midstream, LLC prohibits DCP Midstream, LLC and its affiliates, including Phillips 66 and Enbridge, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, DCP Midstream, LLC and its affiliates, including Phillips 66 and Enbridge, may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Each of these entities is a large, established participant in the midstream energy business, and each has significantly greater resources than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, will be material.

Pursuant to the Services Agreement, DCP Midstream, LLC and its affiliates will receive reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services will be material. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. These factors may reduce the amount of cash otherwise available for distribution to our unitholders.

Our Partnership Agreement limits our general partner’s fiduciary duties to holders of our units.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, DCP Midstream, LLC. Our Partnership Agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our Partnership Agreement permits our general partner to make a number of decisions either in its individual capacity, as opposed to in its capacity as our general partner or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include:

- its limited call right;
- its voting rights with respect to the units it owns;
- its registration rights; and
- its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the Partnership Agreement.

By purchasing a unit, a unitholder will agree to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Our Partnership Agreement restricts the remedies available to holders of our units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that restrict the remedies available to our unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty. For example, our Partnership Agreement:

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the special committee of the board of directors of our general partner and not involving a vote of our unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be “fair and reasonable” to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the

relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

Holders of our units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders do not elect our general partner or its board of directors, and have no right to elect our general partner or its board of directors on an annual or other continuing basis. The members of the board of directors of our general partner are chosen by the owner of our general partner. As a result of these limitations, the price at which the units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our units may experience price volatility.

Our unit price has experienced volatility in the past, and volatility in the price of our units may occur in the future as a result of any of the risk factors contained herein and the risks described in our other public filings with the SEC. For instance, our units may experience price volatility as a result of changes in investor sentiment with respect to our competitors, our business partners and our industry in general, which may be influenced by volatility in prices for NGLs, natural gas and crude oil. In addition, the securities markets have from time to time experienced significant price and volume fluctuations that are unrelated to the operating performance of particular companies but affect the market price of their securities. These market fluctuations may also materially and adversely affect the market price of our units.

Even if our unitholders are dissatisfied, they may be unable to remove our general partner without its consent.

The unitholders may be unable to remove our general partner without its consent because our general partner and its affiliates own a significant percentage of our outstanding units. The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove the general partner. As of December 31, 2021, our general partner and its affiliates owned approximately 57% of our outstanding common units.

Our Partnership Agreement restricts the voting rights of our unitholders owning 20% or more of any class of our units.

Our unitholders' voting rights are further restricted by the Partnership Agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our Partnership Agreement also contains provisions limiting the ability of our unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of management.

If we are deemed an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include certain equity investments, such as minority ownership interests in joint ventures, which may be deemed to be "investment securities" within the meaning of the Investment Company Act of 1940, as amended (the "Investment Company Act"). In the future, we may acquire additional minority-owned interests in joint ventures that could be deemed "investment securities." If a sufficient amount of our assets are deemed to be "investment securities" within the meaning of the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be subject to federal income tax at the corporate tax rate, which could significantly reduce the cash available for distributions. Additionally, distributions to our unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forgo potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be "investment securities."

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, under our Partnership Agreement the owners of our general partner may pledge, impose a lien or transfer all or a portion of their respective ownership interest in our general partner to a third party. Any new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

We may generally issue additional units, including units that are senior to our common units, without our unitholders' approval, which would dilute our unitholders' existing ownership interests.

Our Partnership Agreement does not limit the number of additional common units that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units, preferred units, or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease, including a relative dilution of any voting rights;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

We are prohibited from paying distributions on our common units if distributions on our Preferred Units are in arrears.

The holders of our 7.375% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units"), our 7.875% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Series B Preferred Units"), and our 7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Series C Preferred Units and together with the Series A Preferred Units and the Series B Preferred Units, the "Preferred Units") are entitled to certain rights that are senior to the rights of holders of common units, such as rights to distributions and rights upon liquidation of the Partnership. If we do not pay the required distributions on our Preferred Units, we will be unable to pay distributions on our common units. Additionally, because distributions to our Preferred Unitholders are cumulative, we will have to pay all unpaid accumulated preferred distributions before we can pay any distributions to our common unitholders. Also, because distributions to our common unitholders are not cumulative, if we do not pay distributions on our common units with respect to any quarter, our common unitholders will not be entitled to receive distributions covering any prior periods if we later commence paying distributions on our common units. The preferences and privileges of the Preferred Units could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

Our general partner including its affiliates may sell units in the public or private markets, which could reduce the market price of our outstanding common units.

If our general partner or its affiliates holding unregistered common units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our general partner has a limited call right that may require our unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Our common unitholders may also incur a tax liability upon a sale of their common units.

The liability of holders of limited partner interests may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Holders of limited partner interests could be liable for any and all of our obligations as if such holder were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- the right of holders of limited partner interests to act with other unitholders to remove or replace the general partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute “control” of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the Partnership Agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Risks Inherent in an Investment in Our Preferred Units

Our Preferred Units are subordinated to our existing and future debt obligations, and your interests could be diluted by the issuance of additional units, including additional Preferred Units, and by other transactions.

The Preferred Units are subordinated to all of our existing and future indebtedness. The payment of principal and interest on our debt reduces cash available for distribution to our limited partners, including the holders of Preferred Units. The issuance of additional units on parity with or senior to the Preferred Units (including additional Preferred Units) would dilute the interests of the holders of the Preferred Units, and any issuance of equal or senior ranking securities or additional indebtedness could affect our ability to pay distributions on, redeem or pay the liquidation preference on the Preferred Units.

We distribute all of our available cash to our common unitholders and are not required to accumulate cash for the purpose of meeting our future obligations to holders of the Preferred Units, which may limit the cash available to make distributions on the Preferred Units.

Our Partnership Agreement requires us to distribute all of our “available cash” each quarter to our common unitholders. “Available cash” is defined in our Partnership Agreement and described in Note 16 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data.". As a result, we do not expect to accumulate significant amounts of cash. Depending on the timing and amount of our cash distributions, these distributions could significantly reduce the cash available to us in subsequent periods to make payments on the Preferred Units.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our being subject to minimal entity-level taxation by individual states. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, or we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS regarding our status as a partnership.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we will be treated as a corporation, the IRS could disagree with the positions we take or a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently 21%, and would likely pay state income tax at varying rates. Distributions to a unitholder would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to the unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to a unitholder would be substantially reduced. Therefore, treatment of us as a corporation for federal tax purposes would result in a material reduction in the anticipated cash flow and after-tax return to a unitholder, likely causing a substantial reduction in the value of our units.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception that allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our units. The U.S. Treasury Department issued final regulations interpreting the scope of activities that generate qualifying income under Section 7704 of the Internal Revenue Code of 1986, as amended, or the Code. We believe that the income we currently treat as qualifying income satisfies the requirements for qualifying income under the final regulations.

Public Law 115-97, known as the Tax Cuts and Jobs Act enacted on December 22, 2017 (the "Tax Cuts and Jobs Act") provides a deduction under Code Section 199A to a non-corporate common unitholder, for taxable years beginning after December 31, 2017 and ending on or before December 31, 2025, equal to 20% of his or her allocable share of our “qualified business income.” For purposes of this deduction, our “qualified business income” is equal to the sum of the net amount of our items of income, gain, deduction and loss to the extent such items are included or allowed in the determination of taxable income for the year, excluding, however, certain specified types of passive investment income (such as capital gains and dividends); and any gain recognized upon a disposition of our units to the extent such gain is attributable to certain assets, such as depreciation recapture and our “inventory items,” and is thus treated as ordinary income under Section 751 of the Code. This law also includes certain new limitations on the use of losses and other deductions to offset taxable income. Various aspects of this deduction and these limitations may be modified by administrative, legislative or judicial interpretations at any time, which may or may not be applied retroactively.

Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation, which would reduce the cash available for distribution to our unitholders. For example, we are required to pay the State of Texas a margin tax that is assessed at 0.75% of taxable margin apportioned to Texas.

Changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, with respect to federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future.

If tax authorities contest the tax positions we take, the market for our units may be adversely impacted, and the cost of any contest with a tax authority would reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. Tax authorities may adopt positions that differ from the conclusions of our counsel or from the positions we take, and the tax authority's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take. A court may not agree with some or all of our counsel’s conclusions or positions we take. Any contest with a tax authority, and the outcome of any such contest, may increase a unitholder’s tax liability and result in adjustment to items unrelated to us and could materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with any tax authority will be borne indirectly by our unitholders because such costs will reduce our cash available for distribution.

For taxable years beginning after December 31, 2017, the procedures for auditing large partnerships and the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit changed. Unless we are eligible to (and choose to) elect to issue statements similar to revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new procedures. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

Our unitholders may be required to pay taxes on income from us even if the unitholders do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income, which could be different in amount than the cash we distribute, unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the tax liability that results from that income.

Certain actions that we may take, such as issuing additional units, may increase the federal income tax liability of unitholders.

In the event we issue additional units or engage in certain other transactions in the future, the allocable share of nonrecourse liabilities allocated to the unitholders will be recalculated to take into account our issuance of any additional units. Any reduction in a unitholder’s share of our nonrecourse liabilities will be treated as a distribution of cash to that unitholder and will result in a corresponding tax basis reduction in a unitholder’s units. A deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a unitholder, to the extent that the deemed cash distribution exceeds such unitholder’s tax basis in its units.

In addition, the federal income tax liability of a unitholder could be increased if we dispose of assets or make a future offering of units and use the proceeds in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

Tax gain or loss on disposition of common units could be more or less than expected.

If a unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions to a unitholder in excess of the total net taxable income allocated to it for a common unit decreases its tax basis in that common unit, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if a unitholder sells its units, the unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

Our unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for “business interest” is limited to the sum of our business interest income and 30% (or 50% for 2020, as amended by the Coronavirus Aid, Relief and Economic Security Act on March 27, 2020) of our “adjusted taxable income.” For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion that is not required to be capitalized as part of cost of goods sold.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, such as individual retirement accounts, or IRAs, other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income, which may be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) may be required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business or vice versa.

Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. Gain recognized from a sale or other disposition of our units by a non-U.S. person will be subject to federal income tax as income effectively connected with a U.S. trade or business. Moreover, the transferee of our units (or the transferee's broker, if applicable) is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person. Recent final Treasury regulations provide for the application of this withholding rule to open market transfers of interest in publicly traded partnerships beginning on January 1, 2023. Under these regulations, the “amount realized” for purposes of this withholding is the gross proceeds paid or credited upon the transfer.

If a unitholder is a tax-exempt entity or a non-U.S. person, the unitholder should consult its tax advisor before investing in our units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to the unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders’ tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Treasury Department has adopted final regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. These regulations do not specifically authorize the proration method we have previously used. If the IRS were to challenge our proration method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may be required to recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and such unitholder may be required to recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of our units may have a greater portion of their adjustment under Section 743(b) of the Code allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of our units and could have a negative impact on the value of our units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Treatment of distributions on our Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of Preferred Units than the holders of our common units.

The tax treatment of distributions on our Preferred Units is uncertain. We will treat the holders of our Preferred Units as partners for tax purposes and will treat distributions on our Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of our Preferred Units as ordinary income and will not be eligible for the deduction provided for under Code Section 199A. Although a holder of our Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions associated with the Preferred Units. Because the guaranteed payment for each unit must accrue as income to a holder during the taxable year of the accrual, the guaranteed payments attributable to the period beginning December 15 and ending December 31 will accrue as income to the holder of record of a Preferred Unit on December 31 for such period, regardless of whether such holder continues to own the Preferred Units at the time the actual distribution is made. Otherwise, the holders of our Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction, except to the extent necessary to provide, to the extent possible, the Preferred Units with the benefit of the liquidation preference. We will not allocate any share of our nonrecourse liabilities to the holders of our Preferred Units. If our Preferred Units were treated as indebtedness for tax purposes, rather than as partnership interests, distributions on our Preferred Units likely would be treated as payments of interest by us to the holders of our Preferred Units, rather than as guaranteed payments for the use of capital.

A holder of our Preferred Units will be required to recognize gain or loss on a sale of its Preferred Units equal to the difference between the amount realized by such holder and tax basis in the Preferred Units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder of the Preferred Unit to acquire such Preferred Unit. Gain or loss recognized by a holder of a Preferred Unit on the sale or exchange of a Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of our

Preferred Units will generally not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our units.

In addition to federal income taxes, unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if the unitholders do not live in any of those jurisdictions. Unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, the unitholder may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax or an entity level tax. It is each unitholder’s responsibility to file all United States federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our units.

General Risk Factors

Our ability to manage and grow our business effectively could be adversely affected if we or DCP Midstream, LLC and its subsidiaries fail to attract and retain key management personnel and skilled employees.

We rely on our executive management team to manage our day-to-day affairs and establish and execute our strategic business and operational plans. This executive management team has significant experience in the midstream energy industry. The loss of any of our executives or the failure to fill new positions created by expansion, turnover or retirement could adversely affect our ability to implement our business strategy. In addition, our operations require engineers, operational and field technicians and other highly skilled employees. Competition for experienced executives and skilled employees is intense and increases when the demand from other energy companies for such personnel is high. Our ability to execute on our business strategy and to grow or continue our level of service to our current customers may be impaired and our business may be adversely impacted if we or DCP Midstream, LLC and its subsidiaries are unable to attract, train and retain such personnel, which may have an adverse effect on our results of operations and ability to make cash distributions.

Future disruptions in the global credit markets may make equity and debt markets less accessible and capital markets more costly, create a shortage in the availability of credit and lead to credit market volatility, which could disrupt our financing plans and limit our ability to grow.

From time to time, public equity markets experience significant declines, and global credit markets experience a shortage in overall liquidity and a resulting disruption in the availability of credit. Future disruptions in the global financial marketplace, including the bankruptcy or restructuring of financial institutions, could make equity and debt markets inaccessible, and adversely affect the availability of credit already arranged and the availability and cost of credit in the future. We have availability under our Credit Agreement to borrow additional capital, but our ability to borrow under that facility could be impaired if one or more of our lenders fails to honor its contractual obligation to lend to us.

As a publicly traded partnership, these developments could significantly impair our ability to make acquisitions or finance growth projects. We distribute all of our available cash, as defined in our amended and restated Partnership Agreement (the “Partnership Agreement”), to our common unitholders on a quarterly basis. We rely upon external financing sources, including the issuance of debt and equity securities and bank borrowings, to fund acquisitions or expansion capital expenditures or fund routine periodic working capital needs. Any limitations on our access to external capital, including limitations caused by illiquidity or volatility in the capital markets, may impair our ability to complete future acquisitions and construction projects on favorable terms, if at all. As a result, we may be at a competitive disadvantage as compared to businesses that reinvest all of their available cash to expand ongoing operations, particularly under adverse economic conditions.

Volatility in the capital markets may adversely impact our liquidity.

The capital markets may experience volatility, which may lead to financial uncertainty. Our access to funds under the Credit Agreement is dependent on the ability of the lenders that are party to the Credit Agreement to meet their funding obligations. Those lenders may not be able to meet their funding commitments if they experience shortages of capital and liquidity. If lenders under the Credit Agreement were to fail to fund their share of the Credit Agreement, our available borrowings could be further reduced. In addition, our borrowing capacity may be further limited by the financial covenants contained in the Credit Agreement.

A significant downturn in the economy could adversely affect our results of operations, financial position or cash flows. In the event that our results were negatively impacted, we could require additional borrowings. A deterioration of the capital markets could adversely affect our ability to access funds on reasonable terms in a timely manner.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

For details on our plants, fractionation and storage facilities and pipeline systems, please read Item 1. "Business - Our Operating Segments." We believe that our properties are generally in good condition, well maintained and are suitable and adequate to carry on our business at capacity for the foreseeable future.

Our real property falls into two categories: (1) parcels that we own in fee; and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee, and the fee owner of the lands, as lessors. We, or our predecessors, have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Our principal executive offices are located at 6900 E. Layton Avenue, Suite 900, Denver, Colorado 80237, our telephone number is 303-595-3331 and our website address is *www.dcpmidstream.com*.

Item 3. ***Legal Proceedings***

See Item 8 - Financial Statements - Notes to Consolidated Financial Statements - Note 21 in Part II of this Form 10-K for information about legal proceedings. For the disclosure of environmental proceedings with a governmental entity as a party pursuant to Item 103(c)(3)(iii) of Regulation S-K, the Company has elected to disclose matters where the Company reasonably believes such proceeding would result in monetary sanctions, exclusive of interest costs, of $1.0 million or more.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

Item 5. ***Market for Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Common Units***

Market Information

Our common units are listed on the New York Stock Exchange ("NYSE") under the symbol "DCP". As of February 16, 2022, there were approximately 34 unitholders of record of our common units. This number does not include unitholders whose common units are held in trust by other entities.

Securities Authorized for Issuance Under Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Item 6. [Reserved]

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this Annual Report on Form 10-K. This section of this Annual Report on Form 10-K generally discusses performance during the fiscal years ended December 31, 2021 and 2020 items and year-to-year comparisons between 2021 and 2020. Discussions of 2019 performance and year-to-year comparisons between 2020 and 2019 are not included in this Annual Report on Form 10-K, but rather can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

Overview

We are a Delaware limited partnership formed by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. Our operations are organized into two reportable segments: (i) Logistics and Marketing and (ii) Gathering and Processing. Our Logistics and Marketing segment includes transporting, trading, marketing and storing natural gas and NGLs, and fractionating NGLs. Our Gathering and Processing segment consists of gathering, compressing, treating, and processing natural gas, producing and fractionating NGLs, and recovering condensate.

General Trends and Outlook

We anticipate our business will continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

In March 2020, the World Health Organization declared the outbreak of COVID-19 a pandemic, and the U.S. economy began to experience pronounced effects of the COVID-19 pandemic. The pandemic caused by the COVID-19 virus and its variant strains ("COVID-19") has disrupted the U.S. economy since the first quarter of 2020 and immediately resulted in a decline in demand for our products. We began to see improvement in demand for our natural gas and NGL products and services beginning late in the second half of 2020, which continued through 2021. The COVID-19 pandemic continues to be dynamic, and near-term challenges across the economy remain. The extent of the continuing impact of the COVID-19 pandemic remain uncertain due to numerous factors outside of the Company's control, including but not limited to the severity, duration and resurgence of the outbreak, new variants, the effectiveness of public safety measures, distribution and effectiveness of vaccines, and supply chain pressures. Management continues to monitor the COVID-19 pandemic, however, the degree to which these factors will impact our business and our results of operations in 2022 and beyond remains uncertain and the related financial impact of any such disruption cannot be reasonably estimated at this time.

We have taken measures to address the COVID-19 pandemic in order to maintain essential business functions at our plants and critical infrastructure with minimal disruptions. Our current continuity plan specifically addresses technology, communications, and remote operations. We continue to prioritize safe and reliable operations and have not experienced a disruption to operations or incurred significant additional costs as a result of the COVID-19 pandemic.

Our business is impacted by commodity prices and volumes. We mitigate a significant portion of commodity price risk on an overall Partnership basis through our fee-based assets and by executing on our hedging program. Various factors impact both commodity prices and volumes, and as indicated in Item 7A. "Quantitative and Qualitative Disclosures about Market Risk," we have sensitivities to certain cash and non-cash changes in commodity prices. Commodity prices have rebounded due to increasing demand and tightening supply from the lows seen at the start of the pandemic. However, domestic exploration, development and production remain limited, and are growing slower than demand and our natural gas throughput and NGL volumes continue to be impacted as a result.

Our long-term view is that commodity prices will be at levels that we believe will support sustained or increasing levels of domestic production. In recent years we have transformed our business to a more fee-based portfolio, more heavily focused on the business of the Logistics and Marketing segment to reduce commodity exposure. In addition, we use our strategic hedging program to further mitigate commodity price exposure. We expect future commodity prices will be influenced by tariffs and other global economic conditions, the level of North American production and drilling activity by exploration and production companies, the balance of trade between imports and exports of liquid natural gas, NGLs and crude oil, and the severity of winter and summer weather.

We intend to be a proactive participant in the transition to a lower carbon energy future. In August 2021, we announced two goals for companywide greenhouse gas (GHG) emission intensity reductions targets. By 2030, our goal is to reduce our total Scope 1 and Scope 2 greenhouse gas emissions by 30% from the 2018 baseline utilizing the energy infrastructure council GPA Midstream Association Reporting Template Protocol. By 2050, our goal is to achieve net zero greenhouse gas emissions. We plan to achieve those targets through a two-pronged approach focused on cleaning the core, or increased efficiency and modernization of existing operations, and leveraging our existing strategy and infrastructure to establish adjacent lines of business, capture growing market opportunities, and capitalize on green energy growth. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations and made progress towards our goals by reducing Scope 1 and Scope 2 GHG emissions across our operations by approximately 15% from the 2018 baseline through 2020. Additionally, we reduced our methane emissions by 23% over the same period of time. While we believe all of these goals align with our long-term growth strategy, financial and operational priorities, they are aspirational and may change, and there is no guarantee that they will be met.

Our business is primarily driven by the level of production of natural gas by producers and of NGLs from processing plants connected to our pipelines and fractionators. These volumes can be impacted negatively by, among other things, reduced drilling activity, depressed commodity prices, severe weather disruptions, operational outages and ethane rejection. Upstream producers reduced capital expenditures during 2021 and their response to changes in commodity prices and demand remain uncertain.

We hedge commodity prices associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing segment. Drilling activity levels vary by geographic area, and we will continue to target our strategy in geographic areas where we expect producer drilling activity.

We believe our contract structure with our producers provides us with significant protection from credit risk since we generally hold the product, sell it and withhold our fees prior to remittance of payments to the producer. Currently, our top 20 producers account for a majority of the total natural gas that we gather and process and of these top 20 producers, 6 have investment grade credit ratings. During February 2021, Winter Storm Uri resulted in lower volumes and abnormally high gas prices in certain regions. Certain counterparty billings during this time remain under dispute and are taking longer to collect than normal.

The global economic outlook continues to be a cause for concern for U.S. financial markets and businesses and investors alike. This uncertainty may contribute to volatility in financial and commodity markets.

We believe we are positioned to withstand future commodity price volatility as a result of the following:

- Our fee-based business represents a significant portion of our margins.
- We have positive operating cash flow from our well-positioned and diversified assets.
- We have a well-defined and targeted multi-year hedging program.
- We manage our disciplined capital growth program with a significant focus on fee-based agreements and projects with long-term volume outlooks.
- We believe we have a solid capital structure and balance sheet.
- We believe we have access to sufficient capital to fund our growth including excess distribution coverage and divestitures.

During 2022, our strategic objectives are to generate Excess Free Cash Flows (a non-GAAP measure defined in "Reconciliation of Non-GAAP Measures - Excess Free Cash Flows") and reduce leverage. We believe the key elements to generating Excess Free Cash Flows are the diversity of our asset portfolio, our fee-based business which represents a significant portion of our estimated margins, plus our hedged commodity position, the objective of which is to protect against downside risk in our Excess Free Cash Flows. We will continue to pursue incremental revenue, cost efficiencies and operating improvements of our assets through process and technology improvements.

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. Our 2022 plan includes sustaining capital expenditures of between $100 million and $140 million and expansion capital expenditures of between $100 million and $150 million.

Recent Events

Senior Notes

On January 3, 2022, we repaid, at par, prior to maturity all $350 million of aggregate principal amount outstanding of our 4.95% Senior Notes due April 1, 2022 using borrowings under our Revolving Credit Facility and AR Securitization Facility.

Common and Preferred Distributions

On January 24, 2022, we announced that the board of directors of the General Partner declared a quarterly distribution on our common units of $0.39 per common unit. The distribution will be paid on February 14, 2022 to unitholders of record on February 4, 2022.

On the same date, the board of directors of the General Partner declared a quarterly distribution on our Series B and Series C Preferred Units of $0.4922 and $0.4969 per unit, respectively. The Series B distributions will be paid on March 15, 2022 to unitholders of record on March 1, 2022. The Series C distribution will be paid on April 15, 2022 to unitholders of record on April 1, 2022.

Factors That May Significantly Affect Our Results

Logistics and Marketing Segment

Our Logistics and Marketing segment operating results are impacted by, among other things, the throughput volumes of the NGLs we transport on our NGL pipelines and the volumes of NGLs we fractionate and store. We transport, fractionate and store NGLs primarily on a fee basis. Throughput may be negatively impacted as a result of our customers operating their processing plants in ethane rejection mode, often as a result of low ethane prices relative to natural gas prices. Factors that impact the supply and demand of NGLs, as described below in our Gathering and Processing segment, may also impact the throughput and volume for our Logistics and Marketing segment.

These contractual arrangements may require our customers to commit a minimum level of volumes to our pipelines and facilities, thereby mitigating our exposure to volume risk. However, the results of operations for this business segment are generally dependent upon the volume of product transported, fractionated or stored and the level of fees charged to customers. We do not take title to the products transported on our NGL pipelines, fractionated in our fractionation facilities or stored in our storage facility; rather, the customer retains title and the associated commodity price risk. The volumes of NGLs transported on our pipelines are dependent on the level of production of NGLs from processing plants connected to our NGL pipelines. When natural gas prices are high relative to NGL prices, it is less profitable to process natural gas because of the higher value of natural gas compared to the value of NGLs and because of the increased cost of separating the NGLs from the natural gas. As a result, we have experienced periods in the past, in which higher natural gas or lower NGL prices reduce the volume of NGLs extracted at plants connected to our NGL pipelines and, in turn, lower the NGL throughput on our assets.

Our results of operations for our Logistics and Marketing segment are also impacted by increases and decreases in the volume, price and basis differentials of natural gas associated with our natural gas storage and pipeline assets, as well as our underlying derivatives associated with these assets. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads. A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage.

Gathering and Processing Segment

Our results of operations for our Gathering and Processing segment are impacted by (1) the prices of and relationship between commodities such as NGLs, crude oil and natural gas, (2) increases and decreases in the wellhead volume and quality of natural gas that we gather, (3) the associated Btu content of our system throughput and our related processing volumes, (4) the operating efficiency and reliability of our processing facilities, (5) potential limitations on throughput volumes arising from downstream and infrastructure capacity constraints, and (6) the terms of our processing contract arrangements with producers. This is not a complete list of factors that may impact our results of operations but, rather, are those we believe are most likely to impact those results.

Volume and operating efficiency generally are driven by wellhead production, plant recoveries, operating availability of our facilities, physical integrity and our competitive position on a regional basis, and more broadly by demand for natural gas, NGLs and condensate. Historical and current trends in the price changes of commodities may not be indicative of future trends. Volume and prices are also driven by demand and take-away capacity for residue natural gas and NGLs.

Our processing contract arrangements can have a significant impact on our profitability and cash flow. Our actual contract terms are based upon a variety of factors, including the commodity pricing environment at the time the contract is executed, natural gas quality, geographic location, customer requirements and competition from other midstream service providers. Our gathering and processing contract mix and, accordingly, our exposure to natural gas, NGL and condensate prices, may change as a result of producer preferences, impacting our expansion in regions where certain types of contracts are more common as well as other market factors. We generate our revenues and our adjusted gross margin for our Gathering and Processing segment principally from contracts that contain a combination of fee based arrangements and percent-of-proceeds/liquids arrangements.

Our Gathering and Processing segment operating results are impacted by market conditions causing variability in natural gas, crude oil and NGL prices. The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by drilling activity, which may be impacted by prevailing commodity prices and global demand. The number of active oil and gas drilling rigs in the United States increased, from 351 on December 31, 2020 to 586 on December 31, 2021. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term, the growth and sustainability of our business depends on commodity prices being at levels sufficient to provide incentives and capital for producers to explore for and produce natural gas.

The prices of NGLs, crude oil and natural gas can be extremely volatile for periods of time, and may not always have a close relationship. Due to our hedging program, changes in the relationship of the price of NGLs and crude oil may cause our commodity price exposure to vary, which we have attempted to capture in our commodity price sensitivities in Item 7A in this 2021 Form 10-K, “Quantitative and Qualitative Disclosures about Market Risk.” Our results may also be impacted as a result of non-cash lower of cost or net realizable value inventory or imbalance adjustments, which occur when the market value of commodities decline below our carrying value.

We face strong competition in acquiring raw natural gas supplies. Our competitors in obtaining additional gas supplies and in gathering and processing raw natural gas includes major integrated oil and gas companies, interstate and intrastate pipelines, and companies that gather, compress, treat, process, transport, store and/or market natural gas. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas and/or NGLs. Competition is also increased in those geographic areas where our commercial contracts with our customers are shorter term and therefore must be renegotiated on a more frequent basis.

Weather

The economic impact of severe weather may negatively affect the nation’s short-term energy supply and demand, and may result in commodity price volatility. Wide fluctuations in the price of natural gas caused by extreme weather events may increase our working capital requirements in order to fund settlements or margin requirements on open positions on commodities exchanges. Additionally, severe weather may restrict or prevent us from fully utilizing our assets, by damaging our assets, interrupting utilities, and through possible NGL and natural gas curtailments downstream of our facilities, which could restrict our production. These impacts may linger past the time of the actual weather event. Although we carry insurance on the vast majority of our assets, insurance may be inadequate to cover our loss in some instances, and in certain circumstances we have been unable to obtain insurance on commercially reasonable terms, if at all.

Climate change may have a long-term impact on our operations. For example, our facilities that are located in low lying areas such as the gulf coast of Texas and Louisiana may be at increased risk due to flooding, rising sea levels, or disruption to operations from more frequent and severe weather events. Changes in climate or weather patterns may hinder exploration and production activities or increase the cost of production of oil and gas resources and consequently affect throughput volumes entering our systems. Changes in climate or weather may also impact demand for energy products and services or alter the overall energy demand by fuel.

Capital Markets

Volatility in the capital markets may impact our business in multiple ways, including limiting our producers' ability to finance their drilling programs and operations and limiting our ability to support or fund our operations and growth. These events may impact our counterparties' ability to perform under their credit or commercial obligations. Where possible, we have obtained additional collateral agreements, letters of credit from highly rated banks, or have managed credit lines to mitigate a portion of these risks.

Impact of Inflation

We anticipate that an increase in labor costs, along with increased supply chain costs primarily related to inflationary pressures that began in the latter half of 2021, will have an impact on our operations in 2022. However, these cost increases should be partially offset by benefits to our commodity sales, transportation and processing prices. However, inflationary pressures on interest rates impact our business, as well as the broader economy and energy business. Consequently, our costs for chemicals, utilities, materials and supplies, labor and major equipment purchases may increase during periods of general business inflation or periods of relatively high energy commodity prices.

Other

The above factors, including sustained deterioration in commodity prices and volumes, other market declines or a decline in our common unit price, may negatively impact our results of operations, and may increase the likelihood of a non-cash impairment charge or non-cash lower of cost or net realizable value inventory adjustments.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) volumes; (2) adjusted gross margin and segment adjusted gross margin; (3) operating and maintenance expense, and general and administrative expense; (4) adjusted EBITDA; (5) adjusted segment EBITDA; (6) Distributable Cash Flow and (7) Excess Free Cash Flow. Adjusted gross margin, segment adjusted gross margin, adjusted EBITDA, adjusted segment EBITDA, Distributable Cash Flow and Excess Free Cash Flow are non-GAAP measures. To the extent permitted, we present certain non-GAAP measures and reconciliations of those measures to their most directly comparable financial measures as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

Volumes

We view wellhead, throughput and storage volumes as important factors affecting our profitability. We gather and transport some of the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from existing and successful new wells in other areas. The throughput volumes of NGLs and gas on our pipelines are substantially dependent upon the quantities of NGLs and gas produced at our processing plants, as well as NGLs and gas produced at other processing plants that have pipeline connections with our NGL and gas pipelines. We regularly monitor producer activity in the areas we serve and in which our pipelines are located, and pursue opportunities to connect new supply to these pipelines. We also monitor our inventory in our NGL and gas storage facilities, as well as overall demand for storage based on seasonal patterns and other market factors such as weather and overall market demand.

Results of Operations

Consolidated Overview

The following table and discussion provides a summary of our consolidated results of operations for the years ended December 31, 2021 and 2020. The results of operations by segment are discussed in further detail following this consolidated overview discussion. Discussions for the year ended December 31, 2020 versus the year ended December 31, 2019 can be found in our Annual Report Form 10-K for the year ended December 31, 2020 and should be read in conjunction with the discussions below.

	Year Ended December 31,		Variance 2021 vs. 2020	
	2021	2020	Increase (Decrease)	Percent
	(millions, except operating data)			
Operating revenues (a):				
Logistics and Marketing	$ 9,734	$ 5,530	$ 4,204	76 %
Gathering and Processing	6,894	3,479	3,415	98 %
Inter-segment eliminations	(5,921)	(2,707)	3,214	*
Total operating revenues	10,707	6,302	4,405	70 %
Purchases and related costs				
Logistics and Marketing	(9,596)	(5,197)	4,399	85 %
Gathering and Processing	(5,590)	(2,253)	3,337	*
Inter-segment eliminations	5,921	2,707	3,214	*
Total purchases	(9,265)	(4,743)	4,522	95 %
Operating and maintenance expense	(659)	(607)	52	9 %
Depreciation and amortization expense	(364)	(376)	(12)	(3 %)
General and administrative expense	(223)	(253)	(30)	(12 %)
Asset impairments	(31)	(746)	(715)	(96 %)
Other income (expense), net	5	(15)	(20)	*
Loss on sale of assets, net	(5)	—	5	*
Restructuring costs	—	(9)	(9)	*
Earnings from unconsolidated affiliates (b)	535	447	88	20 %
Interest expense	(299)	(302)	(3)	(1 %)
Income tax expense	(6)	—	6	*
Net income attributable to noncontrolling interests	(4)	(4)	—	— %
Net income (loss) attributable to partners	$ 391	$ (306)	$ 697	*
Other data:				
Adjusted gross margin (c):				
Logistics and Marketing	$ 138	$ 333	$ (195)	(59 %)
Gathering and Processing	1,304	1,226	78	6 %
Total adjusted gross margin	$ 1,442	$ 1,559	$ (117)	(8 %)
Non-cash commodity derivative mark-to-market	$ (125)	$ 55	$ (180)	*
NGL pipelines throughput (MBbls/d) (d)	652	661	(9)	(1 %)
Gas pipelines throughput (TBtu/d) (d)	1.0	1.1	(0.1)	(9 %)
Natural gas wellhead (MMcf/d) (d)	4,196	4,558	(362)	(8 %)
NGL gross production (MBbls/d) (d)	398	400	(2)	(1 %)

* Percentage change is not meaningful.

(a) Operating revenues include the impact of trading and marketing gains (losses), net.

(b) Earnings for certain unconsolidated affiliates include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities and the other than temporary impairment of $61 million taken on the equity investment in Discovery Producer Services LLC in the first quarter of 2020.

(c) Adjusted gross margin consists of total operating revenues less purchases and related costs. Segment adjusted gross margin for each segment consists of total operating revenues for that segment, less purchases and related costs for that segment. Please read “Reconciliation of Non-GAAP Measures”.
(d) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and throughput volumes and NGL production.

Year Ended December 31, 2021 vs. Year Ended December 31, 2020

Total Operating Revenues — Total operating revenues increased $4,405 million in 2021 compared to 2020, primarily as a result of the following:

- $4,204 million increase for our Logistics and Marketing segment, primarily due to higher commodity prices and an increase in transportation, processing and other, partially offset by lower gas and NGL volumes, and unfavorable commodity derivative activity; and

- $3,415 million increase for our Gathering and Processing segment, primarily due to higher commodity prices, an increase in transportation, processing and other, and increased volumes in the DJ Basin, partially offset by unfavorable commodity derivative activity, and lower volumes in the South, Permian, and Midcontinent regions.

These increases were partially offset by:

- $3,214 million change in inter-segment eliminations, which relate to sales of gas and NGL volumes from our Gathering and Processing segment to our Logistics and Marketing segment, primarily due to higher commodity prices.

Total Purchases — Total purchases increased $4,522 million in 2021 compared to 2020, primarily as a result of the following:

- $4,399 million increase for our Logistics and Marketing segment for the commodity price and volume changes discussed above; and

- $3,337 million increase for our Gathering and Processing segment for the commodity price and volume changes discussed above.

These increases were partially offset by:

- $3,214 million change in inter-segment eliminations, for the reasons discussed above.

General and Administrative Expense — General and administrative expense decreased in 2021 compared to 2020, primarily as a result of reduced headcount and benefits, and higher fees in 2020.

Asset Impairments — Asset impairments in 2021 relate to long-lived assets in the Midcontinent and South regions of our Gathering and Processing segment, and long-lived assets in South Texas in our Logistics and Marketing segment. Asset impairments in 2020 relate to long-lived assets in the Permian and South regions and goodwill related to our North region.

Other Income (Expense) — Other income in 2021 was primarily a result of a contractual settlement. Other expense in 2020 was primarily related to asset write-offs and pipeline linefill adjustments.

Loss on Sale of Assets, net — The net loss on sale of assets in 2021 primarily represent the sale of gathering systems in the Midcontinent region.

Restructuring Costs — Restructuring costs decreased in 2021 compared to 2020, primarily as a result of our reduction in force in the second quarter of 2020.

Earnings from Unconsolidated Affiliates — Earnings from unconsolidated affiliates increased in 2021 compared to 2020, primarily as a result of an impairment in our equity investment in Discovery in 2020.

Income Tax Expense — Income tax expense changed in 2021 compared to 2020 based on forecasted reversals of temporary differences using our future expected apportionment in Texas.

Net Income (Loss) Attributable to Partners — Net income (loss) attributable to partners increased in 2021 compared to 2020 for all of the reasons discussed above.

Adjusted Gross Margin — Adjusted gross margin decreased $117 million in 2021 compared to 2020, primarily as a result of the following:

- $195 million decrease for our Logistics and Marketing segment, primarily as a result of unfavorable commodity derivative activity, unfavorable NGL marketing and storage activity, and a decrease related to Winter Storm Uri, which adversely impacted our gas marketing pipeline assets, partially offset by an increase in gas pipeline and storage marketing margins due to more favorable commodity spreads, and an increase in NGL pipeline margins.

  This decrease was partially offset by:

- $78 million increase for our Gathering and Processing segment, primarily as a result of higher commodity prices and higher volumes in the DJ Basin, partially offset by unfavorable commodity derivative activity attributable to our corporate equity hedge program, lower gathering and processing margins, lower volumes in the South, Permian, and Midcontinent regions, and the negative impact of Winter Storm Uri resulting in producer shut-ins.

Supplemental Information on Unconsolidated Affiliates

The following tables present financial information related to unconsolidated affiliates during the years ended December 31, 2021 and 2020, respectively:

Earnings from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,	
	2021	2020
	(millions)	
DCP Sand Hills Pipeline, LLC	$ 274	$ 279
DCP Southern Hills Pipeline, LLC	91	78
Gulf Coast Express LLC	63	66
Front Range Pipeline LLC	38	38
Texas Express Pipeline LLC	19	18
Mont Belvieu 1 Fractionator	17	12
Discovery Producer Services LLC (a)	16	(63)
Cheyenne Connector, LLC	12	6
Mont Belvieu Enterprise Fractionator	3	11
Other	2	2
Total earnings from unconsolidated affiliates	$ 535	$ 447

(a) Includes an other than temporary impairment of $61 million taken on the investment in the first quarter of 2020.

