Cheniere Energy Partners, L.P.
Form 10-K
February 26, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
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 001-33366
Cheniere Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	20-5913059
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
700 Milam Street, Suite 1900	
Houston, Texas	77002
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: (713) 375-5000
Securities registered pursuant to Section 12(b) of the Act:

Common Units Representing Limited Partner Interests	NYSE American
(Title of each class)	(Name of each exchange on which registered)

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 Act. Yes x No o
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 o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x
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 Act.

Large accelerated filer	x	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	o
		Emerging growth company	o

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 Act. o

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

The aggregate market value of the registrant’s common units held by non-affiliates of the registrant was approximately $8.8 billion as of June 30, 2018.

The registrant had 348,625,292 common units and 135,383,831 subordinated units outstanding as of February 20, 2019.

Documents incorporated by reference: None

CHENIERE ENERGY PARTNERS, L.P.
TABLE OF CONTENTS

PART I	
Items 1. and 2. Business and Properties	4
Item 1A. Risk Factors	15
Item 1B. Unresolved Staff Comments	38
Item 3. Legal Proceedings	38
Item 4. Mine Safety Disclosure	39
PART II	
Item 5. Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	40
Item 6. Selected Financial Data	42
Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations	43
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	58
Item 8. Financial Statements and Supplementary Data	58
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	104
Item 9A. Controls and Procedures	104
Item 9B. Other Information	104
PART III	
Item 10. Directors, Executive Officers of Our General Partner and Corporate Governance	105
Item 11. Executive Compensation	109
Item 12. Security Ownership of Certain Beneficial Owners and Management, and Related Unitholder Matters	112
Item 13. Certain Relationships and Related Transactions, and Director Independence	114
Item 14. Principal Accountant Fees and Services	116
PART IV	
Item 15. Exhibits and Financial Statement Schedules	117
Item 16. Form 10-K Summary	126
Signatures	127

DEFINITIONS

As used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bcf/yr	billion cubic feet per year
Bcfe	billion cubic feet equivalent
DOE	U.S. Department of Energy
EPC	engineering, procurement and construction
FERC	Federal Energy Regulatory Commission
FTA countries	countries with which the United States has a free trade agreement providing for national treatment for trade in natural gas
GAAP	generally accepted accounting principles in the United States
Henry Hub	the final settlement price (in USD per MMBtu) for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which a relevant cargo's delivery window is scheduled to begin
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas, a product of natural gas that, through a refrigeration process, has been cooled to a liquid state, which occupies a volume that is approximately 1/600th of its gaseous state
MMBtu	million British thermal units, an energy unit
mtpa	million tonnes per annum
non-FTA countries	countries with which the United States does not have a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
SEC	U.S. Securities and Exchange Commission
SPA	LNG sale and purchase agreement
TBtu	trillion British thermal units, an energy unit
Train	an industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
TUA	terminal use agreement

Abbreviated Legal Entity Structure

The following diagram depicts our abbreviated legal entity structure as of December 31, 2018, including our ownership of certain subsidiaries, and the references to these entities used in this annual report:

Unless the context requires otherwise, references to “Cheniere Partners,” “the Partnership,” “we,” “us” and “our” refer to Cheniere Energy Partners, L.P. and its consolidated subsidiaries, including SPLNG, SPL and CTPL.

References to “Blackstone Group” refer to The Blackstone Group, L.P. References to “Blackstone CQP Holdco” refer to Blackstone CQP Holdco LP. References to “Blackstone” refer to Blackstone Group and Blackstone CQP Holdco.

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical or present facts or conditions, included herein or incorporated herein by reference are “forward-looking statements.” Included among “forward-looking statements” are, among other things:

- statements regarding our ability to pay distributions to our unitholders;
- statements regarding our expected receipt of cash distributions from SPLNG, SPL or CTPL;
- statements that we expect to commence or complete construction of our proposed LNG terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions or portions thereof, by certain dates, or at all;
- statements regarding future levels of domestic and international natural gas production, supply or consumption or future levels of LNG imports into or exports from North America and other countries worldwide or purchases of natural gas, regardless of the source of such information, or the transportation or other infrastructure or demand for and prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or our ability to enter into such transactions;
- statements relating to the construction of our Trains, including statements concerning the engagement of any EPC contractor or other contractor and the anticipated terms and provisions of any agreement with any EPC or other contractor, and anticipated costs related thereto;
- statements regarding any SPA or other agreement to be entered into or performed substantially in the future, including any revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total LNG regasification, natural gas liquefaction or storage capacities that are, or may become, subject to contracts;
- statements regarding counterparties to our commercial contracts, construction contracts, and other contracts;
- statements regarding our planned development and construction of additional Trains, including the financing of such Trains;
- statements that our Trains, when completed, will have certain characteristics, including amounts of liquefaction capacities;
- statements regarding our business strategy, our strengths, our business and operation plans or any other plans, forecasts, projections, or objectives, including anticipated revenues, capital expenditures, maintenance and operating costs and cash flows, any or all of which are subject to change;
- statements regarding legislative, governmental, regulatory, administrative or other public body actions, approvals, requirements, permits, applications, filings, investigations, proceedings or decisions; and
- any other statements that relate to non-historical or future information.

All of these types of statements, other than statements of historical or present facts or conditions, are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “achieve,” “anticipate,” “believe,” “contemplate,” “continue,” “estimate,” “expect,” “intend,” “plan,” “potential,” “pr “pursue,” “target,” the negative of such terms or other comparable terminology. The forward-looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe that such estimates are reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond our control. In addition, assumptions may prove to be inaccurate. We caution that the forward-looking statements contained in this annual report are not guarantees of future performance and that such statements may not be realized or the forward-looking statements or events may not occur. Actual results may differ materially from those anticipated or implied in forward-looking statements as a result of a variety of factors described in this annual report and in the other reports and other information that we file with the SEC. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to update or revise any forward-looking statement or provide reasons why actual results may differ, whether as a result of new information, future events or otherwise.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We are a publicly traded Delaware limited partnership formed by Cheniere in 2006. Our vision is to provide clean, secure and affordable energy to the world, while responsibly delivering a reliable, competitive and integrated source of LNG, in a safe and rewarding work environment. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to economically justify the use of LNG. Through our wholly owned subsidiary, SPL, we are developing, constructing and operating natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. We plan to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is undergoing commissioning and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability, potential overdesign and debottlenecking opportunities, of approximately 4.5 mtpa of LNG per Train, and run rate adjusted nominal production capacity of approximately 4.5 to 4.9 mtpa of LNG per Train. Through our wholly owned subsidiary, SPLNG, we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We also own a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through our wholly owned subsidiary, CTPL.

The following diagram depicts our abbreviated capital structure as of December 31, 2018:

Our Business Strategy

Our primary business strategy is to develop, construct and operate assets supported by long-term, fixed fee contracts. We plan to implement our strategy by:

- achieving the date of first commercial delivery for our SPA customers;
- safely, efficiently and reliably maintaining and operating our assets, including our Trains;
- completing construction and commencing operation of Train 5 of the Liquefaction Project;
- making LNG available to our long-term SPA customers to generate steady and reliable revenues and operating cash flows;
- obtaining the requisite long-term commercial contracts and financing to reach a final investment decision ("FID") regarding Train 6 of the Liquefaction Project;
- further expanding and optimizing the Liquefaction Project by leveraging existing infrastructure; and
- expanding our existing asset base through acquisitions from Cheniere or third parties or our own development of the Liquefaction Project or complementary businesses or assets such as other LNG facilities, midstream assets, natural gas storage assets and natural gas pipelines.

Our Business

Liquefaction Facilities

We are developing, constructing and operating the Liquefaction Project at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. We have achieved substantial completion of Trains 1, 2, 3 and 4 of the Liquefaction Project and commenced operating activities in May 2016, September 2016, March 2017 and October 2017, respectively. Train 5 of the Liquefaction Project is undergoing commissioning and the following table summarizes the status as of December 31, 2018:

	Train 5
Overall project completion percentage	99.7%
Completion percentage of:	
Engineering	100%
Procurement	100%
Subcontract work	98.0%
Construction	99.6%
Date of expected substantial completion	1Q 2019

The following orders have been issued by the DOE authorizing the export of domestically produced LNG by vessel from the Sabine Pass LNG terminal:

- Trains 1 through 4—FTA countries for a 30-year term, which commenced on May 15, 2016, and non-FTA countries for a 20-year term, which commenced on June 3, 2016, in an amount up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr of natural gas).
- Trains 1 through 4—FTA countries for a 25-year term and non-FTA countries for a 20-year term in an amount up to a combined total of the equivalent of approximately 203 Bcf/yr of natural gas (approximately 4 mtpa).
- Trains 5 and 6—FTA countries and non-FTA countries for a 20-year term, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from five to 10 years from the date the order was issued. In addition, SPL received an order providing for a three-year makeup period with respect to each of the non-FTA orders for LNG volumes SPL was authorized but unable to export during any portion of the initial 20-year export period of such order.

In January 2018, the DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2018, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,509 Bcf/yr).

Customers

SPL has entered into fixed price SPAs with terms of at least 20 years (plus extension rights) with six third parties for Trains 1 through 5 of the Liquefaction Project, to make available an aggregate amount of LNG that is between approximately 80% to 95% of the expected aggregate adjusted nominal production capacity from these Trains. Under these SPAs, the customers will purchase LNG from SPL for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. In certain circumstances, the customers may elect to cancel or suspend deliveries of LNG cargoes, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered as a result of such cancellation or suspension. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under SPL's SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under SPL's SPAs. The variable fees under SPL's SPAs were sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation related to, and operating and maintenance costs to produce, the LNG to be sold under each such SPA. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train. Under SPL's SPA with BG Gulf Coast LNG, LLC ("BG"), BG has contracted for volumes related to Trains 3 and 4, for which the obligation to make volumes related to Train 3 available to BG has commenced and the obligation to make volumes related to Train 4 available to BG is expected to commence approximately one year after the date of first commercial delivery under SPL's SPA with GAIL (India) Limited ("GAIL") for Train 4.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $2.2 billion for Trains 1 through 3 and the SPA with GAIL for Train 4, increasing to $2.3 billion upon the date of first commercial delivery of Train 4 under the SPA with BG and to $2.9 billion upon the date of first commercial delivery of Train 5, with the applicable fixed fees starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

The annual contracted cash flows from fixed fees of each buyer of LNG under SPL's third-party SPAs that constitute more than 10% of SPL's aggregate fixed fees under all its SPAs are:

- approximately $720 million from BG, which is guaranteed by BG Energy Holdings Limited;
- approximately $550 million from Korea Gas Corporation ("KOGAS");
- approximately $550 million from GAIL; and
- approximately $450 million from Naturgy LNG GOM, Limited (formerly known as Gas Natural Fenosa LNG GOM, Limited) ("Naturgy"), which is guaranteed by Naturgy Energy Group, S.A. (formerly known as Gas Natural SDG S.A.).

SPL also has SPAs with Total Gas & Power North America, Inc. ("Total"), which is guaranteed by Total S.A., and Centrica plc with annual aggregate fixed fees of approximately $590 million. In addition, Cheniere Marketing has entered into an SPA with SPL to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers.

During the year ended December 31, 2018, four customers, BG, Naturgy, KOGAS and GAIL, individually accounted for more than 10% of our total revenues from external customers at 28%, 21%, 23% and 19%, respectively. During the year ended December 31, 2017, three customers, BG, Naturgy and KOGAS, individually accounted for more than 10% of our total revenues from external customers at 39%, 27% and 23%, respectively. During the year ended December 31, 2016, BG individually accounted for 52% of our total revenues from external customers.

Natural Gas Transportation, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing variability in natural gas needs for the Liquefaction Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2018, SPL had secured up to approximately 3,464 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts.

Construction

SPL entered into lump sum turnkey contracts with Bechtel Oil, Gas and Chemicals, Inc. (“Bechtel”) for the engineering, procurement and construction of Trains 1 through 6 of the Liquefaction Project, under which Bechtel charges a lump sum for all work performed and generally bears project cost risk unless certain specified events occur, in which case Bechtel may cause SPL to enter into a change order, or SPL agrees with Bechtel to a change order.

The total contract price of the EPC contract for Train 5 of the Liquefaction Project is approximately $3.1 billion reflecting amounts incurred under change orders through December 31, 2018. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.5 billion and $18.5 billion after financing costs, including, in each case, estimated owner’s costs and contingencies. The total contract price of the EPC contract for Train 6 of the Liquefaction Project is approximately $2.5 billion, including estimated costs for an optional third marine berth.

Final Investment Decision on Train 6

SPL has issued limited notices to proceed to Bechtel for the commencement of certain engineering, procurement and site works for Train 6 of the Liquefaction Project and a schedule for completion has been established. FID and full notice to proceed for Train 6 of the Liquefaction Project will be contingent upon, among other things, entering into acceptable commercial arrangements and obtaining adequate financing to construct Train 6.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4.0 Bcf/d and aggregate LNG storage capacity of approximately 16.9 Bcfe. Approximately 2.0 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term third-party TUAs, under which SPLNG’s customers are required to pay fixed monthly fees, whether or not they use the LNG terminal. Each of Total and Chevron U.S.A. Inc. (“Chevron”) has reserved approximately 1.0 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009. Total S.A. has guaranteed Total’s obligations under its TUA up to $2.5 billion, subject to certain exceptions, and Chevron Corporation has guaranteed Chevron’s obligations under its TUA up to 80% of the fees payable by Chevron.

The remaining approximately 2.0 Bcf/d of capacity has been reserved under a TUA by SPL. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, continuing until at least May 2036. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 3 of the Liquefaction Project, SPL gained access to a portion of Total’s capacity and other services provided under Total’s TUA with SPLNG. Upon substantial completion of Train 5, SPL will gain access to substantially all of Total’s capacity. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the years ended December 31, 2018 and 2017, SPL recorded $30 million and $23 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Under each of these TUAs, SPLNG is entitled to retain 2% of the LNG delivered to the Sabine Pass LNG terminal.

Governmental Regulation

The Sabine Pass LNG terminal is subject to extensive regulation under federal, state and local statutes, rules, regulations and laws. These laws require that we engage in consultations with appropriate federal and state agencies and that we obtain and maintain applicable permits and other authorizations. This regulatory requirement increases the cost of construction and operation, and failure to comply with such laws could result in substantial penalties and/or loss of necessary authorizations.

Federal Energy Regulatory Commission
The design, construction and operation of our liquefaction facilities, the export of LNG and the transportation of natural gas through the Creole Trail Pipeline and the Corpus Christi Pipeline are highly regulated activities. Under the Natural Gas Act of 1938, as amended (the “NGA”), the FERC’s jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial or any other use and to natural gas companies engaged in such transportation or sale. However, the FERC’s jurisdiction does not extend to the production, gathering, local distribution or export of natural gas.

In general, the FERC’s authority to regulate interstate natural gas pipelines and the services that they provide includes:

- rates and charges, and terms and conditions for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;
- the administration of accounting and financial reporting regulations, including the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

In addition, under the NGA, our pipelines are not permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service to any shipper, including its own marketing affiliate. The FERC has the authority to grant certificates allowing construction and operation of facilities used in interstate gas transportation and authorizing the provision of services.

In order to site, construct and operate the Sabine Pass LNG terminal, we received and are required to maintain authorizations from the FERC under Section 3 of the NGA as well as several other material governmental and regulatory approvals and permits. The Energy Policy Act of 2005 (the “EPAct”) amended Section 3 of the NGA to establish or clarify the FERC’s exclusive authority to approve or deny an application for the siting, construction, expansion or operation of LNG terminals, although except as specifically provided in the EPAct, nothing in the EPAct is intended to affect otherwise applicable law related to any other federal or state agency’s authorities or responsibilities related to LNG terminals. The FERC issued final orders in April and July 2012 approving our application for an order under Section 3 of the NGA authorizing the siting, construction and operation of Trains 1 through 4 of the Liquefaction Project (and related facilities). Subsequently, the FERC issued written approval to commence site preparation work for Trains 1 through 4. In October 2012, we applied to amend the FERC approval to reflect certain modifications to the Liquefaction Project, and in August 2013, the FERC issued an order approving the modifications. In October 2013, we applied to further amend the FERC approval, requesting authorization to increase the total permitted LNG production capacity of Trains 1 through 4 from the then authorized 803 Bcf/yr to 1,006 Bcf/yr so as to more accurately reflect the estimated maximum LNG production capacity of Trains 1 through 4. In February 2014, the FERC issued an order approving the October 2013 application (the “February 2014 Order”). A party to the proceeding requested a rehearing of the February 2014 Order, and in September 2014, the FERC issued an order denying the rehearing request (the “FERC Order Denying Rehearing”). The party petitioned the U.S. Court of Appeals for the District of Columbia Circuit to review the February 2014 Order and the FERC Order Denying Rehearing. The court denied the petition in June 2016. In September 2013, we filed an application with the FERC for authorization to add Trains 5 and 6 to the Liquefaction Project, which was granted by the FERC in an order issued in April 2015 and an order denying rehearing issued in June 2015. These orders are not subject to appellate court review.

In 2002, the FERC concluded that it would apply light-handed regulation over the rates, terms and conditions agreed to by parties for LNG terminalling services, such that LNG terminal owners would not be required to provide open-access service at non-discriminatory rates or maintain a tariff or rate schedule on file with the FERC, as distinguished from the requirements applied to our FERC-regulated natural gas pipeline. The EPAct codified the FERC's policy, but those provisions expired on January 1, 2015. Nonetheless, we see no indication that the FERC intends to modify its longstanding policy of light-handed regulation of LNG terminals.

In order to construct, own, operate and maintain the Creole Trail Pipeline, CTPL received a certificate of public convenience and necessity from the FERC under Section 7 of the NGA. The FERC's approval under Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, may be required prior to making any modifications to the Creole Trail Pipeline as it is a regulated, interstate natural gas pipeline. In 2013, the FERC also approved CTPL's application for authorization to construct, own, operate and maintain certain new facilities in order to enable bi-directional natural gas flow on the Creole Trail Pipeline system to allow for the delivery of up to 1,530,000 dekatherms per day of feed gas to the Liquefaction Project. In November 2013, CTPL received approval from the Louisiana Department of Environmental Quality ("LDEQ") for the proposed modifications and, with subsequent final FERC clearance, construction was completed in 2015. In September 2013, we filed an application with the FERC for authorization to construct and operate an extension and expansion of the Creole Trail Pipeline and related facilities in order to deliver additional domestic natural gas supplies to the Liquefaction Project, which was granted by the FERC in an order issued in April 2015 and an order denying rehearing issued in June 2015. These orders are not subject to appellate court review.

The FERC's Standards of Conduct apply to interstate pipelines that conduct transmission transactions with an affiliate that engages in marketing functions. Interstate pipelines must treat all transmission customers on a not unduly discriminatory basis. The general principles of the Standards of Conduct are: (1) independent functioning, which requires transmission function employees to function independently of marketing function employees; (2) no-conduit rule, which prohibits passing transmission function information to marketing function employees; and (3) transparency, which imposes posting requirements to detect undue preference due to the improper disclosure of non-public transmission function information. CTPL has established the required policies and procedures to comply with the FERC's Standards of Conduct and is subject to audit by the FERC to review compliance, policies and its training programs.

Several other material governmental and regulatory approvals and permits will be required throughout the life of our Liquefaction Project. In addition, the FERC orders require us to comply with certain ongoing conditions and obtain certain additional FERC and other regulatory agency approvals as construction progresses. To date, we have been able to obtain these approvals as needed and the need for these approvals has not materially affected our construction progress. Throughout the life of our LNG terminal and the Creole Trail Pipeline, we will be subject to regular reporting requirements to the FERC, the U.S. Department of Transportation's ("DOT") and Pipeline Hazardous Materials Safety Administration ("PHMSA") and applicable federal and state regulatory agencies regarding the operation and maintenance of our facilities.

The FERC's jurisdiction under the NGA allows it to impose civil and criminal penalties for any violations of the NGA and any rules, regulations or orders of the FERC up to approximately $1.3 million per day per violation, including any conduct that violates the NGA's prohibition against market manipulation.

DOE Export License

The DOE has authorized the export of domestically produced LNG by vessel from the Sabine Pass LNG terminal as discussed in Liquefaction Facilities. Although it is not expected to occur, the loss of an export authorization could be a force majeure event under our SPAs.

Exports of natural gas to FTA countries are "deemed to be consistent with the public interest" and authorization to export LNG to FTA countries shall be granted by the DOE without "modification or delay." FTA countries which currently import LNG include Canada, Chile, Colombia, Dominican Republic, Israel, Jordan, Mexico, Panama, Singapore and South Korea. Exports of natural gas to non-FTA countries are considered by the DOE in the context of a comment period whereby interveners are provided the opportunity to assert that such authorization would not be consistent with the public interest.

Pipeline

The Creole Trail Pipeline is also subject to regulation by the PHMSA, pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities.

The Pipeline Safety Improvement Act of 2002, as amended (“PSIA”), which is administered by the PHMSA Office of Pipeline Safety, governs the areas of testing, education, training and communication. The PSIA requires pipeline companies to perform extensive integrity tests on natural gas transportation pipelines that exist in high population density areas designated as “high consequence areas.” Pipeline companies are required to perform the integrity tests on a seven-year cycle. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. Pipeline operators also must develop integrity management programs for gas transportation pipelines, which requires pipeline operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline, as necessary; and implement preventive and mitigation actions.

In 2009, the PHMSA issued a final rule (known as “Control Room Management/Human Factors Rule”) that became effective in 2010 requiring pipeline operators to write and institute certain control room procedures that address human factors and fatigue management.

In March 2015, PHMSA issued a final rule amending the pipeline safety regulations to update and clarify certain regulatory requirements, including who can perform post-construction inspections on transmission pipelines. In September 2015, PHMSA issued a rule indefinitely delaying the effective date for the amendment to the regulation regarding post-construction inspections.
In May 2015, PHMSA issued a notice of proposed rulemaking proposing to amend gas pipeline safety regulations regarding plastic piping systems used in gas services, including the installation of plastic pipe used for gas transmission lines. The PHMSA has not finalized any of the regulations proposed in this notice.

In July 2015, PHMSA issued a notice of proposed rulemaking proposing to add a specific timeframe for operators’ notification of accidents or incidents, as well as amending the safety regulations regarding operator qualification requirements by expanding the requirements to include new construction and certain previously excluded operation and maintenance tasks, requiring a program effectiveness review and adding new recordkeeping requirements. In January 2017, PHMSA issued a final rule (effective as of March 24, 2017) adding a specific time frame for operators’ notification of accidents or incidents but delayed final action on the proposed operator qualification requirements until a later date.
In April 2016, the PHMSA issued a notice of proposed rulemaking addressing changes to the regulations governing the safety of gas transmission pipelines. Specifically, PHMSA is considering certain integrity management requirements for “moderate consequence areas,” requiring an integrity verification process for specific categories of pipelines, and mandating more explicit requirements for the integration of data from integrity assessments to an operator’s compliance procedures. The PHMSA is also considering whether to revise requirements for corrosion control and expanding the definition of regulated gathering lines. These notices of proposed rulemaking are still pending at the PHMSA. The PHMSA has not finalized any of the regulations proposed in this notice.

Natural Gas Pipeline Safety Act of 1968 (“NGPSA”)

Louisiana administers federal pipeline safety standards under the NGPSA, which requires certain pipelines to comply with safety standards in constructing and operating the pipelines and subjects the pipelines to regular inspections. Failure to comply with the NGPSA may result in the imposition of administrative, civil and criminal sanctions.

Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011

The Creole Trail Pipeline is also subject to the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. Under the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, PHMSA has civil penalty authority up to approximately $200,000 per day per violation (increased from the prior $100,000), with a maximum of approximately $2 million in civil penalties for any related series of violations (increased from the prior $1 million).

Other Governmental Permits, Approvals and Authorizations

The construction and operation of the Sabine Pass LNG terminal requires additional federal permits, orders, approvals and consultations required by federal agencies, including the DOT, Advisory Council on Historic Preservation, U.S. Army Corps of Engineers ("USACE"), U.S. Department of Commerce, National Marine Fisheries Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, Environmental Protection Agency (the "EPA") and U.S. Department of Homeland Security.

Three significant permits are the USACE Section 404 of the Clean Water Act/Section 10 of the Rivers and Harbors Act Permit (the "Section 10/404 Permit"), the Clean Air Act Title V Operating Permit (the "Title V Permit") and the Prevention of Significant Deterioration Permit (the "PSD Permit"), of which the latter two permits are issued by the LDEQ.