Distributions received from unconsolidated affiliates were as follows:

	Year Ended December 31, 2021	2020
	(millions)	
DCP Sand Hills Pipeline, LLC	$ 293	$ 335
DCP Southern Hills Pipeline, LLC	102	92
Gulf Coast Express LLC	78	81
Front Range Pipeline LLC	42	49
Texas Express Pipeline LLC	21	22
Mont Belvieu 1 Fractionator	17	14
Discovery Producer Services LLC	29	14
Cheyenne Connector, LLC	17	7
Mont Belvieu Enterprise Fractionator	1	12
Other	4	5
Total distributions from unconsolidated affiliates	$ 604	$ 631

Results of Operations — Logistics and Marketing Segment

The results of operations for our Logistics and Marketing segment are as follows:

	Year Ended December 31,		Variance 2021 vs. 2020	
	2021	2020	Increase (Decrease)	Percent
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 9,931	$ 5,355	$ 4,576	85 %
Transportation, processing and other	65	51	14	27 %
Trading and marketing (losses) gains, net	(262)	124	(386)	*
Total operating revenues	9,734	5,530	4,204	76 %
Purchases and related costs	(9,596)	(5,197)	4,399	85 %
Operating and maintenance expense	(38)	(36)	2	6 %
Depreciation and amortization expense	(12)	(13)	(1)	(8 %)
General and administrative expense	(6)	(7)	(1)	(14 %)
Asset impairments	(13)	—	13	*
Other income (expense), net	6	(10)	(16)	*
Earnings from unconsolidated affiliates (a)	519	510	9	2 %
Gain on sale of assets, net	2	—	(2)	*
Segment net income attributable to partners	$ 596	$ 777	$ (181)	(23 %)
Other data:				
Segment adjusted gross margin (b)	$ 138	$ 333	$ (195)	(59 %)
Non-cash commodity derivative mark-to-market	$ (19)	$ 78	$ (97)	*
NGL pipelines throughput (MBbls/d) (c)	652	661	(9)	(1 %)
Gas pipelines throughput (TBtu/d) (c)	1.0	1.1	(0.1)	(9 %)

* Percentage change is not meaningful.

(a) Earnings for certain unconsolidated affiliates include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities.

(b) Adjusted gross margin consists of total operating revenues less purchases and related costs. Segment adjusted gross margin for each segment consists of total operating revenues for that segment less purchases and related costs for that segment. Please read “Reconciliation of Non-GAAP Measures”.
(c) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the throughput volumes.

Year Ended December 31, 2021 vs. Year Ended December 31, 2020

Total Operating Revenues — Total operating revenues increased $4,204 million in 2021 compared to 2020, primarily as a result of the following:

- $5,485 million increase as a result of higher commodity prices before the impact of derivative activity; and
- $14 million increase in transportation, processing and other.

These increases were partially offset by:

- $909 million decrease attributable to lower gas and NGL volumes; and
- $386 million decrease as a result of commodity derivative activity attributable to an increase in unrealized cash settlement losses of $97 million and an increase in realized commodity derivative losses of $289 million due to movements in forward prices of commodities.

Purchases and Related Costs — Purchases and related costs increased $4,399 million in 2021 compared to 2020, for the reasons discussed above.

Asset Impairments — Asset impairments in 2021 relate to long-lived assets in South Texas where we determined a triggering event occurred due to a negative outlook for long-term volume forecasts.

Other Income (Expense) — Other income in 2021 was primarily a result of a contractual settlement. Other expense in 2020 primarily relates to pipeline linefill adjustments.

Segment Adjusted Gross Margin — Segment adjusted gross margin decreased $195 million in 2021 compared to 2020, primarily as a result of the following:

- $386 million decrease as a result of commodity derivative activity as discussed above, which includes an increase in unrealized derivatives losses of $97 million due to forward price movements of commodities in 2021; and
- $27 million decrease as a result of unfavorable NGL marketing and storage activity in 2021; and
- $5 million decrease as a result of Winter Storm Uri, which adversely impacted our gas marketing pipeline assets, net of a large favorable offset at gas storage margins.

These decreases were partially offset by:

- $210 million increase as a result of increased gas pipeline and storage marketing margins due to more favorable commodity spreads in 2021; and
- $13 million increase as a result of NGL pipeline margins.

Results of Operations — Gathering and Processing Segment

The results of operations for our Gathering and Processing segment are as follows:

	Year Ended December 31,		Variance 2021 vs. 2020	
	2021	2020	Increase (Decrease)	Percent
	(millions, except operating data)			
Operating revenues:				
Sales of natural gas, NGLs and condensate	$ 6,776	$ 3,042	$ 3,734	*
Transportation, processing and other	474	405	69	17 %
Trading and marketing (losses) gains, net	(356)	32	(388)	*
Total operating revenues	6,894	3,479	3,415	98 %
Purchases and related costs	(5,590)	(2,253)	3,337	*
Operating and maintenance expense	(603)	(554)	49	9 %
Depreciation and amortization expense	(325)	(333)	(8)	(2 %)
General and administrative expense	(15)	(22)	(7)	(32 %)
Asset impairments	(18)	(746)	(728)	*
Other expense, net	(1)	(3)	(2)	(67 %)
Loss on sale of assets, net	(7)	—	7	*
Earnings (loss) from unconsolidated affiliates (a)	16	(63)	79	*
Segment net income (loss)	351	(495)	846	*
Segment net income attributable to noncontrolling interests	(4)	(4)	—	— %
Segment net income (loss) attributable to partners	$ 347	$ (499)	$ 846	*
Other data:				
Segment adjusted gross margin (b)	$ 1,304	$ 1,226	$ 78	6 %
Non-cash commodity derivative mark-to-market	$ (106)	$ (23)	$ (83)	*
Natural gas wellhead (MMcf/d) (c)	4,196	4,558	(362)	(8 %)
NGL gross production (MBbls/d) (c)	398	400	(2)	(1 %)

* Percentage change is not meaningful.

(a) Earnings for certain unconsolidated affiliates include the amortization of the net difference between the carrying amount of the investments and the underlying equity of the entities and impairment of $61 million of our equity investment in Discovery Producer Services LLC in the first quarter of 2020.

(b) Segment adjusted gross margin for each segment consists of total operating revenues for that segment less purchases and related costs for that segment. Please read “Reconciliation of Non-GAAP Measures”.

(c) For entities not wholly-owned by us, includes our share, based on our ownership percentage, of the wellhead and NGL production

Year Ended December 31, 2021 vs. Year Ended December 31, 2020

Total Operating Revenues — Total operating revenues increased $3,415 million in 2021 compared to 2020, primarily as a result of the following:

- $3,999 million increase attributable to higher commodity prices, before the impact of derivative activity; and
- $69 million increase in transportation, processing and other.

These increases were partially offset by:

- $388 million decrease as a result of commodity derivative activity attributable to an increase in unrealized commodity derivative losses of $83 million due to movements in forward prices of commodities in 2021 and an increase in realized cash settlement losses of $305 million; and

- $265 million decrease as a result of lower volumes in the South, Permian, and Midcontinent regions, partially offset by increased volumes in the DJ Basin.

Purchases and Related Costs — Purchases and related costs increased $3,337 million in 2021 compared to 2020, primarily as a result of the commodity price and volume changes discussed above.

General and Administrative Expense — General and administrative expense decreased in 2021 compared to 2020, primarily due to higher fees in 2020.

Asset Impairments — Asset impairments in 2021 relate to long-lived assets in the Midcontinent and South regions. Asset impairments in 2020 relate to long-lived assets in the Permian and South regions and goodwill in the North region.

Loss on Sale of Assets, net — The net loss on sale of assets in 2021 primarily represent the sale of gathering systems in the Midcontinent region.

Earnings (Loss) from Unconsolidated Affiliates — Earnings (loss) from unconsolidated affiliates increased in 2021 compared to 2020, primarily as a result of an impairment in our equity investment in Discovery in 2020.

Segment Adjusted Gross Margin — Segment adjusted gross margin increased $78 million in 2021 compared to 2020, primarily as a result of the following:

- $555 million increase as a result of higher commodity prices.

This increase was partially offset by:

- $323 million decrease as a result of unfavorable commodity derivative activity attributable to our corporate equity hedge program; and

- $119 million decrease due to lower gathering and processing margins, and lower volumes in the South, Permian, and Midcontinent regions, partially offset by higher volumes in the DJ Basin; and

- $35 million decrease as a result of Winter Storm Uri, reflecting reduced volumes due to producer shut-ins, commodity derivative activity associated with swaps, and the net impact of producer payments and marketing activity.

Liquidity and Capital Resources

We expect our sources of liquidity to include:

- cash generated from operations;
- cash distributions from our unconsolidated affiliates;
- borrowings under our Credit Agreement;
- proceeds from asset rationalization;
- debt offerings;
- borrowings under term loans, securitization agreements or other credit facilities; and
- issuances of additional common units, preferred units or other securities.

We anticipate our more significant uses of resources to include:

- quarterly distributions to our common unitholders and distributions to our preferred unitholders;
- payments to service our debt;
- capital expenditures;
- contributions to our unconsolidated affiliates to finance our share of their capital expenditures;
- business and asset acquisitions; and
- collateral with counterparties to our swap contracts to secure potential exposure under these contracts, which may, at times, be significant depending on commodity price movements.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditures and quarterly cash distributions for at least the next twelve months.

We routinely evaluate opportunities for strategic investments or acquisitions. Future material investments or acquisitions may require that we obtain additional capital, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities or acquisitions.

Based on current and anticipated levels of operations, we believe we have adequate committed financial resources to conduct our ongoing business, although deterioration in our operating environment could limit our borrowing capacity, impact our credit ratings, raise our financing costs, as well as impact our compliance with the financial covenants contained in the Credit Agreement and other debt instruments.

Senior Notes — On November 19, 2021, we issued $400 million aggregate principal amount of 3.250% Senior Notes due February 2032, unless redeemed prior to maturity. We used the net proceeds from the offering to repay indebtedness under our revolving credit facility and for general partnership purposes. Interest on the notes is payable semi-annually in arrears on February 15 and August 15 of each year, commencing on August 15, 2022.

On January 3, 2022, we repaid, at par, prior to maturity all $350 million of aggregate principal amount outstanding of our 4.95% Senior Notes due April 1, 2022 using borrowings under our Revolving Credit Facility and AR Securitization Facility.

Credit Agreement — As of December 31, 2021, we had unused borrowing capacity of $1,383 million, net of $17 million of letters of credit, under the Credit Agreement, of which $1,383 million would have been available to borrow for working capital and other general partnership purposes based on the financial covenants set forth in the Credit Agreement. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the December 9, 2024 maturity date. As of February 16, 2022, we had unused borrowing capacity of $1,120 million, net of $263 million of outstanding borrowings and $17 million of letters of credit under the Credit Agreement. Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid.

Accounts Receivable Securitization Facility — As of December 31, 2021, we had $260 million of outstanding borrowings under our Securitization Facility at LIBOR market index rates plus a margin. On August 2, 2021 we entered into an amendment to our Securitization Facility to extend the term of the facility until August 12, 2024 and to provide for an alternative interest rate under the Securitization Facility based on SOFR upon LIBOR becoming unavailable. The amendment also includes Environmental, Social, and Governance linked Key Performance Indicators that increase or decrease certain fees based on our safety performance relative to our peers, and year-over-year change in our greenhouse gas emissions intensity rate. The Securitization Facility provides for up to $350 million borrowing capacity at LIBOR market interest rates plus a margin. Such interest rates will change as described above upon LIBOR becoming unavailable.

Issuance of Securities — In October 2020, we filed a shelf registration statement with the SEC that became effective upon filing and allows us to issue an indeterminate number of common units, preferred units, debt securities, and guarantees of debt securities. During the year ended December 31, 2021, we issued $400 million in aggregate principal amount of our 3.25% Senior Notes due February 2032 pursuant to this shelf registration statement.

In October 2020, we also filed a shelf registration statement with the SEC, which allows us to issue up to $750 million in common units pursuant to our at-the-market program. During the year ended December 31, 2021, we did not issue any common units pursuant to this registration statement, and $750 million remained available for future sales.

Guarantee of Registered Debt Securities — The consolidated financial statements of DCP Midstream, LP, or “parent guarantor”, include the accounts of DCP Midstream Operating LP, or “subsidiary issuer”, which is a 100% owned subsidiary, and all other subsidiaries which are all non-guarantor subsidiaries. The parent guarantor has agreed to fully and unconditionally guarantee the senior notes. The entirety of the Company’s operating assets and liabilities, operating revenues, expenses and other comprehensive income exist at its non-guarantor subsidiaries, and the parent guarantor and subsidiary issuer have no assets, liabilities or operations independent of their respective financing activities and investments in non-guarantor subsidiaries. All covenants in the indentures governing the notes limit the activities of subsidiary issuer, including limitations on the ability to pay dividends, incur additional indebtedness, make restricted payments, create liens, sell assets or make loans to parent guarantor.

The Company qualifies for alternative disclosure under Rule 13-01 of Regulation S-X, because the combined financial information of the subsidiary issuer and parent guarantor, excluding investments in subsidiaries that are not issuers or guarantors, reflect no material assets, liabilities or results of operations apart from their respective financing activities and investments in non-guarantor subsidiaries. Summarized financial information is presented as follows. The only assets, liabilities and results of operations of the subsidiary issuer and parent guarantor on a combined basis, independent of their respective investments in non-guarantor subsidiaries are:

- Accounts payable and other current liabilities of $81 million and $87 million as of December 31, 2021 and December 31, 2020, respectively;
- Balances related to debt of $5.174 billion and $5.273 billion as of December 31, 2021 and December 31, 2020, respectively; and
- Interest expense, net of $296 million and $297 million for the year ended December 31, 2021 and 2020, respectively.

Commodity Swaps and Collateral — Changes in natural gas, NGL and condensate prices and the terms of our processing arrangements have a direct impact on our generation and use of cash from operations due to their impact on net income, along with the resulting changes in working capital. For additional information regarding our derivative activities, please read Item 7A. “Quantitative and Qualitative Disclosures about Market Risk” contained herein.

When we enter into commodity swap contracts, we may be required to provide collateral to the counterparties in the event that our potential payment exposure exceeds a predetermined collateral threshold. Collateral thresholds are set by us and each counterparty, as applicable, in the master contract that governs our financial transactions based on our and the counterparty’s assessment of creditworthiness. The assessment of our position with respect to the collateral thresholds are determined on a counterparty by counterparty basis, and are impacted by the representative forward price curves and notional quantities under our swap contracts. Due to the interrelation between the representative crude oil and natural gas forward price curves, it is not practical to determine a pricing point at which our swap contracts will meet the collateral thresholds as we may transact multiple commodities with the same counterparty. Depending on daily commodity prices, the amount of collateral posted can go up or down on a daily basis.

Working Capital — Working capital is the amount by which current assets exceed current liabilities. Current assets are reduced in part by our quarterly distributions, which are required under the terms of our Partnership Agreement based on

Available Cash, as defined in the Partnership Agreement. In general, our working capital is impacted by changes in the prices of commodities that we buy and sell, inventory levels, and other business factors that affect our net income and cash flows. Our working capital is also impacted by the timing of operating cash receipts and disbursements, cash collateral we may be required to post with counterparties to our commodity derivative instruments, borrowings of and payments on debt and the Securitization Facility, capital expenditures, and increases or decreases in other long-term assets. We expect that our future working capital requirements will be impacted by these same recurring factors. During February 2021, Winter Storm Uri resulted in lower regional volumes and abnormally high gas prices for a period of days. A majority of our receivables associated with Winter Storm Uri have been collected. Certain counterparty billings during this time are under dispute and are taking longer to collect than normal, which negatively impacted our working capital at December 31, 2021. We believe the amounts due to us are owed and are vigorously pursuing legal avenues to collect these receivables.

We had working capital deficits of $261 million and $613 million as of December 31, 2021 and December 31, 2020, respectively, driven by current maturities of long term debt of $355 million and $505 million, respectively. We had a net derivative working capital deficit of $59 million as of December 31, 2021 and surplus of $7 million as of December 31, 2020.

Cash Flow — Operating, investing and financing activities were as follows:

	Year Ended December 31,		
	2021	2020	2019
	(millions)		
Net cash provided by operating activities	$ 646	$ 1,099	$ 85
Net cash used in investing activities	$ (110)	$ (259)	$ (76
Net cash used in financing activities	$ (591)	$ (785)	$ (9

Year Ended December 31, 2021 vs. Year Ended December 31, 2020

Operating Activities — Net cash provided by operating activities decreased $453 million in 2021 compared to the same period in 2020. The changes in net cash provided by operating activities are attributable to our net income (loss) adjusted for non-cash charges and changes in working capital as presented in the consolidated statements of cash flows. At December 31, 2021, a substantial portion of this was due to increased collateral cash deposits to fund margin requirements on open positions on commodities exchanges that we enter into to mitigate a portion of our natural gas and NGL price risk. During February 2021, Winter Storm Uri resulted in lower regional volumes and abnormally high gas prices for a period of days. A majority of our receivables associated with Winter Storm Uri have been collected. Certain counterparty billings during this time are under dispute and are taking longer to collect than normal. For additional information regarding fluctuations in our earnings and distributions from unconsolidated affiliates, please read “Supplemental Information on Unconsolidated Affiliates” under “Results of Operations”.

*Investing Activitie*s — Net cash used in investing activities decreased $149 million in 2021 compared to the same period in 2020, primarily as a result of lower capital expenditures and lower investments in unconsolidated affiliates.

*Financing Activitie*s — Net cash used in financing activities decreased $194 million in 2021 compared to the same period in 2020, primarily as a result of higher distributions in the first quarter of 2020 and higher net payments of debt.

*Contractual Obligation*s — Material contractual obligations arising in the normal course of business primarily consist of purchase obligations, long-term debt and related interest payments, leases, and other long-term liabilities. See Notes 13 and 14 to the Consolidated Financial Statements included in Item 1 "Financial Statements" for amounts outstanding on December 31, 2021, related to leases and debt.

Purchase Obligations are contractual obligations and include various non-cancelable commitments to purchase physical quantities of commodities in future periods and other items, including gas supply, fractionation and transportation agreements in the ordinary course of business.

Management believes that our cash and investment position and operating cash flows as well as capacity under existing and available credit agreements will be sufficient to meet our liquidity and capital requirements for the foreseeable future. We believe that our current and projected asset position is sufficient to meet our liquidity requirements.

Capital Requirements — The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. We may enter into purchase order and non-cancelable construction agreements for capital expenditures. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of the following:

- Sustaining capital expenditures, which are cash expenditures to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Sustaining capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets; and

- Expansion capital expenditures, which are cash expenditures to increase our cash flows, or operating or earnings capacity. Expansion capital expenditures include acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines and well connects, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets).

We incur capital expenditures for our consolidated entities and our unconsolidated affiliates. Our 2022 plan includes sustaining capital expenditures of between $100 million and $140 million and expansion capital expenditures of between $100 million and $150 million.

We expect to fund future acquisitions and capital expenditures with funds generated from our operations, borrowings under our Credit Agreement, Securitization Facility and the issuance of additional debt and equity securities. Future material investments or acquisitions may require that we obtain additional capital, assume third party debt or incur other long-term obligations. We have the option to utilize both equity and debt instruments as vehicles for the long-term financing of our investment activities and acquisitions.

Cash Distributions to Unitholders — Our Partnership Agreement requires that, within 45 days after the end of each quarter, we distribute all Available Cash, as defined in the Partnership Agreement. We made cash distributions to our common unitholders and general partner of $325 million and $406 million during the years ended December 31, 2021 and 2020, respectively.

On January 24, 2022, we announced that the board of directors of the General Partner declared a quarterly distribution on our common units of $0.39 per common unit. The distribution was paid on February 14, 2022 to unitholders of record on February 4, 2022.

On the same date, the board of directors of the General Partner declared a quarterly distribution on our Series B and Series C Preferred Units of $0.4922 and $0.4969 per unit, respectively. The Series B distributions will be paid on March 15, 2022 to unitholders of record on March 1, 2022. The Series C distribution will be paid on April 15, 2022 to unitholders of record on April 1, 2022.

We expect to continue to use cash provided by operating activities for the payment of distributions to our unitholders. See Note 16. “Partnership Equity and Distributions” in the Notes to the Consolidated Financial Statements in Item 8. “Financial Statements.”

Reconciliation of Non-GAAP Measures

Adjusted Gross Margin and Segment Adjusted Gross Margin — In addition to net income, we view our adjusted gross margin as an important performance measure of the core profitability of our operations. We review our adjusted gross margin monthly for consistency and trend analysis.

We define adjusted gross margin as total operating revenues, less purchases and related costs, and we define segment adjusted gross margin for each segment as total operating revenues for that segment less purchases and related costs for that segment. Our adjusted gross margin equals the sum of our segment adjusted gross margins. Adjusted gross margin and segment adjusted gross margin are primary performance measures used by management, as these measures represent the results of product sales and purchases, a key component of our operations. As an indicator of our operating performance, adjusted gross margin and segment adjusted gross margin should not be considered an alternative to, or more meaningful than, operating revenues, gross margin, segment gross margin, net income or loss, net income or loss attributable to partners, operating income, net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP.

We believe adjusted gross margin provides useful information to our investors because our management views our adjusted gross margin and segment adjusted gross margin as important performance measures that represent the results of product sales and purchases, a key component of our operations. We review our adjusted gross margin and segment adjusted gross margin monthly for consistency and trend analysis. We believe that investors benefit from having access to the same financial measures that management uses in evaluating our operating results.

Adjusted EBITDA — We define adjusted EBITDA as net income or loss attributable to partners adjusted for (i) distributions from unconsolidated affiliates, net of earnings, (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives, (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations. Management believes these measures provide investors meaningful insight into results from ongoing operations.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or loss, net income or loss attributable to partners, operating income, net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations.

Adjusted EBITDA is used as a supplemental liquidity and performance measure and adjusted segment EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others to assess:

- 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 those of other companies in the midstream energy industry, without regard to financing methods or capital structure;
- viability and performance of acquisitions and capital expenditure projects and the overall rates of return on investment opportunities; and
- in the case of Adjusted EBITDA, the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness, make cash distributions to our unitholders and pay capital expenditures.

Adjusted Segment EBITDA — We define adjusted segment EBITDA for each segment as segment net income or loss attributable to partners adjusted for (i) distributions from unconsolidated affiliates, net of earnings, (ii) depreciation and amortization expense, (iii) net interest expense, (iv) noncontrolling interest in depreciation and income tax expense, (v) unrealized gains and losses from commodity derivatives, (vi) income tax expense or benefit, (vii) impairment expense and (viii) certain other non-cash items. Adjusted segment EBITDA further excludes items of income or loss that we characterize as unrepresentative of our ongoing operations for that segment. Our adjusted segment EBITDA may not be comparable to similarly titled measures of other companies because they may not calculate adjusted segment EBITDA in the same manner.

Adjusted segment EBITDA should not be considered in isolation or as an alternative to our financial measures presented in accordance with GAAP, including operating revenues, net income or loss attributable to partners, or any other measure of performance presented in accordance with GAAP.

Our adjusted gross margin, segment adjusted gross margin, adjusted EBITDA and adjusted segment EBITDA may not be comparable to a similarly titled measure of another company because other entities may not calculate these measures in the same manner. The accompanying schedules provide reconciliations of adjusted gross margin, segment adjusted gross margin and adjusted segment EBITDA to their most directly comparable GAAP financial measures.

Distributable Cash Flow — We define Distributable Cash Flow as adjusted EBITDA, as defined above, less sustaining capital expenditures, net of reimbursable projects, less interest expense, less income attributable to preferred units, and certain other items. Sustaining capital expenditures are cash expenditures made to maintain our cash flows, operating or earnings capacity. These expenditures add on to or improve capital assets owned, including certain system integrity, compliance and safety improvements. Sustaining capital expenditures also include certain well connects, and may include the acquisition or construction of new capital assets. Income attributable to preferred units represent cash distributions earned by the preferred units. Cash distributions to be paid to the holders of the preferred units assuming a distribution is declared by our board of directors, are not available to common unit holders. Non-cash mark-to-market of derivative instruments is considered to be non-cash for the purpose of computing Distributable Cash Flow because settlement will not occur until future periods, and will be impacted by future changes in commodity prices and interest rates. We compare the Distributable Cash Flow we generate to the cash distributions we expect to pay our partners. Distributable Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess our ability to make cash distributions to our unitholders and our general partner.

Our Distributable Cash Flow may not be comparable to a similarly titled measure of another company because other entities may not calculate Distributable Cash Flow in the same manner.

Excess Free Cash Flow — We define Excess Free Cash Flow as Distributable Cash Flow, as defined above, less distributions to limited partners, less expansion capital expenditures, net of reimbursable projects, and contributions to equity method investments and certain other items. Expansion capital expenditures are cash expenditures to increase our cash flows, or operating or earnings capacity. Expansion capital expenditures include acquisitions or capital improvements (where we add on to or improve the capital assets owned, or acquire or construct new gathering lines and well connects, treating facilities, processing plants, fractionation facilities, pipelines, terminals, docks, truck racks, tankage and other storage, distribution or transportation facilities and related or similar midstream assets).

Excess Free Cash Flow is used as a supplemental liquidity and performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, and is useful to investors and management as a measure of our ability to generate cash. Once business needs and obligations are met, including cash reserves to provide funds for distribution payments on our units and the proper conduct of our business, which includes cash reserves for future capital expenditures and anticipated credit needs, this cash can be used to reduce debt, reinvest in the company for future growth, or return to unitholders.

Our definition of Excess Free Cash Flow is limited in that it does not represent residual cash flows available for discretionary expenditures. Therefore, we believe the use of Excess Free Cash Flow for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure. Excess Free Cash Flow may not be comparable to a similarly titled measure of another company because other entities may not calculate Excess Free Cash Flow in the same manner.

The following table sets forth our reconciliation of certain non-GAAP measures:

	Year Ended December 31,		
	2021	2020	2019
Reconciliation of Non-GAAP Measures		(millions)	
Reconciliation of gross margin to adjusted gross margin:			
Operating revenues	$ 10,707	$ 6,302	$ 7,625
Cost of revenues			
Purchases and related costs	8,093	3,627	4,933
Purchases and related costs from affiliates	188	166	223
Transportation and related costs from affiliates	984	950	866
Depreciation and amortization expense	364	376	404
Gross margin	1,078	1,183	1,199
Depreciation and amortization expense	364	376	$ 404
Adjusted gross margin	$ 1,442	$ 1,559	$ 1,603
Reconciliation of segment gross margin to segment adjusted gross margin:			
Logistics and Marketing segment:			
Operating revenues	$ 9,734	$ 5,530	$ 6,856
Cost of revenues			
Purchases and related costs	9,596	5,197	6,602
Depreciation and amortization expense	12	13	19
Segment gross margin	126	320	$ 235
Depreciation and amortization expense	12	13	$ 19
Segment adjusted gross margin	$ 138	$ 333	$ 254
Gathering and Processing segment:			
Operating revenues	$ 6,894	$ 3,479	$ 4,319
Cost of revenues			
Purchases and related costs	5,590	2,253	2,970
Depreciation and amortization expense	325	333	355
Segment gross margin	979	893	994
Depreciation and amortization expense	325	333	355
Segment adjusted gross margin	$ 1,304	$ 1,226	$ 1,349

	2021	2020	2019
	Year Ended December 31,		
		(millions)	
Reconciliation of net income attributable to partners to adjusted segment EBITDA:			
Logistics and Marketing segment:			
Segment net income attributable to partners (a)	$ 596	$ 777	$ 605
Non-cash commodity derivative mark-to-market	19	(78)	29
Depreciation and amortization expense, net of noncontrolling interest	12	13	19
Distributions from unconsolidated affiliates, net of earnings	56	106	44
Asset impairments	13	—	35
Other (income) expense	(2)	2	10
Adjusted segment EBITDA	$ 694	$ 820	$ 742
Gathering and Processing segment:			
Segment net income (loss) attributable to partners	$ 347	$ (499)	$ 22
Non-cash commodity derivative mark-to-market	106	23	49
Depreciation and amortization expense, net of noncontrolling interest	324	332	354
Distributions from unconsolidated affiliates, net of earnings	13	78	22
Asset impairments	18	746	212
Other expense	9	3	76
Adjusted segment EBITDA	$ 817	$ 683	$ 735

(a) We recognized no lower of cost or net realizable value adjustment for the year ended December 31, 2021. We recognized $6 million of lower of cost or net realizable value adjustments for the year ended December 31, 2020.

Operating and Maintenance and General and Administrative Expense

Pursuant to the Contribution Agreement, on January 1, 2017, the Partnership entered into the Services Agreement, which replaced the services agreement between the Partnership and DCP Midstream, LLC, dated February 14, 2013, as amended. Under the Services Agreement, we are required to reimburse DCP Midstream, LLC for salaries of personnel and employee benefits, as well as capital expenditures, maintenance and repair costs, taxes and other direct costs incurred by DCP Midstream, LLC on our behalf. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for other expenses and expenditures incurred or payments made on our behalf.

Operating and maintenance expenses are costs associated with the operation of a specific asset and are primarily comprised of direct labor, ad valorem taxes, repairs and maintenance, lease expenses, utilities and contract services. These expenses fluctuate depending on the activities performed during a specific period.

General and administrative expense represents costs incurred to manage the business. This expense includes cost of centralized corporate functions performed by DCP Midstream, LLC, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll and engineering and all other expenses necessary or appropriate to the conduct of the business.
We also incurred third party general and administrative expenses, which were primarily related to compensation and benefit expenses of the personnel who provide direct support to our operations. Also included are expenses associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, due diligence and acquisition costs, costs associated with the Sarbanes-Oxley Act of 2002, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs, and director compensation.

Critical Accounting Estimates

Our financial statements reflect the selection and application of accounting policies that require management to make estimates and assumptions. Management believes that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations. Management bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities. Our significant accounting policies are described further in Note 2 of the Notes to Consolidated Financial Statements in Item 8. "Financial Statements and Supplementary Data."

Impairment of long-lived assets - We evaluate property, plant and equipment, operating lease right-of-use (“ROU”) assets and other finite-lived assets for impairment when facts and circumstances indicate that the carrying values of such assets may not be recoverable.

If it is determined that a triggering event has occurred, we prepare a quantitative evaluation based on undiscounted cash flow projections expected to be realized over the remaining useful life of the primary asset. The carrying amount is not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset’s carrying value over its fair value.

We estimate fair value measurements to record impairment to certain long-lived assets and to determine fair value disclosures in accordance with Accounting Standards Codification ("ASC") 360 and 820. These significant estimates, judgments, inputs, and assumptions include, when applicable, the selection of an appropriate valuation method depending on the nature of the respective asset, such as the income approach, the market or sales comparison approach. The fair value of our operating asset groups is estimated using a discounted cash flow model as quoted market prices are not available. For other long-lived assets, fair value is determined using an approach that is appropriate based on the relevant facts and circumstances, which may include discounted cash flows or comparable transactions analyses.

Determining whether impairment indicators exist, estimating the undiscounted cash flows and fair value of the Company’s long lived assets for impairment testing requires significant judgment. The assumptions used to assess impairment consider historical trends, macroeconomic and industry conditions, and projections consistent with the Company’s operating strategy. Our undiscounted cash flow forecasts contain uncertainties because they require management to make assumptions and to apply judgment in estimating future cash flows including forecasting projected revenues and margins based on the future volumes of gas or other applicable throughputs, future commodity prices, operating costs, forecasting useful lives of the assets, assessing the probability of different outcomes, and with respect to asset fair values selecting an appropriate discount rate to estimate the present value of those projected cash flows. The discount rate is selected based on the return we believe a market participant would require that appropriately reflects the risks associated with the cash flows when determining a purchase price for the asset groups.

Using the impairment review methodology described herein, we recorded $31 million of impairment charges on long-lived assets during the year ended December 31, 2021. These estimates are sensitive to change and if actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to additional impairment charges that could be material. If our forecast indicates lower commodity prices in future periods at a level and duration that results in producers curtailing or redirecting drilling in areas where we operate this may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Impairment of investments in unconsolidated affiliates - We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate, in management’s judgment, that the fair value of such investment may have experienced a decline to less than its carrying value and the impairment is other than temporary.

We estimate fair value measurements to record impairment to certain unconsolidated affiliates and to determine fair value disclosures in accordance with ASC 323 and 820. These significant estimates, judgments, inputs, and assumptions include, when applicable, the selection of an appropriate valuation method depending on the nature of the respective asset, such as the income approach, the market or sales comparison approach. When determining whether a decline in value is other than temporary, management considers factors such as the duration and extent of the decline, the investee’s financial condition and near-term prospects, and our ability and intention to retain our investment for a period that allows for recovery. The fair value of our unconsolidated affiliates is primarily estimated using a discounted cash flow model as quoted market prices are not available.

Determining whether impairment indicators exist and estimating the fair value of the Company’s unconsolidated affiliates for impairment testing requires significant judgment. The assumptions used to assess other than temporary impairment consider historical trends, macroeconomic and industry conditions, and projections consistent with the Company’s operating strategy. Our fair value calculations contain uncertainties because they require management to make assumptions and to apply judgment in estimating future cash flows including forecasting projected revenues and margins based on the future volumes of gas or other applicable throughputs, future commodity prices, operating costs, forecasting useful lives of the assets, assessing the probability of different outcomes, and with respect to asset fair values selecting an appropriate discount rate to estimate the present value of those projected cash flows. The discount rate is selected based on the return we believe a market participant would require that appropriately reflects the risks associated with the cash flows.

Using the impairment review methodology described herein, we have not recorded any significant impairment charges on investments in unconsolidated affiliates during the year ended December 31, 2021. These estimates are sensitive to change and if actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to impairment charges that could be material. If the estimated fair value of our unconsolidated affiliates is less than the carrying value, we would recognize an impairment loss for the excess of the carrying value over the estimated fair value only if the loss is other than temporary. A period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on the investee's operations and cash flows.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

Market risk is the risk of loss arising from adverse changes in market prices and rates. We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as forward contracts, swaps and futures to mitigate a portion of the effects of identified risks. In general, we attempt to mitigate a portion of the risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements.

Risk Management Policy

We have established a comprehensive risk management policy, or Risk Management Policy, and a risk management committee, or the Risk Management Committee, to monitor and manage market risks associated with commodity prices and counterparty credit. Our Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of commodity price risk and counterparty credit risk, including monitoring trading and marketing risk exposure, risk limits, valuation and risk measurement methodologies, risk management activities, commodity contracts, and other related operations, policies and procedures, exposure limits and internal controls in place.

We have established volumetric limits, tenor limits, operational timing and required exit strategies for our commodity cash flow protection activities.

We have also established total volumetric limits, volumetric imbalance limits, tenor limits, and total value limits, which are all monitored daily, for our natural gas asset based trading and marketing.

See Note 15, Risk Management and Hedging Activities, of the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data” for further discussion of the accounting for derivative contracts.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering services, we receive fees or commodities from producers to bring the natural gas from the wellhead to the processing plant. For processing and storage services, we either receive fees or commodities as payment for these services, depending on the types of contracts. The Risk Management Committee approves the commodities, products and types of transactions to be entered into in the execution of our risk taking and mitigation strategy. We use swaps, futures, forwards and options in various markets to manage the execution of our commodity price risk mitigation strategy and use the market knowledge gained from our physical commodity market activities to capture market opportunities.

Our use of derivative instruments is governed by our Risk Management Policy approved by our Board of Directors and Risk Management Committee, which policy prohibits the use of highly leveraged derivatives or derivative instruments without sufficient market liquidity for comparable valuations and establishes risk limits, policies and procedures to manage risks associated with our trading, marketing and hedging activities. Compliance with these limits is monitored daily by our Risk Management Committee.

Commodity Cash Flow Protection Activities - We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various fixed price swap contracts to mitigate a portion of the effect pricing fluctuations may have on the value of our assets and operations. Depending on our risk management objectives, we may periodically settle a portion of these instruments prior to their maturity.

We enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. Our commodity derivative instruments used for our hedging program are a combination of direct NGL product, crude oil, and natural gas hedges.

Commodity prices experienced volatility during 2021, as illustrated in Item 1A. Risk Factors - “Our cash flow is affected by natural gas, NGL and condensate prices.” A decline in commodity prices could result in a decrease in exploration and development activities in certain fields served by our gas gathering and residue gas and NGL pipeline transportation systems, and our natural gas processing and treating plants, which could lead to further reduced utilization of these assets.

The derivative financial instruments we have entered into are typically referred to as “swap” contracts. The swap contracts entitle us to receive payment at settlement from the counterparty to the contract to the extent that the reference price is below the swap price stated in the contract, and we are required to make payment at settlement to the counterparty to the extent that the reference price is higher than the swap price stated in the contract.

We use the mark-to-market method of accounting for all commodity cash flow protection activities, which has significantly increased the volatility of our results of operations as we recognize, in current earnings, all non-cash gains and losses from the mark-to-market on derivative activity.

The following tables set forth additional information about our fixed price swaps used to mitigate a portion of our natural gas and NGL price risk associated with our percent-of-proceeds arrangements and our condensate price risk associated with our gathering and processing operations. Our positions as of February 16, 2022 were as follows:

Commodity Swaps

Period	Commodity	Notional Volume - Short Positions	Reference Price	Price Range
January 2022 — December 2022	Natural Gas	(142,500) MMBtu/d (d)	NYMEX Final Settlement Price (a)	$2.40-$5.90/MMBtu
January 2023 — December 2023	Natural Gas	(17,500) MMBtu/d (d)	NYMEX Final Settlement Price (a)	$2.80-$3.25/MMBtu
January 2022 — December 2022	NGLs	(9,622) Bbls/d (e)	Mt.Belvieu (b)	$.54-$1.30/Gal
January 2022 — February 2022	Crude Oil	(5,988) Bbls/d (e)	NYMEX crude oil futures (c)	$45.46-$65.56/Bbl
March 2022 — February 2023	Crude Oil	(4,025) Bbls/d (e)	NYMEX crude oil futures (c)	$46.86-$82.07/Bbl
March 2023 — December 2023	Crude Oil	(1,961) Bbls/d (e)	NYMEX crude oil futures (c)	$60.37-$74.18/Bbl

(a) NYMEX final settlement price for natural gas futures contracts (NG).
(b) The average monthly OPIS price for Mt. Belvieu TET/Non-TET.
(c) Monthly average of the daily close prices for the prompt month NYMEX light, sweet crude oil futures contract (CL).
(d) Average MMBtu/d per time period.
(e) Average Bbls/d per time period.

Our sensitivities for 2022 as shown in the table below are estimated based on our average estimated commodity price exposure and commodity cash flow protection activities for the calendar year 2022, and exclude the impact of non-cash mark-to-market changes on our commodity derivatives. We utilize direct product crude oil, natural gas and NGL derivatives to mitigate a portion of our condensate, natural gas and NGL commodity price exposure. These sensitivities are associated with our condensate, natural gas and NGL volumes that are currently unhedged.

Commodity Sensitivities Net of Cash Flow Protection Activities

	Per Unit Decrease		Unit of Measurement	Estimated Decrease in Annual Net Income Attributable to Partners	
				(millions)	
NGL prices	$	0.01	Gallon	$	5
Natural gas prices	$	0.10	MMBtu	$	2
Crude oil prices	$	1.00	Barrel	$	3

In addition to the linear relationships in our commodity sensitivities above, additional factors may cause us to be less sensitive to commodity price declines. A portion of our net income is derived from fee-based contracts and a portion from percentage-of-proceeds and percentage-of-liquids processing arrangements that contain minimum fee clauses in which our processing margins convert to fee-based arrangements as commodity prices decline.

We estimate the following sensitivities related to the non-cash mark-to-market on our commodity derivatives associated with our open position on our commodity cash flow protection activities:

Non-Cash Mark-To-Market Commodity Sensitivities

	Per Unit Increase	Unit of Measurement	Estimated Mark-to-Market Impact (Decrease in Net Income Attributable to Partners)
			(millions)
NGL prices	$ 0.01	Gallon	$
Natural gas prices	$ 0.10	MMBtu	$
Crude oil prices	$ 1.00	Barrel	$

While the above commodity price sensitivities are indicative of the impact that changes in commodity prices may have on our annualized net income, changes during certain periods of extreme price volatility and market conditions or changes in the relationship of the price of NGLs and crude oil may cause our commodity price sensitivities to vary significantly from these estimates.

The midstream natural gas industry is cyclical, with the operating results of companies in the industry significantly affected by the prevailing price of NGLs, which in turn has been generally related to the price of crude oil. Although the prevailing price of residue natural gas has less short-term significance to our operating results than the price of NGLs, in the long-term the growth and sustainability of our business depends on natural gas prices being at levels sufficient to provide incentives and capital for producers to increase natural gas exploration and production. To minimize potential future commodity-based pricing and cash flow volatility, we have entered into a series of derivative financial instruments.