The Sabine Pass LNG terminal's Section 10/404 Permit authorizing construction of Trains 1 through 4 was received from the USACE in March 2012. A modification to the Section 10/404 Permit, to address wetlands impacted by the construction of Trains 5 and 6, was issued by the USACE in June 2015. The USACE acted in the capacity as a cooperating agency in the review process under the National Environmental Policy Act of 1969. The LDEQ issued amended PSD and Title V Permits in September 2017 to reflect certain facility modifications, updated emissions and as-built capacity factors. In October 2018, Sabine Pass LNG Terminal applied to the LDEQ for another amendment to its PSD and Title V Permits to reflect certain facility modifications and as-built reconciliation revisions.

The LDEQ issued an administrative amendment to the Title V Permit for CTPL in February 2017 to correct permit representations. In April 2018, CTPL applied to the LDEQ for another amendment to the Title V Permit to update permit representations.

LDEQ issued a modification of the wastewater discharge permit to Sabine Pass LNG Terminal in December 2017 to include wastewaters generated with respect to the anticipated operations of Trains 5 and 6 of the Liquefaction Project.

Commodity Futures Trading Commission ("CFTC")

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") amended the Commodity Exchange Act to provide for federal regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The regulatory regime created by the Dodd-Frank Act is designed primarily to (1) regulate certain participants in the swaps markets, including entities falling within the categories of "Swap Dealer" and "Major Swap Participant," (2) require clearing and exchange trading of standardized swaps of certain classes as designated by the CFTC, (3) increase swap market transparency through robust reporting and recordkeeping requirements, (4) reduce financial risks in the derivatives market by imposing margin or collateral requirements on both cleared and, in certain cases, uncleared swaps, (5) provide the CFTC with expanded authority to establish position limits on certain physical commodity futures and options contracts and their economically equivalent swaps as it finds necessary and appropriate and (6) otherwise enhance the rulemaking and enforcement authority of the CFTC and the SEC regarding the derivatives markets. Most of the regulations are already in effect, while other rules and regulations, including the proposed margin rules, position limits, and commodity clearing requirements, remain to be finalized or effectuated. Therefore, the impact of those rules and regulations on our business continues to be uncertain.

A provision of the Dodd-Frank Act requires the CFTC, in order to diminish or prevent excessive speculation in commodity markets, to adopt rules, as it finds necessary and appropriate, imposing new position limits on certain physical commodity futures contracts and options thereon, as well as economically equivalent swaps traded on registered swap trading platforms and on over-the-counter swaps that perform a significant price discovery function with respect to certain markets. In that regard, the CFTC has re-proposed position limits rules that would modify and expand the applicability of limits on speculative positions in certain physical commodity futures contracts, and economically equivalent futures, options and swaps for or linked to certain physical commodities, including Henry Hub natural gas, that market participants may hold, subject to limited exemptions for certain bona fide hedging and other types of transactions. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits rules may become final and effective.

Pursuant to rules adopted by the CFTC, certain interest rate swaps and index credit default swaps must be cleared through a derivatives clearing organization and executed on an exchange or swap execution facility. The CFTC has not yet proposed to designate swaps in any other asset classes, including swaps relating to physical commodities, for mandatory clearing and trade execution, but could do so in the future. Although we expect to qualify for the end-user exception from the mandatory clearing and exchange-trading requirements applicable to any swaps that we enter into to hedge our commercial risks, the mandatory clearing and exchange-trading requirements may apply to other market participants, including our counterparties (who may be registered as Swap Dealers), with respect to other swaps, and the application of such rules may change the market cost and general availability in the market of swaps of the type we enter into to hedge our commercial risks and, thus, the cost and availability of the swaps that we use for hedging.

As required by provisions of the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require Swap Dealers and Major Swap Participants, including those that are regulated financial institutions, to collect initial and/or variation margin with respect to uncleared swaps from their counterparties that are financial end users, registered swap dealers or major swap participants. These rules, which, as to the collection of initial margin, are being phased in, do not require collection of margin from non-financial-entity end users who qualify for the end user exception from the mandatory clearing requirement or from non-financial end users or certain other counterparties in certain instances. We expect to qualify as such a non-financial-entity end user with respect to the swaps that we enter into to hedge our commercial risks.

Any new rules or changes to existing rules promulgated under the Dodd-Frank Act could (1) impair the availability of derivatives, (2) materially increase the cost of, or decrease the liquidity of, the derivatives we use to hedge, (3) significantly alter the terms and conditions of derivatives and (4) potentially increase our exposure to less creditworthy counterparties. Further, any resulting reduction in the use of derivatives could make cash flow more volatile and less predictable, which in turn could adversely affect our ability to plan for and fund capital expenditures.

Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-manipulation and anti-disruptive trading practices regulations that prohibit, among other things, manipulative, deceptive or fraudulent schemes or material misrepresentation in the futures, options, swaps and cash markets. In addition, separate from the Dodd-Frank Act, our use of futures and options on commodities is subject to the Commodity Exchange Act and CFTC regulations, as well as the rules of futures exchanges on which any of these instruments are executed. Should we violate any of these laws and regulations, we could be subject to a CFTC or an exchange enforcement action and material penalties, possibly resulting in changes in the rates we can charge.

Environmental Regulation

The Sabine Pass LNG terminal is subject to various federal, state and local laws and regulations relating to the protection of the environment and natural resources. These environmental laws and regulations require significant expenditures for compliance, can affect the cost and output of operations and may impose substantial penalties for non-compliance and substantial liabilities for pollution. Many of these laws and regulations, such as those noted below, restrict or prohibit impacts to the environment or the types, quantities and concentration of substances that can be released into the environment and can lead to substantial administrative, civil and criminal fines and penalties for non-compliance.

Clean Air Act ("CAA")

The Sabine Pass LNG terminal is subject to the federal CAA and comparable state and local laws. We may be required to incur certain capital expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining permits and approvals addressing air emission-related issues. We do not believe, however, that our operations, or the construction and operations of our liquefaction facilities, will be materially and adversely affected by any such requirements.

In 2009, the EPA promulgated and finalized the Mandatory Greenhouse Gas Reporting Rule for multiple sections of the economy. This rule requires mandatory reporting of greenhouse gas ("GHG") emissions from stationary sources, including fuel combustion sources. In 2010, the EPA expanded the rule to include reporting obligations for LNG terminals. In addition, the EPA has defined GHG emissions thresholds that would subject GHG emissions from new and modified industrial sources to regulation if the source is subject to PSD Permit requirements due to its emissions of non-GHG criteria pollutants. The Obama Administration took several actions intended to limit GHG emissions, including regulating emissions from new and existing Electricity Generating Units and from new and modified oil and gas operations. The timing, extent and impact of these rules and other Obama Administration initiatives remain uncertain as the Trump Administration has undertaken steps to delay their implementation, and to review, repeal and potentially replace them. On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan after concluding the October 2015 final rule exceeds EPA's statutory authority under the CAA. In August 2018, the EPA proposed the Affordable Clean Energy rule as a replacement for the Clean Power Plan, which requires states to develop plans to implement certain performance standards within three years after the Final Rule is published in the Federal Register. Many of the Trump Administration's efforts to rollback Obama Administration actions have been challenged in court.

From time to time, Congress has considered proposed legislation directed at reducing GHG emissions. In addition, many states have already taken regulatory action to monitor and/or reduce emissions of GHGs, primarily through the development of GHG emission inventories or regional GHG cap and trade programs. It is not possible at this time to predict how future regulations or legislation may address GHG emissions and impact our business. However, future regulations and laws could result in increased compliance costs or additional operating restrictions and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Coastal Zone Management Act ("CZMA")

The siting and construction of the Sabine Pass LNG terminal within the coastal zone is subject to the requirements of the CZMA. The CZMA is administered by the states (in Louisiana, by the Department of Natural Resources). This program is implemented to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas.

Clean Water Act ("CWA")

The Sabine Pass LNG terminal is subject to the federal CWA and analogous state and local laws. The CWA imposes strict controls on the discharge of pollutants into the navigable waters of the United States, including discharges of wastewater and storm water runoff and fill/discharges into waters of the United States. Permits must be obtained prior to discharging pollutants into state and federal waters. The CWA is administered by the EPA, the USACE and by the states (in Louisiana, by the LDEQ).

Resource Conservation and Recovery Act ("RCRA")

The federal RCRA and comparable state statutes govern the generation, handling and disposal of solid and hazardous wastes and require corrective action for releases into the environment. In the event such wastes are generated in connection with our facilities, we will be subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes.

Protection of Species, Habitats and Wetlands

Various federal and state statutes, such as the Endangered Species Act (the "ESA"), the Migratory Bird Treaty Act, the CWA and the Oil Pollution Act, prohibit certain activities that may adversely affect endangered or threatened animal, fish and plant species and/or their designated habitats, wetlands, or other natural resources. If the Sabine Pass LNG terminal or the Creole Trail Pipeline adversely affect a protected species or its habitat, we may be required to develop and follow a plan to avoid those impacts. In that case, siting, construction or operation may be delayed or restricted and cause us to incur increased costs.

In July 2018, the U.S. Fish and Wildlife Service (the "FWS") announced a series of proposed changes to the rules implementing the ESA, including proposed revisions to the regulations governing interagency cooperation, listing species and delisting critical habitat, and prohibitions related to threatened wildlife and plants. The proposed revisions are intended to streamline these processes and create more flexibility for the FWS when making ESA-related decisions. It is not possible at this time to predict how such changes, if adopted, would impact our business.

In addition, in December 2017, the Department of Interior's ("DOI's") Solicitor's Office issued an official opinion that the Migratory Bird Treaty Act's broad prohibition on "taking" migratory birds applies only to affirmative actions and does not include incidental taking. In April 2018 the FWS issued guidance consistent with the DOI's opinion. The opinion has been challenged in court.

Market Factors and Competition

SPL has entered into fixed price SPAs with terms of at least 20 years (plus extension rights) with six third parties for Trains 1 through 5 of the Liquefaction Project, to make available an aggregate amount of LNG that is between approximately 80% to 95% of the expected aggregate adjusted nominal production capacity from these Trains. Each customer will be required to pay an escalating fixed fee for its annual contract quantity even if it elects not to purchase any LNG from us.

If and when SPL needs to replace any existing SPA or enter into new SPAs, SPL will compete on the basis of price per contracted volume of LNG with other natural gas liquefaction projects throughout the world. Cheniere is currently developing a natural gas liquefaction facility near Corpus Christi, Texas and Corpus Christi Liquefaction, LLC ("CCL") has entered into fixed price SPAs generally with terms of 20 years (plus extension rights) for the sale of LNG from this natural gas liquefaction facility, and may continue to enter into commercial agreements with respect to this natural gas liquefaction facility that might otherwise have been entered into with respect to Train 6. Revenues associated with any incremental volumes of the Liquefaction Project, including those under the Cheniere Marketing SPA discussed above, will also be subject to market-based price competition. Many of the companies with which we compete are major energy corporations with longer operating histories, more development experience, greater name recognition, greater financial, technical and marketing resources and greater access to markets than us.

SPLNG currently does not experience competition for its terminal capacity because the entire approximately 4.0 Bcf/d of regasification capacity that is available at the Sabine Pass LNG terminal has been fully contracted. If and when SPLNG has to replace any TUAs, it will compete with other then-existing LNG terminals for customers.

Our ability to enter into additional long-term SPAs to underpin the development of additional Trains, sell any quantities of LNG available under the SPAs with Cheniere Marketing, or develop new projects is subject to market factors. These factors include changes in worldwide supply and demand for natural gas, LNG and substitute products, the relative prices for natural gas, crude oil and substitute products in North America and international markets, the rate of fuel switching for power generation from coal, nuclear or oil to natural gas and economic growth in developing countries. In addition, Cheniere's ability to obtain additional funding to execute its business strategy is subject to the investment community's appetite for investment in LNG and natural gas infrastructure and Cheniere's ability to access capital markets.

We expect that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to oil and coal. Global demand for natural gas is projected by the International Energy Agency to grow by approximately 19 trillion cubic feet ("Tcf") between 2017 and 2025, with LNG's share growing from about 10% in 2017 to about 15% of the global gas market in 2025. Wood Mackenzie Limited forecasts that global demand for LNG will increase by approximately 60%, from approximately 287 mtpa, or 13.8 Tcf in 2017, to approximately 461 mtpa, or 22.1 Tcf, in 2025, and that LNG production from existing operational facilities and new facilities already under construction will be able to supply the market with approximately 413 mtpa in 2025, resulting in a market need for construction of an additional approximately 48 mtpa of LNG production. We believe the capital and operating costs of the uncommitted capacity of our Liquefaction Project is competitive with new proposed projects globally and we are well-positioned to capture a portion of this incremental market need.

Our LNG terminal business has limited exposure to the decline in oil prices as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements. These agreements contain fixed fees that are required to be paid even if the customers elect to cancel or suspend delivery of LNG cargoes. We have contracted an aggregate amount of LNG that is between approximately 80% to 95% of the expected aggregate adjusted nominal production capacity for Trains 1 through 5 of the Liquefaction Project with third-party customers. As of January 31, 2019, U.S. natural gas prices indicate that LNG exported from the U.S. continues to be competitively priced, supporting the opportunity for U.S. LNG to fill uncontracted future demand through the execution of long-term, medium-term and short-term contracting of LNG from our terminal.

Subsidiaries

Our assets are generally held by or under our subsidiaries. We conduct most of our business through these subsidiaries, including the development, construction and operation of our LNG terminal business.

Employees

We have no employees. We rely on our general partner to manage all aspects of the development, construction, operation and maintenance of the Sabine Pass LNG terminal and the Liquefaction Project and to conduct our business. Because our general partner has no employees, it relies on subsidiaries of Cheniere to provide the personnel necessary to allow it to meet its management obligations to us, SPLNG, SPL and CTPL. As of January 31, 2019, Cheniere and its subsidiaries had 1,372 full-time employees, including 483 employees who directly supported the Sabine Pass LNG terminal operations. See Note 13—Related Party Transactions of our Notes to Consolidated Financial Statements for a discussion of the services agreements pursuant to which general and administrative services are provided to us, SPLNG, SPL and CTPL.

Available Information

Our common units have been publicly traded since March 21, 2007 and are traded on the NYSE American under the symbol “CQP.” Our principal executive offices are located at 700 Milam Street, Suite 1900, Houston, Texas 77002, and our telephone number is (713) 375-5000. Our internet address is www.cheniere.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes and is not incorporated by reference into this Form 10-K.

We will also make available to any unitholder, without charge, copies of our annual report on Form 10-K as filed with the SEC. For copies of this, or any other filing, please contact: Cheniere Energy Partners, L.P, Investor Relations Department, 700 Milam Street, Suite 1900, Houston, Texas 77002 or call (713) 375-5000. The SEC maintains an internet site (www.sec.gov) that contains reports and other information regarding issuers.

ITEM 1A.RISK FACTORS

Limited partner interests are inherently different from the 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 a similar business. The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates or expectations contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.
The risk factors in this report are grouped into the following categories:
- Risks Relating to Our Financial Matters;
- Risks Relating to Our Business;
- Risks Relating to Our Cash Distributions;
- Risks Relating to an Investment in Us and Our Common Units; and
- Risks Relating to Tax Matters.

Risks Relating to Our Financial Matters

Our existing level of cash resources and significant debt could cause us to have inadequate liquidity and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

As of December 31, 2018, we had zero cash and cash equivalents, $1.5 billion of current restricted cash and $16.3 billion of total debt outstanding on a consolidated basis (before unamortized premium, discount and debt issuance costs), excluding $425 million aggregate outstanding letters of credit. We incur, and will incur, significant interest expense relating to the assets at the Sabine Pass LNG terminal and we anticipate needing to incur additional debt to finance the construction of Train 6 of the Liquefaction Project. Our ability to fund our capital expenditures and refinance our indebtedness will depend on our ability to access additional project financing as well as the debt and equity capital markets. A variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations and the repricing of market risks and volatility in capital and financial markets. Our financing costs could increase or future borrowings or equity offerings may be unavailable to us or unsuccessful, which could cause us to be unable to pay or refinance our indebtedness or to fund our other liquidity needs.

We have not been profitable historically. We may not achieve profitability or generate positive operating cash flow in the future.

We had a net loss of $171 million for the year ended December 31, 2016 and net losses in prior years. In the future, we may incur operating losses and experience negative operating cash flow. We may not be able to reduce costs, increase revenues, or reduce our debt service obligations sufficiently to maintain our cash resources, which could cause us to have inadequate liquidity to continue our business.

We will continue to incur significant capital and operating expenditures while we develop and construct the Liquefaction Project. Any delays beyond the expected development period for our Trains could cause, and could increase the level of, our operating losses and negative operating cash flows. Our future liquidity may also be affected by the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and by the timing of receipt of cash flows under SPAs in relation to the incurrence of project and operating expenses. Moreover, many factors (including factors beyond our control) could result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements. Our ability to generate any significant positive operating cash flow and achieve profitability in the future is dependent on our ability to successfully and timely complete and operate the applicable Train.

We may sell equity or equity-related securities, including additional common units. Such sales could dilute our unitholders’ proportionate indirect interests in our assets, business operations, Liquefaction Project and other projects, and could adversely affect the market price of our common units.

We have pursued and are pursuing a number of alternatives in order to finance the construction of Train 6, including potential issuances and sales of additional equity or equity-related securities. Such sales, in one or more transactions, could dilute our unitholders’ proportionate indirect interests in our assets, business operations and proposed projects, including the Liquefaction Project. In addition, such sales, or the anticipation of such sales, could adversely affect the market price of our common units.

Our ability to generate cash is substantially dependent upon the performance by customers under long-term contracts that we have entered into, and we could be materially and adversely affected if any customer fails to perform its contractual obligations for any reason.

Our future results and liquidity are substantially dependent upon performance by our customers to make the payments under long-term contracts. As of December 31, 2018, SPL had SPAs with seven third-party customers and SPLNG had TUAs with two third-party customers. We are dependent on each customer’s continued willingness and ability to perform its obligations under the SPA or TUA. We are exposed to the credit risk of any guarantor of these customers’ obligations under their respective agreements in the event that we must seek recourse under a guaranty. If any customer fails to perform its obligations under the SPA or TUA, our business, contracts, financial condition, operating results, cash flow, liquidity and prospects could be materially and adversely affected, even if we were ultimately successful in seeking damages from that customer or its guarantor for a breach of the agreement.

Each of our customer contracts is subject to termination under certain circumstances.

Each of SPL’s SPAs contains various termination rights allowing our customers to terminate their SPAs, including, without limitation: (1) upon the occurrence of certain events of force majeure; (2) if we fail to make available specified scheduled cargo quantities; and (3) delays in the commencement of commercial operations. We may not be able to replace these SPAs on desirable terms, or at all, if they are terminated.

Each of SPLNG’s long-term TUAs contains various termination rights. For example, each customer may terminate its TUA if the Sabine Pass LNG terminal experiences a force majeure delay for longer than 18 months, fails to redeliver a specified amount of natural gas in accordance with the customer’s redelivery nominations or fails to accept and unload a specified number of the customer’s proposed LNG cargoes. SPLNG may not be able to replace these TUAs on desirable terms, or at all, if they are terminated.

Our use of hedging arrangements may adversely affect our future operating results or liquidity.

To reduce our exposure to fluctuations in the price, volume and timing risk associated with the purchase of natural gas, we use futures, swaps and option contracts traded or cleared on the Intercontinental Exchange and the New York Mercantile Exchange or over-the-counter options and swaps with other natural gas merchants and financial institutions. Hedging arrangements could expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices change.

The swaps regulatory and other provisions of the Dodd-Frank Act and the rules adopted thereunder and other regulations could adversely affect our ability to hedge risks associated with our business and our operating results and cash flows.

The provisions of the Dodd-Frank Act and the rules adopted and to be adopted by the CFTC, the SEC and other federal regulators establishing federal regulation of the over-the-counter ("OTC") derivatives market and entities like us that participate in that market may adversely affect our ability to manage certain of our risks on a cost effective basis. Such laws and regulations may also adversely affect our ability to execute our strategies with respect to hedging our exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory and to price risk attributable to future purchases of natural gas to be utilized as fuel to operate our LNG terminals and to secure natural gas feedstock for our Liquefaction Project.

The CFTC has re-proposed position limits rules that would modify and expand the applicability of position limits on the amounts of certain speculative futures contracts, as well as economically equivalent options, futures and swaps for or linked to certain physical commodities, including Henry Hub natural gas, that market participants may hold, subject to limited exemptions for certain bona fide hedging positions and other types of transactions. To the extent the revised CFTC position limits proposal becomes final, our ability to execute our hedging strategies described above could be limited. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits rules may become final and effective.

Under the Dodd-Frank Act and the rules adopted thereunder, we may be required to clear through a derivatives clearing organization any swaps into which we enter that fall within a class of swaps designated by the CFTC for mandatory clearing and we could have to execute trades in such swaps on certain trading platforms or exchanges. The CFTC has designated certain interest rate swaps and index credit default swaps for mandatory clearing, but has not yet finalized rules designating any physical commodity swaps, for mandatory clearing or mandatory exchange trading. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered into to hedge our commercial risks, if we fail to qualify for that exception as to any swap we enter into and have to clear that swap through a derivatives clearing organization, we could be required to post margin with respect to such swap, our cost of entering into and maintaining such swap could increase and we would not enjoy the same flexibility with the cleared swaps that we enjoy with the uncleared OTC swaps we enter into. Moreover, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the market cost and general availability in the market of swaps of the type we enter into to hedge our commercial risks and, thus, the cost and availability of the swaps that we use for hedging.

As required by the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require certain market participants to collect and post initial and/or variation margin with respect to uncleared swaps from their counterparties that are financial end users and certain registered swap dealers and major swap participants. Although we believe we will not be required to post margin with respect to any uncleared swaps we enter into in the future, were we required to post margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would be increased. Our counterparties that are subject to the regulations imposing the Basel III capital requirements on them may increase the cost to us of entering into swaps with them or, although not required to collect margin from us under the margin rules, contractually require us to post collateral with them in connection with such swaps in order to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets.

The Dodd-Frank Act also imposes other regulatory requirements on swaps market participants, including end users of swaps, such as regulations relating to swap documentation, reporting and recordkeeping, and certain business conduct rules applicable to swap dealers and major swap participants. Together with the Basel III capital requirements on certain swaps market participants, the regulatory requirements of the Dodd-Frank Act and the rules thereunder relating to swaps and derivatives market participants could significantly increase the cost of derivative contracts (including through requirements to post margin or collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against certain risks that we encounter and reduce our ability to monetize or restructure our existing derivative contracts and to execute our hedging strategies. If, as a result of the swaps regulatory regime discussed above, we were to reduce our use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our operating results and cash flows may become more volatile and could be otherwise adversely affected.

We expect that our hedging activities will remain subject to significant and developing regulations and regulatory oversight. However, the full impact of the various U.S. (and non-U.S.) regulatory developments in connection with these activities will not be known with certainty until such derivatives market regulations are fully implemented and related market practices and structures are fully developed.

Risks Relating to Our Business

Operation of the Sabine Pass LNG terminal, the Liquefaction Project, the Creole Trail Pipeline and other facilities that we may construct involves significant risks.

As more fully discussed in these Risk Factors, the Sabine Pass LNG terminal, the Liquefaction Project, the Creole Trail Pipeline and our other existing and proposed LNG facilities face operational risks, including the following:
- the facilities' performing below expected levels of efficiency;
- breakdown or failures of equipment;
- operational errors by vessel or tug operators;
- operational errors by us or any contracted facility operator;
- labor disputes; and
- weather-related interruptions of operations.

Cost overruns and delays in the completion of one or more Trains, as well as difficulties in obtaining sufficient financing to pay for such costs and delays, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The actual construction costs of the Trains may be significantly higher than our current estimates as a result of many factors, including change orders under existing or future EPC contracts resulting from the occurrence of certain specified events that may give Bechtel the right to cause us to enter into change orders or resulting from changes with which we otherwise agree. We have already experienced increased costs due to change orders. As construction progresses, we may decide or be forced to submit change orders to our contractor that could result in longer construction periods, higher construction costs or both, including change orders to comply with existing or future environmental or other regulations.