Based on historical trends, we generally expect NGL prices to directionally follow changes in crude oil prices over the long-term. However, the pricing relationship between NGLs and crude oil may vary, as we believe crude oil prices will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy, whereas NGL prices are more correlated to supply and U.S. petrochemical demand. Additionally, the level of NGL export demand may also have an impact on prices. We believe that future natural gas prices will be influenced by the level of North American production and drilling activity of exploration and production companies, the balance of trade between imports and exports of liquid natural gas and NGLs and the severity of winter and summer weather. Drilling activity can be adversely affected as natural gas prices decrease. Energy market uncertainty could also reduce North American drilling activity. Limited access to capital could also decrease drilling. Lower drilling levels over a sustained period would reduce natural gas volumes gathered and processed, but could increase commodity prices, if supply were to fall relative to demand levels.

Natural Gas Storage and Pipeline Asset Based Commodity Derivative Program — Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or net realizable value, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost-or-market accounting for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

The following tables set forth additional information about our derivative instruments, used to mitigate a portion of our natural gas price risk associated with our inventory within our natural gas storage operations as of December 31, 2021:

Inventory

Period ended	Commodity	Notional Volume - Long Positions		Fair Value (millions)		Weighted Average Price
December 31, 2021	Natural Gas	11,394,892	MMBtu	$	43	$3.74/MMBtu

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Fair Value (millions)		Price Range
January 2022 — March 2022	Natural Gas	(17,765,000)	MMBtu	$	17	$3.53-$6.33/MMBtu
January 2022 — February 2022	Natural Gas	6,022,500	MMBtu	$	—	$3.66-$4.39/MMBtu

Natural Gas Asset Based Trading and Marketing - Our trading and marketing activities are subject to commodity price fluctuations in response to changes in supply and demand, market conditions and other factors.

We may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. The following table sets forth our commodity derivative instruments as of December 31, 2021:

Commodity Swaps

Period	Commodity	Notional Volume - (Short)/Long Positions		Fair Value (millions)	Price Range (a)
January 2022 — December 2025	Natural Gas	(71,077,500)	MMBtu	$(7)	$0.05-$0.60/MMBtu
January 2022 — October 2026	Natural Gas	72,210,000	MMBtu	$(4)	$0.19-$1.70/MMBtu

(a) Represents the basis differential from NYMEX final settlement price for natural gas futures contracts for stated time period

We manage our commodity derivative activities in accordance with our Risk Management Policy which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Valuation - Valuation of a contract's fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationships with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

The fair value of our commodity non-trading derivatives is expected to be realized in future periods, as detailed in the following table. The amount of cash ultimately realized for these contracts will differ from the amounts shown in the following table due to factors such as market volatility, counterparty default and other unforeseen events that could impact the amount and/or realization of these values.

Fair Value of Contracts as of December 31, 2021

Sources of Fair Value	Total	Maturity in 2022
	(millions)	
Prices supported by quoted market prices and other external sources	$ (74)	$ (56)
Prices based on models or other valuation techniques	(5)	(3)
Total	$ (79)	$ (59)

The “prices supported by quoted market prices and other external sources” category includes our commodity positions in natural gas, NGLs and crude oil. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which over-the-counter, or OTC, broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate.

The “prices based on models and other valuation techniques” category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the market point.

Credit Risk

Our customers include large multi-national petrochemical and refining companies, natural gas marketers, as well as commodity producers. Substantially all of our natural gas, propane and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, as these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties’ financial condition prior to entering into an agreement, establish credit limits, and monitor the appropriateness of these limits on an ongoing basis. Our corporate credit policy, as well as the standard terms and conditions of our agreements, prescribe the use of financial responsibility and reasonable grounds for adequate assurances. These provisions allow our credit department to request that a counterparty remedy its credit limit violations by posting cash or letters of credit for exposure in excess of an established credit line. The credit line represents an open credit limit, determined in accordance with our credit policy. Our standard agreements also provide that the inability of a counterparty to post collateral is sufficient cause to terminate a contract and liquidate all positions. The adequate assurance provisions also allow us to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment to us in a satisfactory form.

Interest Rate Risk

Interest rates on Credit Agreement and Securitization Facility borrowings, and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. We may mitigate a portion of our future interest rate risk with interest rate swaps that reduce our exposure to market rate fluctuations by converting variable interest rates on our debt to fixed interest rates and locking in rates on our anticipated future fixed-rate debt, respectively. Additionally, see the risk factor “It is unclear how changes in the regulation of LIBOR or the discontinuation of LIBOR altogether may affect our financing costs in the future.” in Item 1A. Risk Factors.

At December 31, 2021, the effective weighted-average interest rate on our outstanding debt was 5.23%.

Item 8. ***Financial Statements***

INDEX TO FINANCIAL STATEMENTS

DCP MIDSTREAM, LP CONSOLIDATED FINANCIAL STATEMENTS:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of DCP Midstream GP, LLC and the Unitholders of DCP Midstream, LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of DCP Midstream, LP and subsidiaries (the "Partnership") as of December 31, 2021 and 2020, the related consolidated statements of operations, comprehensive (loss) income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

We did not audit the financial statements of Gulf Coast Express Pipeline, LLC, an investment which is accounted for by the Partnership using the equity method. The accompanying consolidated financial statements of the Partnership include its equity investment in Gulf Coast Express Pipeline, LLC of $422 million as of December 31, 2021, and its equity earnings in Gulf Coast Express Pipeline, LLC of $63 million for the year ended December 31, 2021. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Gulf Coast Express Pipeline LLC, is based solely on the report of the other auditors.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2021, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2022, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Property, Plant and Equipment, Net - Determination of Impairment Indicators– Refer to Notes 2, 9 and 12 to the financial statements

Critical Audit Matter Description

The Partnership periodically evaluates whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of long-lived assets may not be recoverable. Management considers various factors when determining if long-lived assets should be evaluated for impairment including a significant adverse change in the business climate, a current period operating or cash flow loss combined with a history of losses, a significant adverse change in the extent or manner in which an asset is used, or a current expectation that the asset will be sold or otherwise disposed of before the end of its useful life.

The Partnership’s determination of whether impairment indicators exist for long lived assets requires management to apply significant judgment. When events or circumstances exist that indicate the carrying value of long-lived assets may not be recoverable, the Partnership evaluates its long-lived assets for impairment by comparing the carrying amount of the applicable asset group to the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset.

If management determines the carrying value is not recoverable, the impairment loss is measured as the excess of the asset’s carrying value over its fair value.

The property, plant, and equipment, net balance was $7,701 million as of December 31, 2021. The Partnership recorded $31 million of impairment charges related to property, plant and equipment during the year ended December 31, 2021 as the carrying value of the respective asset groups were determined to be not recoverable.

We identified the identification of impairment indicators for property, plant and equipment as a critical audit matter because of the significant assumptions management makes when determining whether events or changes in circumstances have occurred indicating that the carrying amounts of property, plant and equipment may not be recoverable.

This required a high degree of auditor judgment, including an increased extent of effort related to evaluating indicators of impairment and auditing whether management appropriately identified impairment indicators.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the identification of impairment indicators for long-lived assets included the following, among others:

- We tested the effectiveness of internal controls over financial reporting related to management’s identification of possible impairment indicators for long-lived assets that may indicate the carrying amount of long-lived assets may not be recoverable.
- We evaluated management’s analysis of impairment indicators by:
    - Assessing whether long-lived assets having indicators of impairment were appropriately identified
    - Considering industry and analysts reports and the impact of macroeconomic factors, such as adverse changes in the regulatory environment, legislation or other factors that may represent impairment indicators not previously contemplated in management's analysis
    - Evaluating management’s judgments around historical trends, macroeconomic and industry conditions, and whether projections are consistent with the Partnership’s operating strategy
    - Evaluating management’s forecasts by comparing such forecasts to: information included in the Partnership's public disclosures, recent results of operations, trends in operational data for asset groups such as measures of profitability over recent years and quarters
    - Inquiry of management over whether long-lived assets may be sold or otherwise disposed of significantly before the end of the assets' previously estimated useful life
    - Inspecting minutes of the board of directors and committees of executive management to understand if there were factors that would represent potential impairment indicators for long-lived assets

/s/ Deloitte & Touche LLP

Denver, Colorado
February 18, 2022

We have served as the Partnership’s auditor since 2004.

Report of Independent Registered Public Accounting Firm

Board of Directors and Members
Gulf Coast Express Pipeline LLC
Houston, Texas

Opinion on the Financial Statements

We have audited the balance sheets of Gulf Coast Express Pipeline LLC (the "Company") as of December 31, 2021 and 2020, the related statements of income, members' equity and cash flows for the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2021 and 2020, and the results of its operations and its cash flows for the years then ended**,** in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

Emphasis of Matter – Significant Transactions with Related Parties

As discussed in Note 4 to the financial statements, the Company has entered into significant transactions with related parties.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2020.

Houston Texas
February 16, 2022

DCP MIDSTREAM, LP
CONSOLIDATED BALANCE SHEETS

ASSETS	December 31, 2021	December 31, 2020
	(millions)	
Current assets:		
Cash and cash equivalents	$ 1	$ 52
Accounts receivable:		
Trade, net of allowance for credit losses of $2 and $2 million, respectively	1,029	572
Affiliates	389	238
Other	7	10
Inventories	77	38
Unrealized gains on derivative instruments	86	63
Collateral cash deposits	128	14
Other	32	21
Total current assets	1,749	1,008
Property, plant and equipment, net	7,701	7,993
Intangible assets, net	39	44
Investments in unconsolidated affiliates	3,578	3,641
Unrealized gains on derivative instruments	10	16
Operating lease assets	104	85
Other long-term assets	199	170
Total assets	$ 13,380	$ 12,957
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 977	$ 536
Affiliates	205	161
Other	16	23
Current debt	355	505
Unrealized losses on derivative instruments	145	56
Accrued interest	79	85
Accrued taxes	51	59
Accrued wages and benefits	60	70
Capital spending accrual	7	4
Other	115	122
Total current liabilities	2,010	1,621
Long-term debt	5,078	5,119
Unrealized losses on derivative instruments	30	7
Deferred income taxes	34	30
Operating lease liabilities	93	76
Other long-term liabilities	259	243
Total liabilities	7,504	7,096
Commitments and contingent liabilities (see note 21)		
Equity:		
Series A preferred limited partners (500,000 preferred units authorized, issued and outstanding, respectively)	489	489
Series B preferred limited partners (6,450,000 preferred units authorized, issued and outstanding, respectively)	156	156
Series C preferred limited partners (4,400,000 preferred units authorized, issued and outstanding, respectively)	106	106
Limited partners (208,373,672 and 208,351,528 common units authorized, issued and outstanding, respectively)	5,106	5,090
Accumulated other comprehensive loss	(6)	(7)
Total partners' equity	5,851	5,834
Noncontrolling interests	25	27
Total equity	5,876	5,861
Total liabilities and equity	$ 13,380	$ 12,957

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2021	2020	2019
	(millions, except per unit amounts)		
Operating revenues:			
Sales of natural gas, NGLs and condensate	$ 7,681	$ 4,603	$ 6,023
Sales of natural gas, NGLs and condensate to affiliates	3,105	1,088	1,176
Transportation, processing and other	539	455	439
Trading and marketing (losses) gains, net	(618)	156	(13)
Total operating revenues	10,707	6,302	7,625
Operating costs and expenses:			
Purchases and related costs	8,093	3,627	4,933
Purchases and related costs from affiliates	188	166	223
Transportation and related costs from affiliates	984	950	866
Operating and maintenance expense	659	607	728
Depreciation and amortization expense	364	376	404
General and administrative expense	223	253	275
Asset impairments	31	746	247
Other (income) expense, net	(5)	15	8
Loss on sale of assets, net	5	—	80
Restructuring costs	—	9	11
Total operating costs and expenses	10,542	6,749	7,775
Operating income (loss)	165	(447)	(150)
Earnings from unconsolidated affiliates	535	447	474
Interest expense, net	(299)	(302)	(304)
Income (loss) before income taxes	401	(302)	20
Income tax (expense) benefit	(6)	—	1
Net income (loss)	395	(302)	21
Net income attributable to noncontrolling interests	(4)	(4)	(4)
Net income (loss) attributable to partners	391	(306)	17
Series A preferred limited partners' interest in net income	(37)	(37)	(37)
Series B preferred limited partners' interest in net income	(13)	(13)	(13)
Series C preferred limited partners' interest in net income	(9)	(9)	(9)
General partner’s interest in net income	—	—	(118)
Net income (loss) allocable to limited partners	$ 332	$ (365)	$ (160)
Net income (loss) per limited partner unit — basic and diluted	$ 1.59	$ (1.75)	$ (1.05)
Weighted-average limited partner units outstanding — basic	208.4	208.3	153.1
Weighted-average limited partner units outstanding — diluted	208.6	208.3	153.1

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2021	2020	2019
	(millions)		
Net income (loss)	$ 395	$ (302)	$ 21
Other comprehensive income:			
Reclassification of cash flow hedge losses into earnings	1	—	1
Total other comprehensive income	1	—	1
Total comprehensive income (loss)	396	(302)	22
Total comprehensive income attributable to noncontrolling interests	(4)	(4)	(4)
Total comprehensive income (loss) attributable to partners	$ 392	$ (306)	$ 18

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Partners' Equity						
	Series A Preferred Limited Partners	Series B Preferred Limited Partners	Series C Preferred Limited Partners	Limited Partners	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
	(millions)						
Balance, January 1, 2021	$ 489	$ 156	$ 106	$ 5,090	$ (7)	$ 27	$ 5,861
Net income	37	13	9	332	—	4	395
Other comprehensive income	—	—	—	—	1	—	1
Distributions to unitholders	(37)	(13)	(9)	(325)	—	—	(384)
Distributions to noncontrolling interests	—	—	—	—	—	(6)	(6)
Equity based compensation	—	—	—	9	—	—	9
Balance, December 31, 2021	$ 489	$ 156	$ 106	$ 5,106	$ (6)	$ 25	$ 5,876

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Partner's Equity						
	Series A Preferred Limited Partners	Series B Preferred Limited Partners	Series C Preferred Limited Partners	Limited Partners	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
	(millions)						
Balance, January 1, 2020	$ 489	$ 156	$ 106	$ 5,861	$ (7)	$ 28	$ 6,633
Net income (loss)	37	13	9	(365)	—	4	(302)
Distributions to unitholders	(37)	(13)	(9)	(406)	—	—	(465)
Distributions to noncontrolling interests	—	—	—	—	—	(5)	(5)
Balance, December 31, 2020	$ 489	$ 156	$ 106	$ 5,090	$ (7)	$ 27	$ 5,861

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Partners' Equity							
	Series A Preferred Limited Partners	Series B Preferred Limited Partners	Series C Preferred Limited Partners	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Total Equity
					(millions)			
Balance, January 1, 2019	$ 489	$ 156	$ 106	$ 6,418	$ 107	$ (8)	$ 29	$ 7,297
Net income (loss)	37	13	9	(160)	118	—	4	21
Other comprehensive income	—	—	—	—	—	1	—	1
Distributions to unitholders	(37)	(13)	(9)	(447)	(171)	—	—	(677)
Distributions to noncontrolling interests	—	—	—	—	—	—	(5)	(5)
Conversion of GP economic interest and IDRs	—	—	—	50	(54)	—	—	(4)
Balance, December 31, 2019	$ 489	$ 156	$ 106	$ 5,861	$ —	$ (7)	$ 28	$ 6,633

See accompanying notes to consolidated financial statements.

DCP MIDSTREAM, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	2020	2019
	(millions)		
OPERATING ACTIVITIES:			
Net income (loss)	$ 395	$ (302)	$ 21
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense	364	376	404
Earnings from unconsolidated affiliates	(535)	(447)	(474)
Distributions from unconsolidated affiliates	604	631	540
Net unrealized losses (gains) on derivative instruments	125	(55)	78
Asset impairments	31	746	247
Loss on sale of assets, net	5	—	80
Other, net	26	22	21
Change in operating assets and liabilities, which (used) provided cash:			
Accounts receivable	(605)	62	170
Inventories	(39)	3	9
Accounts payable	478	(47)	(133)
Other assets and liabilities	(203)	110	(104)
Net cash provided by operating activities	646	1,099	859
INVESTING ACTIVITIES:			
Capital expenditures	(108)	(160)	(519)
Investments in unconsolidated affiliates	(5)	(107)	(450)
Distributions from unconsolidated affiliates	—	6	—
Proceeds from sale of assets	3	2	209
Net cash used in investing activities	(110)	(259)	(760)
FINANCING ACTIVITIES:			
Proceeds from debt	4,721	4,407	5,971
Payments of debt	(4,916)	(4,713)	(5,372)
Costs incurred related to conversion of GP economic interest and IDRs	—	—	(3)
Distributions to preferred limited partners	(59)	(59)	(59)
Distributions to limited partners and general partner	(325)	(406)	(618)
Distributions to noncontrolling interests	(6)	(5)	(5)
Debt issuance costs	(6)	(8)	(13)
Other	—	(1)	—
Net cash used in financing activities	(591)	(785)	(99)
Net change in cash, cash equivalents and restricted cash	(55)	55	—
Cash, cash equivalents and restricted cash, beginning of period	56	1	1
Cash, cash equivalents and restricted cash, end of period	$ 1	$ 56	$ 1

Reconciliation of cash, cash equivalents, and restricted cash:	December 31, 2021	December 31, 2020	December 31, 2019
Cash and cash equivalents	$ 1	$ 52	$ 1
Restricted cash included in other current assets	—	4	—
Total cash, cash equivalents, and restricted cash	$ 1	$ 56	$ 1

See accompanying notes to consolidated financial statements.

1. Description of Business and Basis of Presentation

DCP Midstream, LP, with its consolidated subsidiaries, or “us,” “we,” “our” or the “Partnership” is a Delaware limited partnership formed in 2005 by DCP Midstream, LLC to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets.

Our Partnership includes our Logistics and Marketing and Gathering and Processing segments. For additional information regarding these segments, see Note 23 - Business Segments.

Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as the General Partner, and which is 100% owned by DCP Midstream, LLC. DCP Midstream, LLC and its subsidiaries and affiliates, collectively referred to as DCP Midstream, LLC, is owned 50% by Phillips 66 and 50% by Enbridge Inc. and its affiliates, or Enbridge. DCP Midstream, LLC directs our business operations through its ownership and control of the General Partner. As of December 31, 2021, DCP Midstream, LLC, together with our general partner, owned approximately 57% of us through limited partner interests.

The consolidated financial statements include the accounts of the Partnership and all majority-owned subsidiaries where we have the ability to exercise control. Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method.

The consolidated financial statements have been prepared in accordance with GAAP. All intercompany balances and transactions have been eliminated in consolidation.

2. Summary of Significant Accounting Policies

Use of Estimates - Conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management’s best available knowledge of current and expected future events, actual results could differ from those estimates, which may be significantly impacted by various factors, including those outside of our control, such as the impact of sustained deterioration in commodity prices and volumes, which would negatively impact our results of operations, financial condition and cash flows.

Cash, Cash Equivalents, and Restricted Cash - We consider investments in highly liquid financial instruments purchased with an original stated maturity of 90 days or less and temporary investments of cash in short-term money market securities to be cash equivalents. Restricted cash primarily consists of amounts held in our non-qualified deferred compensation plan. Restricted cash is excluded from cash and cash equivalents and is included in other current or long-term assets.

Allowance for Credit Losses - Management estimates the amount of required allowances for credit losses based upon our assessment of various factors, including historical loss rates, the age of the accounts receivable balances, the credit quality of our customers, current economic conditions, reasonable and supportable forecasts of future economic conditions, and other relevant factors that may affect our ability to collect from customers.

Inventories - Inventories, which consist primarily of NGLs and natural gas, are recorded at the lower of weighted-average cost or net realizable value. Transportation costs are included in inventory.

Accounting for Risk Management Activities and Financial Instruments - Non-trading energy commodity derivatives are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or normal purchases or normal sales. The remaining non-trading derivatives, which are related to asset-based activities for which the normal purchase or normal sale exception is not elected, are recorded at fair value in the consolidated balance sheets as unrealized gains or unrealized losses in derivative instruments, with changes in the fair value recognized in the consolidated statements of operations. For each derivative, the accounting method and presentation of gains and losses or revenue and expense in the consolidated statements of operations are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method (a)	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Fair Value Hedge	Hedge method (b)	Gross basis in the same consolidated statements of operations category as the related hedged item
Normal Purchases or Normal Sales	Accrual method (c)	Gross basis upon settlement in the corresponding consolidated statements of operations category based on purchase or sale
Other Non-Trading Derivative Activity	Mark-to-market method (a)	Net basis in trading and marketing gains and losses, net

(a) Mark-to-market method - An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations in trading and marketing gains and losses, net during the current period.
(b) Hedge method - An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations for the effective portion until the service is provided or the associated delivery impacts earnings. For fair value hedges, the change in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations in the same category as the related hedged item.
(c) Accrual method - An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations for changes in fair value of a contract until the service is provided or the associated delivery impacts earnings.

Cash Flow and Fair Value Hedges - For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedging relationship and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on derivative instruments. The change in fair value of the effective portion of a derivative designated as a cash flow hedge is recorded in partners' equity in accumulated other comprehensive income, or AOCI, and the ineffective portion is recorded in the consolidated statements of operations. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations in the same line item as the item being hedged. Hedge accounting is discontinued prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

The fair value of a derivative designated as a fair value hedge is recorded for balance sheet purposes as unrealized gains or unrealized losses on derivative instruments. We recognize the gain or loss on the derivative instrument, as well as the offsetting loss or gain on the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the results of operations.

Valuation - When available, quoted market prices or prices obtained through external sources are used to determine a contract's fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical relationships with quoted market prices and the expected relationship with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment - Property, plant and equipment are recorded at historical cost. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Capitalized Interest - We capitalize interest during construction of major projects. Interest is calculated on the monthly outstanding capital balance and ceases in the month that the asset is placed into service. We also capitalize interest on our equity method investments which are devoting substantially all efforts to establishing a new business and have not yet begun planned principal operations. Capitalization ceases when the investee commences planned principal operations. The rates used to calculate capitalized interest are the weighted-average cost of debt, including the impact of interest rate swaps.

Asset Retirement Obligations - Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities and obligations related to right-of-way and land easement agreements. We adjust our asset retirement obligation each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability is determined using a credit-adjusted risk free interest rate, and accretes due to the passage of time based on the time value of money until the obligation is settled.

Intangible Assets - Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts, and related relationships. These intangible assets are amortized on a straight-line basis over the period of expected future benefit. Intangible assets are removed from the gross carrying amount and the total of accumulated amortization in the period in which they become fully amortized.

Investments in Unconsolidated Affiliates - We use the equity method to account for investments in greater than 20% owned affiliates.

We evaluate our investments in unconsolidated affiliates for impairment whenever events or changes in circumstances indicate a decline in value of such investments has occurred that is other than temporary. When there is evidence of impairment that is other than temporary, we compare the estimated fair value of the investment to the carrying value of the investment to determine whether impairment has occurred. We assess the fair value of our investments in unconsolidated affiliates using commonly accepted techniques, and may use more than one method, but is primarily measured with discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

Long-Lived Assets - We periodically evaluate whether the carrying value of long-lived assets, including intangible assets, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- significant adverse change in legal factors or business climate;
- a current-period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- significant adverse change in the market value of an asset; or

- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset’s carrying value over its fair value. We assess the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management’s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets. A period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

Leases - Our leasing activity primarily consists of transportation agreements, office space, vehicles, and field equipment. We determine if an arrangement is an operating or finance lease at inception. Right of use assets represent our right to use an underlying asset for the lease term when we control the use of the asset by obtaining substantially all of the economic benefits of the asset and direct the use of the asset. Lease liabilities represent our obligation to make lease payments arising from the lease. Right of use assets and lease liabilities are recognized at the commencement date based on the present value of lease payments over the lease term. The interest rate used to calculate the present value of lease payments is the rate implicit in the lease when determinable or our incremental borrowing rate. Our incremental borrowing rate is primarily based on our collateralized borrowing rate when such borrowings exist or an estimated collateralized borrowing rate based on independent third party quotes when such borrowings do not exist. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that we will exercise that option. Operating lease expense is recognized on a straight-line basis over the lease term. Finance lease expense is recognized based on the effective-interest method and amortization of the right of use asset is recognized based on the straight-line method.

Practical expedients - We apply certain practical expedients in Accounting Standards Codification ("ASC") 842, Leases and we do not recognize ROU assets and lease liabilities for short-term leases and, instead, record them in a manner similar to operating leases under legacy lease accounting guidelines. A short-term lease is one with a maximum lease term of 12 months or less and does not include a purchase option the lessee is reasonably certain to exercise. We combine lease and nonlease components relating to our office and warehouse leases, as applicable.

Unamortized Debt Discount and Expense - Discounts and expenses incurred with the issuance of long-term debt are amortized over the term of the debt using the effective interest method. The discounts and unamortized expenses are recorded on the consolidated balance sheets within the carrying amount of long-term debt.

Noncontrolling Interest - Noncontrolling interest represents any third party or affiliate interest in non-wholly owned entities that we consolidate. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party or affiliate interest in our consolidated balance sheet amounts shown as noncontrolling interest in equity. Distributions to and contributions from noncontrolling interests represent cash payments to and cash contributions from, respectively, such third party and affiliate investors.

Revenue Recognition - Our operating revenues are primarily derived from the following activities:

- sales of natural gas, NGLs and condensate;
- services related to gathering, compressing, treating, and processing natural gas; and
- services related to transportation and storage of natural gas and NGLs.

Sales of natural gas, NGLs and condensate - We sell our commodities to a variety of customers ranging from large, multi-national petrochemical and refining companies to regional retail propane distributors. We recognize revenue from commodity sales at the point in time when control is obtained by the customer. Generally, the transaction price is determined at the time of each delivery as the variability of commodity pricing is resolved. Customers usually pay monthly based on the products purchased the previous month.

Sales of natural gas, NGLs and condensate include physical sales contracts which qualify as financial derivative instruments, and buy-sell and exchange transactions which involve purchases and sales of inventory with the same counterparty that are legally contingent or in contemplation of one another as a single transaction on a combined net basis. Neither of these types of arrangements are contracts with customers within the scope of Financial Accounting Standards Board, or "FASB", Accounting Standards Update, or "ASU", 2014-09 Revenue from Contracts with Customers, or "Topic 606".

Gathering, compressing, treating and processing natural gas - For natural gas gathering and processing activities, we receive either fees and/or a percentage of proceeds from commodity sales as payment for these services, depending on the type of contract. For gathering and processing agreements within the scope of Topic 606, we recognize the revenue associated with our services when the gas is gathered, treated or processed at our facilities. Under fee-based contracts, we receive a fee for our services based on throughput volumes. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds received from our sale of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Our percent-of-proceeds contracts may also include a fee-based component.

Transportation and storage - Revenue from transportation and storage agreements is recognized based on contracted volumes transported and stored in the period the services are provided.

Our service contracts sometimes have terms that extend beyond one year, and are recognized over time. The performance obligation for most of our service contracts encompasses a series of distinct services performed on discrete daily quantities of natural gas or NGLs for purposes of allocating variable consideration and recognizing revenue while the customer simultaneously receives and consumes the benefits of the services provided. Revenue is recognized over time consistent with the transfer of goods or services over time to the customer based on daily volumes delivered or stored. Consideration is generally variable, and the transaction price cannot be determined at the inception of the contract, because the volume of natural gas or NGLs for which the service is provided is only specified on a daily or monthly basis. The transaction price is determined at the time the service is provided and the uncertainty is resolved. Customers usually pay monthly based on the services performed the previous month.

Purchase arrangements - Under purchase arrangements, we purchase natural gas at either the wellhead or the tailgate of a plant. These purchase arrangements represent an arrangement with a supplier and are recorded in “Purchases and related costs”. Often, we earn fees for services performed prior to taking control of the product in these arrangements and service revenue is recorded for these fees. Revenue generated from the sale of product obtained in these purchase arrangements are reported as “Sales of natural gas, NGLs and condensate” on the consolidated statements of operations and are recognized on a gross basis as we purchase and take control of the product prior to sale and are the principal in the transaction.

Practical expedients - We apply certain practical expedients in Topic 606 and do not disclose information about transaction prices allocated to remaining performance obligations that have original expected durations of one year or less, nor do we disclose information about transaction prices allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

Contract liabilities - We have contracts with customers whereby the customer reimburses us for costs to construct certain connections to our operating assets. These agreements are typically entered into in contemplation with gathering and processing agreements and transportation agreements with customers, and are part of the consideration of the contract. We record these payments as deferred revenue which are amortized into revenue over the expected contract term.

Purchases and related costs - Purchases and related costs primarily includes (i) the cost of purchased commodities, including NGLs, natural gas and condensate, and (ii) fees incurred for transportation and fractionation of commodities.

Significant Customers - There were no third party customers that accounted for more than 10% of total operating revenues for the years ended December 31, 2021, 2020 and 2019. We had significant transactions with affiliates for the years ended December 31, 2021, 2020 and 2019.

Environmental Expenditures - Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not generate current or future revenue are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated.

Equity-Based Compensation - Equity classified awards are measured at their grant date fair value, which is recognized on a straight line basis over the requisite service or vesting period. Equity classified awards are expected to result in the issuance of common units upon vesting. Liability classified equity-based compensation cost is remeasured at each reporting date at fair value, based on the closing security price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award.

Income Taxes - We are structured as a master limited partnership which is a pass-through entity for federal income tax purposes. Our income tax expense includes certain jurisdictions, including state, local, franchise and margin taxes of the master limited partnership and subsidiaries. We follow the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities. Our taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statements of operations, is proportionately included in the federal income tax returns of each partner.

Net Income or Loss per Limited Partner Unit - Basic and diluted net income or loss per limited partner unit, or LPU, is calculated by dividing net income or loss allocable to limited partners, by the weighted-average number of outstanding LPUs during the period using the two-class method. Diluted net income or loss per limited partner unit is computed based on the weighted average number of limited partner units, plus the effect of dilutive potential units, if any, outstanding during the period.

3. Recent Accounting Pronouncements

FASB ASU, 2020-04 "Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting" or ASU 2020-04 - In March 2020, the FASB issued ASU 2020-04, which provides optional expedients and exceptions for applying GAAP to contract modifications, hedging relationships, and other transactions that reference LIBOR or another reference rate expected to be discontinued because of reference rate reform. This ASU is effective for interim and annual reporting periods that include or are subsequent to March 12, 2020. We adopted this ASU on March 12, 2020 and it did not have a material impact on our consolidated financial statements.

The FASB has issued certain accounting updates which were assessed and either determined to be not applicable or are not expected to have a significant impact on our financial statements.

4. Dispositions

During 2021 we divested several non-core assets in our Midcontinent region of our Gathering and Processing segment and in West Texas in our Logistics and Marketing segment. We received proceeds of $3 million and recognized a net loss on sale of assets and businesses of $5 million during 2021.

On January 30, 2019, we entered into a purchase and sale agreement with NGL Energy Partners LP to sell Gas Supply Resources, our wholesale propane business primarily consisting of seven natural gas liquids terminals in the Eastern United States within our Logistics and Marketing segment for a purchase price of $90 million. Net proceeds received were approximately $103 million due to customary purchase price adjustments and a loss of $9 million was recognized. The transaction closed effective March 1, 2019.

In addition to the sale of Gas Supply Resources, we divested several non-core assets in our Midcontinent and Permian regions. We received proceeds of $106 million and recognized a net loss on sale of assets and businesses of $71 million during 2019.

5. Revenue Recognition

We disaggregate our revenue from contracts with customers by type of contract for each of our reportable segments, as we believe it best depicts the nature, timing and uncertainty of our revenue and cash flows. The following tables set forth our revenue by those categories:

	Year Ended December 31, 2021			
	Logistics and Marketing	Gathering and Processing	Eliminations	Total
		(millions)		
Sales of natural gas	$ 3,798	$ 2,824	$ (2,614)	$ 4,00
Sales of NGLs and condensate (a)	6,133	3,952	(3,307)	6,77
Transportation, processing and other	65	474	—	53
Trading and marketing losses, net (b)	(262)	(356)	—	(61
Total operating revenues	$ 9,734	$ 6,894	$ (5,921)	$ 10,70

(a) Includes $2,111 million for the year ended December 31, 2021 of revenues from physical sales contracts and buy-sell exchange transactions in our Logistics and Marketing segment, which is net of $2,590 million of buy-sell purchases related to buy-sell revenues of $2,857 million which are not within the scope of FASB ASC 606 "Revenue from Contractors with Customer" ("Topic 606").

(b) Not within the scope of Topic 606.

	Year Ended December 31, 2020			
	Logistics and Marketing	Gathering and Processing	Eliminations	Total
		(millions)		
Sales of natural gas	$ 1,786	$ 1,384	$ (1,263)	$ 1,907
Sales of NGLs and condensate (a)	3,569	1,658	(1,443)	3,784
Transportation, processing and other	51	405	(1)	455
Trading and marketing gains, net (b)	124	32	—	156
Total operating revenues	$ 5,530	$ 3,479	$ (2,707)	$ 6,302

(a) Includes $1,786 million of revenues for the year ended December 31, 2020, from physical sales contracts and buy-sell exchange transactions in our Logistics and Marketing segment, which is net of $1,004 million of buy-sell purchases related to buy-sell revenues of $1,300 million which are not within the scope of Topic 606.

(b) Not within the scope of Topic 606.

	Year Ended December 31, 2019			
	Logistics and Marketing	Gathering and Processing	Eliminations	Total
		(millions)		
Sales of natural gas	$ 2,098	$ 1,734	$ (1,525)	$ 2,307
Sales of NGLs and condensate (a)	4,744	2,171	(2,023)	4,892
Transportation, processing and other	46	395	(2)	439
Trading and marketing (losses) gains, net (b)	(32)	19	—	(13)
Total operating revenues	$ 6,856	$ 4,319	$ (3,550)	$ 7,625

(a) Includes $3,236 million for the year ended December 31, 2019 of revenues from physical sales contracts and buy-sell exchange transactions in our Logistics and Marketing segment, which are not within the scope of Topic 606.

(b) Not within the scope of Topic 606.

The revenue expected to be recognized in the future related to performance obligations that are not satisfied is approximately $442 million as of December 31, 2021. Our remaining performance obligations primarily consist of minimum volume commitment fee arrangements and are expected to be recognized through 2031 with a weighted average remaining life of three years as of December 31, 2021. As a practical expedient permitted by Topic 606, this amount excludes variable consideration as well as remaining performance obligations that have original expected durations of one year or less, as applicable. Our remaining performance obligations also exclude estimates of variable rate escalation clauses in our contracts with customers.

6. Contract Liabilities

Our contract liabilities consist of deferred revenue received from reimbursable projects. The noncurrent portion of deferred revenue is included in other long-term liabilities on our consolidated balance sheets.

The following table summarizes changes in contract liabilities included in our consolidated balance sheets:

	December 31, 2021	December 31, 2020
	(millions)	
Balance, beginning of period	$ 35	$ 33
Additions	1	3
Revenue recognized (a)	(2)	(1)
Balance, end of period	$ 34	$ 35

(a) Deferred revenue recognized is included in transportation, processing and other on the consolidated statements of operations.

The contract liabilities disclosed in the table above will be recognized as revenue as the obligations are satisfied over their average remaining contract life, which is 35 years as of December 31, 2021.

7. Agreements and Transactions with Affiliates

DCP Midstream, LLC

Services Agreement and Other General and Administrative Charges

Under the Services and Employee Secondment Agreement (the "Services Agreement"), we are required to reimburse DCP Midstream, LLC for costs, expenses, and expenditures incurred or payments made on our behalf for general and administrative functions including, but not limited to, legal, accounting, compliance, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, benefit plan maintenance and administration, credit, payroll, internal audit, taxes and engineering, as well as salaries and benefits of seconded employees, insurance coverage and claims, capital expenditures, maintenance and repair costs and taxes. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for costs, expenses and expenditures incurred or payments made on our behalf. The following table summarizes employee related costs that were charged by DCP Midstream, LLC to the Partnership that are included in the consolidated statements of operations:

	Year Ended December 31, 2021	2020	2019
		(millions)	
Employee related costs charged by DCP Midstream, LLC			
Operating and maintenance expense	$ 157	$ 160	$ 197
General and administrative expense	$ 149	$ 165	$ 189
Restructuring costs	$ —	$ 9	$ 11

Phillips 66 and its Affiliates

We sell a portion of our residue gas and NGLs to and purchase NGLs from Phillips 66 and its respective affiliates. We anticipate continuing to sell commodities to and purchase commodities from Phillips 66 and its affiliates in the ordinary course of business.

Enbridge and its Affiliates

We purchase NGLs from Enbridge and its affiliates. We anticipate continuing to purchase commodities from Enbridge and its affiliates in the ordinary course of business.

Unconsolidated Affiliates

We have entered into transportation agreements with DCP Sand Hills Pipeline, LLC, or Sand Hills, DCP Southern Hills Pipeline, LLC, or Southern Hills, Front Range Pipeline LLC, or Front Range, Texas Express Pipeline LLC, or Texas Express, Gulf Coast Express Pipeline, LLC, or Gulf Coast and Cheyenne Connector LLC, or Cheyenne Connector. Under the terms of these agreements, which expire between 2028 and 2030, we have committed to transport minimum throughput volumes at rates defined in each of the pipelines' respective tariffs.

We sell a portion of our residue gas and NGLs to, purchase natural gas and other NGL products from, provide gathering and transportation services to, and receive transportation services from unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and receive and provide services to unconsolidated affiliates in the ordinary course of business.

Under the terms of the Sand Hills LLC Agreement and the Southern Hills LLC Agreement, or the Sand Hills and Southern Hills LLC Agreements, Sand Hills and Southern Hills are required to reimburse us for any direct costs or expenses (other than general and administration services) which we incur on behalf of Sand Hills and Southern Hills. Additionally, Sand Hills and Southern Hills each pay us an annual service fee of $5 million, for centralized corporate functions provided by us as operator of Sand Hills and Southern Hills, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual service fee, there is no limit on the reimbursements Sand Hills and Southern Hills make to us under the Sand Hills and Southern Hills LLC Agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

Summary of Transactions with Affiliates

The following table summarizes our transactions with affiliates:

	Year Ended December 31, 2021	2020	2019
		(millions)	
Phillips 66 (including its affiliates):			
Sales of natural gas, NGLs and condensate to affiliates	$ 3,000	$ 1,037	$ 1,140
Purchases and related costs from affiliates	$ 62	$ 96	$ 142
Transportation and related costs from affiliates	$ 158	$ 113	$ 67
Operating and maintenance and general administrative expenses	$ 14	$ 11	$ 13
Enbridge (including its affiliates):			
Sales of natural gas, NGLs and condensate to affiliates	$ 2	$ 2	$ (2)
Purchases and related costs from affiliates	$ 40	$ 20	$ 26
Transportation and related costs from affiliates	$ 1	$ 1	$ 1
Operating and maintenance and general administrative expenses	$ 1	$ 2	$ 2
Unconsolidated affiliates:			
Sales of natural gas, NGLs and condensate to affiliates	$ 103	$ 49	$ 38
Transportation, processing, and other to affiliates	$ 18	$ 13	$ 4
Purchases and related costs from affiliates	$ 86	$ 50	$ 70
Transportation and related costs from affiliates	$ 825	$ 836	$ 783

We had balances with affiliates as follows:

	December 31, 2021	December 31, 2020
	(millions)	
Phillips 66 (including its affiliates):		
Accounts receivable	$ 361	$ 217
Accounts payable	$ 114	$ 89
Other assets	$ 1	$ 1
Enbridge (including its affiliates):		
Accounts payable	$ 4	$ 2
Unconsolidated affiliates:		
Accounts receivable	$ 28	$ 21
Accounts payable	$ 87	$ 70

8. Inventories

Inventories were as follows:

	December 31, 2021	December 31, 2020
	(millions)	
Natural gas	$ 43	$ 18
NGLs	34	20
Total inventories	$ 77	$ 38

We recognize lower of cost or net realizable value adjustments when the carrying value of our inventories exceeds their net realizable value. These non-cash charges are a component of purchases and related costs in the consolidated statements of operations. We recognized zero, $6 million, and $10 million of lower of cost or net realizable value adjustments for the years ended December 31, 2021, 2020, and 2019, respectively.

9. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	Depreciable Life	December 31, 2021	December 31, 2020
		(millions)	
Gathering and transmission systems	20 — 50 Years	$ 7,645	$ 7,680
Processing, storage and terminal facilities	35 — 60 Years	5,057	4,986
Other	3 — 30 Years	585	585
Finance lease assets	2 — 5 Years	28	25
Construction work in progress		103	144
Property, plant and equipment		13,418	13,420
Accumulated depreciation		(5,717)	(5,427)
Property, plant and equipment, net		$ 7,701	$ 7,993

Capitalized interest on construction projects was $2 million, $7 million, and $13 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Depreciation expense was $358 million, $370 million, and $396 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Asset Retirement Obligations

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

The following table summarizes changes in the asset retirement obligations included in our balance sheets:

	December 31, 2021 (a)		December 31, 2020 (a)	
	(millions)			
Balance, beginning of period	$	150	$	1
Accretion expense		10	$	
Dispositions		(2)	$	
Balance, end of period	$	158	$	1

(a) Asset retirement obligations are included in other long-term liabilities in the consolidated balance sheets. Accretion expense is recorded within operating and maintenance expense in our consolidated statement of operations. Accretion expense for the year ended December 31, 2019 was $9 million.

10. Goodwill and Intangible Assets

During the first quarter of 2020, certain areas of our business, as well as those of other midstream companies in our peer group, suffered a significant decline in market value, primarily as result of significantly depressed commodity prices and demand for oil and gas products. This was the result of both a reduction in estimated enterprise value and an increase to our estimated discount rate. We performed an analysis to determine the estimated fair value of the North reporting unit as of March 31, 2020 and concluded that its carrying value exceeded its fair value by more than the recorded amount of goodwill within the reporting unit, resulting in an impairment charge of $159 million.

The significant decline in commodity prices and demand for oil and gas products decreased forecasted cash flows such that, while in excess of asset book value on an undiscounted basis, they were not sufficient to recover the value of allocated goodwill in the North reporting unit.

We primarily used a discounted cash flow analysis, supplemented by a market approach analysis, to perform our goodwill assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows, including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information (including forecasted volumes and commodity prices), as well as historical and other factors.

The carrying amount of goodwill in each of our reportable segments was as follows:

	Gathering and Processing		Logistics and Marketing		Total	
	(millions)					
Balance, December 31, 2019	$	159	$	—	$	159
Impairment		(159)		—		(159)
Balance, December 31, 2020	$	—	$	—	$	—

Intangible assets consist of customer contracts, including commodity purchase, transportation and processing contracts and related relationships. The gross carrying amount and accumulated amortization of these intangible assets are included in the accompanying consolidated balance sheets as intangible assets, net, and are as follows:

	December 31, 2021	December 31, 2020
	(millions)	
Gross carrying amount	$ 110	$ 111
Accumulated amortization	(71)	(67)
Intangible assets, net	$ 39	$ 44

We recorded amortization expense of $6 million, $6 million and $8 million for the years ended December 31, 2021, 2020, and 2019, respectively. As of December 31, 2021, the remaining amortization periods ranged from approximately 1 year to 13 years, with a weighted-average remaining period of approximately 10 years.

Estimated future amortization for these intangible assets is as follows:

	Estimated Future Amortization
	(millions)
2022	$ 4
2023	4
2024	4
2025	4
2026	4
Thereafter	19
Total	$ 39

11. Investments in Unconsolidated Affiliates

The following table summarizes our investments in unconsolidated affiliates:

	Percentage Ownership	Carrying Value as of December 31, 2021	Carrying Value as of December 31, 2020
		(millions)	
DCP Sand Hills Pipeline, LLC	66.67%	$ 1,703	$ 1,723
DCP Southern Hills Pipeline, LLC	66.67%	728	734
Gulf Coast Express LLC	25.00%	422	436
Front Range Pipeline LLC	33.33%	195	198
Texas Express Pipeline LLC	10.00%	94	97
Mont Belvieu 1 Fractionator	20.00%	6	7
Discovery Producer Services LLC	40.00%	231	244
Cheyenne Connector, LLC	50.00%	148	152
Mont Belvieu Enterprise Fractionator	12.50%	28	26
Panola Pipeline Company, LLC	15.00%	20	21
Other	Various	3	3
Total investments in unconsolidated affiliates		$ 3,578	$ 3,641

The following table represents the excess (deficit) of the carrying amount of the investment over (under) the underlying equity of our investments in unconsolidated affiliates as of December 31, 2021 and 2020:

	Excess (Deficit) of Carrying Value over (under) Underlying Equity in Unconsolidated Affiliates	
	December 31, 2021	December 31, 2020
	(millions)	
DCP Sand Hills Pipeline, LLC	$ 590	$ 605
DCP Southern Hills Pipeline, LLC	$ 132	$ 135
Gulf Coast Express Pipeline LLC	$ 1	$ 1
Front Range Pipeline LLC	$ 4	$ 4
Texas Express Pipeline LLC	$ 2	$ 2
Discovery Producer Services LLC	$ 1	$ (8)
Cheyenne Connector, LLC	$ 4	$ 4

Carrying amounts in excess or deficit of the underlying equity of our unconsolidated affiliates are amortized over the life of the underlying long-lived assets of the affiliate.

Earnings from investments in unconsolidated affiliates were as follows:

	Year Ended December 31,		
	2021	2020	2019
		(millions)	
DCP Sand Hills Pipeline, LLC	$ 274	$ 279	$ 287
DCP Southern Hills Pipeline, LLC	91	78	77
Gulf Coast Express LLC	63	66	27
Front Range Pipeline LLC	38	38	32
Texas Express Pipeline LLC	19	18	16
Mont Belvieu 1 Fractionator	17	12	13
Discovery Producer Services LLC (a)	16	(63)	6
Cheyenne Connector, LLC	12	6	—
Mont Belvieu Enterprise Fractionator	3	11	14
Other	2	2	2
Total earnings from unconsolidated affiliates	$ 535	$ 447	$ 474

(a) See Note 12 for further discussion.

The following tables summarize the combined financial information of our investments in unconsolidated affiliates:

	Year Ended December 31,		
	2021	2020	2019
		(millions)	
Statements of operations:			
Operating revenue	$ 2,110	$ 2,049	$ 1,798
Operating expenses	$ 844	$ 746	$ 695
Net income	$ 1,261	$ 1,297	$ 1,103

	December 31, 2021	December 31, 2020
	(millions)	
Balance sheets:		
Current assets	$ 429	$ 355
Long-term assets	7,277	7,510
Current liabilities	(200)	(177)
Long-term liabilities	(254)	(258)
Net assets	$ 7,252	$ 7,430

12. Fair Value Measurement

Determination of Fair Value

Below is a general description of our valuation methodologies for derivative financial assets and liabilities which are measured at fair value. Fair values are generally based upon quoted market prices or prices obtained through external sources, where available. If listed market prices or quotes are not available, we determine fair value based upon a market quote, adjusted by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. These adjustments result in a fair value for each asset or liability under an "exit price" methodology, in line with how we believe a marketplace participant would value that asset or liability. Fair values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. These adjustments may include amounts to reflect counterparty credit quality, the effect of our own creditworthiness, and/or the liquidity of the market.

- Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. Therefore, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. We record counterparty credit valuation adjustments on all derivatives that are in a net asset position as of the measurement date in accordance with our established counterparty credit policy, which takes into account any collateral margin that a counterparty may have posted with us as well as any letters of credit that they have provided.

- Entity valuation adjustments are necessary to reflect the effect of our own credit quality on the fair value of our net liability positions with each counterparty. This adjustment takes into account any credit enhancements, such as collateral margin we may have posted with a counterparty, as well as any letters of credit that we have provided. The methodology to determine this adjustment is consistent with how we evaluate counterparty credit risk, taking into account our own credit rating, current credit spreads, as well as any change in such spreads since the last measurement date.

- Liquidity valuation adjustments are necessary when we are not able to observe a recent market price for financial instruments that trade in less active markets for the fair value to reflect the cost of exiting the position. Exchange traded contracts are valued at market value without making any additional valuation adjustments and, therefore, no liquidity reserve is applied. For contracts other than exchange traded instruments, we mark our positions to the midpoint of the bid/ask spread, and record a liquidity reserve based upon our total net position. We believe that such practice results in the most reliable fair value measurement as viewed by a market participant.

We manage our derivative instruments on a portfolio basis and the valuation adjustments described above are calculated on this basis. We believe that the portfolio level approach represents the highest and best use for these assets as there are benefits inherent in naturally offsetting positions within the portfolio at any given time, and this approach is consistent with how a market participant would view and value the assets and liabilities. Although we take a portfolio approach to managing these assets and liabilities, in order to reflect the fair value of any one individual contract within the portfolio, we allocate all valuation adjustments down to the contract level, to the extent deemed necessary, based upon either the notional contract volume, or the contract value, whichever is more applicable.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. While we believe that our valuation methods are appropriate and consistent with other market participants, we recognize that the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. We review our fair value policies on a regular basis taking into consideration changes in the marketplace and, if necessary, will adjust our policies accordingly. See Note 15 - Risk Management and Hedging Activities.

Valuation Hierarchy

Our fair value measurements are grouped into a three-level valuation hierarchy and are categorized in their entirety in the same level of the fair value hierarchy as the lowest level input that is significant to the entire measurement. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows.

- Level 1 — inputs are unadjusted quoted prices for identical assets or liabilities in active markets.
- Level 2 — inputs include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 — inputs are unobservable and considered significant to the fair value measurement.

A financial instrument's categorization within the hierarchy is based upon the level of judgment involved in the most significant input in the determination of the instrument's fair value. Following is a description of the valuation methodologies used as well as the general classification of such instruments pursuant to the hierarchy.

Commodity Derivative Assets and Liabilities

We enter into a variety of derivative financial instruments, which may include exchange traded instruments (such as New York Mercantile Exchange, or NYMEX, crude oil or natural gas futures) or over-the-counter, or OTC, instruments (such as natural gas contracts, crude oil or NGL swaps). The exchange traded instruments are generally executed with a highly rated broker dealer serving as the clearinghouse for individual transactions.

Our activities expose us to varying degrees of commodity price risk. To mitigate a portion of this risk and to manage commodity price risk related primarily to owned natural gas storage and pipeline assets, we engage in natural gas asset based trading and marketing, and we may enter into natural gas and crude oil derivatives to lock in a specific margin when market conditions are favorable. A portion of this may be accomplished through the use of exchange traded derivative contracts. Such instruments are generally classified as Level 1 since the value is equal to the quoted market price of the exchange traded instrument as of our balance sheet date, and no adjustments are required. Depending upon market conditions and our strategy we may enter into exchange traded derivative positions with a significant time horizon to maturity. Although such instruments are exchange traded, market prices may only be readily observable for a portion of the duration of the instrument. In order to calculate the fair value of these instruments, readily observable market information is utilized to the extent it is available; however, in the event that readily observable market data is not available, we may interpolate or extrapolate based upon observable data. In instances where we utilize an interpolated or extrapolated value, and it is considered significant to the valuation of the contract as a whole, we would classify the instrument within Level 3.

We also engage in the business of trading energy related products and services, which exposes us to market variables and commodity price risk. We may enter into physical contracts or financial instruments with the objective of realizing a positive margin from the purchase and sale of these commodity-based instruments. We may enter into derivative instruments for NGLs or other energy related products, primarily using the OTC derivative instrument markets, which are not as active and liquid as exchange traded instruments. Market quotes for such contracts may only be available for short dated positions (up to six months), and an active market itself may not exist beyond such time horizon. Contracts entered into with a relatively short time horizon for which prices are readily observable in the OTC market are generally classified within Level 2. Contracts with a longer time horizon, for which we internally generate a forward curve to value such instruments, are generally classified within Level 3. The internally generated curve may utilize a variety of assumptions including, but not limited to, data obtained from third-party pricing services, historical and future expected relationship of NGL prices to crude oil prices, the knowledge of expected supply sources coming online, expected weather trends within certain regions of the United States, and the future expected demand for NGLs.

Each instrument is assigned to a level within the hierarchy at the end of each financial quarter depending upon the extent to which the valuation inputs are observable. Generally, an instrument will move toward a level within the hierarchy that requires a lower degree of judgment as the time to maturity approaches, and as the markets in which the asset trades will likely become more liquid and prices more readily available in the market, thus reducing the need to rely upon our internally developed assumptions. However, the level of a given instrument may change, in either direction, depending upon market conditions and the availability of market observable data.

The following table presents the financial instruments carried at fair value on a recurring basis as of December 31, 2021 and December 31, 2020, by consolidated balance sheet caption and by valuation hierarchy, as described above:

	December 31, 2021				December 31, 2020			
	Level 1	Level 2	Level 3	Total Carrying Value	Level 1	Level 2	Level 3	Total Carrying Value
				(millions)				
Current assets:								
Commodity derivatives	$ 24	$ 62	$ —	$ 86	$ 21	$ 42	$ —	$
Short-term investments (a)	$ 4	$ 1	$ —	$ 5	$ —	$ —	$ —	$
Long-term assets:								
Commodity derivatives	$ —	$ 8	$ 2	$ 10	$ 1	$ 13	$ 2	$
Investments in marketable securities (a)	$ 28	$ —	$ —	$ 28	22	$ 1	$ —	$
Current liabilities:								
Commodity derivatives	$ (42)	$ (100)	$ (3)	$ (145)	$ (19)	$ (34)	$ (3)	$ (
Long-term liabilities:								
Commodity derivatives	$ (1)	$ (25)	$ (4)	$ (30)	$ —	$ (6)	$ (1)	$

(a) $5 million and $4 million recorded within "other" current assets and $28 million and $19 million recorded within "Other long-term assets" as of December 31, 2021 and December 31, 2020, respectively.

Changes in Levels 1 and 2 Fair Value Measurements

The determination to classify a financial instrument within Level 1 or Level 2 is based upon the availability of quoted prices for identical or similar assets and liabilities in active markets. Depending upon the information readily observable in the market, and/or the use of identical or similar quoted prices, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next.

Changes in Level 3 Fair Value Measurements

The tables below illustrate a rollforward of the amounts included in our consolidated balance sheets for derivative financial instruments that we have classified within Level 3. Since financial instruments classified as Level 3 typically include a combination of observable components (that is, components that are actively quoted and can be validated to external sources) and unobservable components, the gains and losses in the table below may include changes in fair value due in part to observable market factors, or changes to our assumptions on the unobservable components. Depending upon the information readily observable in the market, and/or the use of unobservable inputs, which are significant to the overall valuation, the classification of any individual financial instrument may differ from one measurement date to the next. The significant unobservable inputs used in determining fair value include adjustments by other market-based or independently sourced market data such as historical commodity volatilities, crude oil future yield curves, and/or counterparty specific considerations. In the event that there is a movement to/from the classification of an instrument as Level 3, we would reflect such items in the table below within the “Transfers into/out of Level 3” captions.

We manage our overall risk at the portfolio level and in the execution of our strategy, we may use a combination of financial instruments, which may be classified within any level. Since Level 1 and Level 2 risk management instruments are not included in the rollforward below, the gains or losses in the table do not reflect the effect of our total risk management activities.

	Commodity Derivative Instruments			
	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities
	(millions)			
Year ended December 31, 2021 (a):				
Beginning balance	$ —	$ 2	$ (3)	$ (1)
Net unrealized losses included in earnings	—	—	(10)	(6)
Transfers out of Level 3	—	—	3	3
Settlements	—	—	7	—
Ending balance	$ —	$ 2	$ (3)	$ (4)
Net unrealized gains (losses) on derivatives still held included in earnings	$ —	$ 1	$ (3)	$ (4)
Year ended December 31, 2020 (a):				
Beginning balance	$ 4	$ —	$ (1)	$ (3)
Net unrealized (losses) gains included in earnings	(1)	5	5	2
Transfers out of Level 3	—	(3)	—	—
Settlements	(3)	—	(7)	—
Ending balance	$ —	$ 2	$ (3)	$ (1)
Net unrealized gains (losses) on derivatives still held included in earnings	$ —	$ 2	$ (3)	$ (1)

(a) There were no purchases, issuances or sales of derivatives or transfers into Level 3 for the years ended December 31, 2021 and 2020.

Quantitative Information and Fair Value Sensitivities Related to Level 3 Unobservable Inputs

We utilize the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

	December 31, 2021					
Product Group	Fair Value (millions)	Valuation Techniques	Unobservable Input	Forward Curve Range	Weighted Average (a)	
Assets						
Natural gas	$ 2	Market approach	Longer dated forward curve prices	$2.22-$3.37	$2.86	Per MMBtu
Liabilities						
NGLs	$ (4)	Market approach	Longer dated forward curve prices	$0.30-$1.82	$0.93	Per gallon
Natural gas	$ (3)	Market approach	Longer dated forward curve prices	$2.17-$3.55	$2.57	Per MMBtu

(a) Unobservable inputs were weighted by the instrument's notional amounts.

Nonfinancial Assets and Liabilities

We utilize fair value to perform impairment tests as required on our property, plant and equipment, goodwill, equity investments in unconsolidated affiliates, and intangible assets. The inputs used to determine such fair value are primarily based upon internally developed cash flow models and would generally be classified within Level 3 in the event that we were required to measure and record such assets at fair value within our consolidated financial statements. Additionally, we use fair value to determine the inception value of our asset retirement obligations. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition, and would be classified within Level 3.

During the year ended December 31, 2021 we determined that a triggering event occurred due to a negative outlook for long-term future throughput volume forecasts for certain assets within the South region of our Gathering and Processing segment and our Logistics and Marketing segment as our expectation for future use of the assets changed. As such, we recognized impairments of long lived assets of $24 million in our consolidated statements of operations. We also recognized a $7 million impairment associated with certain non-core assets held for sale in the Midcontinent region of our Gathering and Processing segment that were sold in July 2021. During the year ended December 31, 2020, we determined that triggering events had occurred with respect to specific asset groups as a result of the impact of commodity prices on the respective recently prepared budget forecasts, coupled with a negative outlook for long-term production volume forecasts for these asset groups. For each of the respective asset groups we determined that the carrying value exceeded the respective undiscounted cash flows. We used the income approach to calculate the fair value of the asset group and compared it to the carrying value. The primary inputs to our calculation were forecasted gathering and processing volumes, future commodity pricing and the discount rate. The impairment amount recorded represented the difference between the fair and carrying values. As a result, we recognized a $587 million impairment loss associated with certain asset groups in the Permian and South regions of our Gathering and Processing segment, including $11 million related to customer contract intangible assets, and an other than temporary impairment of $61 million of our equity investment in Discovery Producer Services LLC (“Discovery”). We may identify additional triggering events requiring future evaluations of the recoverability of the carrying value of our long-lived assets and investments that could result in future impairments. Such impairments could have significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to be not fully recoverable.

The following table presents certain assets and asset groups measured at fair value on a non-recurring basis, by consolidated balance sheet caption as of the date of measurement.

	Fair Value	Asset Impairments 2021	Asset Impairments 2020
	(millions)		
Long-lived assets	$ 1	$ 31	
Long-lived assets (a)	96		$ 587
Goodwill	—		159
Direct investment in unconsolidated affiliate	256		61
Total		$ 31	$ 807

(a) Includes $11 million related to customer contract intangible assets.

Estimated Fair Value of Financial Instruments

Valuation of a contract’s fair value is validated by an internal group independent of the marketing group. While common industry practices are used to develop valuation techniques, changes in pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition. When available, quoted market prices or prices obtained through external sources are used to determine a contract’s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected relationships with quoted market prices.

The fair value of our interest rate swaps, if any, and commodity non-trading derivatives is based on prices supported by quoted market prices and other external sources and prices based on models and other valuation methods. The “prices supported by quoted market prices and other external sources” category includes our interest rate swaps, if any, our NGL and crude oil swaps and our NYMEX positions in natural gas. In addition, this category includes our forward positions in natural gas for which our forward price curves are obtained from a third party pricing service and then validated through an internal process which includes the use of independent broker quotes. This category also includes our forward positions in NGLs at points for which OTC broker quotes for similar assets or liabilities are available for the full term of the instrument. This category also includes “strip” transactions whose pricing inputs are directly or indirectly observable from external sources and then modeled to daily or monthly prices as appropriate. The “prices based on models and other valuation methods” category includes the value of transactions for which inputs to the fair value of the instrument are unobservable in the marketplace and are considered significant to the overall fair value of the instrument. The fair value of these instruments may be based upon an internally developed price curve, which was constructed as a result of the long dated nature of the transaction or the illiquidity of the specific market point.

We have determined fair value amounts using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Derivative instruments are carried at fair value.

We determine the fair value of our fixed-rate senior notes and junior subordinated notes based on quotes obtained from bond dealers. The carrying value of borrowings under the Credit Agreement and the Securitization Facility approximate fair value as their interest rates are based on prevailing market interest rates. We classify the fair values of our outstanding debt balances within Level 2 of the valuation hierarchy. As of December 31, 2021 and December 31, 2020, the carrying value and fair value of our total debt, including current maturities, were as follows:

	December 31, 2021		December 31, 2020	
	Carrying Value (a)	Fair Value	Carrying Value (a)	Fair Value
	(millions)			
Total debt	$ 5,445	$ 6,107	$ 5,635	$ 5,938

(a) Excludes unamortized issuance costs and finance lease liabilities.

13. Leases

We have operating leases for transportation agreements, office space, and field equipment. We have finance leases for field equipment and vehicles. Our leases have remaining lease terms ranging from less than one year to 19 years, some of which may include options to extend leases up to 20 years, and some of which may include options to terminate the leases in less than one year. Extension options on certain compressors and field equipment were included in the lease terms used to calculate our operating lease assets and liabilities as it is reasonably certain that we exercise those options. Operating and finance leases are included on our consolidated balance sheet as follows:

	Location in Consolidated Balance Sheet	As of December 31, 2021	As of December 31, 2020
		(millions)	
Assets			
Operating lease assets	Operating lease assets	$ 104	$ 85
Finance lease assets	Property, plant and equipment	28	25
Total right of use assets		$ 132	$ 110
Liabilities			
Current liabilities			
Operating lease liabilities	Other current liabilities	$ 26	$ 24
Finance lease liabilities	Current debt	5	5
Noncurrent liabilities			
Operating lease liabilities	Operating lease liabilities	$ 93	$ 76
Finance lease liabilities	Long-term debt	21	22
Total lease liabilities		$ 145	$ 127

Variable lease costs primarily consist of common area maintenance on our office spaces and variable transportation costs. The components of lease expense are as follows:

	Location in Consolidated Statement of Operations	Year Ended December 31, 2021	Year Ended December 31, 2020
		(millions)	
Operating lease cost	Operating and maintenance expense	$ 28	$ 27
Finance lease cost			
Amortization of right of use assets	Depreciation and amortization expense	3	2
Interest on lease liabilities	Interest expense	1	1
Variable lease cost	Operating and maintenance expense	6	6
Short term lease cost	Operating and maintenance expense	4	4
Total lease cost		$ 42	$ 40

Maturities of operating and finance lease liabilities under non-cancelable leases as of December 31, 2021 are as follows:

	Future Minimum Lease Payments as of December 31, 2021	
	Operating Leases	Finance Leases
	(millions)	
2022	$ 29	$ 6
2023	28	6
2024	19	7
2025	15	3
2026	9	5
Thereafter	33	5
Total lease payments	$ 133	$ 32
Less imputed interest	(14)	(6)
Total lease liabilities	$ 119	$ 26

Supplemental cash flow information related to leases is as follows:

	Year Ended December 31,	
	2021	2020
	(millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 30	$ 27
Operating cash flows from finance leases	5	4
Financing cash flows from finance leases	1	1
Right-of-use assets obtained in exchange for operating lease obligations:	$ 44	$ 13
Right-of-use assets obtained in exchange for finance lease obligations:	$ 4	$ 5
Other information related to operating leases as follows:		
Weighted average remaining lease term	6 years	6 years
Weighted average discount rate	4.00 %	4.00 %
Other information related to finance leases as follows:		
Weighted average remaining lease term	4 years	5 years
Weighted average discount rate	3.00 %	3.00 %

14. Debt

	December 31, 2021	December 31, 2020
	(millions)	
Senior notes:		
Issued September 2011, interest at 4.750% payable semi-annually, due September 2021	$ —	$ 500
Issued March 2012, interest at 4.950% payable semi-annually, due April 2022	350	350
Issued March 2013, interest at 3.875% payable semi-annually, due March 2023	500	500
Issued July 2018 and January 2019, interest at 5.375% payable semi-annually, due July 2025	825	825
Issued June 2020, interest at 5.625% payable semi-annually, due July 2027	500	500
Issued May 2019, interest at 5.125% payable semi-annually, due May 2029	600	600
Issued August 2000, interest at 8.125% payable semi-annually, due August 2030 (a)	300	300
Issued November 2021, interest at 3.250% payable semi-annually, due February 2032	400	—
Issued October 2006, interest at 6.450% payable semi-annually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semi-annually, due September 2037	450	450
Issued March 2014, interest at 5.600% payable semi-annually, due April 2044	400	400
Junior subordinated notes:		
Issued May 2013, interest at 5.850% payable semi-annually, due May 2043	550	550
Accounts receivable securitization facility:		
Accounts receivable securitization facility, interest at 1.000% as of December 31, 2021, due August 2024	260	350
Fair value adjustments related to interest rate swap fair value hedges (a)	16	17
Unamortized issuance costs	(38)	(38)
Unamortized discount, net	(6)	(7)
Finance lease liabilities	26	27
Total debt	5,433	5,624
Current finance lease liabilities	5	5
Current debt	350	500
Total long-term debt	$ 5,078	$ 5,119

(a) The swaps associated with this debt were previously terminated. The remaining long-term fair value related to the swaps is being amortized as a reduction to interest expense through 2030, the original maturity date of the debt.

Senior Notes Issuance

On November 19, 2021, we issued $400 million aggregate principal amount 3.250% Senior Notes due February 2032, unless redeemed prior to maturity. We received proceeds of $396 million, net of underwriters' fees and related expenses, which we used to repay indebtedness under our revolving credit facility and for general partnership purposes. Interest on the notes is payable semi-annually in arrears on February 15 and August 15 of each year, commencing on August 15, 2022.

Senior Notes and Junior Subordinated Notes

Our senior notes and junior subordinated notes, collectively referred to as our debt securities, mature and become payable on their respective due dates, and are not subject to any sinking fund or mandatory redemption provisions. The senior notes are senior unsecured obligations that are guaranteed by the Partnership and rank equally in a right of payment with our other senior unsecured indebtedness, including indebtedness under our Credit Agreement, and the junior subordinated notes are unsecured and rank subordinate in right of payment to all of our existing and future senior indebtedness. The debt securities include an optional redemption whereby we may elect to redeem the notes, in whole or in part from time-to-time for a premium. Additionally, we may defer the payment of all or part of the interest on the junior subordinated notes for one or more periods up to 5 consecutive years. The underwriters' fees and related expenses are recorded in our consolidated balance sheets within the carrying amount of long-term debt and will be amortized over the term of the notes.

Senior Notes Redemption

On June 30, 2021, we repaid, at par, prior to maturity all $500 million aggregate principal amount outstanding of our 4.750% Senior Notes due September 2021 using borrowings under our Revolving Credit Facility.

Credit Agreement

We are a party to a $1.4 billion unsecured revolving credit facility governed by the Credit Agreement, which matures on December 9, 2024. The Credit Agreement also grants us the option to increase the revolving loan commitment by an aggregate principal amount of up to $500 million, subject to requisite lender approval. The Credit Agreement may be extended for up to two additional one-year periods subject to requisite lender approval. Loans under the Credit Agreement may be used for working capital and other general partnership purposes including acquisitions.

The Credit Agreement allows for unrestricted cash and cash equivalents to be netted against consolidated indebtedness for purposes of calculating the Partnership's Consolidated Leverage Ratio (as defined in the Credit Agreement). Additionally, under the Credit Agreement, the Consolidated Leverage Ratio of the Partnership as of the end of any fiscal quarter shall not exceed 5.00 to 1.0; provided that, if there is a Qualified Acquisition (as defined in the Credit Agreement), the maximum Consolidated Leverage Ratio shall not exceed 5.50 to 1.0 at the end of the three consecutive fiscal quarters, including the fiscal quarter in which the Qualified Acquisition occurs.

Our cost of borrowing under the Credit Agreement is determined by a ratings-based pricing grid. Indebtedness under the Credit Agreement bears interest at either: (1) LIBOR, plus an applicable margin of 1.35% based on our current credit rating; or (2) (a) the base rate which shall be the higher of the prime rate, the Federal Funds rate plus 0.50% or the LIBOR Market Index rate plus 1.00%, plus (b) an applicable margin of 0.35% based on our current credit rating. The Credit Agreement incurs an annual facility fee of 0.275% based on our current credit rating. This fee is paid on drawn and undrawn portions of the $1.4 billion revolving credit facility. On December 31, 2021, one-week and two-month U.S. dollar LIBOR settings became permanently unavailable, and all other U.S. dollar LIBOR settings (overnight, one-month, three-month, six-month and 12-month U.S. dollar LIBOR settings) will become permanently unavailable on June 30, 2023.

As of December 31, 2021, we had unused borrowing capacity of $1,383 million, net of $17 million of letters of credit, under the Credit Agreement, of which $1,383 million would have been available to borrow for working capital and other general partnership purposes based on the financial covenants set forth in the Credit Agreement. Except in the case of a default, amounts borrowed under our Credit Agreement will not become due prior to the December 9, 2024 maturity date.

Accounts Receivable Securitization Facility

On August 2, 2021 we entered into an amendment to our Securitization Facility to extend the term of the facility until August 12, 2024 and to provide for an alternative interest rate under the Securitization Facility based on SOFR upon LIBOR becoming unavailable. The amendment also includes Environmental, Social, and Governance linked Key Performance Indicators that increase or decrease certain fees based on our safety performance relative to our peers, and year-over-year change in our greenhouse gas emissions intensity rate. The Securitization Facility provides for up to $350 million of borrowing capacity through August 2024 at LIBOR market index rates plus a margin. Such interest rates will change as described above upon LIBOR becoming unavailable. Under this Securitization Facility, certain of the Partnership's wholly owned subsidiaries sell or contribute receivables to another of the Partnership's consolidated subsidiaries, DCP Receivables LLC ("DCP Receivables"), a bankruptcy-remote special purpose entity created for the sole purpose of the Securitization Facility.

DCP Receivables' sole activity consists of purchasing receivables from the Partnership's wholly owned subsidiaries that participate in the Securitization Facility and providing these receivables as collateral for DCP Receivables' borrowings under the Securitization Facility. DCP Receivables is a separate legal entity and the accounts receivable of DCP Receivables, up to the amount of the outstanding debt under the Securitization Facility, are not available to satisfy the claims of creditors of the Partnership, its subsidiaries selling receivables under the Securitization Facility, or their affiliates. Any excess receivables are eligible to satisfy the claims of creditors of the Partnership, its subsidiaries selling receivables under the Securitization Facility, or their affiliates. The amount available for borrowing may be limited by the availability of eligible receivables and other customary factors and conditions, as well as the covenants set forth in the Securitization Facility. As of December 31, 2021, DCP Receivables had approximately $1,175 of our accounts receivable securing borrowings of $260 million under the Securitization Facility.

The maturities of our debt as of December 31, 2021 are as follows:

	Debt Maturities
	(millions)
2022	$ 350
2023	500
2024	260
2025	825
2026	—
Thereafter	3,500
Total debt	$ 5,435

15. Risk Management and Hedging Activities

Our operations expose us to a variety of risks including but not limited to changes in the prices of commodities that we buy or sell, changes in interest rates, and the creditworthiness of each of our counterparties. We manage certain of these exposures with either physical or financial transactions. We have established a comprehensive risk management policy and a risk management committee (the "Risk Management Committee"), to monitor and manage market risks associated with commodity prices and counterparty credit. The Risk Management Committee is composed of senior executives who receive regular briefings on positions and exposures, credit exposures and overall risk management in the context of market activities. The Risk Management Committee is responsible for the overall management of credit risk and commodity price risk, including monitoring exposure limits.

Commodity Price Risk

Our portfolio of commodity derivative activity is primarily accounted for using the mark-to-market method of accounting; however, depending upon our risk profile and objectives, in certain limited cases, we may execute transactions that qualify for the hedge method of accounting. The risks, strategies and instruments used to mitigate such risks, as well as the method of accounting are discussed and summarized below.

Natural Gas Asset Based Trading and Marketing

Our natural gas storage and pipeline assets are exposed to certain risks including changes in commodity prices. We manage commodity price risk related to our natural gas storage and pipeline assets through our commodity derivative program. The commercial activities related to our natural gas storage and pipeline assets primarily consist of the purchase and sale of gas and associated time spreads and basis spreads.

A time spread transaction is executed by establishing a long gas position at one point in time and establishing an equal short gas position at a different point in time. Time spread transactions allow us to lock in a margin supported by the injection, withdrawal, and storage capacity of our natural gas storage assets. We may execute basis spread transactions to mitigate the risk of sale and purchase price differentials across our system. A basis spread transaction allows us to lock in a margin on our physical purchases and sales of gas, including injections and withdrawals from storage. We typically use swaps to execute these transactions, which are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations. While gas held in our storage locations is recorded at the lower of average cost or market, the derivative instruments that are used to manage our storage facilities are recorded at fair value and any changes in fair value are currently recorded in our consolidated statements of operations. Even though we may have economically hedged our exposure and locked in a future margin, the use of lower-of-cost or net realizable value for our physical inventory and the use of mark-to-market accounting for our derivative instruments may subject our earnings to market volatility.

Commodity Cash Flow Hedges

In order for our natural gas storage facility to remain operational, a minimum level of base gas must be maintained in each storage cavern, which is capitalized on our consolidated balance sheets as a component of property, plant and equipment, net. During construction or expansion of our storage caverns, we may execute a series of derivative financial instruments to mitigate a portion of the risk associated with the forecasted purchase of natural gas when we bring the storage caverns into operation. These derivative financial instruments may be designated as cash flow hedges. While the cash paid upon settlement of these hedges economically fixes the cash required to purchase base gas, the deferred losses or gains would remain in accumulated other comprehensive income (AOCI), until the cavern is emptied and the base gas is sold. The balance in AOCI of our previously settled base gas cash flow hedges was in a loss position of $6 million as of December 31, 2021.

Commodity Cash Flow Protection Activities

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of our gathering, processing, sales and storage activities. For gathering, processing and storage services, we may receive cash or commodities as payment for these services, depending on the contract type. We may enter into derivative financial instruments to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices associated with our gathering, processing and sales activities, thereby stabilizing our cash flows. As of December 31, 2021 our derivative financial instruments used to mitigate a portion of the risk of weakening natural gas, NGL and condensate prices extend through the end of 2023. The commodity derivative instruments used for our hedging programs are a combination of direct NGL product, crude oil and natural gas hedges. Crude oil and NGL transactions are primarily accomplished through the use of forward contracts that effectively exchange floating price risk for a fixed price. The type of instrument used to mitigate a portion of the risk may vary depending on our risk management objectives. These transactions are not designated as hedging instruments for accounting purposes and the change in fair value is reflected in the current period within our consolidated statements of operations as trading and marketing gains and (losses), net.

NGL Proprietary Trading

Our NGL proprietary trading activity includes trading energy related products and services. We undertake these activities through the use of fixed forward sales and purchases, basis and spread trades, storage opportunities, put/call options, term contracts and spot market trading. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and these operations may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. These physical and financial instruments are not designated as hedging instruments and are recorded at fair value with changes in fair value recorded in the current period consolidated statements of operations.

We employ established risk limits, policies and procedures to manage risks associated with our natural gas asset based trading and marketing and NGL proprietary trading.

Credit Risk

Our principal customers range from large, natural gas marketers to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties’ financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use various master agreements that include language giving us the right to request collateral to mitigate credit exposure. The collateral language provides for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral language also provides that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our master agreements and our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides acceptable security for payment.

Contingent Credit Features

Each of the above risks is managed through the execution of individual contracts with a variety of counterparties. Certain of our derivative contracts may contain credit-risk related contingent provisions that may require us to take certain actions in certain circumstances.

We have International Swaps and Derivatives Association, or ISDA, contracts which are standardized master legal arrangements that establish key terms and conditions which govern certain derivative transactions. These ISDA contracts contain standard credit-risk related contingent provisions. Some of the provisions we are subject to are outlined below.

- If we were to have an effective event of default under our Credit Agreement that occurs and is continuing, our ISDA counterparties may have the right to request early termination and net settlement of any outstanding derivative liability positions.
- Our ISDA counterparties generally have collateral thresholds of zero, requiring us to fully collateralize any commodity contracts in a net liability position, when our credit rating is below investment grade.
- Additionally, in some cases, our ISDA contracts contain cross-default provisions that could constitute a credit-risk related contingent feature. These provisions apply if we default in making timely payments under other credit arrangements and the amount of the default is above certain predefined thresholds, which are significantly high and are generally consistent with the terms of our Credit Agreement. As of December 31, 2021, we were not a party to any agreements that would trigger the cross-default provisions.

Our commodity derivative contracts that are not governed by ISDA contracts do not have any credit-risk related contingent features. Depending upon the movement of commodity prices and interest rates, each of our individual contracts with counterparties to our commodity derivative instruments or interest rate swap instruments are in either a net asset or net liability position. As of December 31, 2021, we had $5 million of individual commodity derivative contracts that contain credit-risk related contingent features that were in a net liability position. If we were required to net settle our position with an individual counterparty, due to a credit-risk related event, our ISDA contracts may permit us to net all outstanding contracts with that counterparty, whether in a net asset or net liability position, as well as any cash collateral already posted. As of December 31, 2021, we have not been required to post additional collateral. Although our commodity derivative contracts that contain credit-risk related contingent features were in a net liability position as of December 31, 2021, the net liability position would be offset by contracts in a net asset position reducing our net liability to $2 million.

Collateral

As of December 31, 2021, we had cash deposits of $128 million, included in collateral cash deposits in our consolidated balance sheets. Additionally, as of December 31, 2021, we held letters of credit of $131 million from counterparties to secure their future performance under financial or physical contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, services, trading and hedging contracts. In many cases, we and our counterparties have publicly disclosed credit ratings, which may impact the amounts of collateral requirements.

Physical forward contracts and financial derivatives are cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Offsetting

Certain of our financial derivative instruments are subject to a master netting or similar arrangement, whereby we may elect to settle multiple positions with an individual counterparty through a single net payment. Each of our individual derivative instruments are presented on a gross basis on the consolidated balance sheets, regardless of our ability to net settle our positions. Instruments that are governed by agreements that include net settle provisions allow final settlement, when presented with a termination event, of outstanding amounts by extinguishing the mutual debts owed between the parties in exchange for a net amount due. We have trade receivables and payables associated with derivative instruments, subject to master netting or similar agreements, which are not included in the table below. The following summarizes the gross and net amounts of our derivative instruments:

	December 31, 2021			December 31, 2020		
	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments	Net Amount	Gross Amounts of Assets and (Liabilities) Presented in the Balance Sheet	Amounts Not Offset in the Balance Sheet - Financial Instruments	Net Amount
	(millions)					
Assets:						
Commodity derivatives	$ 96	$ —	$ 96	$ 79	$ —	$ 79
Liabilities:						
Commodity derivatives	$ (175)	$ —	$ (175)	$ (63)	$ —	$ (63)

Summarized Derivative Information

The fair value of our derivative instruments that are marked-to-market each period, as well as the location of each within our consolidated balance sheets, by major category, is summarized below. We have no derivative instruments that are designated as hedging instruments for accounting purposes as of December 31, 2021 and December 31, 2020.