Delays in the construction of one or more Trains beyond the estimated development periods, as well as change orders to the EPC contracts with Bechtel or any future EPC contract related to additional Trains, could increase the cost of completion beyond the amounts that we estimate, which could require us to obtain additional sources of financing to fund our operations until the Liquefaction Project is fully constructed (which could cause further delays). Our ability to obtain financing that may be needed to provide additional funding to cover increased costs will depend, in part, on factors beyond our control. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, or at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Delays in the completion of one or more Trains could lead to reduced revenues or termination of one or more of the SPAs by our customers.

Any delay in completion of a Train could cause a delay in the receipt of revenues projected therefrom or cause a loss of one or more customers in the event of significant delays. In particular, each of our SPAs provides that the customer may terminate that SPA if the relevant Train does not timely commence commercial operations. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our ability to complete development of Train 6 will be contingent on our ability to obtain additional funding. If we are unable to obtain sufficient funding, we may be unable to fully execute our business strategy.

We will require significant additional funding to be able to commence construction of Train 6, which we may not be able to obtain at a cost that results in positive economics, or at all. The inability to achieve acceptable funding may cause a delay in the development of Train 6, and we may not be able to complete our business plan. Even if we are able to obtain funding, the funding may be inadequate to cover any increases in costs or delays in completion of Train

6, which may cause a delay in the receipt of revenues projected therefrom or cause a loss of one or more future customers in the event of significant delays. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Hurricanes or other disasters could result in an interruption of our operations, a delay in the completion of the Liquefaction Project, higher construction costs and the deferral of the dates on which payments are due to SPL under the SPAs, all of which could adversely affect us.

In August and September of 2005, Hurricanes Katrina and Rita, respectively, damaged coastal and inland areas located in Texas, Louisiana, Mississippi and Alabama, resulting in the temporary suspension of construction of the Sabine Pass LNG terminal. In September 2008, Hurricane Ike struck the Texas and Louisiana coasts, and the Sabine Pass LNG terminal experienced minor damage. In August 2017, Hurricane Harvey struck the Texas and Louisiana coasts, and the Sabine Pass LNG terminal experienced a temporary suspension in construction and LNG loading operations.

Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, or interruption of operations at, the Sabine Pass LNG terminal or related infrastructure, as well as delays or cost increases in the construction and the development of the Liquefaction Project and related infrastructure. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods and rising sea levels; if any such effects were to occur, they could have an adverse effect on our coastal operations.

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the design, construction and operation of our facilities and our pipeline could impede operations and construction and could have a material adverse effect on us.

The design, construction and operation of interstate natural gas pipelines, LNG terminals, including the Liquefaction Project, and other facilities, and the import and export of LNG and the transportation of natural gas, are highly regulated activities. Approvals of the FERC and DOE under Section 3 and Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, including several under the CAA and the CWA, are required in order to construct and operate an LNG facility and an interstate natural gas pipeline and export LNG. Although the FERC has issued orders under Section 3 of the NGA authorizing the siting, construction and operation of six Trains and related facilities and Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline, the FERC orders require us to comply with certain ongoing conditions and obtain certain additional approvals in conjunction with ongoing construction and operations of the Liquefaction Project and the operations of the Creole Trail Pipeline. We will be required to obtain similar approvals and permits with respect to any expansion or modification of our liquefaction and pipeline facilities. We cannot control the outcome of the FERC’s or the DOE’s review and approval processes. Certain of these governmental permits, approvals and authorizations are or may be subject to rehearing requests, appeals and other challenges.

Authorizations obtained from the FERC, DOE and other federal and state regulatory agencies also contain ongoing conditions, and additional approval and permit requirements may be imposed. We do not know whether or when any such approvals or permits can be obtained, or whether any existing or potential interventions or other actions by third parties will interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, including as a result of untimely notices or filings, we may not be able to recover our investment in our projects. Additionally, government disruptions, such as a U.S. government shutdown, may delay or halt our ability to obtain and maintain necessary approvals and permits. There is no assurance that we will obtain and maintain these governmental permits, approvals and authorizations, or that we will be able to obtain them on a timely basis, and failure to obtain and maintain any of these permits, approvals or authorizations could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We are entirely dependent on Cheniere, including employees of Cheniere and its subsidiaries, for key personnel, and the unavailability of skilled workers or failure to attract and retain qualified personnel could adversely affect us. In addition, changes in our general partner’s senior management or other key personnel could affect our business results.

As of January 31, 2019, Cheniere and its subsidiaries had 1,372 full-time employees, including 483 employees who directly supported the Sabine Pass LNG terminal operations. We have contracted with subsidiaries of Cheniere to provide the personnel necessary for the operation, maintenance and management of the Sabine Pass LNG terminal, the Creole Trail Pipeline and construction of the Liquefaction Project. We depend on Cheniere’s subsidiaries hiring and retaining personnel sufficient to provide support for the Sabine Pass LNG terminal. Cheniere competes with other liquefaction projects in the United States and globally, other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct and operate liquefaction facilities and pipelines and to provide our customers with the highest quality service. We also compete with any other project Cheniere is developing, including its liquefaction project at Corpus Christi, Texas, for the time and expertise of Cheniere's personnel. Further, we and Cheniere face competition for these highly skilled employees in the immediate vicinity of the Sabine Pass LNG terminal and more generally from the Gulf Coast hydrocarbon processing and construction industries.

The executive officers of our general partner are officers and employees of Cheniere and its affiliates. We do not maintain key person life insurance policies on any personnel, and our general partner does not have any employment contracts or other agreements with key personnel binding them to provide services for any particular term. The loss of the services of any of these individuals could have a material adverse effect on our business. In addition, our future success will depend in part on our general partner's ability to engage, and Cheniere's ability to attract and retain additional qualified personnel.

A shortage in the labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult to attract and retain qualified personnel and could require an increase in the wage and benefits packages that are offered, thereby increasing our operating costs. Any increase in our operating costs could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We have numerous contractual and commercial relationships, and conflicts of interest, with Cheniere and its affiliates, including Cheniere Marketing.

We have agreements to compensate and to reimburse expenses of affiliates of Cheniere. In addition, Cheniere Investments has entered into an amended and restated variable capacity rights agreement (the "Amended and Restated VCRA") with Cheniere Marketing, under which Cheniere Marketing will be able to derive economic benefits to the extent it assists Cheniere Investments in commercializing Cheniere Investments' access to capacity at the Sabine Pass LNG terminal through its agreement with SPL, which has a TUA with SPLNG. In addition, Cheniere Marketing has entered into an SPA to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers. All of these agreements involve conflicts of interest between us, on the one hand, and Cheniere and its other affiliates, on the other hand. In addition, Cheniere is currently developing and constructing a natural gas liquefaction facility near Corpus Christi, Texas and CCL has entered into fixed price SPAs with third parties for the sale of LNG from this natural gas liquefaction facility, and may continue to enter into commercial arrangements with respect to this liquefaction facility that might otherwise have been entered into with respect to Train 6.

We expect that there will be additional agreements or arrangements with Cheniere and its affiliates, including future transportation, interconnection and gas balancing agreements with one or more Cheniere-affiliated natural gas pipelines as well as other agreements and arrangements that cannot now be anticipated. In those circumstances where additional contracts with Cheniere and its affiliates may be necessary or desirable, additional conflicts of interest will be involved.

We are dependent on Cheniere and its affiliates to provide services to us. If Cheniere or its affiliates are unable or unwilling to perform according to the negotiated terms and timetable of their respective agreement for any reason or terminate their agreement, we would be required to engage a substitute service provider. This could result in a significant interference with operations and increased costs.

We are dependent on Bechtel and other contractors for the successful completion of the Liquefaction Project.

Timely and cost-effective completion of the Liquefaction Project in compliance with agreed specifications is central to our business strategy and is highly dependent on the performance of Bechtel and our other contractors under their agreements. The ability of Bechtel and our other contractors to perform successfully under their agreements is dependent on a number of factors, including their ability to:

- design and engineer each Train to operate in accordance with specifications;

- engage and retain third-party subcontractors and procure equipment and supplies;
- respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control;
- attract, develop and retain skilled personnel, including engineers;
- post required construction bonds and comply with the terms thereof;
- manage the construction process generally, including coordinating with other contractors and regulatory agencies; and
- maintain their own financial condition, including adequate working capital.

Although some agreements may provide for liquidated damages if the contractor fails to perform in the manner required with respect to certain of its obligations, the events that trigger a requirement to pay liquidated damages may delay or impair the operation of the Liquefaction Project, and any liquidated damages that we receive may not be sufficient to cover the damages that we suffer as a result of any such delay or impairment. The obligations of Bechtel and our other contractors to pay liquidated damages under their agreements are subject to caps on liability, as set forth therein.

Furthermore, we may have disagreements with our contractors about different elements of the construction process, which could lead to the assertion of rights and remedies under their contracts and increase the cost of the Liquefaction Project or result in a contractor's unwillingness to perform further work on the Liquefaction Project. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor. This would likely result in significant project delays and increased costs, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We are relying on third-party engineers to estimate the future capacity ratings and performance capabilities of the Liquefaction Project, and these estimates may prove to be inaccurate.

We are relying on third parties, principally Bechtel, for the design and engineering services underlying our estimates of the future capacity ratings and performance capabilities of the Liquefaction Project. If any Train, when actually constructed, fails to have the capacity ratings and performance capabilities that we intend, our estimates may not be accurate. Failure of any of our Trains to achieve our intended capacity ratings and performance capabilities could prevent us from achieving the commercial start dates under our SPAs and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

If third-party pipelines and other facilities interconnected to our pipelines and facilities are or become unavailable to transport natural gas, this could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We depend upon third-party pipelines and other facilities that provide gas delivery options to the Liquefaction Project and to and from the Creole Trail Pipeline. If the construction of new or modified pipeline connections is not completed on schedule or any pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to meet our SPA obligations and continue shipping natural gas from producing regions or to end markets could be restricted, thereby reducing our revenues, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We may not be able to purchase or receive physical delivery of sufficient natural gas to satisfy our delivery obligations under the SPAs, which could have a material adverse effect on us.

Under the SPAs with our customers, we are required to make available to them a specified amount of LNG at specified times. However, we may not be able to purchase or receive physical delivery of sufficient quantities of natural gas to satisfy those obligations, which may provide affected SPA customers with the right to terminate their SPAs. Our failure to purchase or receive physical delivery of sufficient quantities of natural gas could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We are subject to significant operating hazards and uninsured risks, one or more of which may create significant liabilities and losses for us.

The construction and operation of the Sabine Pass LNG terminal and the Creole Trail Pipeline are, and will be, subject to the inherent risks associated with these types of operations, including explosions, pollution, release of toxic substances, fires, hurricanes and adverse weather conditions, and other hazards, each of which could result in significant delays in commencement or interruptions of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations and the facilities and vessels of third parties on which our operations are dependent face possible risks associated with acts of aggression or terrorism.

We do not, nor do we intend to, maintain insurance against all of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect our LNG business and the performance of our customers and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

Our LNG business and the development of domestic LNG facilities and projects generally is based on assumptions about the future availability and price of natural gas and LNG, and the prospects for international natural gas and LNG markets. Natural gas and LNG prices have been, and are likely to continue to be, volatile and subject to wide fluctuations in response to one or more of the following factors:

- additions to competitive regasification capacity in North America, Europe, Asia and other markets, which could divert LNG from the Sabine Pass LNG terminal;
- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient LNG tanker capacity;
- weather conditions;
- reduced demand and lower prices for natural gas;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- decreased oil and natural gas exploration activities, which may decrease the production of natural gas;
- cost improvements that allow competitors to offer LNG regasification services or provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;
- political conditions in natural gas producing regions;
- adverse relative demand for LNG compared to other markets, which may decrease LNG imports into or exports from North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

Adverse trends or developments affecting any of these factors could result in decreases in the price of LNG and/or natural gas, which could materially and adversely affect the performance of our customers, and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects.

Failure of imported or exported LNG to be a competitive source of energy for international markets could adversely affect our customers and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Operations of the Liquefaction Project will be dependent upon the ability of our SPA customers to deliver LNG supplies from the United States, which is primarily dependent upon LNG being a competitive source of energy internationally. The success of our business plan is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be supplied from North America and delivered to international markets at a lower cost than the cost of alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside the United States, which could increase the available supply of natural gas outside the United States and could result in natural gas in those markets being available at a lower cost than LNG exported to those markets.

Although SPL has entered into arrangements to utilize up to approximately three-quarters of the regasification capacity at the Sabine Pass LNG terminal in connection with operations of the SPL Project, operations at the Sabine Pass LNG terminal are

dependent, in part, upon the ability of our TUA customers to import LNG supplies into the United States, which is primarily dependent upon LNG being a competitive source of energy in North America. In North America, due mainly to a historically abundant supply of natural gas and discoveries of substantial quantities of unconventional, or shale, natural gas, imported LNG has not developed into a significant energy source. The success of the regasification services component of our business plan is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be produced internationally and delivered to North America at a lower cost than the cost to produce some domestic supplies of natural gas, or other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas have recently been and may continue to be discovered in North America, which could further increase the available supply of natural gas and could result in natural gas being available at a lower cost than imported LNG.

Political instability in foreign countries that import or export natural gas, or strained relations between such countries and the United States, may also impede the willingness or ability of LNG purchasers or suppliers and merchants in such countries to import or export LNG from or to the United States. Furthermore, some foreign purchasers or suppliers of LNG may have economic or other reasons to obtain their LNG from, or direct their LNG to, non-U.S. markets or from or to our competitors' liquefaction or regasification facilities in the United States.

In addition to natural gas, LNG also competes with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy. LNG from the Liquefaction Project also competes with other sources of LNG, including LNG that is priced to indices other than Henry Hub. Some of these sources of energy may be available at a lower cost than LNG from the Liquefaction Project in certain markets. The cost of LNG supplies from the United States, including the Liquefaction Project, may also be impacted by an increase in natural gas prices in the United States.

As a result of these and other factors, LNG may not be a competitive source of energy in the United States or internationally. The failure of LNG to be a competitive supply alternative to local natural gas, oil and other alternative energy sources in markets accessible to our customers could adversely affect the ability of our customers to deliver LNG from the United States or to the United States on a commercial basis. Any significant impediment to the ability to deliver LNG to or from the United States generally, or to the Sabine Pass LNG terminal or from the Liquefaction Project specifically, could have a material adverse effect on our customers and on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Various economic and political factors could negatively affect the development, construction and operation of LNG facilities, including the Liquefaction Project, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Commercial development of an LNG facility takes a number of years, requires a substantial capital investment and may be delayed by factors such as:

- increased construction costs;
- economic downturns, increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of LNG, which might decrease the expected returns relating to investments in LNG projects;
- the inability of project owners or operators to obtain governmental approvals to construct or operate LNG facilities;
- political unrest or local community resistance to the siting of LNG facilities due to safety, environmental or security concerns; and
- any significant explosion, spill or similar incident involving an LNG facility or LNG vessel.

There may be shortages of LNG vessels worldwide, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The construction and delivery of LNG vessels require significant capital and long construction lead times, and the availability of the vessels could be delayed to the detriment of our business and our customers because of:

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;
- changes in governmental regulations or maritime self-regulatory organizations;

- work stoppages or other labor disturbances at the shipyards;
- bankruptcy or other financial crisis of shipbuilders;
- quality or engineering problems;
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and
- shortages of or delays in the receipt of necessary construction materials.

We may not be able to secure firm pipeline transportation capacity on economic terms that is sufficient to meet our feed gas transportation requirements, which could have a material adverse effect on us.

We have contracted for firm capacity for our natural gas feedstock transportation requirements for Trains 1 through 5 of the Liquefaction Project. We cannot control the regulatory and permitting approvals or third parties' construction times. If and when we need to replace one or more of our agreements with these interconnecting pipelines, we may not be able to do so on commercially reasonable terms or at all, which could impair our ability to fulfill our obligations under certain of our SPAs and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We face competition based upon the international market price for LNG.

The Liquefaction Project is subject to the risk of LNG price competition at times when we need to replace any existing SPA, whether due to natural expiration, default or otherwise, or enter into new SPAs with respect to Train 6. Factors relating to competition may prevent us from entering into a new or replacement SPA on economically comparable terms as existing SPAs, or at all. Such an event could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Factors which may negatively affect potential demand for LNG from the Liquefaction Project are diverse and include, among others:

- increases in worldwide LNG production capacity and availability of LNG for market supply;
- increases in demand for LNG but at levels below those required to maintain current price equilibrium with respect to supply;
- increases in the cost to supply natural gas feedstock to the Liquefaction Project;
- decreases in the cost of competing sources of natural gas or alternate fuels such as coal, heavy fuel oil and diesel;
- decreases in the price of non-U.S. LNG, including decreases in price as a result of contracts indexed to lower oil prices;
- increases in capacity and utilization of nuclear power and related facilities; and
- displacement of LNG by pipeline natural gas or alternate fuels in locations where access to these energy sources is not currently available.

Terrorist attacks, cyber incidents or military campaigns may adversely impact our business.

A terrorist attack, cyber incident or military incident involving an LNG facility, our infrastructure or an LNG vessel may result in delays in, or cancellation of, construction of new LNG facilities, including one or more of the Trains, which would increase our costs and decrease our cash flows. A terrorist incident or cyber incident may also result in temporary or permanent closure of existing LNG facilities, including the Sabine Pass LNG terminal or the Creole Trail Pipeline, which could increase our costs and decrease our cash flows, depending on the duration and timing of the closure. Our operations could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost to us. In addition, the threat of terrorism and the impact of military campaigns may lead to continued volatility in prices for natural gas that could adversely affect our business and our customers, including their ability to satisfy their obligations to us under our commercial agreements. Instability in the financial markets as a result of terrorism, cyber incidents or war could also materially adversely affect our ability to raise capital. The continuation of these developments may subject our construction and our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

24

Existing and future environmental and similar laws and governmental regulations could result in increased compliance costs or additional operating costs or construction costs and restrictions.

Our business is and will be subject to extensive federal, state and local laws, rules and regulations applicable to our construction and operation activities relating to, among other things, air quality, water quality, waste management, natural resources, and health and safety. Many of these laws and regulations, such as the CAA, the Oil Pollution Act, the CWA and the RCRA, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our facilities, and require us to maintain permits and provide governmental authorities with access to our facilities for inspection and reports related to our compliance. In addition, certain laws and regulations authorize regulators having jurisdiction over our LNG terminals and pipelines, including FERC and PHMSA, to issue compliance orders, which may restrict or limit operations or increase compliance or operating costs. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties or to capital expenditures that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Federal and state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. As the owner and operator of our facilities, we could be liable for the costs of cleaning up hazardous substances released into the environment at or from our facilities and for resulting damage to natural resources.

In October 2015, the EPA promulgated a final rule to implement the Obama Administration’s Clean Power Plan, which is designed to reduce GHG emissions from power plants in the United States. In February 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan after concluding the October 2015 final rule exceeds EPA’s statutory authority under the CAA. In August 2018, the EPA proposed the Affordable Clean Energy rule as a replacement for the Clean Power Plan, which requires states to develop plans to implement certain performance standards within three years after the Final Rule is published in the Federal Register. The Trump Administration announced in June 2017 that the United States would withdraw from the Paris Accord, an international agreement within the United Nations Framework Convention on Climate Change under which the Obama Administration committed the United States to reducing its economy-wide GHG emission by 26-28% below 2005 levels by 2025. Other federal and state initiatives may be considered in the future to address GHG emissions through, for example, United States treaty commitments, direct regulation, a carbon emissions tax, or cap-and-trade programs. Such initiatives could affect the demand for or cost of natural gas, which we consume at our terminals, or could increase compliance costs for our operations.

Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to or exported from the Sabine Pass LNG terminal could cause additional expenditures, restrictions and delays in our business and to our proposed construction, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating or construction costs and restrictions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The Creole Trail Pipeline and its FERC gas tariff are subject to FERC regulation.

The Creole Trail Pipeline is subject to regulation by the FERC under the NGA and the NGPA. The FERC regulates the transportation of natural gas in interstate commerce, including the construction and operation of pipelines, the rates, terms and conditions of service and abandonment of facilities. Under the NGA, the rates charged by CTPL must be just and reasonable, and CTPL is prohibited from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

In addition, as a natural gas market participant, should CTPL fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, CTPL could be subject to substantial penalties and fines. Under the EPAct, the FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1.3 million per day for each violation.

A major health and safety incident relating to our business could be costly in terms of potential liabilities and reputational damages.

Health and safety performance is critical to the success of all areas of our business. Any failure in health and safety performance may result in personal harm or injury, penalties for non-compliance with relevant regulatory requirements or litigation, and a failure that results in a significant health and safety incident is likely to be costly in terms of potential liabilities. Such a failure could generate public concern and have a corresponding impact on our reputation and our relationships with relevant regulatory agencies and local communities, which in turn could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Pipeline safety integrity programs and repairs may impose significant costs and liabilities on us.

The PHMSA requires pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and to take additional measures to protect pipeline segments located in "high consequence areas" where a leak or rupture could potentially do the most harm. As an operator, CTPL is required to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventative and mitigating actions.

CTPL is required to maintain pipeline integrity testing programs that are intended to assess pipeline integrity. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should CTPL fail to comply with the Federal Office of Pipeline Safety's rules and related regulations and orders, CTPL could be subject to significant penalties and fines.

Our business could be materially and adversely affected if we lose the right to situate the Creole Trail Pipeline on property owned by third parties.

We do not own the land on which the Creole Trail Pipeline is situated, and we are subject to the possibility of increased costs to retain necessary land use rights. If we were to lose these rights or be required to relocate the Creole Trail Pipeline, our business could be materially and adversely affected.

Our lack of diversification could have an adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Substantially all of our anticipated revenue in 2019 will be dependent upon one facility, the Sabine Pass LNG terminal located in southern Louisiana. Due to our lack of asset and geographic diversification, an adverse development at the Sabine Pass LNG terminal, including the related pipeline, or in the LNG industry, would have a significantly greater impact on our financial condition and operating results than if we maintained more diverse assets and operating areas.

If we do not make acquisitions or implement capital expansion projects on economically acceptable terms, our future growth and our ability to increase distributions to our unitholders will be limited.

Our ability to grow depends on our ability to make accretive acquisitions or implement accretive capital expansion projects, such as the Liquefaction Project. We may be unable to make accretive acquisitions or implement accretive capital expansion projects for any of the following reasons:

- if we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;

- if we are unable to identify attractive capital expansion projects or negotiate acceptable engineering procurement and construction arrangements for them;
- if we are unable to obtain necessary governmental approvals;

- if we are unable to obtain financing for the acquisitions or capital expansion projects on economically acceptable terms, or at all;
- if we are unable to secure adequate customer commitments to use the acquired or expansion facilities; or
- if we are outbid by competitors.

If we are unable to make accretive acquisitions or implement accretive capital expansion projects, then our future growth and ability to increase distributions to our unitholders will be limited.

We intend to pursue acquisitions of additional LNG terminals, natural gas pipelines and related assets in the future, either directly from Cheniere or from third parties. However, Cheniere is not obligated to offer us any of these assets other than, in certain circumstances under an investors rights agreement with Blackstone CQP Holdco, its liquefaction project at Corpus Christi, Texas. If Cheniere does offer us the opportunity to purchase assets, we may not be able to successfully negotiate a purchase and sale agreement and related agreements, we may not be able to obtain any required financing for such purchase and we may not be able to obtain any required governmental and third-party consents. The decision whether or not to accept such offer, and to negotiate the terms of such offer, will be made by the conflicts committee of our general partner, which may decline the opportunity to accept such offer for a variety of reasons, including a determination that the acquisition of the assets at the proposed purchase price would not result in an increase, or a sufficient increase, in our adjusted operating surplus per unit within an appropriate timeframe.

If we make acquisitions, such acquisitions could adversely affect our business and ability to make distributions to our unitholders.

If we make any acquisitions, they will involve potential risks, including:

- an inability to integrate successfully the businesses that we acquire with our existing business;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the cash generated, or to be generated, by the business acquired or the overall costs of equity or debt;
- the diversion of management’s and employees’ attention from other business concerns; and
- unforeseen difficulties encountered in operating new business segments or in new geographic areas.

If we consummate any future acquisitions, our capitalization and operating results may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of our future funds and other resources. In addition, if we issue additional units in connection with future growth, our existing unitholders’ interest in us will be diluted, and distributions to our unitholders may be reduced.

We may incur impairments to long-lived assets.