Balance Sheet Line Item	December 31, 2021	December 31, 2020	Balance Sheet Line Item	December 31, 2021	December 31, 2020
	(millions)			(millions)	
Derivative Assets Not Designated as Hedging Instruments:			**Derivative Liabilities Not Designated as Hedging Instruments:**		
Commodity derivatives:			**Commodity derivatives:**		
Unrealized gains on derivative instruments — current	$ 86	$ 63	Unrealized losses on derivative instruments — current	$ (145)	$ (56)
Unrealized gains on derivative instruments — long-term	10	16	Unrealized losses on derivative instruments — long-term	(30)	(7)
Total	$ 96	$ 79	Total	$ (175)	$ (63)

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the year ended December 31, 2021:

	Interest Rate Cash Flow Hedges	Commodity Cash Flow Hedges	Foreign Currency Cash Flow Hedges (a)	Total
	(millions)			
Net deferred (losses) gains in AOCI (beginning balance)	$ (2)	$ (6)	$ 1	$ (7)
Losses reclassified from AOCI to earnings — effective portion	1	—	—	1
Net deferred (losses) gains in AOCI (ending balance)	$ (1)	$ (6)	$ 1	$ (6)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$ —	$ —	$ —	$ —

(a) Relates to Discovery, an unconsolidated affiliate.

The following summarizes the balance and activity within AOCI relative to our interest rate, commodity and foreign currency cash flow hedges as of and for the year ended December 31, 2020:

	Interest Rate Cash Flow Hedges		Commodity Cash Flow Hedges		Foreign Currency Cash Flow Hedges (a)		Total	
					(millions)			
Net deferred (losses) gains in AOCI (beginning balance)	$	(2)	$	(6)	$	1	$	(7)
Net deferred (losses) gains in AOCI (ending balance)	$	(2)	$	(6)	$	1	$	(7)
Deferred losses in AOCI expected to be reclassified into earnings over the next 12 months	$	—	$	—	$	—	$	—

(a) Relates to Discovery, an unconsolidated affiliate.

For the years ended December 31, 2021 and 2020, no derivative losses attributable to the ineffective portion or to amounts excluded from effectiveness testing were recognized in trading and marketing gains or losses, net or interest expense in our consolidated statements of operations. For the years ended December 31, 2021 and 2020, no derivative losses were reclassified from AOCI to trading and marketing gains or losses, net or interest expense as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Changes in the value of derivative instruments, for which the hedge method of accounting has not been elected from one period to the next, are recorded in the consolidated statements of operations. The following summarizes these amounts and the location within the consolidated statements of operations that such amounts are reflected:

Commodity Derivatives: Statements of Operations Line Item	Year Ended December 31,					
	2021		2020		2019	
			(millions)			
Realized (losses) gains	$	(493)	$	101	$	(
Unrealized (losses) gains		(125)		55		(7
Trading and marketing (losses) gains, net	$	(618)	$	156	$	(1

We do not have any derivative financial instruments that are designated as a hedge of a net investment.

The following tables represent, by commodity type, our net long or short positions that are expected to partially or entirely settle in each respective year. To the extent that we have long dated derivative positions that span multiple calendar years, the contract will appear in more than one line item in the tables below.

	December 31, 2021			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net (Short) Long Position (MMBtu)	Net Short Position (Bbls)	Net (Short) Long Position (MMBtu)
2022	(1,133,000)	(76,565,200)	(5,080,635)	(7,015,000)
2023	(446,000)	912,500	(1,344,000)	(830,000)
2024	—	—	(1,455,000)	(2,280,000)
2025	—	—	(1,440,000)	9,530,000
2026	—	—	(1,440,000)	535,000

	December 31, 2020			
	Crude Oil	Natural Gas	Natural Gas Liquids	Natural Gas Basis Swaps
Year of Expiration	Net Short Position (Bbls)	Net Short Position (MMBtu)	Net Short Position (Bbls)	Net Long (Short) Position (MMBtu)
2021	(1,969,000)	(69,887,800)	(9,857,339)	(7,130,000)
2022	(214,000)	(36,500,000)	(1,422,842)	10,950,000
2023	—	—	(1,440,000)	3,650,000
2024	—	—	(1,440,000)	2,140,000
2025	—	—	(1,320,000)	1,825,000

16. Partnership Equity and Distributions

Preferred Units — The Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation. Holders of the Preferred Units have no voting rights except for certain limited protective voting rights set forth in our Partnership Agreement.

Distributions of the Preferred Units are payable out of available cash, are accretive and are cumulative from the date of original issuance of the Preferred Units.

- Distributions on the Series A Preferred Units are payable semiannually in arrears on June 15th and December 15th of each year.

- Distributions on the Series B Preferred Units are payable quarterly in arrears on the 15th day of March, June, September and December of each year to holders of record as of the close of business on the first business day of the month in which the distribution will be made.

- Distributions on the Series C Preferred Units are payable quarterly in arrears on the 15th day of January, April, July and October of each year to holders of record as of the close of business on the first business day of the month in which the distribution will be made.

Common Units — During the years ended December 31, 2021 and 2020, we issued no common units pursuant to our at-the-market program. As of December 31, 2021, $750 million of common units remained available for sale pursuant to our at-the-market program.

Our general partner is entitled to a percentage of all quarterly distributions equal to its limited partner interest, together with DCP Midstream, LLC, of approximately 57% as of December 31, 2021.

Definition of Available Cash — Our Partnership Agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash, as defined in the Partnership Agreement, to unitholders of record on the applicable record date, as determined by our general partner. Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner to:
    - provide for the proper conduct of our business, including reserves for future capital expenditures and anticipated credit needs;
    - comply with applicable law or any debt instrument or other agreement or obligation;
    - provide funds to make payments on the Preferred Units; or
    - provide funds for distributions to our common unitholders for any one or more of the next four quarters.
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of available cash for the quarter.

Distributions — The following table presents our cash distributions paid in 2021, 2020, and 2019:

Payment Date	Per Unit Distribution	Total Cash Distribution
		(millions)
Distributions to common unitholders		
November 12, 2021	$ 0.39	$ 81
August 13, 2021	$ 0.39	$ 81
May 14, 2021	$ 0.39	$ 82
February 12, 2021	$ 0.39	$ 81
November 13, 2020	$ 0.39	$ 81
August 14, 2020	$ 0.39	$ 82
May 15, 2020	$ 0.39	$ 81
February 14, 2020	$ 0.78	$ 162
November 14, 2019	$ 0.78	$ 155
August 14, 2019	$ 0.78	$ 154
May 15, 2019	$ 0.78	$ 155
February 14, 2019	$ 0.78	$ 154
Distributions to Series A Preferred unitholders		
December 15, 2021	$ 36.8750	$ 19
June 15, 2021	$ 36.8750	$ 18
December 15, 2020	$ 36.8750	$ 19
June 15, 2020	$ 36.8750	$ 18
December 16, 2019	$ 36.8750	$ 19
June 17, 2019	$ 36.8750	$ 18
Distributions to Series B Preferred unitholders		
December 15, 2021	$ 0.4922	$ 3
September 15, 2021	$ 0.4922	$ 4
June 15, 2021	$ 0.4922	$ 3
March 15, 2021	$ 0.4922	$ 3
December 15, 2020	$ 0.4922	$ 4
September 15, 2020	$ 0.4922	$ 3
June 15, 2020	$ 0.4922	$ 3
March 16, 2020	$ 0.4922	$ 3

December 16, 2019	$	0.4922	$
September 16, 2019	$	0.4922	$
June 17, 2019	$	0.4922	$
March 15, 2019	$	0.4922	$
Distributions to Series C Preferred unitholders			
October 15, 2021	$	0.4969	$
July 15, 2021	$	0.4969	$
April 15, 2021	$	0.4969	$
January 15, 2021	$	0.4969	$
October 15, 2020	$	0.4969	$
July 15, 2020	$	0.4969	$
April 15, 2020	$	0.4969	$
January 15, 2020	$	0.4969	$
October 15, 2019	$	0.4969	$
July 15, 2019	$	0.4969	$
April 15, 2019	$	0.4969	$
January 15, 2019	$	0.5576	$

17. Equity-Based Compensation

On April 28, 2016, the unitholders of the Partnership approved the 2016 Long-Term Incentive Plan (the “2016 LTIP” or, the “LTIP”). The 2016 plan authorizes up to 900,000 common units to be available for issuance under awards to employees, officers, and non-employee directors of the General Partner and its affiliates. Awards under the 2016 LTIP may include unit options, phantom units, restricted units, distribution equivalent rights ("DERs"), unit bonuses, common unit awards, and performance awards. The 2016 LTIP will expire on the earlier of the date it is terminated by the board of directors of the General Partner or the date that all common units available under the plan have been paid or issued.

Under DCP Midstream, LLC's Long-Term Incentive Plan ("DCP Midstream LTIP"), awards may be granted to key employees. The DCP Midstream LTIP provides for the grant of Strategic Performance Units ("SPUs") and Phantom Units. The SPUs and Phantom Units consist of a notional unit based on the fair market value of a common unit of the Partnership.

Since we have the intent and ability to settle certain awards within our control in units, we classify them as equity awards based on their fair value. The fair value of our equity awards is determined based on the closing price of our common units on the grant date. Compensation expense on equity awards is recognized ratably over each vesting period. We account for other awards which are subject to settlement in cash, including DERs, as liability awards. Compensation expense on these awards is recognized ratably over each vesting period, and will be re-measured each reporting period for all awards outstanding until the units are vested. The fair value of all liability awards is determined based on the closing price of our common units at each measurement date. Phantom Units issued in 2020 and thereafter are designed to pay out proportionally in cash and DCP Common LP Units.

Equity-based compensation expense was $20 million, $11 million and $14 million for the years ended December 31, 2021, 2020 and 2019, respectively.

The following table presents the fair value of unvested unit-based awards related to the SPUs and Phantom Units:

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2021 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream LTIP:				
SPUs	3	$ 7	0% - 11%	2
Phantom Units	1 - 3	$ 7	0% - 11%	1

Strategic Performance Units - The number of SPUs that will ultimately vest range in value of up to 200% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period. The final performance payout is determined by the compensation committee of our General Partner. SPU awards include the right to receive DERs, during the performance period or vesting period, as applicable, based on the number of units granted. The DERs are paid in cash at the end of the performance period. The following table presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2019	251,319	$ 43.33	
Granted	222,440	$ 30.60	
Forfeited	(40,348)	$ 34.95	
Vested (a)	(83,054)	$ 56.80	
Outstanding at December 31, 2019	350,357	$ 33.02	
Granted	296,700	$ 23.71	
Forfeited	(76,183)	$ 27.45	
Vested (b)	(141,613)	$ 36.23	
Outstanding at December 31, 2020	429,261	$ 26.52	
Granted	323,460	$ 19.44	
Forfeited	(54,641)	$ 21.32	
Vested (c)	(173,171)	$ 30.60	
Outstanding at December 31, 2021	524,909	$ 21.35	$ 27.48
Expected to vest	481,926	$ 21.35	27.48

(a) The 2017 grants vested at 120%.
(b) The 2018 grants vested at 152%.
(c) The 2019 grants vested at 150%

The estimate of SPUs that are expected to vest is based on highly subjective assumptions that could change over time, including the expected forfeiture rate and achievement of performance targets.

The following table presents the fair value of units vested and the unit-based liabilities paid for unit-based awards related to the strategic performance units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested or paid in cash in 2019	83,054	$ 6	$ 9
Vested or paid in cash in 2020	141,613	$ 4	$ 6
Vested or paid in cash in 2021	173,171	$ 7	$ 4

Phantom Units - Phantom Units generally cliff vest at the end of three years and include the right to receive DERs, during the vesting period, as applicable, based on the number of units granted. The DERs are paid quarterly in arrears. Phantom Units may be settled by issuing units or in cash payments equal to the fair value of the awards, which is based on the market prices of our stock near the end of the performance periods. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at January 1, 2019	231,706	$ 42.55	
Granted	281,930	$ 30.52	
Forfeited	(43,170)	$ 34.14	
Vested	(171,881)	$ 40.92	
Outstanding at December 31, 2019	298,585	$ 33.35	
Granted	671,040	$ 20.07	
Forfeited	(78,320)	$ 22.99	
Vested	(123,817)	$ 36.25	
Outstanding at December 31, 2020	767,488	$ 22.33	
Granted	403,130	$ 21.64	
Forfeited	(221,480)	$ 20.43	
Vested	(362,116)	$ 24.88	
Outstanding at December 31, 2021	587,022	$ 20.99	$ 22.80
Expected to vest	523,046	$ 20.98	$ 22.80

The following table presents the fair value of units vested and the unit-based liabilities paid for unit based awards related to the phantom units:

	Units	Fair Value of Units Vested	Unit-Based Liabilities Paid
		(millions)	
Vested or paid in cash in 2019	171,881	$ 6	$ 5
Vested or paid in cash in 2020	123,817	$ 3	$ 6
Vested or paid in cash in 2021	362,116	$ 5	$ 3

18. Benefits

We do not have our own employees. The employees supporting our operations are employees of DCP Services, LLC, for which we incur charges under the Services Agreement. All DCP Services, LLC employees who have reached the age of 18 and work at least 20 hours per week are eligible for participation in the 401(k) and retirement plan, to which a range of 4% to 7% of each eligible employee's qualified earnings is contributed to the retirement plan, based on years of service. All new employees are automatically enrolled in the 401(k) plan at a 6% contribution level. Employees can opt out of this contribution level or change it at any time. Additionally, DCP Services, LLC matches employees' contributions in the 401(k) plan up to 6% of qualified earnings. During the years ended December 31, 2021, 2020 and 2019, we expensed plan contributions of $24 million, $26 million and $31 million, respectively.

DCP Services, LLC offers certain eligible executives the opportunity to participate in the Executive Deferred Compensation ("EDC") Plan. The EDC Plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The EDC Plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the participant's behalf.

19. Net Income or Loss per Limited Partner Unit

We have the ability to elect to settle restricted phantom units at our discretion in either cash or common units. For restricted phantom units granted during 2021 and 2020, we have the ability and intent to settle vested units through the issuance of common units. There were 304,270 restricted phantom units outstanding as of December 31, 2020 that were not included in the calculation of diluted net loss per unit for the year ended December 31, 2020 because including them would have been anti-dilutive.

Basic and diluted net income per limited partner unit was calculated as follows for the years indicated:

	Year Ended December 31,		
	2021	2020	2019
	(millions, except per unit amounts)		
Net income (loss) attributable to limited partners	$ 332	$ (365)	$ (160)
Weighted average limited partner units outstanding, basic	208,366,254	208,338,544	153,116,233
Dilutive effects of nonvested restricted phantom units	233,804	—	—
Weighted average limited partner units outstanding, diluted	208,600,058	208,338,544	153,116,233
Net income (loss) per limited partner unit, basic and diluted	$ 1.59	$ (1.75)	$ (1.05)

20. Income Taxes

We are structured as a master limited partnership with sufficient qualifying income, which is a pass-through entity for federal income tax purposes.

Income tax expense consists of the following:

	Year Ended December 31,		
	2021	2020	2019
	(millions)		
Current:			
State income tax expense	$ (1)	$ —	$ (1)
Deferred:			
State income tax (expense) benefit	(5)	—	2
Total income tax (expense) benefit	$ (6)	$ —	$ 1

As of December 31, 2021 and 2020, we had state deferred tax liabilities of $34 million and $30 million, respectively. The state deferred tax liabilities are primarily associated with Texas franchise taxes.

Our effective tax rate differs from statutory rates, primarily due to being structured as a master limited partnership, which is a pass-through entity for federal income tax purposes, while being treated as a taxable entity in certain states, primarily Texas. The State of Texas imposes a margin tax that is assessed at 0.75%, of taxable margin apportioned to Texas for each year ended December 31, 2021, 2020 and 2019.

21. Commitments and Contingent Liabilities

Litigation — We are not a party to any material legal proceedings, but are a party to various administrative and regulatory proceedings and commercial disputes that have arisen in the ordinary course of our business. Management currently believes that the ultimate resolution of the foregoing matters, taken as a whole, and after consideration of amounts accrued, insurance coverage or other indemnification arrangements, will not have a material adverse effect on our results of operations, financial position, or cash flow.

Insurance — Our insurance coverage is carried with third-party insurers and with an affiliate of Phillips 66. Our insurance coverage includes: (i) general liability insurance covering third-party exposures; (ii) statutory workers' compensation insurance; (iii) automobile liability insurance for all owned, non-owned and hired vehicles; (iv) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (v) property insurance, which covers the replacement value of real and personal property and includes business interruption; and (vi) insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

Environment, Health and Safety — The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, fractionating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to the environment, health and safety. As an owner or operator of these facilities, we must comply with laws and regulations at the federal, state and, in some cases, local levels that relate to worker health and safety, public health and safety, pipeline safety, air and water quality, solid and hazardous waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities incorporates compliance with environmental laws and regulations, health and safety standards applicable to workers and the public, and safety standards applicable to our various facilities. In addition, there is increasing focus from (i) regulatory bodies and communities, and through litigation, on hydraulic fracturing and the real or perceived environmental or public health impacts of this technique, which indirectly presents some risk to our available supply of natural gas and the resulting supply of NGLs; (ii) regulatory bodies regarding pipeline system safety which could impose additional regulatory burdens and increase the cost of our operations; (iii) state and federal regulatory officials regarding the emission of greenhouse gases and other air emissions associated with our operations or the materials managed as part of our business, which could impose regulatory burdens and increase the cost of our operations; and (iv) regulatory bodies and communities that could prevent or delay the development of fossil fuel energy infrastructure such as pipelines, plants, and other facilities used in our business. Failure to comply with these various health, safety and environmental laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these existing laws and regulations will not have a material adverse effect on our results of operations, financial position or cash flows.

The following pending proceedings involve governmental authorities as a party under federal, state, and local laws regulating the discharge of materials into the environment. We have elected to disclose matters where we reasonably believe such proceeding would result in monetary sanctions, exclusive of interest and costs, of $1.0 million or more. It is not possible for us to predict the final outcome of these pending proceedings; however, we do not expect the outcome of one or more of these proceedings to have a material adverse effect on our results of operations, financial position, or cash flows:

- In March 2019, Region 8 of the U.S. Environmental Protection Agency ("EPA") issued a Notice of Violation alleging various non-compliance with federal Leak Detection and Repair regulations, known as Subparts KKK and OOOO that exist to mitigate emissions of volatile organic compounds from certain equipment at natural gas plants, at various times over the course of late 2011 through 2017 at five of our Colorado natural gas processing plants. DCP does not agree with many of the allegations of non-compliance. DCP has been and is engaging in information exchanges and discussions with EPA about the propriety of the allegations, including the facts and regulatory underpinnings of the various allegations. DCP's recent discussions with EPA include the possibility of resolving the allegations, including potential civil penalties and other elements, although this matter may end up in formal proceedings. EPA may require a civil penalty or equivalent that is larger than the disclosure threshold amount described above, although we do not believe that the result of this matter would have a material adverse effect on our results of operations, financial position, or cash flows.

- In 2018, the Colorado Department of Public Health and Environment ("CDPHE") issued a Compliance Advisory in relation to an improperly permitted facility flare and related air emissions from flare operations at one of our gas processing plants, which we had self-disclosed to CDPHE in December 2017. Following information exchanges and discussions with CDPHE, a resolution was proposed pursuant to which the plant's air permit would be revised to include the flare and emissions limits for such flare in addition to us paying an administrative penalty as well as an economic benefit payment generally covering the period when the flare was required to be included in the facility air permit. A revised air permit was issued in May 2019, but the parties had not yet entered into a final settlement agreement to complete the matter. Subsequently, in July 2020 CDPHE issued a Notice of Violation in relation to amine treater emissions at this gas processing plant, which we had self-disclosed to CDPHE in April 2020. We are still exchanging information and holding discussions with CDPHE as to this and the foregoing flare-related enforcement matter, including possible settlement terms, although these matters, which have since been combined, may end up in formal legal proceedings. It is possible that resolution of this matter may include an administrative penalty and economic benefit payment, further revising the facility air permit, or installation of emissions management equipment, or a combination of these, that could, in the aggregate, exceed the disclosure threshold amount described above, although we do not believe that resolution of this matter would have a material adverse effect on our results of operations, financial position, or cash flows.

22. Restructuring Costs

In April 2020, we announced a reduction in force of 15%, which resulted in $9 million of nonrecurring expense for the year ended December 31, 2020.

23. Business Segments

Our operations are organized into two reportable segments: (i) Logistics and Marketing and (ii) Gathering and Processing. These segments are monitored separately by management for performance against our internal forecast and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Our Gathering and Processing reportable segment includes operating segments that have been aggregated based on the nature of the products and services provided. Adjusted gross margin is a performance measure utilized by management to monitor the operations of each segment. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies included in Note 2.

Our Logistics and Marketing segment includes transporting, trading, marketing, storing natural gas and NGLs, and fractionating NGLs. Our Gathering and Processing segment consists of gathering, compressing, treating, processing natural gas, producing and fractionating NGLs, and recovering condensate. The remainder of our business operations is presented as "Other," and consists of unallocated corporate costs. Elimination of inter-segment transactions are reflected in the Eliminations column.

The following tables set forth our segment information:

Year Ended December 31, 2021

	Logistics and Marketing	Gathering and Processing	Other	Eliminations	Total
			(millions)		
Total operating revenue	$ 9,734	$ 6,894	$ —	$ (5,921)	$ 10,707
Adjusted gross margin (a)	$ 138	$ 1,304	$ —	$ —	$ 1,442
Operating and maintenance expense	(38)	(603)	(18)	—	(659)
General and administrative expense	(6)	(15)	(202)	—	(223)
Depreciation and amortization expense	(12)	(325)	(27)	—	(364)
Asset impairments	(13)	(18)	—	—	(31)
Other income (expense), net	6	(1)	—	—	5
Gain (loss) on sale of assets, net	2	(7)	—	—	(5)
Earnings from unconsolidated affiliates	519	16	—	—	535
Interest expense	—	—	(299)	—	(299)
Income tax expense	—	—	(6)	—	(6)
Net income (loss)	$ 596	$ 351	$ (552)	$ —	$ 395
Net income attributable to noncontrolling interests	—	(4)	—	—	(4)
Net income (loss) attributable to partners	$ 596	$ 347	$ (552)	$ —	$ 391
Non-cash derivative mark-to-market	$ (19)	$ (106)	$ —	$ —	$ (125)
Capital expenditures	$ 7	$ 93	$ 8	$ —	$ 108
Investments in unconsolidated affiliates, net	$ 5	$ —	$ —	$ —	$ 5

Year Ended December 31, 2020:

	Logistics and Marketing	Gathering and Processing	Other	Eliminations	Total
			(millions)		
Total operating revenue	$ 5,530	$ 3,479	$ —	$ (2,707)	$ 6,302
Adjusted gross margin (a)	$ 333	$ 1,226	$ —	$ —	$ 1,559
Operating and maintenance expense	(36)	(554)	(17)	—	(607)
General and administrative expense	(7)	(22)	(224)	—	(253)
Depreciation and amortization expense	(13)	(333)	(30)	—	(376)
Asset impairments	—	(746)	—	—	(746)
Other expense, net	(10)	(3)	(2)	—	(15)
Restructuring costs	—	—	(9)	—	(9)
Earnings (loss) from unconsolidated affiliates	510	(63)	—	—	447
Interest expense	—	—	(302)	—	(302)
Net income (loss)	$ 777	$ (495)	$ (584)	$ —	$ (302)
Net (loss) attributable to noncontrolling interests	—	(4)	—	—	(4)
Net income (loss) attributable to partners	$ 777	$ (499)	$ (584)	$ —	$ (306)
Non-cash derivative mark-to-market	$ 78	$ (23)	$ —	$ —	$ 55
Non-cash lower of cost or net realizable value adjustments	$ 6	$ —	$ —	$ —	$ 6
Capital expenditures	$ 4	$ 140	$ 16	$ —	$ 160
Investments in unconsolidated affiliates, net	$ 101	$ —	$ —	$ —	$ 101

Year Ended December 31, 2019:

	Logistics and Marketing	Gathering and Processing	Other	Eliminations	Total
			(millions)		
Total operating revenue	$ 6,856	$ 4,319	$ —	$ (3,550)	$ 7,625
Adjusted gross margin (a)	$ 254	$ 1,349	$ —	$ —	$ 1,603
Operating and maintenance expense	(42)	(664)	(22)	—	(728)
General and administrative expense	(8)	(23)	(244)	—	(275)
Depreciation and amortization expense	(19)	(355)	(30)	—	(404)
Asset impairments	(35)	(212)	—	—	(247)
Other expense, net	(3)	(5)	—	—	(8)
Loss on sale of assets, net	(10)	(70)	—	—	(80)
Restructuring costs	—	—	(11)	—	(11)
Earnings from unconsolidated affiliates	468	6	—	—	474
Interest expense	—	—	(304)	—	(304)
Income tax expense	—	—	1	—	1
Net income (loss)	$ 605	$ 26	$ (610)	$ —	$ 21
Net income attributable to noncontrolling interests	—	(4)	—	—	(4)
Net income (loss) attributable to partners	$ 605	$ 22	$ (610)	$ —	$ 17
Non-cash derivative mark-to-market	$ (29)	$ (49)	$ —	$ —	$ (78)
Non-cash lower of cost or net realizable value adjustments	$ 10	$ —	$ —	$ —	$ 10
Capital expenditures	$ 29	$ 474	$ 16	$ —	$ 519
Investments in unconsolidated affiliates, net	$ 450	$ —	$ —	$ —	$ 450

	December 31, 2021	December 31, 2020
	(millions)	
Segment long-term assets:		
Gathering and Processing	$ 7,515	$ 7,788
Logistics and Marketing	3,887	3,929
Other (b)	229	232
Total long-term assets	11,631	11,949
Current assets	1,749	1,008
Total assets	$ 13,380	$ 12,957

(a) Adjusted gross margin consists of total operating revenues, including commodity derivative activity, less purchases and related costs. Adjusted gross margin is viewed as a non-GAAP financial measure under the rules of the SEC, but is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, adjusted gross margin should not be considered an alternative to, or more meaningful than, net income, net cash provided by operating activities or gross margin as determined in accordance with GAAP. Our adjusted gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate adjusted gross margin in the same manner.

(b) Other long-term assets not allocable to segments consist of corporate leasehold improvements and other long-term assets

24. Supplemental Cash Flow Information

	Year Ended December 31,		
	2021	2020	2019
		(millions)	
Cash paid for interest:			
Cash paid for interest, net of amounts capitalized	$ 297	$ 283	$ 258
Cash paid for income taxes, net of income tax refunds	$ 3	$ 3	$ 3
Non-cash investing and financing activities:			
Property, plant and equipment acquired with accounts payable and accrued liabilities	$ 10	$ 7	$ 45
Other non-cash changes in property, plant and equipment	$ (9)	$ (3)	$ (2)
Other non-cash activities:			
Operating lease assets arising from the implementation of Topic 842	$ —	$ —	$ 84
Right-of-use assets obtained in exchange for operating and finance lease liabilities	$ 48	$ 18	$ 82

25. Subsequent Events

On January 24, 2022, we announced that the board of directors of the General Partner declared a quarterly distribution on our common units of $0.39 per common unit. The distribution was paid on February 14, 2022 to unitholders of record on February 4, 2022.

On the same date, the board of directors of the General Partner declared a quarterly distribution on our Series B and Series C Preferred Units of $0.4922 and $0.4969 per unit, respectively. The Series B distributions will be paid on March 15, 2022 to unitholders of record on March 1, 2022. The Series C distribution will be paid on April 15, 2022 to unitholders of record on April 1, 2022.

On January 3, 2022, we repaid, at par, prior to maturity all $350 million of aggregate principal amount outstanding of our 4.950% Senior Notes due April 1, 2022 using borrowings under our Revolving Credit Facility and AR Securitization Facility.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

There were no changes in or disagreements with accountants on accounting and financial disclosures during the year ended December 31, 2021.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner's principal executive and principal financial officers (whom we refer to as the "Certifying Officers"), as appropriate to allow timely decisions regarding required disclosure. The management of our general partner evaluated, with the participation of the Certifying Officers, the effectiveness of our disclosure controls and procedures as of December 31, 2021, pursuant to Rule 13a-15(b) under the Exchange Act. Based upon that evaluation, the Certifying Officers concluded that, as of December 31, 2021, our disclosure controls and procedures were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report On Internal Control Over Financial Reporting

Our general partner is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance to our management and board of directors of our general partner regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2021 based on the "Internal Control-Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective at the reasonable assurance level as of December 31, 2021.

Deloitte & Touche LLP, an independent registered public accounting firm, has issued their report, included immediately following, regarding our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of DCP Midstream GP, LLC and the Unitholders of DCP Midstream, LP

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of DCP Midstream, LP and subsidiaries (the "Partnership") as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Partnership and our report dated February 18, 2022, expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 18, 2022

Item 9B. ***Other Information***

Compensatory Arrangements of Certain Officers

On February 16, 2022, the Compensation Committee (the "Compensation Committee") of the Board of Directors of DCP Midstream, LLC, which owns DCP Midstream GP, LLC, the general partner of the general partner of the Partnership, established compensation levels for named executive officers of the Company (the "NEOs") for the 2022 fiscal year, to be effective as of March 21, 2022:

Name	Base Salary	Short-Term Incentive Target	Long-Term Incentive Target	Total
Wouter T. van Kempen	$775,935	100%	450%	$5,043,578
Sean P. O'Brien	$503,327	80%	250%	$2,164,306
Don A. Baldridge	$451,743	80%	255%	$1,965,082
William L. Johnson	$440,725	70%	190%	$1,586,610
George R. Green	$414,800	70%	150%	$1,327,360

The Compensation Committee also established the performance criteria for certain compensation arrangements for the NEOs for the 2022 fiscal year. The performance criteria relate to grants to the NEOs under the 2016 LTIP and awards to the NEOs under the STI.

The 2016 LTIP provides for the grant of cash and common unit-settled phantom units and cash-settled dividend equivalent rights. The phantom units consist of a notional unit based on the fair market value of a common unit of the Partnership. The phantom units will be granted half in restricted phantom units ("RPUs") that will settle in common units, and half in strategic performance units ("SPUs") that will settle in cash. RPUs will vest at the end of a three-year vesting period. SPUs will vest in an amount ranging from 0% to 200% depending on the level of achievement, as determined by the Compensation Committee, during a three-year performance period comprised of the following measures and weightings: (a) 25% for distributable cash flow per common unit of the Partnership for the 3rd year of the performance period, (b) 25% for the average of each of the three annual distributable cash flow per common unit generated during the performance period, and (c) 50% for the relative total shareholder return of the Partnership as compared to the following peer group:

Antero Midstream Corporation	Genesis Energy, L.P.	ONEOK, Inc.
Cheniere Energy, Inc.	Holly Energy Partners, L.P.	Phillips 66 Partners LP
Crestwood Equity Partners LP	Magellan Midstream Partners, L.P.	Shell Midstream Partners, L.P.
DT Midstream, Inc	MPLX LP	Targa Resources Corp.
EnLink Midstream, LLC	NuStar Energy L.P.	Western Midstream Partners, LP
Equitrans Midstream Corporation		

The foregoing description of the SPU and RPU grants is qualified in its entirety by reference to the terms of the grant agreements.

The 2022 payout opportunity for STI awards will be based on the level of performance achieved by the Partnership on annual strategic priorities and goals including the financial metrics of distributable cash flow, constant price cash generation, and cost; safety and environmental objectives relating to recordable injury rates, process safety events, and greenhouse gas emissions; and operational excellence measures such as plant efficiency and reliability, and a culture and people scorecard with criteria relating to employee engagement, inclusion and diversity, and employee development.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not Applicable.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Management of DCP Midstream, LP

We do not have directors or officers, which is commonly the case with publicly traded partnerships. Our operations and activities are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is 100% owned by DCP Midstream, LLC. The officers and directors of our General Partner are responsible for managing us. All of the directors of our General Partner are appointed annually by DCP Midstream, LLC and all of the officers of our General Partner serve at the discretion of the directors. Unitholders are not entitled to elect the directors of our General Partner or participate, directly or indirectly, in our management or operations.

Board of Directors and Executive Officers of DCP Midstream GP, LLC

The board of directors of our General Partner currently has eight members, three of whom are independent as defined under the independence standards established by the NYSE. Because we are a listed limited partnership and a controlled company, we are not required by the NYSE rules to have a majority of independent directors on the board of directors of our General Partner or to establish a compensation committee or a nominating/corporate governance committee. However, the board of directors of our General Partner has established an audit committee consisting of three independent members of the board and a special committee to address conflict situations.

Our General Partner's board of directors annually reviews the independence of directors and affirmatively makes a determination that each director expected to be independent has no material relationship with our General Partner, either directly or indirectly as a partner, unitholder or officer of an organization that has a relationship with our General Partner. Our General Partner's board of directors has affirmatively determined that Messrs. Fowler, Kimble, and Waycaster satisfy the SEC and NYSE independence standards.

The executive officers of our General Partner are responsible for establishing and executing strategic business and operation plans and managing the day-to-day affairs of our business. All of our executive officers are also executive officers of DCP Midstream, LLC. We utilize employees of DCP Midstream, LLC, including the executive officers, to operate our business and provide us with general and administrative services that are reimbursed to DCP Midstream, LLC pursuant to the terms of the Services Agreement.

The following table shows information regarding the current directors and executive officers of our General Partner, DCP Midstream GP, LLC. Directors are appointed annually by DCP Midstream, LLC and hold office for one year or until their successors have been elected and qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of the directors or executive officers.

Name	Age	Position with DCP Midstream GP, LLC
Wouter T. van Kempen	52	Chairman of the Board, President, Chief Executive Officer, and Director
Sean P. O'Brien	52	Group Vice President and Chief Financial Officer
Don A. Baldridge	52	President, Operations
William L. Johnson	50	President, Operations
George R. Green	41	Group Vice President and General Counsel
Allen C. Capps	51	Director
Heather Crowder	52	Director
Fred J. Fowler	75	Director
William F. Kimble	62	Director
Brian Mandell	58	Director
Stephen J. Neyland	54	Director
Bill W. Waycaster	83	Director

Wouter T. van Kempen was appointed as DCP Midstream GP, LLC’s Chief Executive Officer ("CEO") in January 2013, Chairman of the Board in January 2014, and President in February 2016. Mr. van Kempen is also the Chairman of the Board, President and Chief Executive Officer for DCP Midstream, LLC, which is the owner of DCP Midstream GP, LLC, since January 2013. Mr. van Kempen was previously DCP Midstream, LLC’s President and Chief Operating Officer from September 2012 until January 2013, where he led the gathering and processing and the marketing and logistics business units and oversaw all corporate functions of the organization; President, Gathering and Processing, from January 2012 to August 2012; President, Midcontinent Business Unit, and Chief Development Officer, from August 2010 to December 2011. Prior to joining DCP Midstream, LLC in August 2010, Mr. van Kempen was President of Duke Energy Generation Services from September 2006 to July 2010 and Vice President of Mergers and Acquisitions from December 2005 to September 2006. Mr. van Kempen joined Duke Energy in 2003 and served in a number of management positions. Prior to Duke Energy, Mr. van Kempen was employed by General Electric, where he served in increasing roles of responsibility becoming the staff executive for corporate mergers and acquisitions in 1999.

Sean P. O'Brien was appointed Group Vice President and Chief Financial Officer of DCP Midstream GP, LLC in January 2014. Mr. O'Brien is also the Group Vice President and Chief Financial Officer for DCP Midstream, LLC and has served in that position since May 2012. Prior to that time, Mr. O’Brien was Senior Vice President and Treasurer of DCP Midstream, LLC from May 2011 and prior to that, he served as Vice President, Financial Planning and Analysis from September 2009. Prior to joining DCP Midstream, LLC in September 2009, Mr. O’Brien was with Duke Energy Corporation where he served as General Manager of Financial Planning and Forecasting for Duke Energy’s Commercial Business Unit from May 2006, and prior to that, he was Vice President and Controller of Duke Energy Generation Services from May 2005. Mr. O’Brien joined Duke Energy in 1997. Mr. O’Brien is a certified public accountant with over 25 years of experience in the finance area and over 20 years of experience in the energy industry.

Don A. Baldridge was appointed President, Operations of DCP Midstream GP, LLC in February 2017. Mr. Baldridge has also been a President of DCP Midstream, LLC overseeing the commercial, marketing, and logistics businesses since March 2013 and before that was Vice President, Natural Gas and NGL Marketing of DCP Midstream, LLC since February 2011. Mr. Baldridge previously served as Vice President, Business Development of DCP Midstream, LLC from January 2009 until February 2011. Mr. Baldridge joined DCP Midstream, LLC in March 2005. Mr. Baldridge brings more than 25 years of experience in the energy industry, including commercial, trading and business development activities.

William L. Johnson was appointed President, Operations, of DCP Midstream GP, LLC in November 2021. Prior to this appointment, Mr. Johnson served as Group Vice President and Chief Transformation Officer for DCP Midstream GP, LLC since January 2017, where he was responsible for engineering, projects, information technology, operations technology, digital solutions, and DCP Midstream GP, LLC's integrated collaboration center. Prior to that, Mr. Johnson served as Vice President of Operations for the North and Permian regions. He also previously served as the Vice President of Technical Services, responsible for regional engineering, corporate reliability, compression services, and measurement. Before joining DCP Midstream GP, LLC in 2011, Mr. Johnson held management positions in project engineering, operations, reliability and maintenance, turnarounds, corporate engineering, and plant management at multiple chemical and refining plant sites as well as at the corporate headquarters for Arco Chemical, Lyondell, and LyondellBasell.

George R. Green was appointed Group Vice President and General Counsel of DCP Midstream GP, LLC in January 2021. Mr. Green joined the Company's legal department in 2014 and has since held roles of increasing responsibility. He served as Vice President and Deputy General Counsel of DCP Midstream GP, LLC directly prior to his current role. Before joining the Company, he was an attorney in private practice where he represented clients in business disputes, contract claims, product liability cases, and environmental matters.

Allen C. Capps was appointed a director of DCP Midstream GP, LLC in August 2016. Mr. Capps has been the Senior Vice President, Corporate Development and Energy Services for Enbridge since September 2020. Prior to that he was Senior Vice President, Corporate Development and Investment Review for Enbridge since June 2019 and prior to that was Senior Vice President and Chief Accounting Officer since February 2017. Prior to this, Mr. Capps served in a similar capacity as Vice President and Controller of Spectra Energy since January 2012. From April 2010 until January 2012, Mr. Capps served as Vice President, Business Development, Storage and Transmission, for Union Gas Limited, Spectra Energy’s Canadian natural gas utility, and as Vice President and Treasurer of Spectra Energy from December 2007 to April 2010. Mr. Capps has broad experience in the energy industry having served in various senior level finance and accounting roles since 2003.

Heather Crowder was appointed a director of DCP Midstream GP, LLC in November 2020. Ms. Crowder currently serves as Vice President and General Tax Officer for Phillips 66, a role she has held since January 1, 2018. Before joining Phillips 66 in May 2016, Ms. Crowder served as Managing Tax Counsel, Corporate, for five years at ConocoPhillips. Prior to joining

ConocoPhillips in 2011, Ms. Crowder worked for 15 years at KPMG LLP ("KPMG") where she ultimately became a partner in 2008.

Fred J. Fowler was appointed a director of DCP Midstream GP, LLC in March 2015. Mr. Fowler is the former president and chief executive officer of Spectra Energy, retiring from that position in December 2008. Prior to Spectra Energy's separation from Duke Energy Corporation in December 2006, Mr. Fowler served as group president for Duke Energy's gas transmission business since April 2006. Prior to that, Mr. Fowler served as president and chief operating officer of Duke Energy Corporation since November 2002. Mr. Fowler began his career in the energy industry in 1968. Mr. Fowler served as vice chairman of the board of directors of TEPPCO Partners, L.P. from March 1998 to February 2003 and as chairman of the board of directors of our General Partner from April 2007 to January 2009. Mr. Fowler served on the board of directors of Ovintiv Inc. (formerly known as Encana Corp.) until April 28, 2021 and served on the board of directors of PG&E Corporation until June 30, 2020.

William F. Kimble was appointed a director of DCP Midstream GP, LLC in June 2015. Mr. Kimble retired in February 2015 from KPMG, one of the largest audit, tax and advisory services firms in the world. Mr. Kimble served as KPMG's Office Managing Partner for the Atlanta office and Managing Partner - Southeastern United States, where he was responsible for the firm's audit, advisory and tax operations from 2009 until his retirement. Mr. Kimble was also responsible for moderating KPMG's Audit Committee Institute and Audit Committee Chair Sessions. Until his retirement, Mr. Kimble had been with KPMG or its predecessor firm since 1986. During his tenure with KPMG, Mr. Kimble held numerous senior leadership positions, including Global Chairman of Industrial Markets. Mr. Kimble also served as KPMG's Energy Sector Leader for approximately ten years and was the executive director of KPMG's Global Energy Institute. Mr. Kimble currently serves on the board of directors of Liberty Oilfield Services Inc. and its audit committee and previously served on the board of directors of PRGX Global, Inc. and its audit committee.

Brian Mandell was appointed a director of DCP Midstream GP, LLC in May 2015. Mr. Mandell has nearly 30 years of oil and gas industry experience serving in various marketing, commercial, and midstream roles. He is currently Executive Vice President, Marketing and Commercial, for Phillips 66. He previously served as Senior Vice President, Commercial, for Phillips 66. Prior to that, he served as Phillips 66's President, Global Marketing, and prior to that, Global Trading Lead, Clean Products, Commercial. Prior to joining Phillips 66 in May 2012, he worked for ConocoPhillips as Manager, U.S. Gasoline Trading since 2011. Previously, Mr. Mandell served in the Commercial NGL group and was named Manager of NGL Trading after working as Manager of Processing Assets and Business Development in 2006. Mr. Mandell began his career with Conoco in 1991 working in various marketing roles.

Stephen J. Neyland was appointed a director of DCP Midstream GP, LLC in June 2020. Mr. Neyland currently serves as Vice President, Finance, Gas Transmission and Midstream of Enbridge. Since joining Enbridge in 2001, Mr. Neyland has held a variety of progressive leadership positions overseeing financial operations, financial reporting, risk management, and controls for a number of Enbridge's U.S. subsidiaries, including roles as the principal financial officer of several of Enbridge's publicly traded partnerships. Mr. Neyland brings over 25 years of experience in the energy industry having previously held positions at Koch Industries, KCS Energy, Inc., and Arthur Andersen & Co.

Bill W. Waycaster was appointed a director of DCP Midstream GP, LLC in June 2015. Mr. Waycaster retired in April 2003 from Texas Petrochemicals LLC ("Texas Petrochemicals") after working in the hydrocarbon process industries for over 45 years. Mr. Waycaster was President and Chief Executive Officer of Texas Petrochemicals from April 1992 until his retirement. Prior to that, Mr. Waycaster spent 27 years at The Dow Chemical Company ("Dow") serving as Vice President and General Manager of Hydrocarbons and Energy Resources until he left to join Texas Petrochemicals. Mr. Waycaster held positions at Dow ranging from Project Engineer to Vice President of Business and Asset Management. Mr. Waycaster previously served on the board of directors of the National Petrochemical and Refiners Association, where he served as Chairman of the Petrochemicals Committee and Executive Committee, and also served on the board of directors of the American Chemistry Council. Mr. Waycaster has previously served on the board of directors of each of Destec Energy, Inc. and Enterprise Products GP, LLC.

Director Experience and Qualifications

DCP Midstream, LLC evaluates and recommends candidates for membership on the board of directors of our General Partner based on established criteria. When evaluating director candidates, nominees and incumbent directors, DCP Midstream, LLC has informed us that it considers, among other things, educational background, knowledge of our business and industry, professional reputation, independence, and ability to represent the best interests of our unitholders. DCP Midstream, LLC and the board of directors of our General Partner believe that the above-mentioned attributes, along with the leadership skills and experience in the midstream natural gas industry, provide the Partnership with a capable and knowledgeable board of directors.

Wouter T. van Kempen - Mr. van Kempen was appointed a director because of his extensive knowledge of and experience with our assets as Chairman, President, and Chief Executive Officer of DCP Midstream GP, LLC and as Chairman, President and Chief Executive Officer of DCP Midstream, LLC. Mr. van Kempen brings strong management experience having served in positions of increasing responsibility at Duke Energy and General Electric.

Allen C. Capps - Mr. Capps was appointed a director because of his strong background in the energy industry including his leadership roles in accounting, finance, and business development with Enbridge and Spectra Energy.

Heather Crowder - Ms. Crowder was appointed a director because of her more than two decades of experience, covering a wide spectrum of the energy industry, including well services, integrated, upstream, midstream and downstream markets. Ms. Crowder has significant tax experience from participating as legal counsel in external audits focused on financial statement tax disclosures.

Fred J. Fowler - Mr. Fowler was appointed a director because of his extensive knowledge and experience of the energy industry, including a strong understanding of our assets, customers, regulatory environment, and competitive landscape. Mr. Fowler brings leadership, management, and business skills developed as an executive and a director at public and privately held companies.

William F. Kimble - Mr. Kimble was appointed a director because of his extensive accounting background and experience as a director of other public companies. Mr. Kimble brings significant knowledge of the most current and pressing audit and financial compliance matters and reporting obligations faced by public companies.

Brian Mandell - Mr. Mandell was appointed a director because of his strong background and knowledge with over two decades of senior leadership experience in a variety of roles including commercial and marketing within the industry.

Stephen J. Neyland - Mr. Neyland was appointed a director because of his more than two decades of experience in the energy industry and expertise in investor relations, internal controls, audit and merger and acquisition. Mr. Neyland has served as principal financial officer for multiple publicly held entities and is a designated Certified Public Accountant.

Bill W. Waycaster - Mr. Waycaster was appointed a director because of his lengthy tenure in the energy industry and executive management experience, spanning a period of over 50 years. Mr. Waycaster contributes valuable insight into strategic, corporate governance, and compliance matters with his prior public company leadership and board experience.

Delinquent Section 16(a) Reports

Section 16(a) of the Exchange Act requires DCP Midstream GP, LLC’s directors and executive officers, and persons who own more than 10% of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of our common units and our other equity securities and to furnish us with copies of such reports. To our knowledge, based solely on a review of the copies of reports and amendments thereto filed electronically with the SEC or furnished to us and written representations of our directors and executive officers that no other reports were required, all Section 16(a) filing requirements applicable to such reporting persons were complied with on a timely basis during the fiscal year ended December 31, 2021.

Audit Committee

The board of directors of our General Partner has a standing audit committee. The audit committee is composed of three independent directors, William F. Kimble (chairman), Fred J. Fowler, and Bill W. Waycaster, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. Mr. Kimble has been designated by the board as the audit committee's financial expert meeting the requirements promulgated by the SEC as set forth in Item 407(d) of Regulation S-K of the Exchange Act based upon his education and employment experience as more fully detailed in Mr. Kimble's biography set forth above.

The board has determined that each member of the audit committee is independent under Section 303A.02 of the NYSE listing standards and Section 10A(m)(3) of the Exchange Act. In making the independence determination, the board considered the requirements of the NYSE and our Corporate Governance Guidelines. Among other factors, the board considered current or previous employment with us, our auditors or their affiliates by the director or his immediate family members, ownership of our voting securities, and other material relationships with us.

The audit committee has adopted a charter, which has been ratified and approved by the board of directors. The primary purpose of the audit committee is to assist the board of directors in its oversight of (1) the integrity of the financial statements of the Partnership, (2) the compliance by the General Partner and the Partnership with legal and regulatory requirements, and the General Partner's and the Partnership's Code of Business Ethics, (3) the independent auditor's qualifications and independence and (4) the performance of the Partnership's internal audit function and independent auditors.

Special Committee

The board of directors of our General Partner has a special committee. The special committee, comprised of two or more of our independent directors, is convened on an ad hoc basis upon determination of the board and reviews specific matters that the board believes may involve conflicts of interest, including transactions between us and DCP Midstream, LLC or its affiliates. The special committee determines if the resolution of the conflict of interest is fair and reasonable to us, or on grounds no less favorable to us than generally available from unrelated third parties. The members of the special committee may not be officers or employees of our General Partner or directors, officers or employees of its affiliates. Each of the members of the special committee must meet the independence and experience standards established by the NYSE and the Exchange Act. Any matters approved by the special committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our General Partner of any duties it may owe us or our unitholders.

Sustainability Committee

The board of directors of our General Partner has a sustainability committee. The sustainability committee is currently comprised of all members of our board of directors excluding Mr. van Kempen, our Chairman and CEO. The sustainability committee provides oversight to ensure that environmental, social, and governance opportunities and risks are incorporated into our long-term business strategy. The sustainability committee also oversees the development of our sustainability disclosures and reporting and strategic response to stakeholder expectations and concerns regarding sustainability.

Corporate Governance Guidelines, Code of Business Ethics, and Audit Committee Charter

The board of directors of our General Partner adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance.

We have adopted a Code of Business Ethics applicable to all persons serving as our directors, officers (including without limitation, our principal executive officer, principal financial officer and principal accounting officer) and employees. We intend to disclose any amendment to or waiver of our Code of Business Ethics that applies to our executive officers or directors on our website at *www.dcpmidstream.com* in order to satisfy disclosure requirements under SEC and NYSE rules relating to such information.

Copies of our Corporate Governance Guidelines, Code of Business Ethics and Audit Committee Charter are available on our website at *www.dcpmidstream.com*. Copies of these items are also available free of charge in print to any person who sends a request to the office of the Corporate Secretary of DCP Midstream at 6900 E. Layton Avenue, Suite 900, Denver, Colorado 80237. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of the board of directors of our General Partner, the independent directors meet in an executive session, which executive sessions are presided over by William F. Kimble. In addition, at each quarterly meeting of the board of directors, the non-management members of the board meet in executive session, which executive sessions are presided over by Fred J. Fowler.

Unitholders or interested parties may communicate with any and all members of our board, or any committee of our board, by transmitting correspondence to one or more directors by name or to the chairman of the board or any committee of the board at the following address: Name of the Director(s), c/o Corporate Secretary, DCP Midstream, 6900 E. Layton Avenue, Suite 900, Denver, Colorado 80237.

Report of the Audit Committee

The audit committee oversees our financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls over financial reporting. The audit committee operates under a written charter approved by the board of directors. The charter, among other things, provides that the audit committee is responsible for the appointment, compensation, oversight, retention, and termination of the independent auditor. In this context, the audit committee:

- reviewed and discussed quarterly and annual earnings press releases, quarterly unaudited financial statements, and the annual audited financial statements included in this Annual Report on Form 10-K with management and Deloitte & Touche LLP, our independent auditors, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements;
- reviewed with Deloitte & Touche LLP, who are responsible for expressing an opinion on the conformity of the audited financial statements with generally accepted accounting principles, their judgments as to the quality and acceptability of our accounting principles and such other matters as are required to be discussed with the audit committee under the auditing standards of the Public Company Accounting Oversight Board (PCAOB);
- received the written disclosures and the letter required by PCAOB Ethics and Independence Rules (independence discussions with audit committees) provided to the audit committee by Deloitte & Touche LLP;
- discussed with Deloitte & Touche LLP its independence from management and us and considered the compatibility of the provision of nonaudit service by the independent auditors with the auditors’ independence;
- discussed with Deloitte & Touche LLP the matters required to be discussed by statement on auditing standards No. 16 (PCAOB Auditing Standard No. 16, Communications with Audit Committees, Related Amendments to PCAOB Standards and Transitional Amendments to AU Section 380);
- discussed with our internal auditors and Deloitte & Touche LLP the overall scope and plans for their respective audits. The audit committee meets with the internal auditors and Deloitte & Touche LLP, with and without management present, to discuss the results of their examinations, their evaluations of our internal controls and the overall quality of our financial reporting;
- based on the foregoing reviews and discussions, recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2021, for filing with the SEC; and
- approved the reappointment of Deloitte & Touche LLP to serve as our independent auditors based on an annual consideration of, among other factors, the following: their historical and recent performance on our audit, the quality and candor of their communications with the audit committee and management, the depth of expertise of their audit team and the value provided by their national office, the appropriateness of their fees, how effectively they maintained their independence, their tenure as our independent auditors, their knowledge of our operations, accounting policies and practices, and internal control over financial reporting, and external data relating to audit quality and performance by them and their peer firms.

This report has been furnished by the members of the audit committee of the board of directors:

Audit Committee
William F. Kimble (Chairman)

Fred J. Fowler
Bill W. Waycaster

The report of the audit committee in this report shall not be deemed incorporated by reference into any other filing by DCP Midstream, LP under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that we specifically incorporate this information by reference, and shall not otherwise be deemed filed under such laws.

Item 11. ***Executive Compensation***

Compensation Discussion and Analysis

General

We were formed in 2005. Similar to other publicly traded partnerships, our operations are managed by our general partner, DCP Midstream GP, LP, which in turn is managed by its general partner, DCP Midstream GP, LLC, which we refer to as our General Partner. Our General Partner is 100% owned by DCP Midstream, LLC. When we refer herein to the board of directors, we are referring to the board of directors of our General Partner. Additionally, when we refer herein to the compensation committee, we are referring to the compensation committee of the board of directors of DCP Midstream, LLC, comprised of Chairman Greg C. Garland, Chairman and CEO of Phillips 66 and Al Monaco, President and CEO of Enbridge Inc.

We have entered into the Services Agreement with DCP Midstream, LLC pursuant to which, among other matters, DCP Services, LLC makes available its employees who manage and operate our assets and serve as the executive officers, including the named executive officers, or NEOs, of our General Partner. For the year ended December 31, 2021, the NEOs of our General Partner were Wouter T. van Kempen, Chairman of the Board, President, and Chief Executive Officer (Principal Executive Officer); Sean P. O'Brien, Group Vice President and Chief Financial Officer (Principal Financial Officer); Don A. Baldridge, President, Operations; William L. Johnson, President, Operations, who was appointed to the position vacated by the October 30, 2021 departure of Corey D. Walker, former President, Operations; and George R. Green, Group Vice President and General Counsel.

The General Partner has not entered into employment agreements with any of the NEOs. The NEOs do not receive any separate compensation from us for their services to our business or as executive officers of our General Partner. We pay DCP Midstream, LLC the full cost for the compensation of our NEOs. The compensation committee has the ultimate decision-making authority with respect to the compensation that DCP Midstream, LLC pays to the NEOs.

Compensation Decisions

All compensation decisions concerning the executive officers dedicated to our operations and management are made by the compensation committee. The compensation committee's responsibilities on compensation matters include the following:

- annually review the Partnership's goals and objectives relevant to compensation of the NEOs;
- annually evaluate the NEO's performance in light of the Partnership's goals and objectives, and approve the compensation levels for the NEOs;
- periodically evaluate the terms and administration of short-term and long-term incentive plans to assure that they are structured and administered in a manner consistent with the Partnership's goals and objectives;
- retain and terminate any compensation consultant to assist in the evaluation of compensation for NEOs and for directors who are not officers or employees of the General Partner or its affiliates, or our non-employee directors; and
- periodically review the compensation of our non-employee directors.

Compensation Philosophy

The Partnership's compensation program is structured to provide the following benefits:

- attract, retain and reward talented executive officers by providing compensation competitive with that of other executive officers in our industry;
- motivate executive officers to achieve strong financial and operational performance;
- emphasize performance-based compensation, balancing short-term and long-term results; and
- reward individual performance.

Methodology - Advisors and Peer Companies

The compensation committee reviews data from market surveys provided by independent consultants to assess our competitive position with respect to base salary, annual short-term incentives and long-term incentive compensation for our NEOs as well as the compensation package for our non-employee directors. With respect to NEO compensation, the compensation committee also considers individual performance, levels of responsibility, skills and experience. Management, on behalf of the compensation committee, generally engages the services of Mercer, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for the NEOs. We consider Mercer to be independent of the Partnership and therefore, the work performed by Mercer does not create a conflict of interest. The Mercer study is based on compensation for a group of peer companies with similar operations obtained from public documents as well as multiple survey sources, including the current Mercer Benchmark Database and the Mercer Total Compensation Survey for the Energy Sector. The Mercer study is comprised of the following peer companies:

Crestwood Equity Partners LP	MPLX LP
Enable Midstream Partners LP	NuStar Energy L.P.
EnLink Midstream, LLC	ONEOK, Inc.
Genesis Energy, L.P.	Targa Resources Corp.
Magellan Midstream Partners, L.P.	Western Midstream Partners, LP

Studies such as this generally include only the most highly compensated officers of each company, which correlates with the NEOs. The results of the Mercer study as well as other factors such as targeted performance objectives serve as a benchmark for establishing total annual direct compensation packages for the NEOs. Peer data from the Mercer study and the data point that represents the 50th percentile of the market in the surveys are used.

Components of Compensation

The total annual direct compensation program for the NEOs consists of three components: (1) base salary; (2) a short-term cash incentive, or STI, which is based on a percentage of annual base salary; and (3) a long-term incentive consisting of a grant of performance units and phantom units, which are based on a percentage of annual base salary. In February 2020, the compensation committee approved the following base salary, short-term incentive targets, and long-term incentive targets for our NEOs, except for Messrs. Johnson and Green, who were not NEOs prior to the most recently completed fiscal year, that were to be effective March 23, 2020 as shown in our Annual Report on Form 10-K for the fiscal year ended 2020. However, in response to the COVID-19 pandemic and the global demand destruction that impacted our industry, we implemented various cost reductions including voluntary reductions of base salary adjustments, which were eventually reinstated on February 18, 2021 as follows:

Name and Principal Position	Base Salary	Short-Term Incentive Target	Long-Term Incentive Target	Total
Wouter T. van Kempen, Chairman, President & CEO	$730,000	100%	375%	$4,197,500
Sean P. O'Brien, Group Vice President & Chief Financial Officer	$473,530	75%	245%	$1,988,826
Don A. Baldridge, President, Operations	$425,000	75%	250%	$1,806,250
Corey D. Walker, Former President, Operations	$425,000	75%	250%	$1,806,250

In October, all of the NEOs received a 2.5% merit increase to base salary, except for Mr. Green, who received a market-based adjustment effective in August 2021 to his total compensation as shown below. In November 2021, the Compensation Committee established the compensation set forth below for Mr. Johnson in connection with his appointment as President, Operations.

Name	Base Salary	Short-Term Incentive Target	Long-Term Incentive Target	Total
William L. Johnson	$425,000	70%	190%	$1,530,000
George R. Green	$400,000	60%	120%	$1,120,000

In allocating compensation among base salary, short-term incentives and long-term incentives we believe a significant portion of the compensation of the NEOs should be performance-based since these individuals have a greater opportunity to influence our performance. In making this allocation, we have relied in part on the Mercer study and considered each component of compensation as described below.

Base Salary - Base salaries for NEOs are determined based upon individual performance, levels of responsibility, skills and experience, and comparisons to the salaries of individuals in similar positions obtained from the Mercer study. The goal of the base salary component is to compensate NEOs at a level that approximates the median salaries of individuals in comparable positions at comparably sized companies in our industry.

The base salaries for NEOs are generally reevaluated annually as part of our performance review process, or when there is a change in the level of job responsibility. The compensation committee annually considers and approves a merit increase in base salary based upon the results of this performance review process. Merit increases are based on industry trends and a review of individual performance in certain categories, such as business values, environmental, health & safety performance, leadership, financial results, project results, attitude, ability and knowledge.

Short-Term Cash Incentive - Under the STI plan, annual cash incentives are provided to executives to promote the achievement of our performance objectives. Target incentive opportunities for executives under the STI plan are established as a percentage of base salary. Incentive amounts are intended to provide total cash compensation at the market median for executive officers in comparable positions when target performance is achieved, below the market median when performance is less than target and above the market median when performance exceeds target. The Mercer study is used to determine the competitiveness of the incentive opportunity for comparable positions. STI payments generally occur in March of each year for the prior fiscal year's performance.

The 2021 STI objectives were initially designed and proposed by our Chairman of the Board, President, and CEO and subsequently approved by the compensation committee. All STI objectives are tied to the performance of the Partnership and are subject to change each year based on annual strategic priorities and goals. The 2021 objectives comprising the total STI opportunity for the NEOs are described below.

Financial objectives (60% of total STI):

- *Distributable Cash Flow.* An objective intended to capture the annual amount of cash that is available for the quarterly distributions to our unitholders. For this objective, we established a range of performance from a minimum of $710 million to a maximum of $850 million.
- *Constant Price Cash Generation.* An objective intended to capture the cash generated from operations for the Partnership excluding the effect of commodity prices. For this objective, we established a range of performance from a minimum of $1,080 million to a maximum of $1,180 million.
- *Cost.* An objective intended to capture the ongoing operating and general and administrative costs of the Partnership. For this objective, we established a range of performance from a minimum of $910 million to a maximum of $855 million.

Operational Excellence objectives (20% of total STI):

- *Operations/ICC.* An objective intended to measure efficiencies created by leveraging the capabilities of our Integrated Collaboration Center (ICC).
- *Workforce of Today.* An objective to improve the skills and versatility of our employees to support the efficient and reliable operation of our assets.
- *Culture and People.* Regrettable turnover is the key measure DCP uses to track and reduce the turnover of key and critical employees whose skills and talent are very hard to replace. In addition, a Culture & People scorecard is used to improve the attraction and retention of a diverse mix of talent across DCP.

Safety & Environmental objectives (20% of total STI):

- *Total Recordable Injury Rate (TRIR).* An objective of both employee and contractor incident rates covering the assets of the Partnership. For this objective, the maximum level of performance is a TRIR of 0.21 and the minimum level of performance is a TRIR of 0.44.
- *Process Safety Event Rate (PSE Rate).* An objective using Tier 1 and 2 process safety events covering the assets of the Partnership. For this objective, the maximum level of performance is a PSE Rate of 0.70 and a minimum level of performance is a PSE Rate of 1.30.
- *Total Emissions.* An objective of air emissions, natural gas vented or flared, covering the assets of the Partnership. For this objective, we have established certain levels of emissions at such assets.

The payout on the Partnership objectives range from 0% if the minimum level of performance is not achieved, 50% if the minimum level of performance is achieved, 100% if the target level of performance is achieved and 200% if the maximum level of performance is achieved. When the performance level falls between these percentages, the payout will be evaluated using straight-line interpolation with the final percentages determined by the compensation committee.

Early in 2022, management prepared a report on the achievement of the Partnership objectives during 2021. These results were then reviewed and approved by the compensation committee. The level of performance achieved in 2021 for each of the STI objectives was as follows:

STI Objectives	Level of Performance Achieved
Distributable Cash Flow	At Maximum
Constant Price Cash Generation	Below Minimum
Cost	Between Target and Maximum
Operations/ICC	Between Minimum and Target
Workforce of Today	Between Minimum and Target
Culture & People	Between Minimum and Target
Total Recordable Injury Rate (TRIR)	Between Minimum and Target
Process Safety Event Rate (PSE Rate)	Between Target and Maximum
Total Emissions	At Maximum

Long-Term Incentive Plan - The LTIP has the objective of providing a focus on long-term value creation and enhancing executive retention. Under the LTIP, phantom units, which are notional units based on the fair market value of our common units, are issued where half of such phantom units are strategic performance units, or SPUs, and half are restricted phantom units, or RPUs. The SPUs will vest at a multiple based upon the level of achievement of certain performance objectives over a three-year performance period, or the Performance Period, and will settle in cash. The RPUs will vest if the executive officer remains employed at the end of a three-year vesting period, or the Vesting Period, or earlier in the case of death, disability, retirement, or layoff. Our RPUs have historically settled in cash; however, starting with the 2020 grants, RPUs will be settled through the issuance of common units. The SPU and RPU awards are granted annually with a three-year Performance Period and Vesting Period, respectively. We believe this program promotes retention of the executive officers and focuses the executive officers on the goal of long-term value creation.

For 2021, the SPUs had the following three performance measures: (1) a quarter is measured against three-year distributable cash flow, or DCF, as defined in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," per common unit of the Partnership over the Performance Period, which DCF per common unit will be determined using our 2022 financial statements; (2) a quarter is measured against the average of three one-year distributable cash flow measures during the performance period and (3) the remaining half is measured against relative total shareholder return, or RTSR, defined as total shareholder return of the Partnership over the three-year Performance Period relative to the following peer group:

Antero Midstream Corporation	Genesis Energy, L.P.	ONEOK, Inc.
Cheniere Energy, Inc.	Holly Energy Partners, L.P.	Phillips 66 Partners LP
Crestwood Equity Partners LP	Magellan Midstream Partners, L.P.	Shell Midstream Partners, L.P.
Enable Midstream Partners, LP	MPLX LP	Targa Resources Corp.
EnLink Midstream, LLC	NGL Energy Partners L.P.	TC Pipelines, LP
Equitrans Midstream Corporation	NuStar Energy L.P.	Western Midstream Partners, LP

The compensation committee believes in utilizing the DCF per common unit of the Partnership, which is a liquidity and performance measure that reflects our ability to make cash distributions to our unitholders, and RTSR, which reflects our performance as compared to a group of representative companies that investors use to assess our relative performance, because they measure management's effectiveness and directly align the performance of the NEOs with the success of the Partnership. We believe these performance measures provide management with appropriate incentives for our disciplined and steady growth and execution of our strategic priorities.

SPU and RPU awards include the right to receive dividend equivalent rights, or DERs, during the Performance Period or Vesting Period, as applicable, based on the number of phantom common units granted. The DERs on the SPUs are paid in cash when SPUs are settled at the end of the Performance Period and the DERs on the RPUs are paid quarterly in cash during the Vesting Period. The amount paid on the DERs is equal to the quarterly distributions actually paid on the underlying common units during the Performance Period and the Vesting Period on the number of SPUs earned or RPUs granted, respectively.

Our practice is to determine the dollar amount of long-term incentive compensation that we want to provide, and to then grant a number of SPUs and RPUs that have a fair market value equal to that amount on the date of grant, which is based on the average closing price of our common units on the NYSE for the 20 trading days ending two days prior to the date of grant under the LTIP. Target long-term incentive opportunities for executives under the plan are established as a percentage of base salary, using the Mercer study data for individuals in comparable positions.

In the event an award recipient's employment is terminated after one hundred and eighty days following the grant date for reasons of death, disability, retirement, or layoff, the recipient's: (i) SPUs will contingently vest on a pro rata basis for time worked over the Performance Period and final performance, measured at the end of the Performance Period, will determine the payout and (ii) RPUs will become fully vested and payable. Termination of employment for any other reason will result in the forfeiture of any unvested units and unearned DERs.

Unit Ownership Guidelines - In order to further align the interests of our officers with the interests of our unitholders, we have adopted guidelines that our officers beneficially own common units having a value as set forth in the table below. Officers are expected to reach this guideline within five years of becoming subject to the guidelines and to maintain such minimum ownership level during the tenure of their position. DCP common units owned, unvested common unit settled RPUs, and investments in DCP common units in the Executive Deferred Compensation Plan are included when determining whether an executive has met the required ownership levels. Compliance with the unit ownership guidelines is reviewed annually. All NEOs currently comply with these unit ownership guidelines or are on track to comply within the applicable five-year period as shown below.

Position	**Multiple of Base Salary under Guidelines**	**Actual Multiple as of December 31, 2021**
Wouter T. van Kempen	5x	15x
Sean P. O'Brien	3x	6x
Don A. Baldridge	3x	7x
William L. Johnson	3x	4x
George R. Green	3x	0.8x

Anti-Hedging and Anti-Pledging Policy - All of our officers, employees, and directors are subject to our Insider Trading Policy, which, among other things, prohibits directly or indirectly (i) holding our securities in a margin account, (ii) engaging in short sales of our securities, (iii) the purchase or sale of derivative instruments or other hedges including, but not limited to, exchange funds, forwards, swaps, options, puts, calls, collars, and (iv) pledging our securities as collateral. This policy covers our securities received as part of a compensation program as well as our securities acquired personally.

Clawback Policy - In 2021, we adopted an Incentive Compensation Clawback Policy. Our policy provides that incentive-based compensation (cash and equity) paid to our current and former officers may be recovered in the event of a restatement of our financial results, or under certain other circumstances, such as an officer's fraud or misconduct that causes or is reasonably likely to cause us financial or reputational harm. In connection with such events, the Board or Compensation Committee will have the authority to require the reimbursement or forfeiture of any incentive compensation, including payments under the short-term cash incentive plan and payments and grants under the long-term incentive plan. In addition, we will take action to modify the clawback policy to comply with Section 10(D) of the Exchange Act and NYSE rules should the SEC adopt and implement final rules related thereto.

Other Compensation - In addition, executives are eligible to participate in other compensation programs, which include but are not limited to:

Company Matching and Retirement Contributions to Defined Contribution Plans - Executives may elect to participate in a 401(k) and retirement plan. Under the plan, executives may elect to defer up to 75% of their eligible compensation, or up to the limits specified by the Internal Revenue Service. We match the first 6% of eligible compensation contributed by the executive to the plan. In addition, we make retirement contributions ranging from 4% to 7% of the eligible compensation of qualifying participants to the plan, based on years of service, up to the limits specified by the Internal Revenue Service. We have no defined benefit plans.

Miscellaneous Compensation - Executive officers are eligible to participate in a non-qualified deferred compensation program. Executive officers can defer up to 75% of their base salary, up to 90% of their STI and up to 100% of their LTIP or other compensation. Executive officers elect either to receive amounts contributed during specific plan years as a lump sum at a specific date, subject to Internal Revenue Service rules, as an annuity (up to five years) at a specific date, subject to Internal Revenue Service rules, or in a lump sum or annual annuity (over three to ten years) at termination.

Within the non-qualified deferred compensation program is a non-qualified, defined contribution retirement plan in which benefits earned under the plan are attributable to compensation in excess of the annual compensation limits under Section 401(k) of the Code. Under this part of the plan, we contribute up to 13% of annual compensation, as defined by the plan, to the non-qualified deferred compensation program.

Benefit Programs - We provide employees, including the executive officers, with a variety of health and welfare benefit programs. The health and welfare programs are intended to protect employees against catastrophic loss and promote well-being. These programs include medical, dental, life insurance, accidental death and disability, and long-term disability. We also provide employees with a monthly parking pass or a pass to be used on public transportation systems.

We do not provide any material perquisites or any other personal benefits to our executives.

We are a partnership and not a corporation for U.S. federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Section 162(m) of the Code. Accordingly, none of the compensation paid to NEOs is subject to the limitation.

Board of Directors Report on Compensation

Our General Partner’s board of directors does not have a compensation committee. The board of directors of the General Partner has reviewed and discussed with management the “Compensation Discussion and Analysis” presented above. Members of management with whom the board of directors had discussions are the Chairman of the Board, President, and Chief Executive Officer of the General Partner and the Group Vice President and Chief Human Resources Officer of DCP Midstream, LLC. In addition, we engaged the services of Mercer, a compensation consultant, to conduct a study to assist us in establishing overall compensation packages for the executives. Based on this review and discussion, the board of directors of the General Partner recommended that the “Compensation Discussion and Analysis” referred to above be included in this Annual Report on Form 10-K for the year ended December 31, 2021.

The information contained in this Board of Directors Report on Compensation shall not be deemed to be “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any filing with the SEC, or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act of 1933, as amended (the "Securities Act"), or the Exchange Act.

Board of Directors
Wouter T. van Kempen (Chairman)
Allen C. Capps
Heather Crowder
Fred J. Fowler
William F. Kimble
Brian Mandell
Stephen J. Neyland
Bill W. Waycaster

The following tables and accompanying narrative disclosures provide information regarding compensation of our named executive officers, or NEOs, as of December 31, 2021.

Summary Compensation Table

The following table summarizes the compensation awarded to, earned by or paid to the named executive officers of our General Partner for the services they provided to our business:

Name and Principal Position	Year	Salary	LTI Awards (a)	Non-Equity Incentive Plan Compensation (b)	All Other Compensation (c)	Total
Wouter T. van Kempen, ***Chairman of the Board, President and Chief Executive Officer***						
	2021	$ 718,208	$ 2,737,587	$ 1,106,040	$ 913,087	$ 5,474,922
	2020	$ 670,154	$ 2,737,447	$ 1,007,130	$ 858,090	$ 5,272,821
	2019	$ 691,742	$ 2,467,198	$ 1,003,026	$ 925,285	$ 5,087,251
Sean P. O'Brien, ***Group Vice President and Chief Financial Officer***						
	2021	$ 469,341	$ 1,160,238	$ 492,808	$ 416,010	$ 2,538,397
	2020	$ 454,186	$ 1,160,324	$ 511,925	$ 396,208	$ 2,522,643
	2019	$ 453,846	$ 1,034,276	$ 493,558	$ 463,715	$ 2,445,395
Don A. Baldridge, ***President, Operations***						
	2021	$ 421,240	$ 1,062,596	$ 442,302	$ 348,141	$ 2,274,279
	2020	$ 404,533	$ 1,062,441	$ 455,959	$ 316,805	$ 2,239,738
	2019	$ 399,975	$ 706,663	$ 434,973	$ 377,289	$ 1,918,900
William L. Johnson, ***President, Operations***						
	2021	$ 390,435	$ 467,869	$ 440,020	$ 240,328	$ 1,538,652
	2020	$ —	$ —	$ —	$ —	$ —
	2019	$ —	$ —	$ —	$ —	$ —
George R. Green, ***Group Vice President and General Counsel***						
	2021	$ 364,692	$ 276,053	$ 382,927	$ 78,024	$ 1,101,696
	2020	$ —	$ —	$ —	$ —	$ —
	2019	$ —	$ —	$ —	$ —	$ —
Corey D. Walker, ***Former President, Operations (d)***						
	2021	$ 354,221	$ 1,062,596	$ —	$ 372,359	$ 1,789,176
	2020	$ 338,365	$ 4,239,236	$ 564,380	$ 745,405	$ 5,887,386
	2019	$ —	$ —	$ —	$ —	$ —

(a) The amounts in this column reflect the grant date fair value of strategic performance units, or SPUs, and restricted phantom units, or RPUs granted under the LTIP, and are computed in accordance with the provisions of the FASB Accounting Standards Codification, or ASC, 718 "Compensation-Stock Compensation", or ASC 718. SPU awards are subject to performance conditions and the amounts shown are for target performance because target is the probable outcome. For SPUs granted in 2021, the performance conditions are between 0% if the minimum level of performance is not achieved to 200% if the maximum level of performance is achieved. The maximum value payable on the SPUs based on the 2021 grant date fair value, assuming the SPUs vested at the highest level of performance conditions, would be $2,737,621 for Wouter T. van Kempen, $1,160,121 for Sean P. O'Brien, $1,062,668 for Don A. Baldridge, $467,853 for William L. Johnson, $276,053 for George R. Green, and $1,062,668 for Corey D. Walker.

(b) Includes amounts payable under the STI Plan, including any amounts voluntarily deferred into the nonqualified deferred compensation plan. These amounts are expected to be paid in March 2022.

(c) Includes DERs, Partnership contributions to the defined contribution plan, Partnership contributions to the nonqualified deferred compensation plan and accrued vacation, as described in more detail below.

(d) Mr. Walker resigned effective October 30, 2021.

All Other Compensation

"All Other Compensation" in the summary compensation table includes the following for 2021:

Name	Company contributions to defined contribution plans	Company contributions to nonqualified deferred compensation program	DERs	Other (a)	Total
Wouter T. van Kempen	$ 31,900	$ 347,477	$ 533,710	$ —	$ 913,087
Sean P. O'Brien	$ 31,900	$ 158,606	$ 225,504	$ —	$ 416,010
Don A. Baldridge	$ 34,800	$ 121,661	$ 191,680	$ —	$ 348,141
William L. Johnson	$ 31,900	$ 89,760	$ 118,668	$ —	$ 240,328
George R. Green	$ 29,000	$ 15,535	$ 33,489	$ —	$ 78,024
Corey D. Walker	$ 29,000	$ 7,816	$ 322,663	$ 12,880	$ 372,359

(a) Accrued vacation payments in connection with Mr. Walker's departure effective October 30, 2021.

Grants of Plan-Based Awards

Following are the grants of plan-based awards to the NEOs during the year ended December 31, 2021:

		Estimated Future Payouts under Non-Equity Incentive Plan Awards (a)			Estimated Future Payouts under Equity Incentive Plan Awards			
Name	Grant Date (b)	Minimum ($)	Target ($)	Maximum ($)	Minimum (#)	Target (#)	Maximum (#)	Grant Date Fair Value of LTIP Awards ($)
Wouter T. van Kempen	N/A	$ —	$ 718,208	$ 1,436,415	—	—	—	$ —
SPUs		$ —	$ —	$ —	—	70,510	141,020	$ 1,368,811
RPUs		$ —	$ —	$ —	64,360	64,360	64,360	$ 1,368,776
Sean P. O'Brien	N/A	$ —	$ 352,006	$ 704,012	—	—	—	$ —
SPUs		$ —	$ —	$ —	—	29,880	59,760	$ 580,060
RPUs		$ —	$ —	$ —	27,280	27,280	27,280	$ 580,177
Don A. Baldridge	N/A	$ —	$ 315,930	$ 631,861	—	—	—	$ —
SPUs		$ —	$ —	$ —	—	27,370	54,740	$ 531,334
RPUs		$ —	$ —	$ —	24,980	24,980	24,980	$ 531,262
William L. Johnson	N/A	$ —	$ 273,304	$ 546,608	—	—	—	$ —
SPUs		$ —	$ —	$ —	—	12,050	24,100	$ 233,927
RPUs		$ —	$ —	$ —	11,000	11,000	11,000	$ 233,943
George R. Green	N/A	$ —	$ 218,815	$ 437,631	—	—	—	$ —
SPUs		$ —	$ —	$ —	—	7,110	14,220	$ 138,026
RPUs		$ —	$ —	$ —	6,490	6,490	6,490	$ 138,026
Corey D. Walker	N/A	$ —	$ 265,666	$ 531,332	—	—	—	$ —
SPUs (c)		$ —	$ —	$ —	—	27,370	54,740	$ 531,334
RPUs (c)		$ —	$ —	$ —	24,980	24,980	24,980	$ 531,262

(a) Amounts shown represent amounts under the STI. If minimum levels of performance are not met, then the payout for one or more of the components of the STI may be zero.
(b) Grant Date is not applicable with respect to Non-Equity Incentive Plan Awards. The SPUs awarded on January 1, 2021 under the LTIP will vest in their entirety on December 31, 2023 if the specified performance conditions are satisfied or, if minimum levels of performance are not met, then the payout may be zero. The RPUs awarded on February 28, 2021 under the LTIP will vest in their entirety on February 27, 2024 if the NEO is still employed by DCP, or earlier in the case of death, disability, retirement or layoff.
(c) Reflects STI and units awarded in 2021. All STI and units forfeited upon his departure effective October 30, 2021.

Outstanding Equity Awards at Fiscal Year-End

Following are the outstanding equity awards for the NEOs as of December 31, 2021:

	Outstanding LTIP Awards	
Name	**Equity Incentive Plan Awards: Unearned Units That Have Not Vested (a)**	**Equity Incentive Plan Awards: Market Value of Unearned Units That Have Not Vested (b)**
Wouter T. van Kempen	388,880	$ 11,311,187
Sean P. O’Brien	164,820	$ 4,794,048
Don A. Baldridge	150,940	$ 4,390,333
William L. Johnson	83,910	$ 2,412,660
George R. Green	29,930	$ 865,018
Corey D. Walker (c)	—	$ —

(a) SPUs awarded in 2020 and 2021 vest in their entirety over a range of 0% to 200% on December 31, 2022 and 2023, respectively, if the specified performance conditions are satisfied. RPUs awarded in 2020 and 2021 vest in their entirety on February 27, 2023 and February 27, 2024, respectively, if still employed. To determine the outstanding awards, the calculation of the number of SPUs that are expected to vest is based on assumed performance of 200% as the previous fiscal year performance has exceeded target performance.
(b) Value calculated based on the closing price on the NYSE on December 31, 2021 of our common units of $27.48. The disclosed value includes distribution equivalents earned but not vested as of December 31, 2021 with respect to SPUs awarded in 2020 and 2021. Distribution equivalents accrued in 2021 on outstanding SPUs are also reported within “All Other Compensation” in the Summary Compensation Table.
(c) All outstanding units forfeited upon his departure effective October 30, 2021.