We test our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. Significant negative industry or economic trends, reduced estimates of future cash flows for our business or disruptions to our business could lead to an impairment charge of our long-lived assets. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on historical experience and to rely heavily on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. In addition, if our analysis results in an impairment to our long-lived assets, we may be required to record a charge to earnings in our Consolidated Financial Statements during a period in which such impairment is determined to exist, which may negatively impact our operating results.

Risks Relating to Our Cash Distributions

We may not be successful in our efforts to maintain or increase our cash available for distribution to cover the distributions on our common units.

Prior to the quarter ended September 30, 2017, we historically paid the initial quarterly distribution of $0.425 on each of our common units and the related distribution on our general partner units, and did not pay any distributions on our subordinated units. For the quarter ended September 30, 2017 and in each of the subsequent quarters, we have paid increasing distributions on each of our common and subordinated units and the related distribution on our general partner units. For the quarter ended December 31, 2017 and in each of the subsequent quarters, we also paid the related distribution to the holder of our incentive distribution rights (“IDRs”). During the year ended December 31, 2018, we paid aggregate distributions of $1.1 billion on our common units, subordinated units and related general partner units including IDRs.

The amount of cash that we can distribute on our common units principally will depend upon the amount of cash that we generate from our existing operations, which will be based on, among other things:

- performance by counterparties of their obligations under the SPAs;
- performance by SPL of its obligations under the SPAs;
- performance by counterparties of their obligations under the TUAs;
- performance by SPLNG of its obligations under the TUAs;
- performance by, and the level of cash receipts received from, Cheniere Marketing under the Amended and Restated VCRA; and
- the level of our operating costs, including payments to our general partner and its affiliates.

In addition, the actual amount of cash that we will have available for distribution will depend on other factors such as:

- the restrictions contained in our debt agreements and our debt service requirements, including our ability to pay distributions under our CQP Credit Facilities and the ability of SPL to pay distributions to us under its working capital facility and senior notes;
- the costs and capital requirements of acquisitions, if any;
- fluctuations in our working capital needs;
- our ability to borrow for working capital or other purposes; and
- the amount, if any, of cash reserves established by our general partner.

We may not be successful in our efforts to maintain or increase our cash available for distribution to cover the distributions on our units. Any reductions in distributions to our unitholders because of a shortfall in cash flow or other events could result in a decrease of the quarterly distribution on our common units below the initial quarterly distribution. Any portion of the initial quarterly distribution that is not distributed on our common units will accrue and be paid to the common unitholders in accordance with our partnership agreement, if at all.

We will need to refinance, extend or otherwise satisfy our substantial indebtedness, and principal amortization or other terms of our future indebtedness could limit our ability to pay or increase distributions to our unitholders.

As of December 31, 2018, we had $16.3 billion of total consolidated debt (before unamortized premium, discount and debt issuance costs). We anticipate incurring additional consolidated indebtedness in the future, including the issuance of additional notes by us or our subsidiaries, including SPL. Any additional indebtedness incurred could be at higher interest rates and have different maturity dates and more restrictive covenants than our current outstanding indebtedness. Approximately $2.0 billion of our indebtedness will mature in 2021, $1.0 billion will mature in 2022, $1.5 billion will mature in 2023, $11.0 billion will mature between 2024 and 2028 and $0.8 billion will mature in 2037. We are not generally required to make principal payments on any of our long-term indebtedness prior to maturity. Our ability to refinance, extend or otherwise satisfy our indebtedness, and the principal amortization, interest rate and other terms on which we may be able to do so, will depend, among other things, on our then contracted or otherwise anticipated future cash flows available for debt service. SPLNG's TUAs with Total and Chevron will expire in 2029 unless extended and SPL's SPAs will expire beginning in 2036 unless extended. Our ability to pay or increase distributions to our unitholders in future years could be limited by principal amortization, interest rate or other terms of our future indebtedness. If we are unable to refinance, extend or otherwise satisfy our debt as it matures, that would have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our subsidiaries may be restricted under the terms of their indebtedness from making distributions to us under certain circumstances, which may limit our ability to pay or increase distributions to our unitholders and could materially and adversely affect the market price of our common units.

The agreements governing our indebtedness restrict payments that our subsidiaries can make to us in certain events and limit the indebtedness that our subsidiaries can incur. For example, SPL is restricted from making distributions under the agreements governing its indebtedness generally until, among other requirements, deposits are made into debt service reserve accounts and a debt service coverage ratio of 1.25:1.00 is satisfied.

If our subsidiaries are unable to pay distributions to us or incur indebtedness as a result of the foregoing restrictions in agreements governing their indebtedness, we may be inhibited in our ability to pay or increase distributions to our unitholders.

Restrictions in agreements governing our subsidiaries' indebtedness may prevent our subsidiaries from engaging in certain beneficial transactions.

In addition to restrictions on the ability of SPL to make distributions or incur additional indebtedness, the agreements governing their indebtedness also contain various other covenants that may prevent them from engaging in beneficial transactions, including limitations on their ability to:

- make certain investments;
- purchase, redeem or retire equity interests;
- issue preferred stock;
- sell or transfer assets;
- incur liens;
- enter into transactions with affiliates;
- consolidate, merge, sell or lease all or substantially all of its assets; and
- enter into sale and leaseback transactions.

Management fees and cost reimbursements due to our general partner and its affiliates will reduce cash available to pay distributions to our unitholders.

We pay significant management fees to our general partner and its affiliates and reimburse them for expenses incurred on our behalf, which reduces our cash available for distribution to our unitholders. See Note 13—Related Party Transactions of our Notes to Consolidated Financial Statements for a description of these fees and expenses. Our general partner and its affiliates will also be entitled to reimbursement for all other direct expenses that they incur on our behalf. The payment of fees to our general partner and its affiliates and the reimbursement of expenses could adversely affect our ability to pay cash distributions to our unitholders.

The amount of cash that we have available for distributions to our unitholders will depend primarily on our cash flow and not solely on profitability.

The amount of cash that we will have available for distributions will depend primarily on our cash flow, including cash reserves and working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses, and we may not make cash distributions during periods when we record net income. Any reduction in the amount of cash available for distributions could impact our ability to pay quarterly distributions to our unitholders.

We may not be able to maintain or increase the distributions on our common and subordinated units unless we are able to make accretive acquisitions or implement accretive capital expansion projects, which may require us to obtain one or more sources of funding.

We may not be able to make accretive acquisitions or implement accretive capital expansion projects, including our liquefaction facilities, that would result in sufficient cash flow to allow us to maintain or increase common and subordinated unitholder distributions. To fund acquisitions or capital expansion projects, we will need to pursue a variety of sources of funding, including debt and/or equity financings. Our ability to obtain these or other types of financing will depend, in part, on factors beyond our control, such as our ability to obtain commitments from users of the facilities to be acquired or constructed, the status of various debt and equity markets at the time financing is sought and such markets' view of our industry and prospects at such time. Any restrictive lending conditions in the U.S. credit markets may make it more time consuming and expensive for us to obtain financing, if we can obtain such financing at all. Accordingly, we may not be able to obtain financing for acquisitions or capital expansion projects on terms that are acceptable to us, if at all.

Risks Relating to an Investment in Us and Our Common Units

Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to the detriment of us and our unitholders.

Cheniere owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Some of our general partner's directors are also directors of Cheniere, and certain of our general partner's officers are officers of Cheniere. Therefore, conflicts of interest may arise between Cheniere and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of us and our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Cheniere to pursue a business strategy that favors us. Cheniere's directors and officers have a fiduciary duty to make these decisions in favor of the owners of Cheniere, which may be contrary to our interests:
- our general partner controls the interpretation and enforcement of contractual obligations between us, on the one hand, and Cheniere, on the other hand, including provisions governing administrative services and acquisitions;
- our general partner is allowed to take into account the interests of parties other than us, such as Cheniere and its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to us and our unitholders;
- our general partner has limited its liability and reduced its fiduciary duties under the partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;
- Cheniere is not limited in its ability to compete with us. Please read "Cheniere is not restricted from competing with us and is free to develop, operate and dispose of, and is currently developing, LNG facilities, pipelines and other assets without any obligation to offer us the opportunity to develop or acquire those assets";
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities, and the establishment, increase or decrease in the amounts of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance 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 and the ability of the subordinated units to convert to common units;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable 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; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

We expect that there will be additional agreements or arrangements with Cheniere and its affiliates, including future interconnection, natural gas balancing and storage agreements with one or more Cheniere-affiliated natural gas pipelines, services agreements, as well as other agreements and arrangements that cannot now be anticipated. In those circumstances where additional contracts with Cheniere and its affiliates may be necessary or desirable, additional conflicts of interest may be involved.

In the event Cheniere favors its interests over our interests, we may have less available cash to make distributions on our units than we otherwise would have if Cheniere had favored our interests.

Cheniere is not restricted from competing with us and is free to develop, operate and dispose of, and is currently developing, LNG facilities, pipelines and other assets without any obligation to offer us the opportunity to develop or acquire those assets.

Cheniere and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. Cheniere may acquire, construct or dispose of its liquefaction project at Corpus Christi, Texas, its pipelines or any other assets without any obligation to offer us the opportunity to purchase or construct any of those assets, other than, in certain circumstances under an investors rights agreement with Blackstone CQP Holdco, its liquefaction project at Corpus Christi, Texas. In addition, under our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to Cheniere and its affiliates. As a result, neither Cheniere nor any of its affiliates will have any obligation to present new business opportunities to us, they may take advantage of such opportunities themselves and they may enter into commercial arrangements with respect to the liquefaction project at Corpus Christi, Texas that might otherwise have been entered into with respect to Train 6. Cheniere also has significantly greater resources and experience than we have, which may make it more difficult for us to compete with Cheniere and its affiliates with respect to commercial activities or acquisition candidates.

Our partnership agreement limits our general partner’s fiduciary duties to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. 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 the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns, the exercise of 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;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner, as long as it acted in good faith, meaning that 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 conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be “fair and reasonable” to us 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 favorable or advantageous to us;
-

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

- provides that in resolving conflicts of interest, it will be presumed that in making its decision the conflicts committee or the general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a unitholder will become bound by the provisions of our partnership agreement, including the provisions described above.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units trade.

Unlike the holders of common stock in a corporation, our 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 have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen entirely by affiliates of Cheniere. As a result, the price at which the common units trade could be diminished because of the absence or reduction of a control premium in the trading price.

Even if our unitholders are dissatisfied, they cannot initially remove our general partner without its consent.

The vote of the holders of at least 66 2/3% of all outstanding common units and subordinated units (including any units owned by our general partner and its affiliates), voting together as a single class is required to remove our general partner. Cheniere owns 48.6% of our outstanding common units and subordinated units, but it is contractually prohibited from voting our units that it holds in favor of the removal of our general partner. If our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically be converted into common units and any existing arrearages on the common units will be extinguished. A removal of our general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined in our partnership agreement to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of poor management of the business, so the removal of the general partner because of the unitholders' dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Our partnership agreement restricts the voting rights of unitholders (other than our general partner and its affiliates) owning 20% or more of any class of our units.

Our partnership agreement restricts unitholders' voting rights by 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 and 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 unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Our partnership agreement prohibits a unitholder (other than our general partner and its affiliates) who acquires 15% or more of our limited partner units without the approval of our general partner from engaging in a business combination with us for three years unless certain approvals are obtained. This provision could discourage a change of control that our unitholders may favor, which could negatively affect the price of our common units.

Our partnership agreement effectively adopts Section 203 of the General Corporation Law of the State of Delaware ("DGCL"). Section 203 of the DGCL as it applies to us prevents an interested unitholder defined as a person (other than our general partner and its affiliates) who owns 15% or more of our outstanding limited partner units from engaging in business combinations with us for three years following the time such person becomes an interested unitholder unless certain approvals are obtained. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. This provision of our partnership agreement could have an anti-takeover effect with respect to transactions not approved in advance by our general partner, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Our unitholders may not have limited liability 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 contractual obligations of the partnership that are expressly made without recourse to the general partner. We are organized under Delaware law, and we conduct business in other states. As a limited partner in a partnership organized under Delaware law, holders of our common units could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders as a group to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other action under our partnership agreement constituted participation in the "control" of our business. In addition, limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in many jurisdictions.

Our unitholders may have liability to repay distributions wrongfully made.

Under certain circumstances, our unitholders may have to repay amounts wrongfully 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, partners who received such a distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the partnership for the distribution amount. Liabilities to partners on account of their partner interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

We may issue additional units without approval of our unitholders, which would dilute their ownership interest in us.

At any time during the subordination period, with the approval of the conflicts committee of the board of directors of our general partner, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. After the subordination period, we may issue an unlimited number of limited partner interests of any type without limitation of any kind. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available per unit to pay distributions may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk will increase that a shortfall in the payment of the initial quarterly distributions will be borne by our common unitholders;
- 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.

The market price of our common units has fluctuated significantly in the past and is likely to fluctuate in the future. Our unitholders could lose all or part of their investment.

The market price of our common units has historically experienced and may continue to experience volatility. For example, during the three-year period ended December 31, 2018, the market price of our common units ranged between $19.22 and $40.56. Such fluctuations may continue as a result of a variety of factors, some of which are beyond our control, including:

- our quarterly distributions;
- domestic and worldwide supply of and demand for natural gas and corresponding fluctuations in the price of natural gas;

33

- fluctuations in our quarterly or annual financial results or those of other companies in our industry;
- issuance of additional equity securities which causes further dilution to our unitholders;
- sales of a high volume of our common units by our unitholders;
- operating and unit price performance of companies that investors deem comparable to us;
- events affecting other companies that the market deems comparable to us;
- changes in government regulation or proposals applicable to us;
- actual or potential non-performance by any customer or a counterparty under any agreement;
- announcements made by us or our competitors of significant contracts;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general conditions in the industries in which we operate;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial or other estimates by analysts; and
- other factors described in these “Risk Factors.”

In addition, the United States securities markets have experienced significant price and volume fluctuations. These fluctuations have often been unrelated to the operating performance of companies in these markets. Market fluctuations and broad market, economic and industry factors may negatively affect the price of our common units, regardless of our operating performance. If we were to be the object of securities class litigation as a result of volatility in our common unit price or for other reasons, it could result in substantial diversion of our management’s attention and resources, which could negatively affect our financial results.

Affiliates of our general partner or affiliates of Blackstone may sell limited partner units, which sales could have an adverse impact on the trading price of our common units.

Sales by us or any of our affiliated unitholders or affiliates of Blackstone of a substantial number of our common units or our subordinated units, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. As of December 31, 2018, Cheniere owned 104,488,671 of our common units and 135,383,831 of our subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier. We also filed a registration statement for the resale of 202,450,687 common units owned by Blackstone and its affiliates. Any sales of these units could have an adverse impact on the price of our common units.

Risks Relating to Tax Matters

Our tax treatment depends on our status as a partnership for federal income tax purposes. If we were treated as a corporation for federal income tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a “qualifying income” requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement 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 and would likely pay state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, then the initial quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders and, therefore, negatively impact the value of an investment in our common units. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to additional amounts of entity-level taxation for state or local income tax purposes, the initial quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time the U.S. President and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that would affect publicly traded partnerships or an investment in our common units.

The Tax Cuts and Jobs Act (the "TCJA") enacted December 22, 2017, made significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the tax rate on an individual or other non-corporate unitholder's allocable share of certain income from a publicly traded partnership. Unitholders should consult their tax advisor regarding the TCJA and its effect on an investment in our common units.

Any changes to the U.S. federal income tax laws and interpretations thereof (including administrative guidance relating to the TCJA) may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes or otherwise adversely affect us. We are unable to predict whether any changes, or other proposals, will ultimately be enacted. Any such changes or interpretations thereof could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. Although final Treasury Regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, such tax items must be prorated on a daily basis and these regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this 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 successful IRS contest of the federal income tax positions that we take, may adversely impact the market for our common units, and the costs of any contest will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions that we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions that we take. A court may not agree with some or all of the positions that we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we may either pay the taxes directly to the IRS or elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes. If we bear such payment our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, elect to issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own common units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Our unitholders may be required to pay taxes on their share of our taxable income even if they 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 from the cash that we distribute, our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from their share of our taxable income.

We intend to allocate items of income, gain, loss and deduction among the holders of our common units and subordinated units on or after the date that the subordination period ends to ensure that common units issued in exchange for our subordinated units have the same economic and federal income tax characteristics as our other common units. Any such allocation of items of our income or gain to unitholders, which may include allocations to holders of our common units, would not be accompanied by a distribution of cash to such unitholders. In addition, any such allocation of items of deduction or loss to specific unitholders (for example, to the holder of the subordinated units) would effectively reduce the amount of items of deduction or loss that will be allocated to other unitholders.

Tax gain or loss on the disposition of our common units could be different than expected.

If our unitholders sell any of their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholders' allocable share of our net taxable income decrease the unitholders' tax basis in their common units, 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 they sell such units at a price greater than their tax basis in those units, even if the price received is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to the potential recapture items, including depreciation recapture. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

Unitholders may be subject to limitations 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 TCJA, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income plus 30% of our "adjusted taxable income." For the purposes of this limitation, 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. However, recently issued proposed Treasury Regulations provide that depreciation, amortization, or depletion expense that is capitalized to inventory, is not treated as depreciation, amortization, or depletion deduction for purposes of computing adjusted taxable income. Although the proposed Treasury Regulations are not final, we have elected to adopt the proposed Treasury Regulations for the tax year ended December 31, 2018. The adoption of the proposed Treasury Regulations increases the likelihood that our interest will be subject to limitation. To the extent the business interest expense limitation applies, it could result in an increase in the taxable income allocable to a unitholder without any corresponding increase in the cash available for distribution to such unitholder.

Tax-exempt entities face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will 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) is 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 and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our common units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business (“effectively connected income”). A unitholder’s share of our income, gain, loss and deduction, and any gain from the sale or disposition of our common units will generally be considered to be “effectively connected” with a U.S. trade or business and subject to U.S. federal income tax. Additionally, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate.

The TCJA imposes a withholding obligation of 10% of the amount realized upon a non-U.S. unitholder’s sale or disposition of common units. The IRS has temporarily suspended the application of the withholding requirements on sales of publicly traded interests, including our common units, pending promulgation of regulations or other guidance. Non-U.S. unitholders should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury Regulations.

A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of those 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 a unitholder’s tax returns.

Our unitholders will likely be subject to state and local taxes and return filing requirements as a result of an investment in our common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local income 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 unitholder does not live in any of those jurisdictions. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Furthermore, our unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own property or conduct business in additional states or foreign countries that impose a personal tax or an entity level tax. Unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of our unitholders to file all United States federal, state and local tax returns.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates ourselves using a methodology based on the market value of our common units as a means to determine the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

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

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

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder, and any cash distributions received by the unitholder as to those common 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 securities loan are urged to consult with their tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their common units.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We may in the future be involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters.

LDEQ Matter

Certain of our subsidiaries are in discussions with the LDEQ to resolve self-reported deviations arising from operation of the Sabine Pass LNG terminal and the commissioning of the Liquefaction Project, and relating to certain requirements under its Title V Permit. The matter involves deviations self-reported to LDEQ pursuant to the Title V Permit and covering the time period from January 1, 2012 through March 25, 2016. On April 11, 2016, certain of our subsidiaries received a Consolidated Compliance Order and Notice of Potential Penalty (the "Compliance Order") from LDEQ covering deviations self-reported during that time period. Certain of our subsidiaries continue to work with

LDEQ to resolve the matters identified in the Compliance Order. We do not expect that any ultimate sanction will have a material adverse impact on our financial results.

PHMSA Matter

In February 2018, PHMSA issued a Corrective Action Order (the "CAO") to SPL in connection with a minor LNG leak from one tank and minor vapor release from a second tank at the Sabine Pass LNG terminal. These two tanks have been taken out of operational service while we conduct analysis, repair and remediation. On April 20, 2018, SPL and PHMSA executed a

Consent Agreement and Order (the "Consent Order") that replaces and supersedes the CAO. We continue to work with PHMSA and other appropriate regulatory authorities to address the matters identified in the Consent Order. We do not expect that the Consent Order and related analysis, repair and remediation will have a material adverse impact on our financial results or operations.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units began trading on the NYSE American under the symbol "CQP" commencing with our initial public offering on March 21, 2007. As of February 20, 2019, we had 348.6 million common units outstanding held by 10 record owners.

We consider cash distributions to unitholders on a quarterly basis, although there is no assurance as to the future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. The CQP Credit Facilities described in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" may also limit our ability to make distributions.

Upon the closing of our initial public offering, Cheniere received 135.4 million subordinated units. On August 2, 2017, the 45.3 million Class B units held by Cheniere Energy Partners LP Holdings, LLC and 100.0 million Class B units held by Blackstone CQP Holdco mandatorily converted into common units in accordance with the terms of our partnership agreement. Below is a description of our cash distribution policy regarding common and subordinated units. References therein to "unitholders" made in the context of the recipients of quarterly cash distributions refer to our common unitholders and subordinated unitholders.

Cash Distribution Policy

Our cash distribution policy is consistent with the terms of our partnership agreement, which requires that we distribute all of our available cash quarterly.

Subordination Period

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the initial quarterly distribution of $0.425 per quarter, plus any arrearages in the payment of the initial quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. Cheniere owns all of the 135.4 million subordinated units, representing 28.0% of the limited partner interests in us as of December 31, 2018. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until after the common units have received the initial quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordination period is to increase the likelihood that during this period there will be sufficient available cash to pay the initial quarterly distribution on the common units.

As a result of the assignment of Cheniere Marketing's TUA to Cheniere Investments, effective July 1, 2010, our available cash for distributions was reduced. Therefore, we did not pay distributions on our subordinated units with respect to the quarter ended June 30, 2010 through the quarter ended June 30, 2017, but resumed making cash distributions with respect to the quarter ended September 30, 2017.

Definition of Subordination Period

The subordination period will extend until the first business day following the distribution of available cash to partners in respect of any quarter that each of the following occurs:

- distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and any other outstanding units that are senior or equal in right of distribution to the subordinated units equaled or exceeded the sum of the initial quarterly distributions on all of the outstanding common units, subordinated units, general partner units and any other outstanding units that are senior or equal in right of distribution to the subordinated units for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the "adjusted operating surplus" (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the initial quarterly distributions on all of the outstanding common units, subordinated units, general partner units and any other outstanding units that are senior or equal in right of distribution to the subordinated units during those periods on a fully diluted basis; and
- there are no arrearages in payment of the initial quarterly distribution on the common units.

Expiration of the Subordination Period

When the subordination period expires, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by the general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the initial quarterly distribution on the common units will be extinguished; and
- the general partner will have the right to convert its general partner units and its IDRs into common units or to receive cash in exchange for those interests.

Early Conversion of Subordinated Units

The subordination period will automatically terminate and all of the subordinated units will convert into common units on a one-for-one basis on the first business day following the distribution of available cash to partners in respect of any quarter that each of the following occurs:

- in connection with distributions of available cash from operating surplus, the amount of such distributions constituting “contracted adjusted operating surplus” (as defined below) on each outstanding common unit, subordinated unit and any other outstanding unit that is senior or equal in right of distribution to the subordinated units equaled or exceeded $0.638 (150% of the initial quarterly distribution) for each quarter in the four-quarter period immediately preceding that date;
- the contracted adjusted operating surplus generated during each quarter in the four-quarter period immediately preceding that date equaled or exceeded the sum of a distribution of $0.638 (150% of the initial quarterly distribution) on all of the outstanding common units, subordinated units, general partner units, any other units that are senior or equal in right of distribution to the subordinated units, and any other equity securities that are junior to the subordinated units that the board of directors of our general partner deems to be appropriate for the calculation, after consultation with management of our general partner, on a fully diluted basis; and
- there are no arrearages in payment of the initial quarterly distribution on the common units

Definition of Adjusted Operating Surplus

We define adjusted operating surplus in our partnership agreement, and for any period, it generally means:

- operating surplus generated with respect to that period; less
- any net increase in working capital borrowings with respect to that period; less
- any net reduction in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus
- any net decrease in working capital borrowings with respect to that period; plus
- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes the $30 million operating surplus “basket,” net increases in working capital borrowings, net drawdowns of reserves of cash generated in prior periods.

Definition of Contracted Adjusted Operating Surplus

We define contracted adjusted operating surplus in our partnership agreement and it:

- generally means adjusted operating surplus derived solely from SPAs and TUAs, in each case, with a minimum term of three years with counterparties who are not affiliates of Cheniere; and
- excludes revenues and expenses attributable to the portion of payments made under the SPAs related to the final settlement price for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which the relevant cargo's delivery window is scheduled.

General Partner Units and Incentive Distribution Rights

IDRs represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus in excess of the initial quarterly distribution. Our general partner currently holds the IDRs but may transfer these rights separately from its general partner interest.

Assuming we do not issue any additional classes of units that are paid distributions and our general partner maintains its 2% interest, if we have made distributions to our unitholders from operating surplus in an amount equal to the initial quarterly distribution for any quarter, assuming no arrearages, then we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner as follows:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest Distributions	
		Common and Subordinated Unitholders	General Partner
Initial quarterly distribution	$0.425	98%	2%
First Target Distribution	Above $0.425 up to $0.489	98%	2%
Second Target Distribution	Above $0.489 up to $0.531	85%	15%
Third Target Distribution	Above $0.531 up to $0.638	75%	25%
Thereafter	Above $0.638	50%	50%

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data set forth below are derived from our audited Consolidated Financial Statements for the periods indicated (in millions, except per unit data). The financial data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and our Consolidated Financial Statements and the accompanying notes thereto included elsewhere in this report.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
Revenues (including transactions with affiliates)	$6,426	$4,304	$1,100	$270	$269
Income from operations	1,979	1,156	250	3	1
Interest expense, net of capitalized interest	(733)	(614)	(357)	(185)	(177)
Net income (loss)	1,274	490	(171)	(319)	(410)
Net income (loss) per common unit	$2.51	$(1.32)	$(0.20)	$(0.43)	$(0.89)
Weighted average units outstanding	348.6	178.5	57.1	57.1	57.1

	December 31,				
	2018	2017	2016	2015	2014
Property, plant and equipment, net	$15,390	$15,139	$14,158	$11,932	$8,978
Total assets	17,974	17,533	15,542	12,833	10,247
Current debt, net	—	—	224	1,673	—
Long-term debt, net	16,066	16,046	14,209	10,018	8,851

42

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion and analysis presents management's view of our business, financial condition and overall performance and should be read in conjunction with our Consolidated Financial Statements and the accompanying notes. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future. Our discussion and analysis includes the following subjects:

- Overview of Business
- Overview of Significant Events
- Liquidity and Capital Resources
- Contractual Obligations
- Results of Operations
- Off-Balance Sheet Arrangements
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

Overview of Business

We are a publicly traded Delaware limited partnership formed by Cheniere. Our vision is to provide clean, secure and affordable energy to the world, while responsibly delivering a reliable, competitive and integrated source of LNG, in a safe and rewarding work environment. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to economically justify the use of LNG. Through our wholly owned subsidiary, SPL, we are developing, constructing and operating natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. We plan to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is undergoing commissioning and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability, potential overdesign and debottlenecking opportunities, of approximately 4.5 mtpa of LNG per Train, and run rate adjusted nominal production capacity of approximately 4.5 to 4.9 mtpa of LNG per Train. Through our wholly owned subsidiary, SPLNG, we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We also own a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through our wholly owned subsidiary, CTPL.

Overview of Significant Events

Our significant accomplishments since January 1, 2018 and through the filing date of this Form 10-K include the following:

Strategic

- In December 2018, SPL entered into a 20-year SPA with PETRONAS LNG Ltd., subject to conditions precedent including making a final investment decision ("FID") for Train 6 of the Liquefaction Project, for the sale of approximately 1.1 mtpa of LNG on a free on board basis, with deliveries commencing following date of first commercial delivery for Train 6 of Liquefaction Project.
- In November 2018, SPL entered into an EPC contract with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for Train 6 of the Liquefaction Project. SPL also issued limited notices to proceed to Bechtel to commence early engineering,

procurement and site works.

Operational

- As of February 20, 2019, over 570 cumulative LNG cargoes have been produced, loaded and exported from the Liquefaction Project, with more than 270 cargoes in 2018 alone, with deliveries to 31 countries and regions worldwide.
- In November 2018, SPL commenced production and shipment of LNG commissioning cargoes from Train 5 of the Liquefaction Project.

Financial

- In September 2018, we issued an aggregate principal amount of $1.1 billion of 5.625% Senior Notes due 2026 (the "2026 CQP Senior Notes"). Net proceeds of the offering of approximately $1.1 billion, after deducting commissions, fees and expenses, were used to prepay all of the outstanding indebtedness under our credit facilities (the "CQP Credit Facilities"). As of December 31, 2018, only a $115 million revolving credit facility, which is currently undrawn, remains as part of the CQP Credit Facilities.
- We reached the following contractual milestones:
  - In June 2018, the date of first commercial delivery was reached under the 20-year SPA with BG Gulf Coast LNG, LLC ("BG") relating to Train 3 of the Liquefaction Project.

In March 2018, the date of first commercial delivery was reached under the 20-year SPA with GAIL (India) Limited ("GAIL") relating to Train 4 of the Liquefaction Project.

Liquidity and Capital Resources

The following table provides a summary of our liquidity position at December 31, 2018 and 2017 (in millions):

	December 31,	
	2018	2017
Cash and cash equivalents	$ —	$ —
Restricted cash designated for the following purposes:		
Liquefaction Project	756	544
Cash held by us and our guarantor subsidiaries	785	1,045
Available commitments under the following credit facilities:		
$1.2 billion SPL Working Capital Facility ("SPL Working Capital Facility")	775	470
CQP Credit Facilities	115	220

For additional information regarding our debt agreements, see Note 11—Debt of our Notes to Consolidated Financial Statements.

CQP Senior Notes

In September 2018, we issued an aggregate principal amount of $1.1 billion of the 2026 CQP Senior Notes. The existing $1.5 billion of 5.250% Senior Notes due 2025 (the "2025 CQP Senior Notes") and the 2026 CQP Senior Notes (collectively, the "CQP Senior Notes") are jointly and severally guaranteed by each of our subsidiaries other than SPL (the "Guarantors") and, subject to certain conditions governing its guarantee, Sabine Pass LP. The CQP Senior Notes are governed by the same base indenture (the "CQP Base Indenture"). The 2025 CQP Senior Notes are further governed by the First Supplemental Indenture (together with the CQP Base Indenture, the "2025 CQP Notes Indenture") and the 2026 CQP Senior Notes are further governed by the Second Supplemental Indenture (together with the CQP Base Indenture, the "2026 CQP Notes Indenture"). The 2025 CQP Notes Indenture and the 2026 CQP Notes Indenture contain customary terms and events of default and certain covenants that, among other things, limit our ability and the ability of the Guarantors to incur liens and sell assets, enter into transactions with affiliates, enter into sale-leaseback transactions and consolidate, merge or sell, lease or otherwise dispose of all or substantially all of the applicable entity's properties or assets.

At any time prior to October 1, 2020 for the 2025 CQP Senior Notes and October 1, 2021 for the 2026 CQP Senior Notes, we may redeem all or a part of the applicable CQP Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the CQP Senior Notes redeemed, plus the "applicable premium" set forth in the respective indentures governing the CQP Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. In addition, at any time prior to October 1, 2020 for the 2025 CQP Senior Notes and October 1, 2021 for the 2026 CQP Senior Notes, we may redeem up to 35% of the aggregate principal amount of the CQP Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price equal to 105.250% of the aggregate principal amount of the 2025 CQP Senior Notes and 105.625% of the aggregate principal amount of the 2026 CQP Senior Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption. We also may at any time on or after October 1, 2020 through the maturity date of October 1, 2025 for the 2025 CQP Senior Notes and October 1, 2021 through the maturity date of October 1, 2026 for the 2026 CQP Senior Notes, redeem the CQP Senior Notes, in whole or in part, at the redemption prices set forth in the respective indentures governing the CQP Senior Notes,

The CQP Senior Notes are our senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of our future subordinated debt. After applying the proceeds from the 2026 CQP Senior Notes, the CQP Senior Notes became unsecured. In the event that the aggregate amount of our secured indebtedness and the secured indebtedness of the Guarantors (other than the CQP Senior Notes or any other series of notes issued under the CQP Base Indenture) outstanding at any one time exceeds the greater of (1) $1.5 billion and (2) 10% of net tangible assets, the CQP Senior Notes will be secured to the same extent as such obligations under the CQP Credit Facilities. The obligations under the CQP Credit Facilities are secured on a first-priority basis (subject to permitted encumbrances) with liens on (1) substantially all the existing and future tangible and intangible assets and our rights and the rights of the Guarantors and equity interests in the Guarantors (except, in each case, for certain excluded properties set forth in the CQP Credit Facilities) and (2) substantially all of the real property of SPLNG (except for excluded properties referenced in the CQP Credit Facilities). The liens securing the CQP Senior Notes, if applicable, will be shared equally and ratably (subject to permitted liens) with the holders of other senior secured obligations, which include the CQP Credit Facilities obligations and any future additional senior secured debt obligations.

CQP Credit Facilities

In February 2016, we entered into the CQP Credit Facilities. The CQP Credit Facilities originally consisted of: (1) a $450 million CTPL tranche term loan that was used to prepay the $400 million term loan facility in February 2016, (2) an approximately $2.1 billion SPLNG tranche term loan that was used to repay and redeem in November 2016 the approximately $2.1 billion of the senior notes previously issued by SPLNG, (3) a $125 million facility that could be used to satisfy a six-month debt service reserve requirement and (4) a $115 million revolving credit facility that may be used for general business purposes. In September 2017 and September 2018, we issued the 2025 CQP Senior Notes and the 2026 CQP Senior Notes, respectively, and the net proceeds were used to prepay the outstanding term loans under the CQP Credit Facilities. As of December 31, 2018, only a $115 million revolving credit facility, which is currently undrawn, remains as part of the CQP Credit Facilities.

The CQP Credit Facilities mature on February 25, 2020. Any outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest hedging and interest rate breakage costs. The CQP Credit Facilities contain conditions precedent for extensions of credit, as well as customary affirmative and negative covenants and limit our ability to make restricted payments, including distributions, to once per fiscal quarter as long as certain conditions are satisfied. Under the CQP Credit Facilities, we are required to hedge not less than 50% of the variable interest rate exposure on its projected aggregate outstanding balance, maintain a minimum debt service coverage ratio of at least 1.15x at the end of each fiscal quarter beginning March 31, 2019 and have a projected debt service coverage ratio of 1.55x in order to incur additional indebtedness to refinance a portion of the existing obligations.

The CQP Credit Facilities are unconditionally guaranteed by each of our subsidiaries other than (1) SPL and (2) certain of our subsidiaries owning other development projects, as well as certain other specified subsidiaries and members of the foregoing entities.

45

Sabine Pass LNG Terminal

Liquefaction Facilities

We are developing, constructing and operating the Liquefaction Project at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. We have achieved substantial completion of Trains 1, 2, 3 and 4 of the Liquefaction Project and commenced operating activities in May 2016, September 2016, March 2017 and October 2017, respectively. Train 5 of the Liquefaction Project is undergoing commissioning and the following table summarizes the status as of December 31, 2018:

	Train 5
Overall project completion percentage	99.7%
Completion percentage of:	
Engineering	100%
Procurement	100%
Subcontract work	98.0%
Construction	99.6%
Date of expected substantial completion	1Q 2019

The following orders have been issued by the DOE authorizing the export of domestically produced LNG by vessel from the Sabine Pass LNG terminal:

- Trains 1 through 4—FTA countries for a 30-year term, which commenced on May 15, 2016, and non-FTA countries for a 20-year term, which commenced on June 3, 2016, in an amount up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr of natural gas).
- Trains 1 through 4—FTA countries for a 25-year term and non-FTA countries for a 20-year term in an amount up to a combined total of the equivalent of approximately 203 Bcf/yr of natural gas (approximately 4 mtpa).
- Trains 5 and 6—FTA countries and non-FTA countries for a 20-year term, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from five to 10 years from the date the order was issued. In addition, SPL received an order providing for a three-year makeup period with respect to each of the non-FTA orders for LNG volumes SPL was authorized but unable to export during any portion of the initial 20-year export period of such order.

In January 2018, the DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2018, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,509 Bcf/yr).

Customers

SPL has entered into fixed price SPAs with terms of at least 20 years (plus extension rights) with six third parties for Trains 1 through 5 of the Liquefaction Project, to make available an aggregate amount of LNG that is between approximately 80% to 95% of the expected aggregate adjusted nominal production capacity from these Trains. Under these SPAs, the customers will purchase LNG from SPL for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. In certain circumstances, the customers may elect to cancel or suspend deliveries of LNG cargoes, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered as a result of such cancellation or suspension. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under SPL's SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under SPL's SPAs. The variable fees under SPL's SPAs were sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation related to, and operating and maintenance costs to produce, the LNG to be sold under each such SPA. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train. Under SPL's SPA with BG, BG has contracted for volumes related to Trains 3 and 4, for which the obligation to make volumes related to Train 3 available to BG has commenced and the obligation to make volumes related to Train 4 available to BG is expected to commence approximately one year after the date of first commercial delivery under SPL's SPA with GAIL for Train 4.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $2.2 billion for Trains 1 through 3 and the SPA with GAIL for Train 4, increasing to $2.3 billion upon the date of first commercial delivery of Train 4 under the SPA with BG and to $2.9 billion upon the date of first commercial delivery of Train 5, with the applicable fixed fees starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

In addition, Cheniere Marketing has entered into an SPA with SPL to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers.

Natural Gas Transportation, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing variability in natural gas needs for the Liquefaction Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2018, SPL had secured up to approximately 3,464 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts.

Construction

SPL entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Trains 1 through 6 of the Liquefaction Project, under which Bechtel charges a lump sum for all work performed and generally bears project cost risk unless certain specified events occur, in which case Bechtel may cause SPL to enter into a change order, or SPL agrees with Bechtel to a change order.

The total contract price of the EPC contract for Train 5 of the Liquefaction Project is approximately $3.1 billion reflecting amounts incurred under change orders through December 31, 2018. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.5 billion and $18.5 billion after financing costs, including, in each case, estimated owner's costs and contingencies. The total contract price of the EPC contract for Train 6 of the Liquefaction Project is approximately $2.5 billion, including estimated costs for an optional third marine berth.

Final Investment Decision on Train 6

SPL has issued limited notices to proceed to Bechtel for the commencement of certain engineering, procurement and site works for Train 6 of the Liquefaction Project and a schedule for completion has been established. FID and full notice to proceed for Train 6 of the Liquefaction Project will be contingent upon, among other things, entering into acceptable commercial arrangements and obtaining adequate financing to construct Train 6.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4.0 Bcf/d and aggregate LNG storage capacity of approximately 16.9 Bcfe. Approximately 2.0 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term third-party TUAs, under which SPLNG's customers are required to pay fixed monthly fees, whether or not they use the LNG terminal. Each of Total Gas & Power North America, Inc. (“Total”) and Chevron U.S.A. Inc. (“Chevron”) has reserved approximately 1.0 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009. Total S.A. has guaranteed Total’s obligations under its TUA up to $2.5 billion, subject to certain exceptions, and Chevron Corporation has guaranteed Chevron’s obligations under its TUA up to 80% of the fees payable by Chevron.

The remaining approximately 2.0 Bcf/d of capacity has been reserved under a TUA by SPL. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, continuing until at least May 2036. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 3 of the Liquefaction Project, SPL gained access to a portion of Total’s capacity and other services provided under Total’s TUA with SPLNG. Upon substantial completion of Train 5, SPL will gain access to substantially all of Total's capacity. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the years ended December 31, 2018 and 2017, SPL recorded $30 million and $23 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Under each of these TUAs, SPLNG is entitled to retain 2% of the LNG delivered to the Sabine Pass LNG terminal.

Capital Resources

We currently expect that SPL's capital resources requirements with respect to the Liquefaction Project will be financed through project debt and borrowings and cash flows under the SPAs. We believe that with the net proceeds of borrowings, available commitments under the SPL Working Capital Facility and cash flows from operations, we will have adequate financial resources available to complete Train 5 of the Liquefaction Project and to meet our currently anticipated capital, operating and debt service requirements. SPL began generating cash flows from operations from the Liquefaction Project in May 2016, when Train 1 achieved substantial completion and initiated operating activities. Trains 2, 3 and 4 subsequently achieved substantial completion in September 2016, March 2017 and October 2017, respectively. We realized offsets to LNG terminal costs of $94 million, $301 million and $201 million in the years ended December 31, 2018, 2017 and 2016, respectively, that were related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations of the respective Train during the testing phase for its construction. Additionally, SPLNG generates cash flows from the TUAs, as discussed above.

The following table provides a summary of our capital resources from borrowings and available commitments for the Sabine Pass LNG Terminal, excluding equity contributions to our subsidiaries and cash flows from operations (as described in Sources and Uses of Cash), at December 31, 2018 and 2017 (in millions):

	December 31,	
	2018	2017
Senior notes (1)	$16,250	$15,150
Credit facilities outstanding balance (2)	—	1,090
Letters of credit issued (3)	425	730
Available commitments under credit facilities (3)	775	470
Total capital resources from borrowings and available commitments	$17,450	$17,440

(1) Includes SPL's 5.625% Senior Secured Notes due 2021, 6.25% Senior Secured Notes due 2022, 5.625% Senior Secured Notes due 2023, 5.75% Senior Secured Notes due 2024, 5.625% Senior Secured Notes due 2025, 5.875% Senior Secured Notes due 2026 (the "2026 SPL Senior Notes"), 5.00% Senior Secured Notes due 2027 (the "2027 SPL Senior Notes"), 4.200% Senior Secured Notes due 2028 (the "2028 SPL Senior Notes") and 5.00% Senior Secured Notes due 2037 (the "2037 SPL Senior Notes") (collectively, the "SPL Senior Notes") and our 2025 CQP Senior Notes and 2026 CQP Senior Notes.

(2) Includes outstanding balance under the SPL Working Capital Facility and CTPL and SPLNG tranche term loans outstanding under the CQP Credit Facilities.

(3) Consists of SPL Working Capital Facility. Does not include the letters of credit issued or available commitments under the CQP Credit Facilities, which are not specifically for the Sabine Pass LNG Terminal.

For additional information regarding our debt agreements related to the Sabine Pass LNG Terminal, see Note 11—Debt of our Notes to Consolidated Financial Statements.

SPL Senior Notes

The SPL Senior Notes are secured on a pari passu first-priority basis by a security interest in all of the membership interests in SPL and substantially all of SPL's assets.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is six months before the respective dates of maturity), SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the “make-whole” price (except for the 2037 SPL Senior Notes, in which case the redemption price is equal to the “optional redemption” price) set forth in the respective indentures governing the SPL Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPL may also, at any time within three months of the respective maturity dates for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is within six months of the respective dates of maturity), redeem all or part of such series of the SPL Senior Notes at a redemption price equal to 100% of the principal amount of such series of the SPL Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

Both the indenture governing the 2037 SPL Senior Notes (the “2037 SPL Senior Notes Indenture”) and the common indenture governing the remainder of the SPL Senior Notes (the “SPL Indenture”) include restrictive covenants. SPL may incur additional indebtedness in the future, including by issuing additional notes, and such indebtedness could be at higher interest rates and have different maturity dates and more restrictive covenants than the current outstanding indebtedness of SPL, including the SPL Senior Notes and the SPL Working Capital Facility. Under the 2037 SPL Senior Notes Indenture and the SPL Indenture, SPL may not make any distributions until, among other requirements, deposits are made into debt service reserve accounts as required and a debt service coverage ratio test of 1.25:1.00 is satisfied. Semi-annual principal payments for the 2037 SPL Senior Notes are due on March 15 and September 15 of each year beginning September 15, 2025.

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility, which is intended to be used for loans to SPL (“Working Capital Loans”), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL (“Swing Line Loans”), primarily for certain working capital requirements related to developing and placing into operation the Liquefaction Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and, upon the completion of the debt financing of Train 6 of the Liquefaction Project, request an incremental increase in commitments of up to an additional $390 million. As of December 31, 2018 and 2017, SPL had $775 million and $470 million of available commitments and $425 million and $730 million aggregate amount of issued letters of credit under the SPL Working Capital Facility, respectively. SPL did not have any amounts outstanding under the SPL Working Capital Facility as of both December 31, 2018 and 2017.

The SPL Working Capital Facility matures on December 31, 2020, and the outstanding balance may be repaid, in whole or in part, at any time without premium or penalty upon three business days’ notice. Loans deemed made in connection with a draw upon a letter of credit have a term of up to one year. Swing Line Loans terminate upon the earliest of (1) the maturity date or earlier termination of the SPL Working Capital Facility, (2) the date 15 days after such Swing Line Loan is made and (3) the first borrowing date for a Working Capital Loan or Swing Line Loan occurring at least three business days following the date the Swing Line Loan is made. SPL is required to reduce the aggregate outstanding principal amount of all Working Capital Loans to zero for a period of five consecutive business days at least once each year.

The SPL Working Capital Facility contains conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. The obligations of SPL under the SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a pari passu basis with the SPL Senior Notes.

Restrictive Debt Covenants

As of December 31, 2018, we and SPL were in compliance with all covenants related to our respective debt agreements.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash, cash equivalents and restricted cash for the years ended December 31, 2018, 2017 and 2016 (in millions). The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals, which are referred to elsewhere in this report. Additional discussion of these items follows the table.

	Year Ended December 31,		
	2018	2017	2016
Operating cash flows	$1,874	$977	$—
Investing cash flows	(804)	(1,290)	(2,353)
Financing cash flows	(1,118)	1,297	2,524
Net increase (decrease) in cash, cash equivalents and restricted cash	(48)	984	171
Cash, cash equivalents and restricted cash—beginning of period	1,589	605	434
Cash, cash equivalents and restricted cash—end of period	$1,541	$1,589	$605

Operating Cash Flows

Our operating cash net inflows during the years ended December 31, 2018, 2017 and 2016 were $1,874 million, $977 million and zero, respectively. The $897 million increase in operating cash inflows in 2018 compared to 2017 was primarily related to increased cash receipts from the sale of LNG cargoes, partially offset by increased operating costs and expenses as a result of the additional Trains that were operating at the Liquefaction Project in 2018. We had four Trains operational for the entire year during the year ended December 31, 2018, we had two Trains operational for the entire year and two Trains operational partially during the year ended December 31, 2017 and two Trains operational partially during the year ended December 31, 2016. The $977 million increase in operating cash inflows in 2017 compared to 2016 was primarily related to increased cash receipts from the sale of LNG cargoes, partially offset by increased operating costs and expenses as a result of the of additional Trains that were operating at the Liquefaction Project in 2017. During the year ended December 31, 2016, Train 1 was operating for seven months and Train 2 was operating for less than four months.

Investing Cash Flows

Investing cash net outflows during the years ended December 31, 2018, 2017 and 2016 were $804 million, $1,290 million and $2,353 million, respectively, and were primarily used to fund the construction costs for the Liquefaction Project. These costs are capitalized as construction-in-process until achievement of substantial completion. Additionally, during the year ended December 31, 2016, we used $38 million primarily for payments to a municipal water district for water system enhancements to increase potable water supply to the Sabine Pass LNG terminal and payments made pursuant to the information technology services agreement for capital assets purchased on our behalf.

Financing Cash Flows

Financing cash net outflows during the year ended December 31, 2018 were $1,118 million, primarily as a result of:

- issuance of an aggregate principal amount of $1.1 billion of the 2026 CQP Senior Notes, which was used to prepay $1.1 billion of the outstanding borrowings under the CQP Credit Facilities;
- $8 million of debt issuance costs related to up-front fees paid upon the closing of these transactions;
- $7 million in debt extinguishment costs related to the prepayment of the CQP Credit Facilities; and
- $1.1 billion in distributions to unitholders.

Financing cash net inflows during the year ended December 31, 2017 were $1,297 million, primarily as a result of:

- issuances of SPL’s senior notes for an aggregate principal amount of $2.15 billion;

- $55 million of borrowings and $369 million of repayments made under the credit facilities SPL entered into in June 2015 (the “SPL Credit Facilities”);
- issuance of an aggregate principal amount of $1.5 billion of the 2025 CQP Senior Notes, which was used to prepay $1.5 billion of the outstanding borrowings under the CQP Credit Facilities;
- $110 million of borrowings and $334 million of repayments made under the SPL Working Capital Facility;
- $50 million of debt issuance costs related to up-front fees paid upon the closing of these transactions; and
- $294 million of distributions to unitholders.