Stock Awards Vested

Following are the stock awards vested for the NEOs for the year ended December 31, 2021:

	Stock Awards	
Name	**Number of Units Acquired on Vesting**	**Value Realized on Vesting (a)**
Wouter T. van Kempen	97,502	$ 3,135,725
Sean P. O’Brien	40,874	$ 1,315,380
Don A. Baldridge	27,927	$ 916,622
William L. Johnson	16,819	$ 567,823
George R. Green	3,170	$ 108,971
Corey D. Walker (b)	—	$ 322,663

(a) Value calculated based on the average closing prices on the NYSE for the last 20 trading days in 2021 of our common units of $25.76. The disclosed value includes distribution equivalents accrued as of December 31, 2021 with respect to SPUs awarded in 2019 and distribution equivalents paid in 2021 on RPUs awarded in 2019, 2020 and 2021. The distribution equivalents attributable to 2021 for such SPUs, and the distribution equivalents attributable to all of such RPUs, are also reported within “All Other Compensation” in the Summary Compensation Table.

(b) Reflects distribution equivalents attributable to 2021 for RPUs granted in 2020 and 2021. All units and accrued distribution equivalents, with respect to SPUs, forfeited upon Mr. Walker's departure.

Nonqualified Deferred Compensation

Following is the nonqualified deferred compensation for the NEOs for the year ended December 31, 2021:

Name	Executive Contributions in Last Fiscal Year (a)	Registrant Contributions in Last Fiscal Year (b)	Aggregate Earnings in Last Fiscal Year (c)	Aggregate Withdrawal/ Distributions	Aggregate Balance at December 31, 2021 (d)
Wouter T. van Kempen	$ 157,023	$ 347,477	$ 2,495,758	$ —	$ 10,646,931
Sean P. O’Brien	$ 151,175	$ 158,606	$ 512,463	$ (672,852)	$ 2,256,569
Don A. Baldridge	$ 69,642	$ 121,661	$ 569,791	$ —	$ 3,441,245
William L. Johnson	$ 51,120	$ 89,760	$ 480,528	$ —	$ 1,692,481
George R. Green	$ 14,588	$ 15,535	$ 9,551	$ —	$ 46,713
Corey D. Walker	$ 50,794	$ 7,816	$ 14,794	$ —	$ 80,717

(a) These amounts are included in the Summary Compensation Table for the year 2021 as follows: $35,910 for Mr. van Kempen, $42,124 for Mr. Baldridge, $19,522 for Mr. Johnson, and $14,588 for Mr. Green.
(b) These amounts are included in the Summary Compensation Table for the year 2021.
(c) At the election of each executive officer, the performance of non-qualified deferred compensation is linked to certain mutual funds, a DCP Common Unit Fund or to the US High Yield BB rated Bond Index specific to the Energy sector.
(d) Includes amounts previously reported in the Summary Compensation Table for prior years.

Potential Payments upon Termination or Change in Control

The General Partner has not entered into any employment agreements with any of our executive officers. The NEOs participate in executive severance arrangements maintained by DCP Services, LLC in the event of termination of employment that is involuntary or not for cause.

As noted above, the SPUs, RPUs and the related dividend equivalent rights, or DERs, will become payable to executive officers under certain circumstances related to termination. When an employee terminates employment, they are entitled to a cash payment for the amount of unused vacation hours at the date of their termination. Retirement eligible employees who provide at least 30 days' notice of retirement are entitled to a cash payment for the amount of earned but unused vacation hours plus unearned vacation hours for the year of retirement.

In the event of a change in control, the disposition of SPUs, RPUs and the related DERs will be determined by the board of directors of DCP Midstream, LLC. There are no formal plans for severance in the event of a change in control.

The following table presents payments in the event of retirement, death, or disability, as may be applicable, as of the last business day of 2021:

	2021 STI	2019 LTI	Accelerated LTIP	Total
Wouter T. van Kempen	$ 1,106,040	$ 2,891,211	$ 5,182,485	$ 9,179,736
Sean P. O'Brien	$ 492,808	$ 1,212,031	$ 2,196,642	$ 3,901,481
Don A. Baldridge	$ 442,302	$ 828,115	$ 2,011,437	$ 3,281,854
William L. Johnson	$ 440,020	$ 498,730	$ 1,335,070	$ 2,273,820
George R. Green	$ 382,927	$ 93,999	$ 376,674	$ 853,600
Corey D. Walker (a)	$ —	$ —	$ —	$ —

(a) Not applicable due to Mr. Walker's departure effective October 30, 2021.

The following table presents additional payments in the event of termination for reasons other than cause as of the last business day of 2021:

	Severance
Wouter T. van Kempen	$ 1,496,500
Sean P. O'Brien	$ 728,052
Don A. Baldridge	$ 653,438
William L. Johnson	$ 637,500
George R. Green	$ 600,000
Corey D. Walker (a)	$ —

(a) Not applicable due to Mr. Walker's departure effective October 30, 2021.

CEO Pay Ratio

We are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Wouter T. van Kempen, the Chairman of the Board, President, and CEO of our General Partner:

For 2021, our last completed fiscal year, the median of the annual total compensation of all employees of our company (other than our CEO) was $127,232 and the annual total compensation of our CEO, as reported in the Summary Compensation Table above, was $5,474,922. Based on this information, for 2021, Mr. van Kempen's total annual compensation was 43 times that of the median of the annual total compensation of all employees.

As permitted by the SEC rules, the median employee utilized for the pay ratio disclosure for the fiscal year ended 2021 is the same employee identified for our prior pay ratio disclosure for the fiscal year ended 2020 because there were no changes during our fiscal year ended 2021 with respect to our employee population, employee compensation arrangements, or to the same median employee's circumstances that we reasonably believe would result in a significant change to this pay ratio disclosure. In preparing this pay ratio disclosure, we took the following steps:

- We determined that, as of December 31, 2021, our employee population consisted of 1,788 individuals with all of these individuals located in the United States (as reported in Item 1, Business, in this Annual Report on Form 10-K). This population consisted of our full-time, part-time, and temporary employees.

- In originally identifying the "median employee" for purposes of our prior pay ratio disclosure for the fiscal year ended 2020, we compared the 2020 earnings eligible under the short-term incentive plan plus the short-term incentive earned in 2019 that was paid in 2020 as reflected in our payroll records for 2020. We identified our median employee using this compensation measure, which was consistently applied to all our employees included in the calculation. Since all our employees are located in the United States, as is our CEO, we did not make any cost-of-living adjustments in identifying the "median employee."

- With respect to calculating the total annual compensation disclosed above for the median employee, we combined all of the elements of such employee's total compensation for 2021.

- The pay ratio disclosed above is a reasonable estimate calculated in accordance with SEC rules, based on our records and the methodologies described above. The SEC rules for identifying the median compensated employee and calculating the pay ratio allow companies to use a variety of methodologies and apply various assumptions. The application of various methodologies may result in significant differences in the results reported by other SEC reporting companies. As a result the pay ratio reported by other SEC reporting companies may differ substantially from, and may not be comparable to, the pay ratio we disclose above.

Director Compensation

General - Members of the board of directors who are officers or employees of the General Partner or its affiliates do not receive compensation for serving as directors.

For 2021, the board approved an annual compensation package for non-employee directors, consisting of an annual $90,000 cash retainer and an annual grant of common units that approximate $100,000 of value on the date of grant. Chairpersons of committees of the board received an additional annual cash retainer of $20,000. All cash retainers are paid on a quarterly basis in arrears. Directors did not receive additional fees for attending meetings of the board or its committees. The directors were reimbursed for out-of-pocket expenses associated with their membership on the board of directors.

Unit Ownership Guidelines - In order to further align the interests of our non-employee directors with the interests of our unitholders, we have adopted guidelines that our non-employee directors beneficially own common units having a value of at least a 3x multiple of the annual cash retainer. Non-employee directors are expected to reach this guideline within five years of becoming a director and to maintain such minimum ownership level during the tenure of the directorship. All non-employee directors currently comply with these unit ownership guidelines.

The following table sets forth the compensation earned by the General Partner's non-employee directors for the year ended December 31, 2021:

Name	Fees Earned in Cash	Unit Awards (a)	Total
Fred J. Fowler (d)	$ 95,000	$ 100,233	$ 195,233
William F. Kimble (b)	$ 110,000	$ 100,233	$ 210,233
Bill W. Waycaster (c)	$ 110,000	$ 100,233	$ 210,233

(a) The amounts in this column reflect the grant date fair value of common unit awards computed in accordance with ASC 718.
(b) Mr. Kimble earned an additional $20,000 in fees as the audit committee chair.
(c) Mr. Waycaster earned an additional $20,000 in fees as the special committee chair.
(d) Mr. Fowler earned an additional $5,000 in fees as the sustainability committee chair commencing December 2021.

Each director is entitled to be fully indemnified by us for his actions associated with being a director to the fullest extent permitted under Delaware law.

Compensation Committee Interlocks and Insider Participation

As discussed above, our General Partner’s board of directors does not maintain a compensation committee. In 2021, the compensation committee of the board of directors of DCP Midstream, LLC, the owner of our General Partner, determined all elements of compensation for our NEOs. Only Mr. van Kempen was a director and a NEO of our General Partner. Further Mr. van Kempen is a non-voting member of the board of directors of DCP Midstream, LLC; however, he is not a member of the compensation committee thereof, nor did he participate in deliberations of such board with regard to his own compensation. During 2021, none of our NEOs served as a director or member of a compensation committee of another entity that has or has had an executive officer who served as a member of our board of directors, the board of directors of DCP Midstream, LLC, or the compensation committee of the board of directors of DCP Midstream, LLC.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters***

The following table sets forth the beneficial ownership of our common units and Preferred Units for:

- each person known by us to be the beneficial owner of more than 5% of our common units;
- each director of DCP Midstream GP, LLC;
- each NEO of DCP Midstream GP, LLC; and
- all directors and executive officers of DCP Midstream GP, LLC as a group.

The percentage of total common units beneficially owned is based on 208,378,739 outstanding common units and the percentage of Series A Preferred Units beneficially owned is based on 500,000 outstanding Series A Preferred Units as of February 16, 2022. None of the named beneficial owners set forth in the table below owns any of the 6,450,000 outstanding Series B Preferred Units or any of the 4,400,000 outstanding Series C Preferred Units as of February 16, 2022.

Name of Beneficial Owner (a)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Series A Preferred Units Beneficially Owned	Percentage of Series A Preferred Units Beneficially Owned
DCP Midstream, LLC (b)	117,762,526	56.5%	—	—
DCP Midstream GP, LP (c)	66,887,618	32.1%	—	—
ALPS Advisors, Inc. (d)	11,603,538	5.6%	—	—
Wouter T. van Kempen	67,040	*	750	*
Sean P. O'Brien	16,500	*	—	—
Don A. Baldridge	20,689	*	50	*
William L. Johnson	5,870	*	—	—
George R. Green	763	*	—	—
Allen C. Capps	—	—	—	—
Heather Crowder	—	—	—	—
Fred J. Fowler	57,900	*	—	—
William F. Kimble	23,800	*	—	—
Brian Mandell	—	—	—	—
Stephen J. Neyland	—	—	—	—
Bill W. Waycaster	23,800	*	—	—
All directors and executive officers as a group (12 persons)	216,362	*	800	*

* Less than 1%.

(a) Unless otherwise indicated, the address for all beneficial owners in this table is 6900 E. Layton Ave, Suite 900, Denver, Colorado 80237.

(b) Includes 50,874,908 common units directly held by DCP Midstream, LLC ("Midstream"); 597,455 common units held in a rabbi trust established in connection with Midstream's executive deferred compensation plan (the "Plan"), which common units were acquired by the Plan on the open market and are being held by the Plan for the sole purpose of funding the Plan's deferred compensation liabilities associated with certain investment elections made by participants to invest in phantom units that are economically equivalent to common units; and 66,887,618 common units directly held by DCP Midstream GP, LP. DCP Midstream, LLC is the sole member of DCP Midstream GP, LLC, which is the general partner of DCP Midstream GP, LP, and therefore may be deemed to indirectly beneficially own such securities, but disclaims beneficial ownership except to the extent of its pecuniary interest therein.

(c) DCP Midstream GP, LLC is the general partner of DCP Midstream GP, LP and therefore may be deemed to indirectly beneficially own such securities, but disclaims beneficial ownership except to the extent of its pecuniary interest therein.

(d) As reported on Schedule 13G/A filed with the SEC on February 3, 2022 by ALPS Advisors, Inc. and Alerian MLP ETF each with an address of 1290 Broadway, Suite 1000, Denver, Colorado 80203. The Schedule 13G/A reports that ALPS Advisors, Inc. ("AAI"), an investment adviser registered under the Investment Advisers Act of 1940, as amended, furnishes investment advice to investment companies registered under the Investment Company Act of 1940, as amended (collectively referred to as the "Funds"). In its role as investment advisor, AAI has voting and/or investment power over the registrant's common units that are owned by the Funds, and may be deemed to be the beneficial owner of such common units held by the Funds. Alerian MLP ETF is an investment company registered under the Investment Company Act of 1940 and is one of the Funds to which AAI provides investment advice. Alerian MLP ETF has shared voting and investment power over 11,603,538 common units. The common units reported herein are owned by the Funds and AAI disclaims beneficial ownership of such common units.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans as of December 31, 2021.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders (1)	535,360	$ —	286,396
Equity compensation plans not approved by unitholders	—	—	—
Total	535,360	$ —	286,396

1. This information relates to our 2016 LTIP, which was approved by unitholders at a special meeting on April 28, 2016. For more information on our 2016 LTIP, refer to Note 17. "Equity-Based Compensation" in the Notes to Consolidated Financial Statements in Item 8. “Financial Statements and Supplementary Data.”

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Distributions and Payments to our General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our General Partner and its affiliates in connection with our ongoing operation and any future liquidation. These distributions and payments are determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage:	
Distributions of Available Cash to our General Partner and its affiliates	We will generally make cash distributions to the unitholders, which includes our general partner and its affiliates, in accordance with their pro rata interest.
Payments to our General Partner and its affiliates	For further information regarding payments to our General Partner, please see the "Services Agreement" section below.
Withdrawal or removal of our General Partner	If our General Partner withdraws or is removed, its general partner interest will be sold to the new general partner in exchange for cash in amount equal to the fair market value of such interest.
Liquidation Stage:	
Liquidation	Upon our liquidation, the partners, including our General Partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Services Agreement

Under the Service Agreement, we are required to reimburse DCP Midstream, LLC for costs, expenses, and expenditures incurred or payments made on our behalf for general and administrative functions including, but not limited to, legal, accounting, compliance, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, benefit plan maintenance and administration, credit, payroll, internal audit, taxes and engineering, as well as salaries and benefits of seconded employees, insurance coverage and claims, capital expenditures, maintenance and repair costs and taxes. There is no limit on the reimbursements we make to DCP Midstream, LLC under the Services Agreement for costs, expenses and expenditures incurred or payments made on our behalf.

Our General Partner and its affiliates will also receive payments from us pursuant to the contractual arrangements described below under the caption "Contracts with Affiliates."

The Services Agreement, other than the indemnification provisions, will be terminable by DCP Midstream, LLC at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Services Agreement will also terminate in the event of a change of control of us, our General Partner or DCP Midstream, LLC.

Competition

None of DCP Midstream, LLC, or any of its affiliates, including Phillips 66 and Enbridge, is restricted, under either the Partnership Agreement or the Services Agreement, from competing with us. DCP Midstream, LLC and any of its affiliates, including Phillips 66 and Enbridge, may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Contracts with Affiliates

We sell a portion of our residue gas and NGLs to and purchase NGLs from Phillips 66 and its respective affiliates. We anticipate continuing to purchase and sell these commodities to Phillips 66 and its respective affiliates in the ordinary course of business.

We purchase NGLs from Enbridge and its affiliates. We anticipate continuing to purchase commodities from Enbridge and its affiliates in the ordinary course of business.

Unconsolidated Affiliates

Under the terms of their respective operating agreements, Sand Hills and Southern Hills are required to reimburse us for any direct costs or expenses (other than general and administration services) which we incur on behalf of Sand Hills and Southern Hills. Additionally, Sand Hills and Southern Hills each pay us an annual service fee of $5 million, for centralized corporate functions provided by us as operator of Sand Hills and Southern Hills, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, taxes and engineering. Except with respect to the annual service fee, there is no limit on the reimbursements Sand Hills and Southern Hills make to us under the respective operating agreements for other expenses and expenditures which we incur on behalf of Sand Hills or Southern Hills.

Transportation Arrangements

The Texas Express, Front Range, Sand Hills, Southern Hills, Gulf Coast Express and Cheyenne Connector pipelines have in place transportation agreements with us, which expire between 2028 and 2030, pursuant to which we have committed to transport minimum throughput volumes at rates defined in each respective pipeline's tariffs.

Review, Approval or Ratification of Transactions with Related Persons

Our Partnership Agreement contains specific provisions that address potential conflicts of interest between the owner of our general partner and its affiliates, including DCP Midstream, LLC on one hand, and us and our subsidiaries, on the other hand. Whenever such a conflict of interest arises, our general partner will resolve the conflict. Our general partner may, but is not required to, seek the approval of such resolution from the special committee of the board of directors of our general partner, which committee is comprised of independent directors and acts as our conflicts committee. The Partnership Agreement provides that our general partner will not be in breach of its obligations under the Partnership Agreement or its duties to us or to our unitholders if the resolution of the conflict is:

- approved by the conflicts committee;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

If our general partner does not seek approval from the special committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our Partnership Agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our Partnership Agreement requires someone to act in good faith, it requires that person to reasonably believe that he is acting in the best interests of the Partnership, unless the context otherwise requires.

In addition, our code of business ethics requires that all employees, including employees of affiliates of DCP Midstream, LLC who perform services for us and our general partner, avoid or disclose any activity that may interfere, or have the appearance of interfering, with their responsibilities to us.

Director Independence

Please see Item 10. "Directors, Executive Officers and Corporate Governance" in this Annual Report on Form 10-K for information about the independence of our general partner's board of directors and its committees.

Item 14. ***Principal Accountant Fees and Services***

The following table presents fees for professional services rendered by Deloitte & Touche LLP, or Deloitte, our principal accountant, for the audit of our financial statements, and the fees billed for other services rendered by Deloitte:

Type of Fees	Year Ended December 31, 2021	2020
	(millions)	
Audit fees (a)	$ 3	$ 3
Audit-related and tax fees (b)(c)	$ —	$ 1

(a) Audit fees are fees billed by Deloitte for professional services for the integrated audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our quarterly reports on Form 10-Q, services that are normally provided by Deloitte in connection with statutory and regulatory filings.

(b) Audit-related fees include assurance and related services performed by Deloitte to comply with generally accepted auditing standards and including comfort and consent letters in connection with SEC filings and financing transactions.

(c) Deloitte Tax was engaged to review the Federal tax return of the Partnership and prepare and process the K-1 schedule for holders for the year ended December 31, 2020 for a total fixed fee of $285,000. Subsequent to this engagement Deloitte has not provided any services to us related to tax compliance, tax services, and tax planning.

Audit Committee Pre-Approval Policy

The audit committee pre-approves all audit and permissible non-audit services provided by the independent auditors on a case-by-case basis. These services may include audit services, audit-related services, tax services and other services. The audit committee has pre-approved audit related services that do not impair the independence of the independent auditors for up to $50,000 per engagement, and up to an aggregate of $100,000 annually, provided the audit committee is notified of such audit-related services in a timely manner. The audit committee may, however, from time to time delegate its authority to any audit committee member, who will report on the independent auditor services that were approved at the next audit committee meeting.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) Financial Statements and Schedules

Our Consolidated Financial Statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Financial Statements."

All other financial statement schedules have been omitted, since they either are not required, not applicable, not present in amounts sufficient to require submission of the schedule, or the information is otherwise included in the consolidated financial statements and accompanying notes.

(b) Exhibits

Exhibit Number		Description
2.1	*#	Contribution, Conveyance and Assumption Agreement, dated December 7, 2005, among DCP Midstream Partners, LP, DCP Midstream Operating LP, DCP Midstream GP, LLC, DCP Midstream GP, LP, Duke Energy Field Services, LLC, DEFS Holding 1, LLC, DEFS Holding, LLC, DCP Assets Holdings, LP, DCP Assets Holdings, GP, LLC, Duke Energy Guadalupe Pipeline Holdings, Inc., Duke Energy NGL Services, LP, DCP LP Holdings, LP and DCP Black Lake Holdings, LLC (attached as Exhibit 10.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
2.2	*#	Contribution Agreement, dated October 9, 2006, between DCP LP Holdings, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 13, 2006).
2.3	*#	Purchase and Sale Agreement, dated March 7, 2007, between Anadarko Gathering Company, Anadarko Energy Services Company and DCP Midstream Partners, LP (attached as Exhibit 99.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 14, 2007).
2.4	*#	Contribution and Sale Agreement, dated May 21, 2007, between Gas Supply Resources Holdings, Inc., DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
2.5	*#	Contribution Agreement, dated May 23, 2007, among DCP LP Holdings, LP, DCP Midstream, LLC, DCP Midstream GP, LP and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 25, 2007).
2.6	*#	Contribution Agreement dated February 24, 2009, among DCP LP Holdings, LLC, DCP Midstream GP, LP DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 10.16 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
2.7	*#	Purchase and Sale Agreement by and Among DCP Midstream, LLC and DCP Midstream Partners, LP dated as of November 4, 2010 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2010).
2.8	*#	Contribution Agreement between DCP Southeast Texas, LLC and DCP Partners SE Texas LLC dated as of November 4, 2010 (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2010).
2.9	*#	Contribution Agreement, dated November 4, 2011, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.7 to DCP Midstream, LLC's Schedule 13D (File No. 005-81287) dated as of January 13, 2012).
2.10	*#	Contribution Agreement, dated February 27, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 1, 2012).
2.11	*	First Amendment to Contribution Agreement, dated March 30, 2012, among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 5, 2012).
2.12	*#	Contribution Agreement among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP dated June 25, 2012 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 29, 2012).

Exhibit Number		Description
2.13	*#	Contribution Agreement, dated November 2, 2012, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 7, 2012).
2.14	*#	Contribution Agreement dated February 27, 2013 among DCP LP Holdings, LLC, DCP Midstream, LLC and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 27, 2013).
2.15	*	First Amendment to Contribution Agreement, dated March 28, 2013, among DCP LP Holdings, LLC, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 3, 2013).
2.16	*#	Purchase and Sale Agreement (O'Connor Plant) by and between DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
2.17	*#	Purchase and Sale Agreement (Front Range Pipeline) by and among DCP Midstream Partners, LP and DCP Midstream, LP dated August 5, 2013 (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 6, 2013).
2.18	*#	Purchase and Sale Agreement, dated February 25, 2014, by and between DCP Midstream, LP, as seller, and DCP Midstream Partners, LP, as buyer (attached as Exhibit 2.2 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 26, 2014).
2.19	*#	Contribution Agreement, dated February 25, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 26, 2014).
2.20	*	First Amendment to Contribution Agreement, dated February 27, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 28, 2014).
2.21	*	Second Amendment to Contribution Agreement, dated March 28, 2014, among DCP LP Holdings, LLC, DCP Midstream GP, LP, DCP Midstream, LLC, and DCP Midstream Partners, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on April 2, 2014).
2.22	*#	Contribution Agreement, dated December 30, 2016, by and among DCP Midstream, LLC, DCP Midstream Partners, LP and DCP Midstream Operating, LP (attached as Exhibit 2.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
3.1	*	Certificate of Limited Partnership of DCP Midstream Partners, LP dated August 5, 2005 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Registration Statement on Form S-1 (File No. 333-128378) filed with the SEC on September 16, 2005).
3.2	*	Certificate of Amendment to Certificate of Limited Partnership of DCP Midstream Partners, LP dated January 11, 2017 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 17, 2017).
3.3	*	Fifth Amended and Restated Agreement of Limited Partnership of DCP Midstream, LP dated November 6, 2019 (attached as Exhibit 3.1 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2019).
4.1	*	Indenture dated as of September 30, 2010 for the issuance of debt securities between DCP Midstream Operating, LP, as issuer, any Guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on September 30, 2010).
4.2	*	Third Supplemental Indenture dated as of June 14, 2012 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 14, 2012).
4.3	*	Fifth Supplemental Indenture dated as of March 14, 2013 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 14, 2013).
4.4	*	Sixth Supplemental Indenture dated as of March 13, 2014 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream Partners, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on March 13, 2014).

Exhibit Number		Description
4.5	*	Seventh Supplemental Indenture dated as of July 17, 2018 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on July 17, 2018).
4.6	*	Eighth Supplemental Indenture dated as of May 10, 2019 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 10, 2019).
4.7	*	Ninth Supplemental Indenture dated as of June 24, 2020 to Indenture dated as of September 30, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on June 24, 2020).
4.8	*	Tenth Supplemental Indenture dated as of November 19, 2021 to Indenture dated as of September 20, 2010 between DCP Midstream Operating, LP, as issuer, DCP Midstream, LP, as guarantor, and the Bank of New York Mellon Trust Company, N.A., as trustee (attached as Exhibit 4.3 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 19, 2021)
4.9	*	Indenture, dated as of August 16, 2000, by and between Duke Energy Field Services, LLC and The Chase Manhattan Bank (attached as Exhibit 4.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.10	*	First Supplemental Indenture, dated August 16, 2000, by and between Duke Energy Field Services, LLC and The Chase Manhattan Bank (attached as Exhibit 4.1 to DCP Midstream, LLC’s Current Report on Form 8-K (File No. 000-31095) filed with the SEC on August 16, 2000).
4.11	*	Fifth Supplemental Indenture, dated as of October 27, 2006, by and between Duke Energy Field Services, LLC and The Bank of New York (as successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank) (attached as Exhibit 4.3 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.12	*	Sixth Supplemental Indenture, dated September 17, 2007, by and between DCP Midstream, LLC (formerly known as Duke Energy Field Services, LLC) and The Bank of New York (as successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank) (attached as Exhibit 4.4 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.13	*	Eleventh Supplemental Indenture, dated January 1, 2017, by and between DCP Midstream Operating, LP, DCP Midstream, LLC and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Mellon, as successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank) (attached as Exhibit 4.8 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.14	*	Twelfth Supplemental Indenture, dated January 1, 2017, by and among DCP Midstream Operating, LP (as successor to DCP Midstream, LLC (formerly known as Duke Energy Field Services, LLC)), DCP Midstream Partners, LP and The Bank of New York Mellon Trust Company, N.A. (as successor to The Bank of New York Mellon, as successor to JPMorgan Chase Bank, N.A., formerly known as The Chase Manhattan Bank) (attached as Exhibit 4.9 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.15	*	Indenture, dated as of May 21, 2013, by and between DCP Midstream Operating, LP (as issuer and successor to DCP Midstream, LLC) and the Bank of New York Mellon Trust Company, N.A (attached as Exhibit 4.10 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.16	*	First Supplemental Indenture, dated May 21, 2013, by and between DCP Midstream, LLC and the Bank of New York Mellon Trust Company, N.A (attached as Exhibit 4.11 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.17	*	Second Supplemental Indenture, dated January 1, 2017, by and between DCP Midstream Operating, LP, DCP Midstream, LLC and The Bank of New York Mellon Trust Company, N.A (attached as Exhibit 4.12 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
4.18	*	Form of Unit Certificate for 7.375% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (attached as Exhibit 4.1 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 20, 2017).

Exhibit Number		Description
4.19	*	Form of Unit Certificate for 7.875% Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (attached as Exhibit 4.1 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on May 11, 2018).
4.20	*	Form of Unit Certificate for 7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (attached as Exhibit 4.1 to DCP Midstream, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on October 4, 2018).
4.21		Description of Securities of DCP Midstream, LP.
10.1	*	Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated December 7, 2005, as amended by Amendment No. 1 dated January 20, 2009 (attached as Exhibit 3.1 to DCP Midstream Partners, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on March 5, 2009).
10.2	*	Amendment No. 2 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated February 14, 2013 (attached as Exhibit 3.1 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on February 21, 2013).
10.3	*	Amendment No. 3 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP, LLC dated November 6, 2013 (attached as Exhibit 3.3 to DCP Midstream Partners, LP’s Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on November 6, 2013).
10.4	*	Amendment No. 4 to Amended and Restated Limited Liability Company Agreement of DCP Midstream GP,LLC dated December 30, 2016 (attached as Exhibit 10.4 to DCP Midstream, LP’s Annual Report onForm 10-K (File No. 001-32678) filed with the SEC on February 15, 2017).
10.5	*	First Amended and Restated Agreement of Limited Partnership of DCP Midstream GP, LP dated December 7, 2005 (attached as Exhibit 3.2 to DCP Midstream Partners, LP’s Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 12, 2005).
10.6	*+	DCP Midstream Partners, LP 2016 Long-Term Incentive Plan (attached as Exhibit A to DCP Midstream Partners, LP's Definitive Proxy Statement on Schedule 14A (File No. 001-32678) filed with the SEC on March 15, 2016).
10.7	*+	DCP Services, LLC 2008 Long-Term Incentive Plan, as amended and restated effective March 1, 2017 (attached as Exhibit 10.3 to DCP Midstream, LP’s Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on May 10, 2017).
10.8	*+	Form of Strategic Performance Unit Grant Agreement under the DCP Services, LLC 2008 Long-Term Incentive Plan (attached as Exhibit 10.12 to DCP Midstream, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 21, 2020).
10.9	*+	Form of Restricted Phantom Unit Grant Agreement under the DCP Services, LLC 2008 Long-Term Incentive Plan (attached as Exhibit 10.13 to DCP Midstream LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 21, 2020).
10.10	*+	Form of Strategic Performance Unit Grant Agreement under the DCP Midstream, LP 2016 Long-Term Incentive Plan (attached as Exhibit 10.1 to DCP Midstream, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on May 7, 2020).
10.11	*+	Form of Restricted Phantom Unit Grant Agreement under the DCP Midstream, LP 2016 Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on May 7, 2020).
10.12	*+	Form of Strategic Performance Unit Grant Agreement under the DCP Midstream, LP 2016 Long-Term Incentive Plan (attached as Exhibit 10.1 to DCP Midstream, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on May 6, 2021).
10.13	*+	Form of Restricted Phantom Unit Grant Agreement under the DCP Midstream, LP 2016 Long-Term Incentive Plan (attached as Exhibit 10.2 to DCP Midstream, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on May 6, 2021).
10.14	+	Form of Restricted Phantom Unit Grant Agreement under the DCP Midstream, LP 2016 Long-Term Incentive Plan
10.15	*+	DCP Midstream, LP Executive Deferred Compensation Plan (attached as Exhibit 10.18 to DCP Midstream, LP’s Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 15, 2017).
10.16	*+	DCP Midstream, LP Executive Deferred Compensation Plan Adoption Agreement (attached as Exhibit 10.19 to DCP Midstream, LP’s Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 15, 2017).

Exhibit Number		Description
10.17	*+	DCP Services, LLC Amended and Restated Executive Severance Plan effective February 19, 2020 (attached as Exhibit 10.3 to DCP Midstream, LP's Quarterly Report on Form 10-Q (File No. 001-32678) filed with the SEC on May 7, 2020).
10.18	*+	Separation Agreement between DCP Services, LLC and Brian Frederick dated December 11, 2019 (attached as Exhibit 10.18 to DCP Midstream, LP's Annual Report on Form 10-K (File No. 001-32678) filed with the SEC on February 21, 2020).
10.19	*	Services and Employee Secondment Agreement, dated January 1, 2017, by and between DCP Services, LLC and DCP Midstream Partners, LP (attached as Exhibit 10.1 to DCP Midstream Partners, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on January 6, 2017).
10.20	*	Second Amended and Restated Credit Agreement, dated as of December 6, 2017, by and among DCP Midstream Operating, LP, DCP Midstream, LP, Mizuho Bank, Ltd., as administrative agent, and the lenders party thereto (attached as Exhibit 10.1 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 8, 2017).
10.21	*	First Amendment to Second Amended and Restated Credit Agreement, dated as of December 9, 2019, by and among DCP Midstream Operating, LP, DCP Midstream, LP, Mizuho Bank, Ltd., as administrative agent, and the financial institutions party thereto (attached as Exhibit 10.2 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 10, 2019).
10.22	*	Receivables Financing Agreement, dated August 13, 2018, among DCP Receivables LLC, as borrower, the Partnership, as initial servicer, the lenders, LC participants and group agents that are parties thereto from time to time, PNC Bank National Association, as Administrative Agent and LC Bank and PNC Capital Markets LLC, as Structuring Agent (attached as Exhibit 10.1 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 14, 2018).
10.23	*	First Amendment to Receivables Financing Agreement, dated August 12, 2019, among DCP Receivables LLC, as borrower, DCP Midstream, LP, as initial servicer, the lenders, LC participants and group agents that are parties thereto from time to time, PNC Bank National Association, as Administrative Agent and LC Bank and PNC Capital Markets LLC, as Structuring Agent (attached as Exhibit 10.1 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 12, 2019).
10.24	*	Second Amendment to Receivables Financing Agreement, dated December 23, 2019, among DCP Receivables LLC, as borrower, DCP Midstream, LP, as initial servicer, the lenders, LC participants and group agents that are parties thereto from time to time, PNC Bank National Association, as Administrative Agent and LC Bank and PNC Capital Markets LLC, as Structuring Agent (attached as Exhibit 10.3 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on December 23, 2019).
10.25	*	Third Amendment to Receivables Financing Agreement, dated April 22, 2021, among DCP Receivables LLC, as borrower, DCP Midstream, LP, as initial servicer, the lenders, LC participants and group agents that are parties thereto from time to time, PNC Bank National association, as Administrative Agent and LC Bank and PNC Capital Markets LLC, as structuring Agent (attached as Exhibit 10.4 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 2, 2021).
10.26	*	Fourth Amendment to Receivables Financing Agreement, dated August 2, 2021, among DCP Receivables LLC, as borrower, DCP Midstream, LP, as initial servicer, the lenders, LC participants and group agents that are parties thereto from time to time, PNC Bank National association, as Administrative Agent and LC Bank and PNC Capital Markets LLC, as structuring Agent (attached as Exhibit 10.5 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 2, 2021).
10.27	*	Receivables Sale and Contribution Agreement, dated August 13, 2018, between the originators from time to time party thereto and DCP Receivables LLC (attached as Exhibit 10.2 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on August 14, 2018).
10.28	*	Equity Restructuring Agreement, dated November 6, 2019, between DCP Midstream GP, LP and DCP Midstream, LP. (attached as Exhibit 10.1 to DCP Midstream, LP's Current Report on Form 8-K (File No. 001-32678) filed with the SEC on November 8, 2019).
21.1		List of Subsidiaries of DCP Midstream, LP.
22		List of Guaranteed Securities
23.1		Consent of Deloitte & Touche LLP on Consolidated Financial Statements of DCP Midstream, LP and the effectiveness of DCP Midstream, LP's internal control over financial reporting.
23.2		Consent of BDO USA, LLP on Financial Statements of Gulf Coast Express Pipeline LLC.
24.1		Power of Attorney (incorporated by reference to the signature page of this Annual Report on Form 10-K).
31.1		Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Description
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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.
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.
101	Financial statements from the Annual Report on Form 10-K of DCP Midstream, LP for the year ended December 31, 2021, formatted in XBRL: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income (Loss), (iv) the Consolidated Statements of Cash Flows, (v) the Consolidated Statements of Changes in Equity, and (vi) the Notes to the Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* Such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

\+ Denotes management contract or compensatory plan or arrangement.

\# Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

Item 16. ***Form 10-K Summary***

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

	DCP Midstream, LP		
	By:	DCP Midstream GP, LP *its General Partner*	
	By:	DCP Midstream GP, LLC *its General Partner*	
February 18, 2022	By:	/s/ Wouter T. van Kempen	
		Name:	Wouter T. van Kempen
		Title:	President and Chief Executive Officer (Principal Executive Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Wouter T. van Kempen and Sean P. O'Brien as his true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, for him and in his name, place, and stead, in any and all capacities, to sign any and all amendments to this annual report, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title (Position with DCP Midstream GP, LLC)	Date
/s/ Wouter T. van Kempen Wouter T. van Kempen	Chief Executive Officer, President, Chairman of the Board and Director (Principal Executive Officer)	February 18, 2022
/s/ Sean P. O'Brien Sean P. O'Brien	Group Vice President and Chief Financial Officer (Principal Financial Officer)	February 18, 2022
/s/ Richard A. Loving Richard A. Loving	Chief Accounting Officer (Principal Accounting Officer)	February 18, 2022
/s/ Allen C. Capps Allen C. Capps	Director	February 18, 2022
/s/ Heather Crowder Heather Crowder	Director	February 18, 2022
/s/ Fred J. Fowler Fred J. Fowler	Director	February 18, 2022
/s/ William F. Kimble William F. Kimble	Director	February 18, 2022
/s/ Brian Mandell Brian Mandell	Director	February 18, 2022
/s/ Stephen J. Neyland Stephen J. Neyland	Director	February 18, 2022
/s/ Bill Waycaster Bill Waycaster	Director	February 18, 2022

DESCRIPTION OF THE REGISTRANT'S SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934

As of December 31, 2021, DCP Midstream, LP has three classes of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): (1) our Common Units representing limited partnership interests; (2) our 7.875% Series B Fixed-to-Floating Rate Cumulative Redeemable Preferred Units; and (3) our 7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Preferred Units.

The following description of our common units representing limited partnership interests (the "Common Units"), our 7.875% Series B Fixed-to-Floating Rate Cumulative Redeemable Preferred Units ("Series B Preferred Units"), and our 7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Preferred Units ("Series C Preferred Units") is a summary and does not purport to be complete. It is subject to, and qualified in its entirety by, reference to our Fifth Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement"), a copy of which is incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit is a part. Capitalized terms used herein that are not defined shall have the meaning ascribed to each such term in the Partnership Agreement. We encourage you to read our Partnership Agreement for additional information.

Description of Common Units Representing Limited Partnership Interests

Number of Common Units

We have authorized the issuance of 208,378,739 Common Units, and as of February 16, 2022, we had 208,378,739 Common Units outstanding.

The Common Units

We currently have outstanding Common Units, which are limited partner interests in us. The holders of our Common Units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under the Partnership Agreement.

Our outstanding Common Units are listed on the NYSE under the symbol "DCP". Any additional common units we issue will also be listed on the NYSE.

Status as Limited Partner

By transfer of common units in accordance with our Partnership Agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records.

A transferee will automatically become a substituted limited partner of our partnership for the transferred common units upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records from time to time.

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. In voting their Common Units, our general partner, DCP Midstream GP, LP (our "general partner") and its affiliates will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners.

Issuance of Additional Securities

Our Partnership Agreement authorizes us to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership securities. Holders of any additional common units that we issue in the future will be entitled to share equally in our distributions of available cash with the then-existing holders of common units. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our Partnership Agreement, we may also issue additional partnership securities that, as determined by our general partner, may have special voting rights to which the common units are not entitled. In addition, our Partnership Agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units.

Amendment of the Partnership Agreement

Amendments to our Partnership Agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by at least a Unit Majority.

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our Partnership Agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates), only if we obtain an opinion of counsel to the effect that such amendment will not affect the limited liability of any limited partner under the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"). As of December 31, 2020, our general partner and its affiliates owned approximately 57% of the outstanding common units.

Our general partner may generally make amendments to our Partnership Agreement without the approval of any limited partner or assignee to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our Partnership Agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor the operating partnership nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from, in any manner, being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed by the U.S. Department of Labor;
- an amendment expressly permitted in our Partnership Agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our Partnership Agreement;
- an amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership, or other entity, as otherwise permitted by our Partnership Agreement;
- a change in our fiscal year or taxable year and related changes;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or

- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our Partnership Agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any national securities exchange on which the limited partner interests are or will be listed or admitted to trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our Partnership Agreement; or
- are required to effect the intent expressed in our original registration statement on Form S-1 (File No. 333-128378), filed with the SEC on September 16, 2005, as amended or supplemented, or the intent of the provisions of our Partnership Agreement or are otherwise contemplated by our Partnership Agreement.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners.