Financing cash net inflows during the year ended December 31, 2016 were $2,524 million, primarily as a result of:

- $2.6 billion of borrowings under the CQP Credit Facilities used to prepay the $400 million CTPL term loan facility and redeem and repay $2.1 billion of the senior notes previously issued by SPLNG;
- $2.0 billion of borrowings under the SPL Credit Facilities;
- issuance of an aggregate principal amount of $1.5 billion of the 2026 SPL Senior Notes in June 2016, which was used to prepay $1.3 billion of the outstanding borrowings under the SPL Credit Facilities;
- issuance of an aggregate principal amount of $1.5 billion of the 2027 SPL Senior Notes in September 2016, which was used to prepay $1.2 billion of the outstanding borrowings under the SPL Credit Facilities and pay a portion of the capital costs in connection with the construction of Trains 1 through 5 of the Liquefaction Project;
- $474 million of borrowings and $265 million of repayments made under the SPL Working Capital Facility;
- $115 million of debt issuance costs related to up-front fees paid upon the closing of these transactions;
- $14 million of debt extinguishment costs paid in connection with redemptions and prepayments of outstanding borrowings; and
- $99 million of distributions to unitholders.

Cash Distributions to Unitholders

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement). Our available cash is our cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions paid to date have been made from accumulated operating surplus. The following provides a summary of distributions paid by us during the years ended December 31, 2018, 2017 and 2016:

				Total Distribution (in millions)			
Date Paid	Period Covered by Distribution	Distribution Per Common Unit	Distribution Per Subordinated Unit	Common Units	Subordinated Units	General Partner Units	Incentive Distribution Rights
November 14, 2018	July 1 - September 30, 2018	$ 0.58	$ 0.58	$202	$ 79	$ 5	$ 11
August 14, 2018	April 1 - June 30, 2018	0.56	0.56	195	76	6	7
May 15, 2018	January 1 - March 31, 2018	0.55	0.55	192	74	5	6
February 14, 2018	October 1 - December 31, 2017	0.50	0.50	174	68	5	1
November 14, 2017	July 1 - September 30, 2017	$ 0.440	$ 0.440	$153	$ 60	$ 4	$ —
August 11, 2017	April 1 - June 30, 2017	0.425	—	24	—	0.5	—
May 15, 2017	January 1 - March 31, 2017	0.425	—	24	—	0.5	—
February 13, 2017	October 1 - December 31, 2016	0.425	—	24	—	0.5	—

November 11, 2016	July 1 - September 30, 2016	$ 0.425	$ —	$24	$ —	$ 0.5	$ —
August 12, 2016	April 1 - June 30, 2016	0.425	—	24	—	0.5	—
May 13, 2016	January 1 - March 31, 2016	0.425	—	24	—	0.5	—
February 12, 2016	October 1 - December 31, 2015	0.425	—	24	—	0.5	—

On January 25, 2019, we declared a $0.59 distribution per common unit and subordinated unit and the related distribution to our general partner and incentive distribution right holders to be paid on February 14, 2019 to unitholders of record as of February 6, 2019 for the period from October 1, 2018 to December 31, 2018.

The subordinated units will receive distributions only to the extent we have available cash above the initial quarterly distributions requirement for our common unitholders and general partner along with certain reserves. Such available cash could be generated through new business development or fees received from Cheniere Marketing under an amended and restated variable capacity rights agreement pursuant to which Cheniere Marketing is obligated to pay Cheniere Investments 80% of the expected gross margin of each cargo of LNG that Cheniere Marketing arranges for delivery to the Sabine Pass LNG terminal. The ending of the subordination period and conversion of the subordinated units into common units will depend upon future business development.

Contractual Obligations

We are committed to make cash payments in the future pursuant to certain of our contracts. The following table summarizes certain contractual obligations in place as of December 31, 2018 (in millions):

	Payments Due By Period (1)				
	Total	2019	2020 - 2021	2022 - 2023	Thereafter
Debt (2)	$16,250	$—	$2,000	$2,500	$ 11,750
Interest payments (2)	5,492	902	1,685	1,378	1,527
Construction obligations (3)	87	87	—	—	—
Purchase obligations (4)	7,935	2,499	2,388	1,396	1,652
Operating lease obligations (5)	174	10	20	20	124
Obligations to affiliates (6)	785	47	93	93	552
Other obligations (7)	7	3	3	—	1
Total	$30,730	$3,548	$6,189	$5,387	$ 15,606

(1) Agreements in force as of December 31, 2018 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2018.

(2) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2018. See Note 11—Debt of our Notes to Consolidated Financial Statements.

(3) Construction obligations relate to the EPC contracts for the Liquefaction Project. The estimated remaining cost pursuant to our EPC contracts as of December 31, 2018 is included for Trains with respect to which we have made an FID to commence construction; the EPC contract termination amount is included for Trains with respect to which we have not made an FID. A discussion of these obligations can be found at Note 16—Commitments and Contingencies of our Notes to Consolidated Financial Statements.

(4) Purchase obligations consist of contracts for which conditions precedent have been met, and primarily relate to natural gas supply, transportation and storage services for the Liquefaction Project. As project milestones and other conditions precedent are achieved, our obligations are expected to increase accordingly.

(5) Operating lease obligations primarily relate to land sites related to the Sabine Pass LNG terminal. A discussion of these obligations can be found in Note 15—Leases of our Notes to Consolidated Financial Statements.

(6) Obligations arising through intercompany service agreements include only fixed fees and do not include variable fees. A discussion of these obligations can be found in Note 13—Related Party Transactions of our Notes to Consolidated Financial Statements.

(7) Other obligations primarily relate to agreements with certain local taxing jurisdictions, and are based on tax obligations as of December 31, 2018.

In addition, in the ordinary course of business, we maintain letters of credit and have certain cash restricted in support of certain performance obligations of our subsidiaries. As of December 31, 2018, we had $425 million aggregate amount of issued letters of credit under our credit facilities and $1.5 billion of current restricted cash. For more information, see Note 4—Restricted Cash of our Notes to Consolidated Financial Statements.

Results of Operations

Our consolidated net income was $1.3 billion, or $2.51 per common unit (basic and diluted), in the year ended December 31, 2018, compared to $490 million, or $1.32 loss per common unit (basic and diluted), in the year ended December 31, 2017. This $784 million increase in net income in 2018 was primarily a result of increased income from operations due to additional Trains operating between the periods and decreased loss on modification or extinguishment of debt, which were partially offset by increased interest expense, net of amounts capitalized.

Our consolidated net loss was $171 million, or $0.20 loss per common unit (basic and diluted), in the year ended December 31, 2016. This $661 million increase in net income in 2017 compared to 2016 was primarily a result of increased income from operations due to additional Trains operating between the periods, which was partially offset by increased interest expense, net of amounts capitalized.

Revenues

	Year Ended December 31,				
(in millions, except volumes)	2018	2017	Change	2016	Change
LNG revenues	$4,827	$2,635	$2,192	$539	$2,096
LNG revenues—affiliate	1,299	1,389	(90)	294	1,095
Regasification revenues	261	260	1	259	1
Other revenues	39	20	19	4	16
Other revenues—affiliate	—	—	—	4	(4)
Total revenues	$6,426	$4,304	$2,122	$1,100	$3,204
LNG volumes recognized as revenues (in TBtu)	955	684	271	151	533

2018 vs. 2017 and 2017 vs. 2016

We begin recognizing LNG revenues from the Liquefaction Project following the substantial completion and the commencement of operating activities of the respective Trains. We had four Trains operational for the entire year during the year ended December 31, 2018, we had two Trains operational for the entire year and two Trains operational partially during the year ended December 31, 2017 and two Trains operational partially during the year ended December 31, 2016. The increase in revenues for each of the years was primarily attributable to the increased volume of LNG sold following the achievement of substantial completion of these Trains, as well as increased revenues per MMBtu. We expect our LNG revenues to increase in the future upon Train 5 of the Liquefaction Project becoming operational.

Prior to substantial completion of a Train, amounts received from the sale of commissioning cargoes from that Train are offset against LNG terminal construction-in-process, because these amounts are earned or loaded during the testing phase for the construction of that Train. During the years ended December 31, 2018, 2017 and 2016, we realized offsets to LNG terminal costs of $94 million corresponding to 13 TBtu of LNG, $301 million corresponding to 51 TBtu of LNG and $201 million corresponding to 45 TBtu of LNG, respectively, that were related to the sale of commissioning cargoes.

Operating costs and expenses

	Year Ended December 31,				
(in millions)	2018	2017	Change	2016	Change
Cost of sales	$3,403	$2,320	$1,083	$410	$1,910
Cost of sales—affiliate	—	—	—	2	(2)
Operating and maintenance expense	409	292	117	127	165
Operating and maintenance expense—affiliate	117	100	17	52	48
Development expense	2	3	(1)	—	3
General and administrative expense	11	12	(1)	13	(1)
General and administrative expense—affiliate	73	80	(7)	90	(10)
Depreciation and amortization expense	424	339	85	156	183
Impairment expense and loss on disposal of assets	8	—	8	—	—
Other	—	2	(2)	—	2
Total operating costs and expenses	$4,447	$3,148	$1,299	$850	$2,298

2018 vs. 2017 and 2017 vs. 2016

Our total operating costs and expenses increased during the year ended December 31, 2018 from the years ended December 31, 2017 and 2016, primarily as a result of additional Trains that were operating between each of the periods.

Cost of sales increased during the year ended December 31, 2018 from the comparable periods in 2017 and 2016, primarily as a result of the increase in operating Trains between each of the periods. Cost of sales includes costs incurred directly for the production and delivery of LNG from the Liquefaction Project, to the extent those costs are not utilized for the commissioning process. The increase during the year ended December 31, 2018 from the comparable period in 2017 was primarily related to the increase in the volume of natural gas feedstock related to our LNG sales. The increase during the year ended December 31, 2017 from the comparable period in 2016 was primarily related to the increase in both the volume and pricing of natural gas feedstock related to our LNG sales. Cost of sales also includes gains and losses from derivatives associated with economic hedges to secure natural gas feedstock for the Liquefaction Project, variable transportation and storage costs and other costs to convert natural gas into LNG.

Operating and maintenance expense (including affiliates) increased during the year ended December 31, 2018 from the comparable periods in 2017 and 2016, as a result of the increase in operating Trains between each of the periods. Operating and maintenance expense primarily includes costs associated with operating and maintaining the Liquefaction Project. The increase during the year ended December 31, 2018 from the comparable periods in 2017 and 2016 was primarily related to third-party service and maintenance contract costs, natural gas transportation and storage capacity demand charges, payroll and benefit costs of operations personnel and TUA reservation charges from payments made under the partial TUA assignment agreement with Total. Operating and maintenance expense (including affiliates) also includes insurance and regulatory costs and other operating costs.

Depreciation and amortization expense increased during the year ended December 31, 2018 from the comparable periods in 2017 and 2016 as a result of an increased number of operational Trains, as the assets related to the Trains of the Liquefaction Project began depreciating upon reaching substantial completion.

Impairment expense and loss on disposal of assets increased during the year ended December 31, 2018 compared to the years ended December 31, 2017 and 2016. The impairment expense and loss on disposal of assets recognized during the year ended December 31, 2018 related to the write down of prepaid assets.

We expect our operating costs and expenses to generally increase in the future upon Train 5 of the Liquefaction Project achieving substantial completion, although certain costs will not proportionally increase with the number of operational Trains as cost efficiencies will be realized.

Other expense (income)

	Year Ended December 31,				
(in millions)	2018	2017	Change	2016	Change
Interest expense, net of capitalized interest	$733	$614	$ 119	$357	$ 257
Loss on modification or extinguishment of debt	12	67	(55)	72	(5)
Derivative gain, net	(14)	(4)	(10)	(6)	2
Other income	(26)	(11)	(15)	(2)	(9)
Total other expense	$705	$666	$ 39	$421	$ 245

2018 vs. 2017

Interest expense, net of capitalized interest, increased during the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily as a result of a decrease in the portion of total interest costs that could be capitalized as additional Trains of the Liquefaction Project completed construction between the periods. For the years ended December 31, 2018 and 2017, we incurred $936 million and $902 million of total interest cost, respectively, of which we capitalized $203 million and $288 million, respectively, which was primarily related to the construction of the Liquefaction Project.

Loss on modification or extinguishment of debt decreased during the year ended December 31, 2018 compared to the year ended December 31, 2017. Loss on modification or extinguishment of debt of $12 million recognized in 2018 was attributable to the incurrence of third party fees and write off of unamortized debt issuance costs in September 2018 as a result of the termination of approximately $1.2 billion of commitments under the CQP Credit Facilities in connection with the issuance of the 2026 CQP Senior Notes. Loss on modification or extinguishment of debt recognized in 2017 was attributable to the $42 million write-off of debt issuance costs in March 2017 upon termination of the remaining available balance of $1.6 billion under the SPL Credit Facilities in connection with the issuance of the 2028 SPL Senior Notes and the 2037 SPL Senior Notes, in addition to the $25 million write-off of debt issuance costs in September 2017 related to the prepayment of $1.5 billion of the outstanding indebtedness under the CQP Credit Facilities in connection with the issuance of the 2025 CQP Senior Notes.

Derivative gain, net increased during the year ended December 31, 2018 compared to the year ended December 31, 2017, primarily due to a favorable shift in the long-term forward LIBOR curve between the periods, including proceeds of $28 million received in October 2018 upon the termination of the interest rate swaps ("CQP Interest Rate Derivatives") previously held to hedge a portion of the variable interest payments on its CQP Credit Facilities.

2017 vs. 2016

Interest expense, net of capitalized interest, increased during the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily as a result of a decrease in the portion of total interest costs that could be capitalized as Trains 1 through 4 of the Liquefaction Project completed construction and an increase in our indebtedness outstanding (before unamortized premium, discount and debt issuance costs), from $14.6 billion as of December 31, 2016 to $16.2 billion as of December 31, 2017. For the year ended December 31, 2016, we incurred $841 million of total interest cost, of which we capitalized $484 million, which was primarily related to the construction of the Liquefaction Project.

Loss on modification or extinguishment of debt decreased during the year ended December 31, 2017, as compared to the year ended December 31, 2016. Loss on modification or extinguishment of debt recognized during the year ended December 31, 2016 was primarily due to (1) a $52 million write-off of debt issuance costs and payment of fees related to the $2.6 billion prepayment of outstanding borrowings and termination of commitments under the SPL Credit Facilities in connection with the issuance of the 2026 SPL Senior Notes and the 2027 SPL Senior Notes and (2) a $20 million write-off of debt issuance costs and unamortized discount in connection with the prepayment of the CTPL term loan facility and the redemption of the senior notes due 2020 previously issued by SPLNG.

Derivative gain, net decreased during the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily due to a favorable shift in the long-term forward LIBOR curve between the periods, partially offset by the $7 million payment made in March 2017 upon the settlement of interest rate swaps associated with approximately $1.6 billion of commitments that were terminated under the SPL Credit Facilities.

Off-Balance Sheet Arrangements

As of December 31, 2018, we had no transactions that met the definition of off-balance sheet arrangements that may have a current or future material effect on our consolidated financial position or operating results.

Summary of Critical Accounting Estimates

The preparation of Consolidated Financial Statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and the accompanying notes. Management evaluates its estimates and related assumptions regularly, including those related to the valuation of derivative instruments and properties, plant and equipment. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve significant judgment.

Derivative Instruments

All derivative instruments, other than those that satisfy specific exceptions, are recorded at fair value. We record changes in the fair value of our derivative positions based on the value for which the derivative instrument could be exchanged between willing parties. If market quotes are not available to estimate fair value, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or determined through industry-standard valuation approaches. Such evaluations may involve significant judgment and the results are based on expected future events or conditions, particularly for those valuations using inputs unobservable in the market.

Our derivative instruments consist of interest rate swaps, financial commodity derivative contracts transacted in an over-the-counter market and index-based physical commodity contracts. We value our interest rate swaps using observable inputs including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data. Valuation of our financial commodity derivative contracts is determined using observable commodity price curves and other relevant data. Valuation of our index-based physical commodity contracts is developed through the use of internal models which are impacted by inputs that may be unobservable in the marketplace, market transactions and other relevant data.

Gains and losses on derivative instruments are recognized in earnings. The ultimate fair value of our derivative instruments is uncertain, and we believe that it is reasonably possible that a change in the estimated fair value could occur in the near future as interest rates and commodity prices change.

Recent Accounting Standards

For descriptions of recently issued accounting standards, see Note 19—Recent Accounting Standards of our Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Marketing and Trading Commodity Price Risk

We have entered into commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the Liquefaction Project ("Liquefaction Supply Derivatives"). In order to test the sensitivity of the fair value of the Liquefaction Supply Derivatives to changes in underlying commodity prices, management modeled a 10% change in the commodity price for natural gas for each delivery location as follows (in millions):

	December 31, 2018		December 31, 2017	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ (43)	$ 7	$ 55	$ 5

Interest Rate Risk

We are exposed to interest rate risk primarily when we incur debt related to project financing. Interest rate risk is managed in part by replacing outstanding floating-rate debt with fixed-rate debt with varying maturities. We previously also had the CQP

Interest Rate Derivatives to hedge the exposure to volatility in a portion of the floating-rate interest payments under the CQP Credit Facilities. See Note 8—Derivative Instruments for additional details about our derivative instruments.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY PARTNERS, L.P.

Management’s Report to the Unitholders of Cheniere Energy Partners, L.P.	59
Reports of Independent Registered Public Accounting Firm	60
Consolidated Balance Sheets	62
Consolidated Statements of Operations	63
Consolidated Statements of Partners’ Equity	64
Consolidated Statements of Cash Flows	65
Notes to Consolidated Financial Statements	66
Supplemental Information to Consolidated Financial Statements—Summarized Quarterly Financial Data	103

MANAGEMENT'S REPORT TO THE UNITHOLDERS OF CHENIERE ENERGY PARTNERS, L.P.

Management's Report on Internal Control Over Financial Reporting

As management, we are responsible for establishing and maintaining adequate internal control over financial reporting for Cheniere Energy Partners, L.P. ("Cheniere Partners") and its subsidiaries. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, we have conducted an assessment, including testing using the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Cheniere Partners' system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and, even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation.

Based on our assessment, we have concluded that Cheniere Partners maintained effective internal control over financial reporting as of December 31, 2018, based on criteria in Internal Control—Integrated Framework (2013) issued by the COSO.

Cheniere Partners' independent registered public accounting firm, KPMG LLP, has issued an audit report on Cheniere Partners' internal control over financial reporting as of December 31, 2018, which is contained in this Form 10-K.

Management's Certifications

The certifications of the Chief Executive Officer and Chief Financial Officer of Cheniere Partners' general partner required by the Sarbanes-Oxley Act of 2002 have been included as Exhibits 31 and 32 in Cheniere Partners' Form 10-K.

Cheniere Energy Partners, L.P.

By: Cheniere Energy Partners GP, LLC,
Its general partner

By: /s/ Jack A. Fusco	By: /s/ Michael J. Wortley
Jack A. Fusco	Michael J. Wortley
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Cheniere Energy Partners, L.P. and
Board of Directors of Cheniere Energy Partners GP, LLC:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cheniere Energy Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2018 and 2017, the related consolidated statements of operations, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have 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, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 25, 2019 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 3 to the consolidated financial statements, the Partnership has changed its method of accounting for revenue recognition in 2018, 2017 and 2016 due to the adoption of ASU 2014-09, Revenue from Contracts with Customers (Topic 606), and subsequent amendments thereto.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP
KPMG LLP

We have served as the Partnership's auditor since 2014.

Houston, Texas
February 25, 2019

60

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Cheniere Energy Partners, L.P. and
Board of Directors of Cheniere Energy Partners GP, LLC:

Opinion on Internal Control Over Financial Reporting

We have audited Cheniere Energy Partners, L.P.'s and subsidiaries' (the Partnership) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2018 and 2017, the related consolidated statements of operations, partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 25, 2019 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 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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 partnership; (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 partnership are being made only in accordance with authorizations of management and directors of the partnership; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the partnership'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/ KPMG LLP
KPMG LLP

Houston, Texas

February 25, 2019

61

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in millions, except unit data)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$—	$—
Restricted cash	1,541	1,589
Accounts and other receivables	348	191
Accounts receivable—affiliate	114	163
Advances to affiliate	228	36
Inventory	99	95
Other current assets	26	65
Total current assets	2,356	2,139
Property, plant and equipment, net	15,390	15,139
Debt issuance costs, net	13	38
Non-current derivative assets	31	31
Other non-current assets, net	184	206
Total assets	$17,974	$17,553
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	$15	$12
Accrued liabilities	821	637
Due to affiliates	49	68
Deferred revenue	116	111
Deferred revenue—affiliate	1	1
Derivative liabilities	66	—
Total current liabilities	1,068	829
Long-term debt, net	16,066	16,046
Non-current derivative liabilities	14	3
Other non-current liabilities	4	11
Other non-current liabilities—affiliate	22	25
Commitments and contingencies (see Note 16)		
Partners' equity		
Common unitholders' interest (348.6 million units issued and outstanding at December 31, 2018 and 2017)	1,806	1,670
Subordinated unitholders' interest (135.4 million units issued and outstanding at December 31, 2018 and 2017)	(990)	(1,043)
General partner's interest (2% interest with 9.9 million units issued and outstanding at December 31, 2018 and 2017)	(16)	12
Total partners' equity	800	639
Total liabilities and partners' equity	$17,974	$17,553

The accompanying notes are an integral part of these consolidated financial statements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Year Ended December 31,		
	2018	2017	2016
Revenues			
LNG revenues	$4,827	$2,635	$539
LNG revenues—affiliate	1,299	1,389	294
Regasification revenues	261	260	259
Other revenues	39	20	4
Other revenues—affiliate	—	—	4
Total revenues	6,426	4,304	1,100
Operating costs and expenses			
Cost of sales (excluding depreciation and amortization expense shown separately below)	3,403	2,320	410
Cost of sales—affiliate	—	—	2
Operating and maintenance expense	409	292	127
Operating and maintenance expense—affiliate	117	100	52
Development expense	2	3	—
General and administrative expense	11	12	13
General and administrative expense—affiliate	73	80	90
Depreciation and amortization expense	424	339	156
Impairment expense and loss on disposal of assets	8	—	—
Other	—	2	—
Total operating costs and expenses	4,447	3,148	850
Income from operations	1,979	1,156	250
Other income (expense)			
Interest expense, net of capitalized interest	(733)	(614)	(357)
Loss on modification or extinguishment of debt	(12)	(67)	(72)
Derivative gain, net	14	4	6
Other income	26	11	2
Total other expense	(705)	(666)	(421)
Net income (loss)	$1,274	$490	$(171)
Basic and diluted net income (loss) per common unit	$2.51	$(1.32)	$(0.20)
Weighted average number of common units outstanding used for basic and diluted net income (loss) per common unit calculation	348.6	178.5	57.1

The accompanying notes are an integral part of these consolidated financial statements.

63

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(in millions)

	Common Unitholders' Interest		Class B Unitholders' Interest		Subordinated Unitholder's Interest		General Partner's Interest		Total Partners' Equity
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	
Balance at December 31, 2015	57.1	$ 306	145.3	$ (37)	135.4	$ 427	6.9	$ 17	$ 713
Net loss	—	(50)	—	—	—	(117)	—	(4)	(171)
Distributions	—	(97)	—	—	—	—	—	(2)	(99)
Amortization of beneficial conversion feature of Class B units	—	(29)	—	99	—	(70)	—	—	—
Balance at December 31, 2016	57.1	130	145.3	62	135.4	240	6.9	11	443
Net income	—	294	—	—	—	186	—	10	490
Distributions	—	(226)	—	—	—	(59)	—	(9)	(294)
Conversion of Class B units into common units	291.5	2,066	(145.3)	(2,066)	—	—	3.0	—	—
Amortization of beneficial conversion feature of Class B units	—	(594)	—	2,004	—	(1,410)	—	—	—
Balance at December 31, 2017	348.6	1,670	—	—	135.4	(1,043)	9.9	12	639
Net income	—	899	—	—	—	349	—	26	1,274
Distributions	—	(763)	—	—	—	(296)	—	(54)	(1,113)
Balance at December 31, 2018	348.6	$ 1,806	—	$ —	135.4	$ (990)	9.9	$ (16)	$ 800

The accompanying notes are an integral part of these consolidated financial statements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2018	2017	2016
Cash flows from operating activities			
Net income (loss)	$1,274	$490	$(171)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense	424	339	156
Amortization of debt issuance costs, deferred commitment fees, premium and discount	30	36	30
Loss on modification or extinguishment of debt	12	67	72
Total losses (gains) on derivatives, net	87	20	(48)
Net cash provided by (used for) settlement of derivative instruments	32	(16)	(8)
Other	13	8	1
Changes in operating assets and liabilities:			
Accounts and other receivables	(122)	(101)	(90)
Accounts receivable—affiliate	47	(62)	(98)
Advances to affiliate	(84)	(12)	—
Inventory	(5)	13	(58)
Accounts payable and accrued liabilities	183	210	167
Due to affiliates	(6)	(42)	11
Deferred revenue	3	34	42
Other, net	(12)	(5)	(7)
Other, net—affiliate	(2)	(2)	1
Net cash provided by operating activities	1,874	977	—
Cash flows from investing activities			
Property, plant and equipment, net	(804)	(1,290)	(2,315)
Other	—	—	(38)
Net cash used in investing activities	(804)	(1,290)	(2,353)
Cash flows from financing activities			
Proceeds from issuances of debt	1,100	3,814	8,003
Repayments of debt	(1,090)	(2,173)	(5,251)
Debt issuance and deferred financing costs	(8)	(50)	(115)
Debt extinguishment costs	(7)	—	(14)
Distributions to owners	(1,113)	(294)	(99)
Net cash provided by (used in) financing activities	(1,118)	1,297	2,524
Net increase (decrease) in cash, cash equivalents and restricted cash	(48)	984	171
Cash, cash equivalents and restricted cash—beginning of period	1,589	605	434
Cash, cash equivalents and restricted cash—end of period	$1,541	$1,589	$605

Balances per Consolidated Balance Sheets:

	December 31,	
	2018	2017
Cash and cash equivalents	$—	$—

Restricted cash	1,541	1,589
Total cash, cash equivalents and restricted cash	$1,541	$1,589

The accompanying notes are an integral part of these consolidated financial statements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

We are a publicly traded Delaware limited partnership formed by Cheniere. Through SPL, we are developing, constructing and operating natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. We plan to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is undergoing commissioning and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability, potential overdesign and debottlenecking opportunities, of approximately 4.5 mtpa of LNG per Train, and run rate adjusted nominal production capacity of approximately 4.5 to 4.9 mtpa of LNG per Train. Through our wholly owned subsidiary, SPLNG, we own and operate regasification facilities at the Sabine Pass LNG terminal, which includes pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We also own a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through our wholly owned subsidiary, CTPL.

As of December 31, 2018, Cheniere owned 48.6% of our limited partner interest in the form of 104.5 million of our common units and 135.4 million of our subordinated units. Cheniere also owns 100% of our general partner interest and our incentive distribution rights.

NOTE 2—UNITHOLDERS' EQUITY

The common units and subordinated units represent limited partner interests in us. The holders of the units are entitled to participate in partnership distributions and exercise the rights and privileges available to limited partners under our partnership agreement. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement). Generally, our available cash is our cash on hand at the end of a quarter less the amount of any reserves established by our general partner. All distributions paid to date have been made from operating surplus as defined in the partnership agreement.

The holders of common units have the right to receive initial quarterly distributions of $0.425 per common unit, plus any arrearages thereon, before any distribution is made to the holders of the subordinated units. The holders of subordinated units will receive distributions only to the extent we have available cash above the initial quarterly distribution requirement for our common unitholders and general partner and certain reserves. Subordinated units will convert into common units on a one-for-one basis when we meet financial tests specified in the partnership agreement. Although common and subordinated unitholders are not obligated to fund losses of the Partnership, their capital accounts, which would be considered in allocating the net assets of the Partnership were it to be liquidated, continue to share in losses.

The general partner interest is entitled to at least 2% of all distributions made by us. In addition, the general partner holds incentive distribution rights ("IDRs"), which allow the general partner to receive a higher percentage of quarterly distributions of available cash from operating surplus after the initial quarterly distributions have been achieved and as additional target levels are met, but may transfer these rights separately from its general partner interest. The higher percentages range from 15% to 50%, inclusive of the general partner interest.

During the year ended December 31, 2018, Cheniere Energy Partners LP Holdings, LLC (“Cheniere Holdings”), which holds limited partner interests in us, merged with a wholly owned subsidiary of Cheniere. As of December 31, 2018, Cheniere, Blackstone CQP Holdco and the public own a 48.6%, 40.3% and 9.1% interest in us, respectively. Cheniere’s ownership percentage includes its subordinated units and Blackstone CQP Holdco’s ownership percentage excludes any common units that may be deemed to be beneficially owned by Blackstone Group, an affiliate of Blackstone CQP Holdco.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 3—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements have been prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of Cheniere Partners and its majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications did not have a material effect on our consolidated financial position, results of operations or cash flows.

On January 1, 2018, we adopted ASU 2014-09, Revenue from Contracts with Customers (Topic 606), and subsequent amendments thereto ("ASC 606") using the full retrospective method. We have elected to adopt the new accounting standard retrospectively and have recast the accompanying Consolidated Financial Statements to reflect the adoption of ASC 606 for all periods presented. The adoption of ASC 606 did not impact our previously reported Consolidated Financial Statements in any prior period nor did it result in a cumulative effect adjustment to retained earnings.

Use of Estimates

The preparation of Consolidated Financial Statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and the accompanying notes. Management evaluates its estimates and related assumptions regularly, including those related to the recoverability of property, plant and equipment, derivative instruments, asset retirement obligations ("AROs") and fair value measurements. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation approaches used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

In determining fair value, we use observable market data when available, or models that incorporate observable market data. In addition to market information, we incorporate transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value. We maximize the use of observable inputs and minimize our use of unobservable inputs in arriving at fair value estimates.

Recurring fair-value measurements are performed for derivative instruments as disclosed in Note 8—Derivative Instruments. The carrying amount of cash and cash equivalents, restricted cash, accounts receivable and accounts payable reported on the Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount we would have to pay to repurchase our debt in the open market, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in Note 11—Debt, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments using observable or unobservable inputs. Non-financial assets and liabilities initially measured at fair value include intangible assets and AROs.

Revenue Recognition

We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration to which we expect to be entitled to in exchange for those goods or services. Revenues from the sale of LNG are recognized as LNG revenues. LNG regasification capacity payments are recognized as regasification revenues. See Note 12—Revenues from Contracts with Customers for further discussion of revenues.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Restricted Cash

Restricted cash consists of funds that are contractually restricted as to usage or withdrawal and have been presented separately from cash and cash equivalents on our Consolidated Balance Sheets.

Accounts Receivable

Accounts receivable is reported net of allowances for doubtful accounts. Impaired receivables are specifically identified and evaluated for expected losses. The expected loss on impaired receivables is primarily determined based on the debtor's ability to pay and the estimated value of any collateral. We did not recognize any impairment expense related to accounts receivable during the years ended December 31, 2018, 2017 and 2016.

Inventory

LNG and natural gas inventory are recorded at the lower of weighted average cost and net realizable value. Materials and other inventory are recorded at the lower of cost and net realizable value and subsequently charged to expense when issued.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of our LNG terminals once the individual project meets the following criteria: (1) regulatory approval has been received, (2) financing for the project is available and (3) management has committed to commence construction. Prior to meeting these criteria, most of the costs associated with a project are expensed as incurred. These costs primarily include professional fees associated with front-end engineering and design work, costs of securing necessary regulatory approvals and other preliminary investigation and development activities related to our LNG terminals.

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land and lease option costs that are capitalized as property, plant and equipment and certain permits that are capitalized as other non-current assets. The costs of lease options are amortized over the life of the lease once obtained. If no land or lease is obtained, the costs are expensed.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction and commissioning activities, major renewals and betterments that extend the useful life of an asset are capitalized, while expenditures for maintenance and repairs (including those for planned major maintenance projects) to maintain property, plant and equipment in operating condition are generally expensed as incurred. We realize offsets to LNG terminal costs for sales of commissioning cargoes that were earned or loaded prior to the start of commercial operations of the respective Train during the testing phase for its construction. We depreciate our property, plant and equipment using the straight-line depreciation method. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed from the account, and the resulting gains or losses are recorded in impairment expense and loss (gain) on disposal of assets.

Management tests property, plant and equipment for impairment whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets for purposes of assessing recoverability. Recoverability generally is determined by comparing the carrying value of the asset to the expected undiscounted future cash flows of the asset. If the carrying value of the asset is not recoverable, the amount of impairment loss is measured as the excess, if any, of the carrying value of the asset over its estimated fair value. We did not recognize any impairment expense related to property, plant and equipment during the years ended December 31, 2018, 2017 and 2016.

Interest Capitalization

We capitalize interest and other related debt costs during the construction period of our LNG terminals and related pipelines as construction-in-process. Upon commencement of operations, these costs are transferred out of construction-in-process into terminal and interconnecting pipeline facilities assets and are amortized over the estimated useful life of the asset.

Regulated Natural Gas Pipelines

The Creole Trail Pipeline is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The economic effects of regulation can result in a regulated company recording as assets those costs that have been or are expected to be approved for recovery from customers, or recording as liabilities those amounts that are expected to be required to be returned to customers, in a rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated rate-making process that may not be recorded under GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, we believe the existing regulatory assets are probable of recovery. These regulatory assets and liabilities are primarily classified in our Consolidated Balance Sheets as other assets and other liabilities. We periodically evaluate their applicability under GAAP and consider factors such as regulatory changes and the effect of competition. If cost-based regulation ends or competition increases, we may have to reduce our asset balances to reflect a market basis less than cost and write off the associated regulatory assets and liabilities.

Items that may influence our assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the rate-making process and the FERC proceedings;
- excess capacity;
- increased competition and discounting in the markets we serve; and
- impacts of ongoing regulatory initiatives in the natural gas industry.

Natural gas pipeline costs include amounts capitalized as an Allowance for Funds Used During Construction ("AFUDC"). The rates used in the calculation of AFUDC are determined in accordance with guidelines established by the FERC. AFUDC represents the cost of debt and equity funds used to finance our natural gas pipeline additions during construction. AFUDC is capitalized as a part of the cost of our natural gas pipelines. Under regulatory rate practices, we generally are permitted to recover AFUDC, and a fair return thereon, through our rate base after our natural gas pipelines are placed in service.

Derivative Instruments

We use derivative instruments to hedge our exposure to cash flow variability from interest rate and commodity price risk. Derivative instruments are recorded at fair value and included in our Consolidated Balance Sheets as assets or liabilities depending on the derivative position and the expected timing of settlement, unless they satisfy criteria for and we elect the normal purchases and sales exception. When we have the contractual right and intend to net settle, derivative assets and liabilities are reported on a net basis.

Changes in the fair value of our derivative instruments are recorded in earnings, unless we elect to apply hedge accounting and meet specified criteria, including completing contemporaneous hedge documentation. We did not have any derivative instruments designated as cash flow hedges during the years ended December 31, 2018, 2017 and 2016. See Note 8—Derivative Instruments for additional details about our derivative instruments.

Concentration of Credit Risk

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash and cash equivalents and restricted cash. We maintain cash balances at financial institutions, which may at times be in excess of federally insured levels. We have not incurred losses related to these balances to date.

The use of derivative instruments exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. Certain of our commodity derivative transactions are executed through over-the-counter contracts which are subject to nominal credit risk as these transactions are settled on a daily margin basis with investment grade financial institutions. Collateral deposited for such contracts is recorded within other current assets. Our interest rate derivative instruments are placed with investment grade financial institutions whom we believe are acceptable credit risks. We monitor counterparty creditworthiness on an ongoing basis; however, we cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

changes are not sudden, we may be limited in our ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, we may not realize the benefit of some of our derivative instruments.

SPL has entered into fixed price SPAs with terms of at least 20 years with seven unaffiliated third parties. SPL is dependent on the respective customers' creditworthiness and their willingness to perform under their respective SPAs. See Note 17—Customer Concentration for additional details about our customer concentration.

SPLNG has entered into two long-term TUAs with unaffiliated third parties for regasification capacity at the Sabine Pass LNG terminal. SPLNG is dependent on the respective customers' creditworthiness and their willingness to perform under their respective TUAs. SPLNG has mitigated this credit risk by securing TUAs for a significant portion of its regasification capacity with creditworthy third-party customers with a minimum Standard & Poor's rating of A.

Debt

Our debt consists of current and long-term secured debt securities and credit facilities with banks and other lenders. Debt issuances are placed directly by us or through securities dealers or underwriters and are held by institutional and retail investors.

Debt is recorded on our Consolidated Balance Sheets at par value adjusted for unamortized discount or premium and net of unamortized debt issuance costs related to term notes. Discounts, premiums and debt issuance costs directly related to the issuance of debt are amortized over the life of the debt and are recorded in interest expense, net of capitalized interest using the effective interest method. Gains and losses on the extinguishment of debt are recorded in gain (loss) on modification or extinguishment of debt on our Consolidated Statements of Operations.

Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees and printing costs. These costs are recorded as a direct deduction from the debt liability unless incurred in connection with a line of credit arrangement, in which case they are presented as an asset on our Consolidated Balance Sheets. Debt issuance costs are amortized to interest expense or property, plant and equipment over the term of the related debt facility. Upon early retirement of debt or amendment to a debt agreement, certain fees are written off to loss on modification or extinguishment of debt.

Asset Retirement Obligations

We recognize AROs for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset and for conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within our control. The fair value of a liability for an ARO is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

We have not recorded an ARO associated with the Sabine Pass LNG terminal. Based on the real property lease agreements at the Sabine Pass LNG terminal, at the expiration of the term of the leases we are required to surrender the LNG terminal in good working order and repair, with normal wear and tear and casualty expected. Our property lease agreements at the Sabine Pass LNG terminal have terms of up to 90 years including renewal options. We have determined that the cost to surrender the Sabine Pass LNG terminal in good order and repair, with normal wear and tear and casualty expected, is immaterial.

We have not recorded an ARO associated with the Creole Trail Pipeline. We believe that it is not feasible to predict when the natural gas transportation services provided by the Creole Trail Pipeline will no longer be utilized. In addition, our right-of-way agreements associated with the Creole Trail Pipeline have no stipulated termination dates. We intend to operate the Creole Trail Pipeline as long as supply and demand for natural gas exists in the United States and intend to maintain it regularly.

Income Taxes

We are not subject to federal or state income taxes, as our partners are taxed individually on their allocable share of our taxable income. At December 31, 2018, the tax basis of our assets and liabilities was $3.4 billion less than the reported amounts of our assets and liabilities. See Note 13—Related Party Transactions for details about income taxes under our tax sharing agreements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Business Segment

Our liquefaction and regasification operations at the Sabine Pass LNG terminal represent a single reportable segment. Our chief operating decision maker reviews the financial results of Cheniere Partners in total when evaluating financial performance and for purposes of allocating resources.

NOTE 4—RESTRICTED CASH

Restricted cash consists of funds that are contractually restricted as to usage or withdrawal and have been presented separately from cash and cash equivalents on our Consolidated Balance Sheets. As of December 31, 2018 and 2017, restricted cash consisted of the following (in millions):

	December 31,	
	2018	2017
Current restricted cash		
Liquefaction Project	$756	$544
Cash held by us and our guarantor subsidiaries	785	1,045
Total current restricted cash	$1,541	$1,589

Pursuant to the accounts agreement entered into with the collateral trustee for the benefit of SPL's debt holders, SPL is required to deposit all cash received into reserve accounts controlled by the collateral trustee. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the Liquefaction Project and other restricted payments.

Under our credit facilities (the "CQP Credit Facilities"), we and each of our subsidiaries other than SPL, as our guarantor subsidiaries, are subject to limitations on the use of cash under the terms of the CQP Credit Facilities and the related depositary agreement governing the extension of credit to us. Specifically, we may only withdraw funds from collateral accounts held at a designated depositary bank on a limited basis and for specific purposes, including for the payment of our operating expenses and the operating expenses of our guarantor subsidiaries. In addition, distributions and capital expenditures may only be made quarterly and are subject to certain restrictions.

NOTE 5—ACCOUNTS AND OTHER RECEIVABLES

As of December 31, 2018 and 2017, accounts and other receivables consisted of the following (in millions):

	December 31,	
	2018	2017
SPL trade receivable	$330	$185
Other accounts receivable	18	6
Total accounts and other receivables	$348	$191

NOTE 6—INVENTORY

As of December 31, 2018 and 2017, inventory consisted of the following (in millions):

	December 31,	
	2018	2017
Natural gas	$28	$17

LNG	6	26
Materials and other	65	52
Total inventory	$ 99	$ 95

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 7—PROPERTY, PLANT AND EQUIPMENT

As of December 31, 2018 and 2017, property, plant and equipment, net consisted of the following (in millions):

	December 31,	
	2018	2017
LNG terminal costs		
LNG terminal and interconnecting pipeline facilities	$12,760	$12,703
LNG terminal construction-in-process	3,913	3,310
Accumulated depreciation	(1,290)	(880)
Total LNG terminal costs, net	15,383	15,133
Fixed assets		
Fixed assets	26	23
Accumulated depreciation	(19)	(17)
Total fixed assets, net	7	6
Property, plant and equipment, net	$15,390	$15,139

Depreciation expense was $413 million, $331 million and $148 million during the years ended December 31, 2018, 2017 and 2016, respectively.

We realize offsets to LNG terminal costs for sales of commissioning cargoes that were earned or loaded prior to the start of commercial operations of the respective Train during the testing phase for its construction. We realized offsets to LNG terminal costs of $94 million, $301 million and $201 million in the years ended December 31, 2018, 2017 and 2016, respectively, for sales of commissioning cargoes from the Liquefaction Project.

LNG Terminal Costs

The Sabine Pass LNG terminal is depreciated using the straight-line depreciation method applied to groups of LNG terminal assets with varying useful lives. The identifiable components of the Sabine Pass LNG terminal with similar estimated useful lives have a depreciable range between 6 and 50 years, as follows:

Components	Useful life (yrs)
LNG storage tanks	50
Natural gas pipeline facilities	40
Marine berth, electrical, facility and roads	35
Water pipelines	30
Regasification processing equipment	30
Sendout pumps	20
Liquefaction processing equipment	6-50
Other	15-30

Fixed Assets and Other

Our fixed assets and other are recorded at cost and are depreciated on a straight-line method based on estimated lives of the individual assets or groups of assets.

NOTE 8—DERIVATIVE INSTRUMENTS

We have entered into the following derivative instruments that are reported at fair value:

- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under certain credit facilities ("Interest Rate Derivatives") and
- commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the Liquefaction Project ("Physical Liquefaction Supply Derivatives") and associated economic hedges ("Financial Liquefaction Supply Derivatives," and collectively with the Physical Liquefaction Supply Derivatives, the "Liquefaction Supply Derivatives");

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

We recognize our derivative instruments as either assets or liabilities and measure those instruments at fair value. None of our derivative instruments are designated as cash flow hedging instruments, and changes in fair value are recorded within our Consolidated Statements of Operations to the extent not utilized for the commissioning process.

The following table shows the fair value of our derivative instruments that are required to be measured at fair value on a recurring basis as of December 31, 2018 and 2017, which are classified as other current assets, non-current derivative assets, derivative liabilities or non-current derivative liabilities in our Consolidated Balance Sheets (in millions).

	Fair Value Measurements as of							
	December 31, 2018				December 31, 2017			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
CQP Interest Rate Derivatives asset	$ —	$ —	$ —	$ —	$ —	$ 21	$ —	$ 21
Liquefaction Supply Derivatives asset (liability)	5	(23)	(25)	(43)	2	10	43	55

We value our Interest Rate Derivatives using an income-based approach, utilizing observable inputs to the valuation model including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data. We value our Liquefaction Supply Derivatives using a market based approach incorporating present value techniques, as needed, using observable commodity price curves, when available, and other relevant data.

The fair value of our Physical Liquefaction Supply Derivatives is predominantly driven by market commodity basis prices and our assessment of the associated conditions precedent, including evaluating whether the respective market is available as pipeline infrastructure is developed. Upon the satisfaction of conditions precedent, including completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow, we recognize a gain or loss based on the fair value of the respective natural gas supply contracts.

We include a portion of our Physical Liquefaction Supply Derivatives as Level 3 within the valuation hierarchy as the fair value is developed through the use of internal models which may be impacted by inputs that are unobservable in the marketplace. The curves used to generate the fair value of our Physical Liquefaction Supply Derivatives are based on basis adjustments applied to forward curves for a liquid trading point. In addition, there may be observable liquid market basis information in the near term, but terms of a Physical Liquefaction Supply Derivatives contract may exceed the period for which such information is available, resulting in a Level 3 classification. In these instances, the fair value of the contract incorporates extrapolation assumptions made in the determination of the market basis price for future delivery periods in which applicable commodity basis prices were either not observable or lacked corroborative market data.

The Level 3 fair value measurements of natural gas positions within our Physical Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas market basis spreads due to the contractual notional amount represented by our Level 3 positions, which is a substantial portion of our overall Physical Liquefaction Supply Derivatives portfolio. The following table includes quantitative information for the unobservable inputs for our Level 3 Physical Liquefaction Supply Derivatives as of December 31, 2018:

	Net Fair Value Liability (in millions)	Valuation Approach	Significant Unobservable Input	Significant Unobservable Inputs Range
Physical Liquefaction Supply Derivatives	$(25)	Market approach incorporating present value techniques	Basis Spread	$(0.892) - $0.085

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The following table shows the changes in the fair value of our Level 3 Physical Liquefaction Supply Derivatives during the years ended December 31, 2018, 2017 and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
Balance, beginning of period	$ 43	$ 79	$ 32
Realized and mark-to-market gains (losses):			
Included in cost of sales (1)	(3)	(37)	48
Purchases and settlements:			
Purchases	(37)	14	1
Settlements (1)	(29)	(12)	(2)
Transfers out of Level 3 (2)	1	(1)	—
Balance, end of period	$ (25)	$ 43	$ 79
Change in unrealized gains (losses) relating to instruments still held at end of period	$ (3)	$ (37)	$ 49

(1) Does not include the decrease in fair value of $1 million related to the realized gains capitalized during the year ended December 31, 2016.
(2) Transferred to Level 2 as a result of observable market for the underlying natural gas purchase agreements.

Derivative assets and liabilities arising from our derivative contracts with the same counterparty are reported on a net basis, as all counterparty derivative contracts provide for net settlement. The use of derivative instruments exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments in instances when our derivative instruments are in an asset position. Additionally, we evaluate our own ability to meet our commitments in instances where our derivative instruments are in a liability position. Our derivative instruments are subject to contractual provisions which provide for the unconditional right of set-off for all derivative assets and liabilities with a given counterparty in the event of default.

Interest Rate Derivatives

We previously had interest rate swaps (“CQP Interest Rate Derivatives”) to hedge a portion of the variable interest payments on the CQP Credit Facilities, based on a portion of the expected outstanding borrowings over the term of the CQP Credit Facilities. In September 2018, we terminated approximately $1.2 billion of commitments under the CQP Credit Facilities, as discussed in Note 11—Debt. In October 2018, we terminated the CQP Interest Rate Derivatives related to the CQP Credit Facilities, which resulted in proceeds of $28 million.

SPL previously had interest rate swaps (“SPL Interest Rate Derivatives”) to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the credit facilities it entered into in June 2015 (the

“SPL Credit Facilities”), based on a portion of the expected outstanding borrowings over the term of the SPL Credit Facilities. In March 2017, SPL settled the SPL Interest Rate Derivatives and paid $7 million in conjunction with the termination of approximately $1.6 billion of commitments under the SPL Credit Facilities.

The following table shows the fair value and location of the CQP Interest Rate Derivatives on our Consolidated Balance Sheets (in millions):

	December 31,	
Consolidated Balance Sheet Location	2018	2017
Other current assets	$ —	$ 7
Non-current derivative assets	—	14
Total derivative assets	$ —	$ 21

The following table shows the changes in the fair value and settlements of our Interest Rate Derivatives recorded in derivative gain, net on our Consolidated Statements of Operations during the years ended December 31, 2018, 2017 and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
CQP Interest Rate Derivatives gain	$ 14	$ 6	$ 12
SPL Interest Rate Derivatives loss	—	(2)	(6)

74

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Liquefaction Supply Derivatives

SPL has entered into primarily index-based physical natural gas supply contracts and associated economic hedges to purchase natural gas for the commissioning and operation of the Liquefaction Project. The terms of the physical natural gas supply contracts range up to six years, some of which commence upon the satisfaction of certain conditions precedent.

Our Financial Liquefaction Supply Derivatives are executed through over-the-counter contracts which are subject to nominal credit risk as these transactions are settled on a daily margin basis with investment grade financial institutions. We are required by these financial institutions to use margin deposits as credit support for our Financial Liquefaction Supply Derivatives activities.