In addition, the Partnership Agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the Partnership Agreement, each of our units will be an identical unit of our partnership following the transaction, and the partnership securities to be issued in connection with such merger or consolidation do not exceed 20% of our outstanding partnership securities immediately prior to the transaction.

If the conditions specified in the Partnership Agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in the Partnership Agreement. The unitholders are not entitled to dissenters' rights of appraisal under the Partnership Agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until terminated under our Partnership Agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with the Delaware Act;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our Partnership Agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our Partnership Agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership, our operating partnership, nor any of our other subsidiaries, would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new limited partnership, the liquidator authorized to wind up our affairs will act with all of the powers of our general partner that are necessary or appropriate to liquidate our assets and apply the proceeds of the liquidation. The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to our partners. The liquidator may distribute our assets, in whole or in part, in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of the General Partner

Our general partner may withdraw as general partner without obtaining approval of any unitholder by giving 90 days' written notice, provided that such withdrawal will not constitute a violation of our Partnership Agreement.

In addition, the Partnership Agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders.

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority, voting as a single class, may select a successor to the withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner.

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66⅔% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of a unit majority. The ownership of more than 33⅓% of the outstanding units by our general partner and its affiliates would give them the ability to prevent our general partner's removal.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates our Partnership Agreement, a successor general partner will have the option to purchase the general partner interest of the departing general partner for a cash payment equal to the fair market value of that interest. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Interest

Our general partner and its affiliates may at any time, transfer the general partner interest to one or more persons, without unitholder approval.

Transfer of Ownership Interests in the General Partner

At any time, DCP Midstream, LLC and its affiliates may sell or transfer all or part of their partnership interests in our general partner, or their membership interest in DCP Midstream GP, LLC, the general partner of our general partner, to an affiliate or third party without the approval of our unitholders.

Change of Management Provisions

Our Partnership Agreement contains specific provisions that are intended to discourage a person or group from attempting to remove DCP Midstream GP, LP as our general partner or otherwise change our management. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group will lose voting rights with respect to all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner (the "Board of Directors").

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days' notice. The purchase price in the event of this purchase is the greater of:

- the highest cash price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price as of the date three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have its limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The U.S. federal income tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of its common units in the market.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called represented in person or by proxy will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of common units has a vote according to its percentage interest in us, although additional limited partner interests having special voting rights may be issued in the future. However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and its nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our Partnership Agreement will be delivered to the record holder by us or by the transfer agent.

Distributions of Available Cash

Our Partnership Agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by our general partner.

"Available Cash" for any quarter, consists of all cash and cash equivalents on the date of determination of available cash for that quarter:

- less the amount of cash reserves established by our general partner to:
    - provide for the proper conduct of our business, including reserves for future capital expenditures and anticipated credit needs;
    - comply with applicable law or any debt instrument or other agreement or obligation;
    - provide funds to make payments on the Preferred Units; or
    - provide funds for distributions to our common unitholders for any one or more of the next four quarters.
- plus, if our general partner so determines, all or a portion of cash and cash equivalents on hand on the date of determination of Available Cash for the quarter.

There is no guarantee that we will maintain our current distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our Partnership Agreement.

Description of 7.875% Series B Fixed-to-Floating Rate Cumulative Redeemable Preferred Units

Number of Series B Units

We have authorized the issuance of 6,450,000 Series B Units, and as of February 17, 2021, we had 6,450,000 Series B Units outstanding.

The Series B Units

The Series B Preferred Units are a series of preferred units. We may, without notice to or consent of the holders of the then-outstanding Series B Preferred Units, authorize and issue additional Series B Preferred Units and Junior Securities.

The holders of our Series B Preferred Units are entitled to receive, to the extent permitted by law, such distributions as may from time to time be declared by our general partner. Upon any liquidation, dissolution or winding up of our affairs, whether voluntary or involuntary, the holders of our Series B Preferred Units are entitled to receive distributions of our assets, after we have satisfied or made provision for our outstanding indebtedness and other obligations and after payment to the holders of any class or series of limited partner interests (including the Series B Preferred Units) having preferential rights to receive distributions of our assets over each such class of limited partner interests.

The Series B Preferred Units are fully paid and generally nonassessable. Each Series B Preferred Unit generally has a fixed liquidation preference of $25.00 per Series B Preferred Unit (subject to adjustment for any splits, combinations or similar adjustment to the Series B Preferred Units) plus an amount equal to accumulated and unpaid distributions thereon to, but not including, the date fixed for payment, whether or not declared.

The Series B Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As such, the Series B Preferred Units rank junior to all of our current and future indebtedness and other liabilities with respect to assets available to satisfy claims against us. The rights of the holders of Series B Preferred Units to receive the liquidation preference will be subject to the proportional rights of holders of Parity Securities.

Except as described below, the Series B Preferred Units are not convertible into our common units or any other securities and do not have exchange rights and are not entitled or subject to any preemptive or similar rights. The Series B Preferred Units are not be subject to mandatory redemption or to any sinking fund requirements. The Series B Preferred Units are subject to redemption, in whole or in part, at our option commencing on June 15, 2023 or upon the occurrence of a Ratings Event.

Our outstanding Series B Preferred Units are listed on the NYSE under the symbol “DCP PRB”. Any additional common units we issue will also be listed on the NYSE.

Ranking

The Series B Preferred Units, with respect to distributions and amounts payable upon the liquidation or dissolution of our affairs, rank:

- senior to the Junior Securities (including our Common Units);
- on parity with any Parity Securities;
- junior to any Senior Securities; and
- junior to all of our existing and future indebtedness and other liabilities with respect to assets available to satisfy claims against us.

Under our Partnership Agreement, we may issue Junior Securities from time to time in one or more series without the consent of the holders of the Series B Preferred Units. The Board of Directors has the authority to determine the preferences, powers, qualifications, limitations, restrictions and special or relative rights or privileges, if any, of any such series before the issuance of any units of that series. The Board of Directors will also determine the number of units constituting each series of securities.

Liquidation Rights

Any liquidation will be made in accordance with capital accounts. The holders of outstanding Series B Preferred Units will be specially allocated items of our gross income and gain in a manner designed to achieve, in the event of any liquidation, dissolution or winding up of our affairs, whether voluntary or involuntary, a liquidation preference of $25.00 per Series B Preferred Unit. If the amount of our gross income and gain available to be specially allocated to the Series B Preferred Units is not sufficient to cause the capital account of a Series B Preferred Unit to equal the liquidation preference of a Series B Preferred Unit, then the amount that a holder of a Series B Preferred Unit would receive upon liquidation may be less than the Series B Preferred Unit liquidation preference. Any accumulated and unpaid distributions on the Series B Preferred Units and Parity Securities will be paid prior to any distributions in liquidation made in accordance with capital accounts. The rights of the holders of Series B Preferred Units to receive the liquidation preference will be subject to the proportional rights of holders of Parity Securities in liquidation.

Voting Rights

The Series B Preferred Units will have no voting rights except as set forth below or as otherwise provided by Delaware law.

Unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series B Preferred Units, voting as a separate class, we may not adopt any amendment to our Partnership Agreement that has a material adverse effect on the terms of the Series B Preferred Units.

In addition, unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series B Preferred Units, voting as a class together with holders of any other Parity Securities upon which like voting rights have been conferred and are exercisable, we may not:

- create or issue any Parity Securities if the cumulative distributions payable on then outstanding Series B Preferred Units or Parity Securities are in arrears;

- create or issue any Senior Securities; or
- make distributions to our common unitholders out of capital surplus.

On any matter described above in which the holders of the Series B Preferred Units are entitled to vote as a class, such holders will be entitled to one vote per Series B Preferred Unit. The Series B Preferred Units held by us or any of our subsidiaries or controlled affiliates will not be entitled to vote.

Distributions

General

Holders of Series B Preferred Units will be entitled to receive, when, as and if declared by our general partner out of legally available funds for such purpose, cumulative cash distributions.

Distribution Rate

Distributions on Series B Preferred Units are cumulative from the date of original issue and are payable quarterly in arrears on each Distribution Payment Date, when, as and if declared by our general partner out of legally available funds for such purpose.

The initial distribution rate for the Series B Preferred Units from and including the date of original issue to, but not including, June 15, 2023, is 7.875% per annum of the $25.00 liquidation preference per unit (equal to $1.9688 per unit per annum). On and after June 15, 2023, distributions on the Series B Preferred Units will accumulate at a percentage of the $25.00 liquidation preference equal to an annual floating rate of the three-month LIBOR plus a spread of 4.919%.

Distribution Payment Dates

The distribution payment dates for the Series B Preferred Units (each, a "Series B Distribution Payment Dates") are the 15th day of March, June, September and December of each year. Distributions will accumulate in each such distribution period from and including the preceding Series B Distribution Payment Date or the initial issue date, as the case may be, to but excluding the applicable Series B Distribution Payment Date for such distribution period, and distributions will accrue on accumulated distributions at the applicable distribution rate.

Change of Control

Optional Redemption Upon a Series B Change of Control Triggering Event

Upon the occurrence of a Series B Change of Control Triggering Event (as defined below), we may, at our option, redeem the Series B Preferred Units in whole or in part within 120 days after the first date on which such Series B Change of Control Triggering Event occurred (a "Series B Change of Control Redemption Period"), by paying the liquidation preference of $25.00 per Series B Preferred Unit, plus all accumulated and unpaid distributions to, but not including, the redemption date, whether or not declared. If, prior to the Series B Change of Control Conversion Date (as defined below), we exercise our right to redeem the Series B Preferred Units as described in the immediately preceding sentence, holders of the Series B Preferred Units we have elected to redeem will not have the conversion right described below under "—Conversion Right Upon a Series B Change of Control Triggering Event."

"Series B Change of Control" means the occurrence of either of the following after the original issue date of the Series B Preferred Units:

- the direct or indirect lease, sale, transfer, conveyance or other disposition (other than by way of merger, consolidation or business combination), in one or a series of related transactions, of all or substantially all of the properties or assets of us and our subsidiaries taken as a whole to any "person" (as that term is used in Section 13(d)(3) of the Exchange Act); or
- the consummation of any transaction (including, without limitation, any merger, consolidation or business combination), the result of which is that any person (as defined above), other than us, our general partner, DCP Midstream, LLC, and Phillips 66 and Enbridge Inc. and their respective subsidiaries, becomes the beneficial owner, directly or indirectly, of more than 50% of the voting interests of us, our general partner, or DCP Midstream, LLC, measured by voting power rather than percentage of interests.

"Series B Change of Control Triggering Event" means the occurrence of a Series B Change of Control that is accompanied or followed by either a downgrade by one or more gradations (including both gradations within ratings categories and between ratings categories) or withdrawal of the rating of the Series B Preferred Units within the Ratings Decline Period (in any combination) by all three Named Rating Agencies, as a result of which the rating of the Series B Preferred Units on any day during such Ratings Decline Period is below the rating by all three Named Rating Agencies in effect immediately preceding the first public announcement of the Series B Change of Control (or occurrence thereof if such Series B Change of Control occurs prior to public announcement).

Conversion Right Upon a Series B Change of Control Triggering Event

Upon the occurrence of a Series B Change of Control Triggering Event, each holder of Series B Preferred Units will have the right (unless we have provided notice of our election to redeem Series B Preferred Units as described above under "—Optional Redemption upon a Series B Change of Control Triggering Event" or below under "—Redemption") to convert some or all of the Series B Preferred Units held by such holder on the Series B Change of Control Conversion Date into a number of our common units per Series B Preferred Unit to be converted equal (the "Common Unit Conversion Consideration") to the lesser of:

- the quotient obtained by dividing (i) the sum of the $25.00 liquidation preference plus the amount of any accumulated and unpaid distributions to, but not including, the Series B Change of Control Conversion Date (unless the Series B Change of Control Conversion Date is after a record date for a Series B Preferred Unit distribution payment and prior to the corresponding Series B Preferred Unit distribution payment date, in which case no additional amount for such accumulated and unpaid distribution will be included in this sum) by (ii) the Common Unit Price (as defined below), and
- 1.3426, which is the quotient obtained by dividing (i) the $25.00 liquidation preference by (ii) one-half of the closing price of the common units on the NYSE on the trading day immediately preceding the date of this prospectus,

subject, in each case, to certain adjustments and to provisions for (i) the payment of any Series B Alternative Conversion Consideration (as defined below) and (ii) splits, combinations and distributions in the form of equity issuances, each as described in greater detail in our Partnership Agreement.

In the case of a Series B Change of Control pursuant to which our common units will be converted into cash, securities or other property or assets (including any combination thereof), a holder of Series B Preferred Units electing to exercise its Series B Change of Control Conversion Right (as defined below) will receive upon conversion of such Series B Preferred Units elected by such holder the kind and amount of such consideration that such holder would have owned or been entitled to receive upon the Series B Change of Control had such holder held a number of our common units equal to the Common Unit Conversion Consideration immediately prior to the effective time of the Series B Change of Control, which we refer to as the "Series B Alternative Conversion Consideration"; provided, however, that if the holders of our common units have the opportunity to elect the form of consideration to be received in the Series B Change of Control, the consideration that the holders of Series B Preferred Units electing to exercise their Series B Change of Control Conversion Right will receive will be the form and proportion of the aggregate consideration elected by the holders of our common units who participate in the determination (based on the weighted average of elections) and will be subject to any limitations to which all holders of our common units are subject, including, without limitation, pro rata reductions applicable to any portion of the consideration payable in the Series B Change of Control. We will not issue fractional common units upon the conversion of the Series B Preferred Units. Instead, we will pay the cash value of such fractional units.

If we provide a redemption notice, whether pursuant to our special optional redemption right in connection with a Series B Change of Control Triggering Event as described under "—Optional Redemption upon a Change of Control Triggering Event" or our optional redemption rights as described below under "—Redemption," holders of Series B Preferred Units will not have any right to convert the Series B Preferred Units that we have elected to redeem and any Series B Preferred Units subsequently selected for redemption that have been tendered for conversion pursuant to the Series B Change of Control Conversion Right will be redeemed on the related redemption date instead of converted on the Series B Change of Control Conversion Date.

Holders of Series B Preferred Units that choose to exercise their Series B Change of Control Conversion Right will be required prior to the close of business on the third Business Day preceding the Series B Change of Control Conversion Date, to notify us of the number of Series B Preferred Units to be converted and otherwise to comply with any applicable procedures contained in the notice described above or otherwise required by the Securities Depositary for effecting the conversion.

Redemption

Early Optional Redemption upon a Ratings Event

At any time prior to June 15, 2023, within 120 days after the conclusion of any review or appeal process instituted by us following the occurrence of a Ratings Event, we may, at our option, redeem the Series B Preferred Units in whole, but not in part, at a redemption price in cash per Series B Preferred Unit equal to $25.50 (102% of the liquidation preference of $25.00) plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date fixed for redemption, whether or not declared.

Optional Redemption on or after June 15, 2023

Any time on or after June 15, 2023, we may redeem, at our option, in whole or in part, the Series B Preferred Units at a redemption price in cash equal to $25.00 per Series B Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date of redemption, whether or not declared. We may undertake multiple partial redemptions. Any such redemption is subject to compliance with the provisions of our revolving credit facility and any other agreements governing our outstanding indebtedness.

We may also redeem the Series B Preferred Units under the terms set forth under "—Change of Control—Optional Redemption Upon a Series B Change of Control Triggering Event."

No Sinking Fund

The Series B Preferred Units will not have the benefit of any sinking fund.

No Fiduciary Duty

We, our general partner, and DCP Midstream GP, LLC, which is the general partner of our general partner, and the officers and directors of the foregoing entities, will not owe any fiduciary duties to holders of the Series B Preferred Units other than a contractual duty of good faith and fair dealing pursuant to our Partnership Agreement.

Description of 7.95% Series C Fixed-to-Floating Rate Cumulative Redeemable Preferred Units

Number of Series C Units

We have authorized the issuance of 4,400,000 Series C Units, and as of February 17, 2021, we had 4,400,000 Series C Units outstanding.

The Series C Units

The Series C Preferred Units are a series of preferred units. We may, without notice to or consent of the holders of the then-outstanding Series C Preferred Units, authorize and issue additional Series C Preferred Units and Junior Securities.

The holders of our Series C Preferred Units are entitled to receive, to the extent permitted by law, such distributions as may from time to time be declared by our general partner. Upon any liquidation, dissolution or winding up of our affairs, whether voluntary or involuntary, the holders of our Series C Preferred Units are entitled to receive distributions of our assets, after we have satisfied or made provision for our outstanding indebtedness and other obligations and after payment to the holders of any class or series of limited partner interests (including the Series C Preferred Units) having preferential rights to receive distributions of our assets over each such class of limited partner interests.

The Series C Preferred Units are fully paid and generally nonassessable. Each Series C Preferred Unit generally has a fixed liquidation preference of $25.00 per Series C Preferred Unit (subject to adjustment for any splits, combinations or similar adjustment to the Series C Preferred Units) plus an amount equal to accumulated and unpaid distributions thereon to, but not including, the date fixed for payment, whether or not declared.

The Series C Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date. As such, the Series C Preferred Units rank junior to all of our current and future indebtedness and other liabilities with respect to assets available to satisfy claims against us. The rights of the holders of Series C Preferred Units to receive the liquidation preference will be subject to the proportional rights of holders of Parity Securities.

Except as described below in "—Change of Control—Conversion Right Upon a Series B Change of Control Triggering Event," the Series C Preferred Units are not convertible into our common units or any other securities, do not have exchange rights and are not entitled, or subject, to any preemptive or similar rights. The Series C Preferred Units are not subject to mandatory redemption or to any sinking fund requirements. The Series C Preferred Units are subject to redemption, in whole or in part, at our option commencing on October 15, 2023 or upon the occurrence of a Ratings Event.

Our outstanding Series C Preferred Units are listed on the NYSE under the symbol "DCP PRC". Any additional common units we issue will also be listed on the NYSE.

Ranking

The Series C Preferred Units will, with respect to the payment of distributions and amounts payable upon the liquidation or dissolution of our affairs, rank:

- senior to the Junior Securities (including our common units);
- on parity with any Parity Securities;
- junior to any Senior Securities; and
- junior to all of our existing and future indebtedness and other liabilities with respect to assets available to satisfy claims against us.

Under our Partnership Agreement, we may issue Junior Securities from time to time in one or more series without the consent of the holders of the Series C Preferred Units. The Board of Directors has the authority to determine the preferences, powers, qualifications, limitations, restrictions and special or relative rights or privileges, if any, of any such series before the issuance of any units of that series. The Board of Directors will also determine the number of units constituting each series of securities. Our ability to issue any Parity Securities in certain circumstances or Senior Securities is limited as described under "—Voting Rights."

Parity Securities with respect to the Series C Preferred Units may include classes of our securities that have different distribution rates, mechanics, periods, payment dates and record dates than our Series C Preferred Units.

Liquidation Rights

Any liquidation will be made in accordance with capital accounts. The holders of outstanding Series C Preferred Units will be specially allocated items of our gross income and gain in a manner designed to achieve, in the event of any liquidation, dissolution or winding up of our affairs, whether voluntary or involuntary, a liquidation preference of $25.00 per Series C Preferred Unit. If the amount of our gross income and gain available to be specially allocated to the Series C Preferred Units is not sufficient to cause the capital account of a Series C Preferred Unit to equal the liquidation preference of a Series C Preferred Unit, then the amount that a holder of a Series C Preferred Unit would receive upon liquidation may be less than the Series C Preferred Unit liquidation preference. Any accumulated and unpaid distributions on the Series C Preferred Units and Parity Securities will be paid prior to any distributions in liquidation made in accordance with capital accounts. The rights of the holders of Series C Preferred Units to receive the liquidation preference will be subject to the proportional rights of holders of Parity Securities in liquidation.

Voting Rights

The Series C Preferred Units will have no voting rights except as set forth below or as otherwise provided by Delaware law.

Unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series C Preferred Units, voting as a separate class, we may not adopt any amendment to our Partnership Agreement that has a material adverse effect on the terms of the Series C Preferred Units.

In addition, unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series C Preferred Units, voting as a class together with holders of any other Parity Securities upon which like voting rights have been conferred and are exercisable, we may not:

- create or issue any Parity Securities if the cumulative distributions payable on then outstanding Series C Preferred Units or Parity Securities are in arrears;
- create or issue any Senior Securities; or
- make distributions to our common unitholders out of capital surplus.

On any matter described above in which the holders of the Series C Preferred Units are entitled to vote as a class, such holders will be entitled to one vote per Series C Preferred Unit. The Series C Preferred Units held by us or any of our subsidiaries or controlled affiliates will not be entitled to vote.

Distributions

General

Holders of Series C Preferred Units will be entitled to receive, when, as and if declared by our general partner out of legally available funds for such purpose, cumulative cash distributions.

Distribution Rate

Distributions on Series C Preferred Units are cumulative from the date of original issue and are payable quarterly in arrears on each Distribution Payment Date, when, as and if declared by our general partner out of legally available funds for such purpose.

The initial distribution rate for the Series C Preferred Units from and including the date of original issue to, but not including, October 15, 2023 is 7.95% per annum of the $25.00 liquidation preference per unit (equal to $1.9875 per unit per annum). On and after October 15, 2023, distributions on the Series C Preferred Units will accumulate at a percentage of the $25.00 liquidation preference equal to an annual floating rate of the three-month LIBOR plus a spread of 4.882%.

Distribution Payment Dates

The distribution payment dates for the Series C Preferred Units (each, a "C Distribution Payment Date") are the 15th day of January, April, July and October of each year. Distributions accumulate in each such distribution period from and including the preceding C Distribution Payment Date or the initial issue date, as the case may be, to but excluding the applicable C Distribution Payment Date for such distribution period, and distributions will accrue on accumulated distributions at the applicable distribution rate.

Change of Control

Optional Redemption Upon a Series C Change of Control Triggering Event

Upon the occurrence of a Series C Change of Control Triggering Event (as defined below), we may, at our option, redeem the Series C Preferred Units in whole or in part during the Series C Change of Control Redemption Period, by paying the liquidation preference of $25.00 per Series C Preferred Unit, plus all accumulated and unpaid distributions to, but not including, the redemption date, whether or not declared. If, prior to the Series C Change of Control Conversion Date (as defined below), we exercise our right to redeem the Series C Preferred Units as described in the immediately preceding sentence, holders of the Series C Preferred Units we have elected to redeem will not have the conversion right described below under "—Conversion Right Upon a Series C Change of Control Triggering Event."

"Series C Change of Control" means the occurrence of either of the following after the original issue date of the Series C Preferred Units:

- the direct or indirect lease, sale, transfer, conveyance or other disposition (other than by way of merger, consolidation or business combination), in one or a series of related transactions, of all or substantially all of the properties or assets of us and our subsidiaries taken as a whole to any "person" (as that term is used in Section 13(d)(3) of the Exchange Act); or

- the consummation of any transaction (including, without limitation, any merger, consolidation or business combination), the result of which is that any person (as defined above), other than us, our general partner, DCP Midstream, LLC, and Phillips 66 and Enbridge Inc. and their respective subsidiaries, becomes the beneficial owner, directly or indirectly, of more than 50% of the voting interests of us, our general partner, or DCP Midstream, LLC, measured by voting power rather than percentage of interests.

"Series C Change of Control Triggering Event" means the occurrence of a Series C Change of Control that is accompanied or followed by either a downgrade by one or more gradations (including both gradations within ratings categories and between ratings categories) or withdrawal of the rating of the Series C Preferred Units within the Ratings Decline Period (in any combination) by all three Named Rating Agencies, as a result of which the rating of the Series C Preferred Units on any day during such Ratings Decline Period is below the rating by all three Named Rating Agencies in effect immediately preceding the first public announcement of the Series C Change of Control (or occurrence thereof if such Series C Change of Control occurs prior to public announcement).

Conversion Right Upon a Series C Change of Control Triggering Event

Upon the occurrence of a Series C Change of Control Triggering Event, each holder of Series C Preferred Units will have the right (unless we have provided notice of our election to redeem Series C Preferred Units as described above under "—Optional Redemption upon a Change of Control Triggering Event" or below under "—Redemption") to convert some or all of the Series C Preferred Units held by such holder on the Series C Change of Control Conversion Date into a number of our common units per Series C Preferred Unit to be converted equal (the "Common Unit Conversion Consideration") to the lesser of:

- the quotient obtained by dividing (i) the sum of the $25.00 liquidation preference plus the amount of any accumulated and unpaid distributions to, but not including, the Series C Change of Control Conversion Date (unless the Series C Change of Control Conversion Date is after a record date for a Series C Preferred Unit distribution payment and prior to the corresponding Series C Preferred Unit distribution payment date, in which case no additional amount for such accumulated and unpaid distribution will be included in this sum) by (ii) the Common Unit Price (as defined below), and
- 1.2225, which is the quotient obtained by dividing (i) the $25.00 liquidation preference by (ii) one-half of the closing price of our common units on the NYSE on the trading day immediately preceding the date of this prospectus supplement,

subject, in each case, to certain adjustments and to provisions for (i) the payment of any Series C Alternative Conversion Consideration (as defined below) and (ii) splits, combinations and distributions in the form of equity issuances, each as described in greater detail in our Partnership Agreement.

In the case of a Series C Change of Control pursuant to which our common units will be converted into cash, securities or other property or assets (including any combination thereof), a holder of Series C Preferred Units electing to exercise its Series C Change of Control Conversion Right (as defined below) will receive upon conversion of such Series C Preferred Units elected by such holder the kind and amount of such consideration that such holder would have owned or been entitled to receive upon the Series C Change of Control had such holder held a number of our common units equal to the Common Unit Conversion Consideration immediately prior to the effective time of the Series C Change of Control, which we refer to as the "Series C Alternative Conversion Consideration"; provided, however, that if the holders of our common units have the opportunity to elect the form of consideration to be received in the Series C Change of Control, the consideration that the holders of Series C Preferred Units electing to exercise their Series C Change of Control Conversion Right will receive will be the form and proportion of the aggregate consideration elected by the holders of our common units who participate in the determination (based on the weighted average of elections) and will be subject to any limitations to which all holders of our common units are subject, including, without limitation, pro rata reductions applicable to any portion of the consideration payable in the Series C Change of Control. We will not issue fractional common units upon the conversion of the Series C Preferred Units. Instead, we will pay the cash value of such fractional units.

If we provide a redemption notice, whether pursuant to our special optional redemption right in connection with a Series C Change of Control Triggering Event as described under "—Optional Redemption upon a Change of Control Triggering Event" or our optional redemption rights as described below under "—Redemption," holders of Series C Preferred Units will not have any right to convert the Series C Preferred Units that we have elected to redeem and any Series C Preferred Units subsequently selected for redemption that have been tendered for conversion pursuant to the Series C Change of Control Conversion Right will be redeemed on the related redemption date instead of converted on the Series C Change of Control Conversion Date.

Holders of Series C Preferred Units that choose to exercise their Series C Change of Control Conversion Right will be required prior to the close of business on the third Business Day preceding the Series C Change of Control Conversion Date, to notify us of the number of Series C Preferred Units to be converted and otherwise to comply with any applicable procedures contained in the notice described above or otherwise required by the Securities Depositary for effecting the conversion.

Redemption

Early Optional Redemption upon a Ratings Event

At any time prior to October 15, 2023, within 120 days after the conclusion of any review or appeal process instituted by us following the occurrence of a Ratings Event, we may, at our option, redeem the Series C Preferred Units in whole, but not in part, at a redemption price in cash per Series C Preferred Unit equal to $25.50 (102% of the liquidation preference of $25.00) plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date fixed for redemption, whether or not declared.

Optional Redemption on or after October 15, 2023

Any time on or after October 15, 2023, we may redeem, at our option, in whole or in part, the Series C Preferred Units at a redemption price in cash equal to $25.00 per Series C Preferred Unit plus an amount equal to all accumulated and unpaid distributions thereon to, but not including, the date of redemption, whether or not declared. We may undertake multiple partial redemptions. Any such redemption is subject to compliance with the provisions of our revolving credit facility and any other agreements governing our outstanding indebtedness.

We may also redeem the Series C Preferred Units under the terms set forth under "—Change of Control—Optional Redemption Upon a Series C Change of Control Triggering Event."

No Sinking Fund

The Series C Preferred Units will not have the benefit of any sinking fund.

No Fiduciary Duty

We, our general partner, and DCP Midstream GP, LLC, which is the general partner of our general partner, and the officers and directors of the foregoing entities, will not owe any fiduciary duties to holders of the Series C Preferred Units other than a contractual duty of good faith and fair dealing pursuant to our Partnership Agreement.

DCP Midstream, LP
2016 Long-Term Incentive Plan
Restricted Phantom Unit Award Agreement

Awardee: __________

Award Date: __________
(also known as Grant Date)

Restricted Period: The three-year period beginning on__________

1. __**Award of Restricted Phantom Units**__ __(also known as Grant)__. DCP Services, LLC (the "Company") hereby grants to you Phantom Units hereafter referred to as Restricted Phantom Units ("RPUs") allocated as __________ DCP common units under the DCP Midstream, LP 2016 Long-Term Incentive Plan (the "Plan") on the terms and conditions set forth herein. The number of RPUs has been determined based on the average closing price of the DCP common units during the previous twenty trading days ending two days prior to the Award Date and includes a tandem Dividend Equivalent Right ("DER") grant with respect to each RPU. The Company will establish a DER bookkeeping account for you with respect to each RPU granted that shall be credited with an amount equal to the cash dividends, expressed in US dollars, made during the Restricted Period with respect to the DCP common units. Unless otherwise defined herein, terms used, but not defined, in this Award Agreement shall have the same meaning as set forth in the Plan.

2. __**Vesting**__. The RPUs are considered "Vested" once they are no longer forfeitable. Except as provided in Paragraph 3 below, the RPUs granted hereunder shall become Vested only if you have not ceased to be an Employee for any reason (a "Termination of Service") prior to the end of the Restricted Period.

3. __**Early Vesting Events**__. You may become Vested prior to the end of the Restricted Period as provided in Paragraph (a) below.

   (a) __**Death, Disability, Layoff or Retirement**__. If you incur a Termination of Service more than 180 days from the Award Date as a result of your death, disability or layoff, or if you incur a Termination of Service more than 180 days from the Award Date and on or after your Retirement Age (defined as age 55 and completion of at least five (5) continuous years of service with the Company and/or its Affiliates) for reasons other than "cause" (as determined by the Company in its discretion), the Restricted Period shall terminate and your RPUs and any earned but unpaid DERs will become fully Vested on the date of your Termination of Service.

   (b) __**Other Terminations of Service**__. If your Termination of Service occurs prior to the end of the Restricted Period for any reason other than as provided in Paragraph 3(a) above, the Restricted Period shall terminate, and all of your RPUs and unearned DERs shall be forfeited without payment automatically upon the date of your Termination of Service.

4. __**Payments**__.

   (a) __**RPUs**__. As soon as administratively practicable after the date the Restricted Period terminates (the "Restricted Period End Date"), you will be issued DCP common units equal to the number of your Vested RPUs, unless the Company decides to pay to you in cash an amount equal to the average closing price of your Vested RPUs based on the previous twenty trading days immediately prior to the Restricted Period End Date multiplied by your Vested RPUs, less any taxes the Company is required to withhold from such payment. The Company has sole discretion to determine which method of payment will be used. Payment will be made no later than 2½ months following the Restricted Period End Date (you are not permitted to designate the year of payment in situations where the payment period crosses multiple years), less all applicable taxes required to be withheld therefrom, unless deferred into the Executive Deferred Compensation Plan in accordance with Code Section 409A or delayed pursuant to Section 8(n) of the Plan (related to the six-month delay requirement under Code Section 409A).

(b) **DERs**. DERs are considered earned as of the quarterly record date. As soon as administratively practicable after each quarterly dividend payment date during the Restricted Period and any six-month delay required under Code Section 409A, the Company shall pay you in cash, with respect to each RPU, an amount equal to the DERs credited to your DER account during that calendar quarter, less any taxes the Company is required to withhold from such payment.

5. **Limitations Upon Transfer**. All rights under this Award Agreement shall belong to you alone and may not be transferred, assigned, pledged, or hypothecated by you in any way (whether by operation of law or otherwise), other than by will or the laws of descent and distribution or by a beneficiary designation form filed with the Company in accordance with the procedures established by the Company for such designation, and shall not be subject to execution, attachment, or similar process. Upon any attempt by you to transfer, assign, pledge, hypothecate, or otherwise dispose of such rights contrary to the provisions in this Award Agreement or the Plan, or upon the levy of any attachment or similar process upon such rights, such rights shall immediately become null and void.

6. **Binding Effect**. This Agreement shall be binding upon and inure to the benefit of any successor or successors of the Company and upon any person lawfully claiming under you.

7. **Entire Agreement**. This Award Agreement along with the Plan constitutes the entire agreement of the parties with regard to the subject matter hereof, and contains all the covenants, promises, representations, warranties and agreements between the parties with respect to the RPUs granted hereby. Without limiting the scope of the preceding sentence, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect.

8. **Modifications**. Any modification of this Agreement shall be effective only if it is in writing and signed by both you and an authorized officer of the Company.

9. **Governing Law**. This award shall be governed by, and construed in accordance with, the laws of the State of Colorado, without regard to conflicts of laws or principles thereof.

10. **Plan Controls**. By accepting this Award, you acknowledge and agree that the RPUs are granted under and governed by the terms and conditions of this Award Agreement and the Plan, a copy of which has been furnished to you. In the event of any conflict between the Plan and this Award Agreement, the terms of the Plan shall control. All decisions or interpretations of the Committee upon any questions relating to the Plan or this Award Agreement are binding, conclusive and final on all persons.

DCP Services, LLC

By: ______________________

Name:

Title:

Awardee Acknowledgement and Acceptance

By: ______________________

Name:

Exhibit 21.1

SUBSIDIARIES OF DCP MIDSTREAM, LP

Entity	Jurisdiction of Organization
Centana Intrastate Pipeline, LLC	Delaware
Cimarron River Pipeline, LLC	Delaware
Collbran Valley Gas Gathering, LLC (75%)	Colorado
Dauphin Island Gathering Partners	Texas
DCP Assets Holding GP, LLC	Delaware
DCP Assets Holding, LP	Delaware
DCP Black Lake Holdings, LP	Delaware
DCP Chesapeake LLC	Texas
DCP Cheyenne Connector, LLC	Delaware
DCP Dauphin Island, LLC	Delaware
DCP East Texas Gathering, LLC	Delaware
DCP GCX Pipeline LLC	Delaware
DCP Grands Lacs LLC	Michigan
DCP Guadalupe Pipeline, LLC	Delaware
DCP Hinshaw Pipeline, LLC	Delaware
DCP Intrastate Network, LLC	Delaware
DCP Litchfield LLC	Michigan
DCP LP Holdings, LLC	Delaware
DCP Lucerne 2 Plant LLC	Delaware
DCP Michigan Holdings LLC	Delaware
DCP Michigan Pipeline & Processing LLC	Michigan
DCP Midstream Holding, LLC	Delaware
DCP Midstream Marketing, LLC	Delaware
DCP Midstream Operating, LLC	Delaware
DCP Midstream Operating, LP	Delaware
DCP Mobile Bay Processing, LLC	Delaware
DCP New Mexico Development, LLC	Delaware
DCP NGL Operating, LLC	Delaware
DCP NGL Services, LLC	Delaware
DCP Operating Company, LP	Delaware
DCP Partners Colorado LLC	Delaware
DCP Partners Logistics, LLC	Delaware
DCP Partners MB I LLC	Delaware
DCP Partners MB II LLC	Delaware
DCP Pipeline Holding LLC	Delaware
DCP Raptor Pipeline, LLC	Delaware
DCP Receivables LLC	Delaware
DCP Saginaw Bay Lateral LLC	Delaware
DCP Sand Hills Pipeline, LLC (66.67%)	Delaware
DCP South Central Texas LLC	Delaware
DCP Southern Hills Pipeline, LLC (66.67%)	Delaware
DCP Sweeny LLC	Delaware
DCP Technology Ventures LLC	Delaware
DCP Tolar Holdings LLC	Delaware
DCP Wattenberg Pipeline LLC	Delaware

DCP Wyoming Assets LLC	Delaware
DCP Zia Plant LLC	Delaware
EasTrans, LLC	Delaware
Fuels Cotton Valley Gathering, LLC	Delaware
Jackson Pipeline Company (75%)	Michigan
Marysville Hydrocarbons Holdings, LLC	Delaware
Marysville Hydrocarbons LLC	Delaware
National Helium, LLC	Delaware
Saginaw Bay Lateral Michigan Limited Partnership (46%)	Michigan
Wilbreeze Pipeline, LLC	Delaware

Exhibit 22

List of Guaranteed Securities

Pursuant to Item 601(b)(22) of Regulation S-K, set forth below are securities issued by DCP Midstream Operating, LP (Subsidiary Issuer) and guaranteed by DCP Midstream, LP (Parent Guarantor).

$500 million of 3.875% Senior Notes due March 2023

$825 million of 5.375% Senior Notes due July 2025

$500 million of 5.625% Senior Notes due July 2027

$600 million of 5.125% Senior Notes due May 2029

$300 million of 8.125% Senior Notes due August 2030

$400 million of 3.250% Senior Notes due February 2032

$300 million of 6.450% Senior Notes due November 2036

$450 million of 6.750% Senior Notes due September 2037

$400 million of 5.600% Senior Notes due April 2044

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-142271 and 333-211905 on Form S-8 and Registration Statement Nos. 333-249271, 333-249270, and 333-182642 on Form S-3 of our reports dated February 18, 2022, relating to the financial statements of DCP Midstream, LP (the “Partnership”) and the effectiveness of the Partnership’s internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2021.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 18, 2022

Consent of Independent Registered Public Accounting Firm

Gulf Coast Express Pipeline LLC
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-249271, 333-249270 and 333-182642) and Form S-8 (No. 333-142271 and 333-211905) of DCP Midstream, LP of our report dated February 16, 2022, relating to the financial statements of Gulf Coast Express Pipeline LLC as of and for the years ended December 31, 2021 and 2020, which appears in this Annual Report on Form 10-K of DCP Midstream, LP.

/s/ BDO USA,LLP

Houston, Texas
February 18, 2022

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Wouter T. van Kempen, certify that:

1. I have reviewed this annual report on Form 10-K of DCP Midstream, LP for the year ended December 31, 2021;

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: February 18, 2022

/s/ Wouter T. van Kempen

Wouter T. van Kempen
President and Chief Executive Officer
(Principal Executive Officer)
DCP Midstream GP, LLC, general partner of
DCP Midstream GP, LP, general partner of
DCP Midstream, LP

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Sean P. O'Brien, certify that:

1. I have reviewed this annual report on Form 10-K of DCP Midstream, LP for the year ended December 31, 2021;

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: February 18, 2022

/s/ Sean P. O'Brien
Sean P. O'Brien
Group Vice President and Chief Financial Officer
(Principal Financial Officer)
DCP Midstream GP, LLC, general partner of
DCP Midstream GP, LP, general partner of
DCP Midstream, LP

Exhibit 32.1

Certification of President and Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

The undersigned, the President and Chief Executive Officer of DCP Midstream GP, LLC, general partner of DCP Midstream GP, LP, general partner of DCP Midstream, LP (the “Partnership”), hereby certifies that, to his knowledge on the date hereof:

(a) the annual report on Form 10-K of the Partnership for the year ended December 31, 2021, filed on the date hereof with the Securities and Exchange Commission (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Wouter T. van Kempen

Wouter T. van Kempen
President and Chief Executive Officer
(Principal Executive Officer)
February 18, 2022

A signed original 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 Group Vice President and Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906
of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

The undersigned, the Group Vice President and Chief Financial Officer of DCP Midstream GP, LLC, general partner of DCP Midstream GP, LP, general partner of DCP Midstream, LP (the "Partnership"), hereby certifies that, to his knowledge on the date hereof:

(a) the annual report on Form 10-K of the Partnership for the year ended December 31, 2021, filed on the date hereof with the Securities and Exchange Commission (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(b) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ Sean P. O'Brien

Sean P. O'Brien
Group Vice President and Chief Financial Officer
(Principal Financial Officer)
February 18, 2022

A signed original 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.