SPL had secured up to approximately 3,464 TBtu and 2,214 TBtu of natural gas feedstock through natural gas supply contracts as of December 31, 2018 and 2017, respectively. The notional natural gas position of our Liquefaction Supply Derivatives was approximately 2,978 TBtu and 1,520 TBtu as of December 31, 2018 and 2017, respectively.

The following table shows the fair value and location of our Liquefaction Supply Derivatives on our Consolidated Balance Sheets (in millions):

	Fair Value Measurements as of (1)	
Consolidated Balance Sheet Location	December 31, 2018	December 31, 2017
Other current assets	$ 6	$ 41
Non-current derivative assets	31	17
Total derivative assets	37	58
Derivative liabilities	(66)	—
Non-current derivative liabilities	(14)	(3)
Total derivative liabilities	(80)	(3)
Derivative asset (liability), net	$ (43)	$ 55

(1) Does not include collateral calls of $1 million as of both December 31, 2018 and 2017 for such contracts, which are included in other current assets in our Consolidated Balance Sheets.

The following table shows the changes in the fair value, settlements and location of our Liquefaction Supply Derivatives on our Consolidated Statements of Operations during the years ended December 31, 2018, 2017 and 2016 (in millions):

		Year Ended December 31,		
	Statement of Operations Location (1)	2018	2017	2016
Liquefaction Supply Derivatives loss	LNG revenues	$(1)	$ —	$ —
Liquefaction Supply Derivatives gain (loss)	Cost of sales	(100)	(24)	42

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery. Fair value fluctuations associated with commodity derivative activities are classified and presented consistently with the item economically hedged and the nature and intent of the derivative instrument.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Consolidated Balance Sheet Presentation

Our derivative instruments are presented on a net basis on our Consolidated Balance Sheets as described above. The following table shows the fair value of our derivatives outstanding on a gross and net basis (in millions):

Offsetting Derivative Assets (Liabilities)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
As of December 31, 2018			
Liquefaction Supply Derivatives	$ 63	$ (26)	$ 37
Liquefaction Supply Derivatives	(92)	12	(80)
As of December 31, 2017			
CQP Interest Rate Derivatives	$ 21	$ —	$ 21
Liquefaction Supply Derivatives	64	(6)	58
Liquefaction Supply Derivatives	(3)	—	(3)

NOTE 9—OTHER NON-CURRENT ASSETS

As of December 31, 2018 and 2017, other non-current assets, net consisted of the following (in millions):

	December 31,	
	2018	2017
Advances made under EPC and non-EPC contracts	$14	$26
Advances made to municipalities for water system enhancements	90	93
Advances and other asset conveyances to third parties to support LNG terminals	36	30
Tax-related payments and receivables	17	25
Information technology service assets	20	24
Other	7	8
Total other non-current assets, net	$184	$206

NOTE 10—ACCRUED LIABILITIES

As of December 31, 2018 and 2017, accrued liabilities consisted of the following (in millions):

	December 31,	
	2018	2017
Interest costs and related debt fees	$ 224	$ 253
Accrued natural gas purchases	518	298
LNG terminal and related pipeline costs	79	86
	$ 821	$ 637

Total accrued liabilities	

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 11—DEBT

As of December 31, 2018 and 2017, our debt consisted of the following (in millions):

	December 31,	
	2018	2017
Long-term debt:		
SPL		
5.625% Senior Secured Notes due 2021 (“2021 SPL Senior Notes”)	$2,000	$2,000
6.25% Senior Secured Notes due 2022 (“2022 SPL Senior Notes”)	1,000	1,000
5.625% Senior Secured Notes due 2023 (“2023 SPL Senior Notes”)	1,500	1,500
5.75% Senior Secured Notes due 2024 (“2024 SPL Senior Notes”)	2,000	2,000
5.625% Senior Secured Notes due 2025 (“2025 SPL Senior Notes”)	2,000	2,000
5.875% Senior Secured Notes due 2026 (“2026 SPL Senior Notes”)	1,500	1,500
5.00% Senior Secured Notes due 2027 (“2027 SPL Senior Notes”)	1,500	1,500
4.200% Senior Secured Notes due 2028 (“2028 SPL Senior Notes”)	1,350	1,350
5.00% Senior Secured Notes due 2037 (“2037 SPL Senior Notes”)	800	800
Cheniere Partners		
5.250% Senior Notes due 2025 (“2025 CQP Senior Notes”)	1,500	1,500
5.625% Senior Notes due 2026 (“2026 CQP Senior Notes”)	1,100	—
CQP Credit Facilities	—	1,090
Unamortized premium, discount and debt issuance costs, net	(184)	(194)
Total long-term debt, net	16,066	16,046
Current debt:		
$1.2 billion SPL Working Capital Facility (“SPL Working Capital Facility”)	—	—
Total debt, net	$16,066	$16,046

Below is a schedule of future principal payments that we are obligated to make, based on current construction schedules, on our outstanding debt at December 31, 2018 (in millions):

Years Ending December 31,	Principal Payments
2019	$ —
2020	—
2021	2,000
2022	1,000
2023	1,500
Thereafter	11,750
Total	$ 16,250

Senior Notes

SPL Senior Notes

The terms of the 2021 SPL Senior Notes, 2022 SPL Senior Notes, 2023 SPL Senior Notes, 2024 SPL Senior Notes, 2025 SPL Senior Notes, 2026 SPL Senior Notes, 2027 SPL Senior Notes and 2028 SPL Senior Notes (collectively with the 2037 SPL Senior Notes, the “SPL Senior Notes”) are governed by a common indenture (the “SPL Indenture”) and the terms of the 2037 SPL Senior Notes are governed by a separate indenture (the “2037 SPL Senior Notes Indenture”). Both the SPL Indenture and the 2037 SPL Senior Notes Indenture contain customary terms and events of default and certain covenants that, among other things, limit SPL’s ability and the ability of SPL’s restricted subsidiaries to incur additional indebtedness or issue preferred stock, make certain investments or pay dividends or distributions on capital stock or subordinated indebtedness or purchase, redeem or retire capital stock, sell or transfer assets, including capital stock of SPL’s restricted subsidiaries, restrict dividends or other payments by restricted subsidiaries, incur liens, enter into transactions with affiliates, dissolve, liquidate, consolidate, merge, sell or lease all or substantially all of SPL’s assets and enter into certain LNG sales contracts. Subject to permitted liens, the SPL Senior Notes are secured on a pari passu first-priority basis by a security interest in all of the membership interests in SPL and substantially all of SPL's assets. SPL may not make any distributions until, among other requirements, deposits are made into debt service reserve accounts as required and a debt service coverage ratio test of 1.25:1.00 is satisfied. Semi-annual principal payments for the 2037 SPL Senior Notes are due on March 15 and September 15 of each year beginning September 15, 2025. Interest on the SPL Senior Notes is payable semi-annually in arrears.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is six months before the respective dates of maturity), SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the "make-whole" price (except for the 2037 SPL Senior Notes, in which case the redemption price is equal to the "optional redemption" price) set forth in the respective indentures governing the SPL Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPL may also, at any time within three months of the respective maturity dates for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is within six months of the respective dates of maturity), redeem all or part of such series of the SPL Senior Notes at a redemption price equal to 100% of the principal amount of such series of the SPL Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

CQP Senior Notes

In September 2018, we issued an aggregate principal amount of $1.1 billion of the 2026 CQP Senior Notes. Net proceeds of the offering of approximately $1.1 billion, after deducting the initial purchasers' commissions and estimated fees and expenses, were used to prepay all of the outstanding indebtedness under the CQP Credit Facilities, resulting in the recognition of debt modification and extinguishment costs of $12 million for the year ended December 31, 2018 relating to the incurrence of third party fees and write off of unamortized debt issuance costs. Borrowings under the 2026 CQP Senior Notes accrue interest at a fixed rate of 5.625%.

The 2025 CQP Senior Notes and the 2026 CQP Senior Notes (collectively, the "CQP Senior Notes") are jointly and severally guaranteed by each of our subsidiaries other than SPL (the "Guarantors") and, subject to certain conditions governing its guarantee, Sabine Pass LP. The CQP Senior Notes are governed by the same base indenture (the "CQP Base Indenture"). The 2025 CQP Senior Notes are further governed by the First Supplemental Indenture (together with the CQP Base Indenture, the "2025 CQP Notes Indenture") and the 2026 CQP Senior Notes are further governed by the Second Supplemental Indenture (together with the CQP Base Indenture, the "2026 CQP Notes Indenture"). The 2025 CQP Notes Indenture and the 2026 CQP Notes Indenture contain customary terms and events of default and certain covenants that, among other things, limit our ability and the ability of the Guarantors to incur liens and sell assets, enter into transactions with affiliates, enter into sale-leaseback transactions and consolidate, merge or sell, lease or otherwise dispose of all or substantially all of the applicable entity's properties or assets. Interest on the CQP Senior Notes is payable semi-annually in arrears.

At any time prior to October 1, 2020 for the 2025 CQP Senior Notes and October 1, 2021 for the 2026 CQP Senior Notes, we may redeem all or a part of the applicable CQP Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the CQP Senior Notes redeemed, plus the "applicable premium" set forth in the respective indentures governing the CQP Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. In addition, at any time prior to October 1, 2020 for the 2025 CQP Senior Notes and October 1, 2021 for the 2026 CQP Senior Notes, we may redeem up to 35% of the aggregate principal amount of the CQP Senior Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price equal to 105.250% of the aggregate principal amount of the 2025 CQP Senior Notes and 105.625% of the aggregate principal amount of the 2026 CQP Senior Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption. We also may at any time on or after October 1, 2020 through the maturity date of October 1, 2025 for the 2025 CQP Senior Notes and October 1, 2021 through the maturity date of October 1, 2026 for the 2026 CQP Senior Notes, redeem the CQP Senior Notes, in whole or in part, at the redemption prices set forth in the respective indentures governing the CQP Senior Notes.

The CQP Senior Notes are our senior obligations, ranking equally in right of payment with our other existing and future unsubordinated debt and senior to any of our future subordinated debt. After applying the proceeds from the 2026 CQP Senior Notes, the CQP Senior Notes became unsecured. In the event that the aggregate amount of our secured indebtedness and the secured indebtedness of the Guarantors (other than the CQP Senior Notes or any other series of notes issued under the CQP Base Indenture) outstanding at any one time exceeds the greater of (1) $1.5 billion and (2) 10% of net tangible assets, the CQP Senior Notes will be secured to the same extent as such obligations under the CQP Credit Facilities. The obligations under the CQP Credit

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Facilities are secured on a first-priority basis (subject to permitted encumbrances) with liens on (1) substantially all the existing and future tangible and intangible assets and our rights and the rights of the Guarantors and equity interests in the Guarantors (except, in each case, for certain excluded properties set forth in the CQP Credit Facilities) and (2) substantially all of the real property of SPLNG (except for excluded properties referenced in the CQP Credit Facilities). The liens securing the CQP Senior Notes, if applicable, will be shared equally and ratably (subject to permitted liens) with the holders of other senior secured obligations, which include the CQP Credit Facilities obligations and any future additional senior secured debt obligations.

In connection with the closing of the 2026 CQP Senior Notes offering, we and the Guarantors entered into a registration rights agreement (the “CQP Registration Rights Agreement”). Under the CQP Registration Rights Agreement, we and the Guarantors have agreed to file with the SEC and cause to become effective a registration statement relating to an offer to exchange any and all of the 2026 CQP Senior Notes for a like aggregate principal amount of our debt securities with terms identical in all material respects to the 2026 CQP Senior Notes sought to be exchanged (other than with respect to restrictions on transfer or to any increase in annual interest rate), within 360 days after the notes issuance date of September 11, 2018. Under specified circumstances, we and the Guarantors have also agreed to cause to become effective a shelf registration statement relating to resales of the 2026 CQP Senior Notes. We will be obligated to pay additional interest on the 2026 CQP Senior Notes if we fail to comply with our obligation to register the 2026 CQP Senior Notes within the specified time period.

Credit Facilities

Below is a summary of our credit facilities outstanding as of December 31, 2018 (in millions):

	SPL Working Capital Facility	CQP Credit Facilities
Original facility size	$ 1,200	$ 2,800
Less:		
Outstanding balance	—	—
Commitments prepaid or terminated	—	2,685
Letters of credit issued	425	—
Available commitment	$ 775	$ 115
Interest rate	LIBOR plus 1.75% or base rate plus 0.75%	2.25% of the undrawn portion with a 0.50% step-up beginning on February 25, 2019
Maturity date	December 31, 2020, with	February 25, 2020

various
terms for
underlying
loans

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility, which is intended to be used for loans to SPL ("Working Capital Loans"), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL ("Swing Line Loans"), primarily for certain working capital requirements related to developing and placing into operation the Liquefaction Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and, upon the completion of the debt financing of Train 6 of the Liquefaction Project, request an incremental increase in commitments of up to an additional $390 million.

Loans under the SPL Working Capital Facility accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of the senior facility agent's published prime rate, the federal funds effective rate, as published by the Federal Reserve Bank of New York, plus 0.50% and one month LIBOR plus 0.50%), plus the applicable margin. The applicable margin for LIBOR loans under the SPL Working Capital Facility is 1.75% per annum, and the applicable margin for base rate loans under the SPL Working Capital Facility is 0.75% per annum. Interest on Swing Line Loans and loans deemed made in connection with a draw upon a letter of credit ("LC Loans") is due and payable on the date the loan becomes due. Interest on LIBOR loans is due and payable at the end of each applicable LIBOR period, and interest on base rate loans is due and payable at the end of each fiscal quarter. However, if such base rate loan is converted into a LIBOR loan, interest is due and payable on that date. Additionally, if the loans become due prior to such periods, the interest also becomes due on that date.

SPL pays (1) a commitment fee equal to an annual rate of 0.70% on the average daily amount of the excess of the total commitment amount over the principal amount outstanding without giving effect to any outstanding Swing Line Loans and (2) a letter of credit fee equal to an annual rate of 1.75% of the undrawn portion of all letters of credit issued under the SPL Working Capital Facility. If draws are made upon a letter of credit issued under the SPL Working Capital Facility and SPL does not elect for such draw (an “LC Draw”) to be deemed an LC Loan, SPL is required to pay the full amount of the LC Draw on or prior to the business day following the notice of the LC Draw. An LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2018, no LC Draws had been made upon any letters of credit issued under the SPL Working Capital Facility.

The SPL Working Capital Facility matures on December 31, 2020, and the outstanding balance may be repaid, in whole or in part, at any time without premium or penalty upon three business days’ notice. LC Loans have a term of up to one year. Swing Line Loans terminate upon the earliest of (1) the maturity date or earlier termination of the SPL Working Capital Facility, (2) the date 15 days after such Swing Line Loan is made and (3) the first borrowing date for a Working Capital Loan or Swing Line Loan occurring at least three business days following the date the Swing Line Loan is made. SPL is required to reduce the aggregate outstanding principal amount of all Working Capital Loans to zero for a period of five consecutive business days at least once each year.

The SPL Working Capital Facility contains conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. The obligations of SPL under the SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a pari passu basis with the SPL Senior Notes.

CQP Credit Facilities

In February 2016, we entered into the CQP Credit Facilities. The CQP Credit Facilities originally consisted of: (1) a $450 million CTPL tranche term loan that was used to prepay the $400 million term loan facility in February 2016, (2) an approximately $2.1 billion SPLNG tranche term loan that was used to repay and redeem in November 2016 the approximately $2.1 billion of the senior notes previously issued by SPLNG, (3) a $125 million facility that could be used to satisfy a six-month debt service reserve requirement and (4) a $115 million revolving credit facility that may be used for general business purposes. In September 2017 and September 2018, we issued the 2025 CQP Senior Notes and the 2026 CQP Senior Notes, respectively, and the net proceeds were used to prepay the outstanding term loans under the CQP Credit Facilities. As of December 31, 2018, only a $115 million revolving credit facility, which is currently undrawn, remains as part of the CQP Credit Facilities. We pay a commitment fee equal to an annual rate of 40% of the margin for LIBOR loans multiplied by the average daily amount of the undrawn commitment, payable quarterly in arrears. The revolving credit facility is available for the issuance of letters of credit, which incurs a fee equal to an annual rate of 2.25% of the undrawn portion with a 0.50% step-up beginning on February 25, 2019.

The CQP Credit Facilities mature on February 25, 2020. Any outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest hedging and interest rate breakage costs. The CQP Credit Facilities contain conditions precedent for extensions of credit, as well as customary affirmative and negative covenants and limit our ability to make restricted payments, including distributions, to once per fiscal quarter as long as certain conditions are satisfied. Under the CQP Credit Facilities, we are required to hedge not less than 50% of the variable interest rate exposure on its projected aggregate outstanding balance, maintain a minimum debt service coverage ratio of at least 1.15x at the end of each fiscal quarter beginning March 31, 2019 and have a projected debt service coverage ratio of 1.55x in order to incur additional indebtedness to refinance a portion of the existing obligations.

The CQP Credit Facilities are unconditionally guaranteed by each of our subsidiaries other than (1) SPL and (2) certain of our subsidiaries owning other development projects, as well as certain other specified subsidiaries and members of the foregoing entities.

Restrictive Debt Covenants

As of December 31, 2018, we and SPL were in compliance with all covenants related to our respective debt agreements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Interest Expense

Total interest expense consisted of the following (in millions):

	Year Ended December 31,		
	2018	2017	2016
Total interest cost	$936	$902	$841
Capitalized interest	(203)	(288)	(484)
Total interest expense, net	$733	$614	$357

Fair Value Disclosures

The following table shows the carrying amount, which is net of unamortized premium, discount and debt issuance costs, and estimated fair value of our debt (in millions):

	December 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes (1)	$15,275	$ 15,672	$14,166	$ 15,485
2037 SPL Senior Notes (2)	791	817	790	871
Credit facilities (3)	—	—	1,090	1,090

(1) Includes 2021 SPL Senior Notes, 2022 SPL Senior Notes, 2023 SPL Senior Notes, 2024 SPL Senior Notes, 2025 SPL Senior Notes, 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes, 2025 CQP Senior Notes and 2026 CQP Senior Notes. The Level 2 estimated fair value was based on quotes obtained from broker-dealers or market makers of these senior notes and other similar instruments.

(2) The Level 3 estimated fair value was calculated based on inputs that are observable in the market or that could be derived from, or corroborated with, observable market data, including our stock price and interest rates based on debt issued by parties with comparable credit ratings to us and inputs that are not observable in the market.

(3) Includes SPL Working Capital Facility and CQP Credit Facilities. The Level 3 estimated fair value approximates the principal amount because the interest rates are variable and reflective of market rates and the debt may be repaid, in full or in part, at any time without penalty.

NOTE 12—REVENUES FROM CONTRACTS WITH CUSTOMERS

The following table represents a disaggregation of revenue earned from contracts with customers during the years ended December 31, 2018, 2017 and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
LNG revenues	$4,687	$2,615	$535
LNG revenues—affiliate	1,299	1,389	294
Regasification revenues	261	260	259
Other revenues	39	20	4
Other revenues—affiliate	—	—	4
Total revenues from customers	6,286	4,284	1,096

Gains from derivative instruments (1)	140	20	4
Total revenues	$6,426	$4,304	$1,100

(1) Includes the realized value associated with a portion of derivative instruments that settle through physical delivery.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

LNG Revenues

We have entered into numerous SPAs with third party customers for the sale of LNG on a free on board (“FOB”) (delivered to the customer at the Sabine Pass LNG terminal) basis. Our customers generally purchase LNG for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. The fixed fee component is the amount payable to us regardless of a cancellation or suspension of LNG cargo deliveries by the customers. The variable fee component is the amount generally payable to us only upon delivery of LNG plus all future adjustments to the fixed fee for inflation. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train.

Revenues from the sale of LNG are recognized at a point in time when the LNG is delivered to the customer, at the Sabine Pass LNG terminal, which is the point legal title, physical possession and the risks and rewards of ownership transfer to the customer. Each individual molecule of LNG is viewed as a separate performance obligation. The stated contract price (including both fixed and variable fees) per MMBtu in each LNG sales arrangement is representative of the stand-alone selling price for LNG at the time the sale was negotiated. We have concluded that the variable fees meet the exception for allocating variable consideration to specific parts of the contract. As such, the variable consideration for these contracts is allocated to each distinct molecule of LNG and recognized when that distinct molecule of LNG is delivered to the customer. Because of the use of the exception, variable consideration related to the sale of LNG is also not included in the transaction price.

Fees received pursuant to SPAs are recognized as LNG revenues only after substantial completion of the respective Train. Prior to substantial completion, sales generated during the commissioning phase are offset against the cost of construction for the respective Train, as the production and removal of LNG from storage is necessary to test the facility and bring the asset to the condition necessary for its intended use.

Regasification Revenues

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4.0 Bcf/d. Approximately 2.0 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term TUAs with unaffiliated third-party customers, under which they are required to pay fixed monthly fees regardless of their use of the LNG terminal. Each of the customers has reserved approximately 1.0 Bcf/d of regasification capacity. The customers are each obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009, which is representative of fixed consideration in the contract. A portion of this fee is adjusted annually for inflation which is considered variable consideration. The remaining capacity of the Sabine Pass LNG terminal has been reserved by SPL, for which the associated revenues are eliminated in consolidation.

Because SPLNG is continuously available to provide regasification service on a daily basis with the same pattern of transfer, we have concluded that SPLNG provides a single performance obligation to its customers on a continuous basis over time. We have determined that an output method of recognition based on elapsed time best reflects the benefits of this service to the customer and accordingly, LNG regasification capacity reservation fees are recognized as regasification revenues on a straight-line basis over the term of the respective TUAs. We have concluded that the inflation element within the contract meets the exception for allocating variable consideration to specific parts of the contract and accordingly the inflation adjustment is not included in the transaction price and will be recognized over the year in which the inflation adjustment relates on a straight-line basis.

In 2012, SPL entered into a partial TUA assignment agreement with Total Gas & Power North America, Inc. ("Total"), whereby SPL would progressively gain access to Total's capacity and other services provided under its TUA with SPLNG. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6.

Upon substantial completion of Train 3 of the Liquefaction Project, which was in March 2017, SPL gained access to a portion of Total's capacity and other services provided under Total's TUA with SPLNG. Upon substantial completion of Train 5, SPL will gain access to substantially all of Total's capacity. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA and we continue

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

to recognize the payments received from Total as revenue. During the years ended December 31, 2018 and 2017, SPL recorded $30 million and $23 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Deferred Revenue Reconciliation

The following table reflects the changes in our contract liabilities, which we classify as deferred revenue on our Consolidated Balance Sheets (in millions):

	Year Ended December 31,	
	2018	2017
Deferred revenues, beginning of period	$111	$78
Cash received but not yet recognized	116	111
Revenue recognized from prior period deferral	(111)	(78)
Deferred revenues, end of period	$116	$111

We record deferred revenue when we receive consideration, or such consideration is unconditionally due from a customer, prior to transferring goods or services to the customer under the terms of a sales contract. Changes in deferred revenue during the years ended December 31, 2018 and 2017 are primarily attributable to differences between the timing of revenue recognition and the receipt of advance payments related to delivery of LNG under certain SPAs.

Transaction Price Allocated to Future Performance Obligations

Because many of our sales contracts have long-term durations, we are contractually entitled to significant future consideration which we have not yet recognized as revenue. The following table discloses the aggregate amount of the transaction price that is allocated to performance obligations that have not yet been satisfied as of December 31, 2018 and 2017:

	December 31, 2018		December 31, 2017	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues	$53.6	10	$55.7	10
Regasification revenues	2.6	6	2.9	6
Total revenues	$56.2		$58.6	

(1) The weighted average recognition timing represents an estimate of the number of years during which we shall have recognized half of the unsatisfied transaction price.

We have elected the following exemptions which omit certain potential future sources of revenue from the table above:
(1)

We omit from the table above all performance obligations that are part of a contract that has an original expected duration of one year or less.

(2) We omit from the table above all variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation when that performance obligation qualifies as a series. The table above excludes all variable consideration under our SPAs and TUAs. The amount of revenue from variable fees that is not included in the transaction price will vary based on the future prices of Henry Hub throughout the contract terms, to the extent customers elect to take delivery of their LNG, and adjustments to the consumer price index. Approximately 57% and 58% of our LNG revenues and approximately 3% and 2% of our regasification revenues were related to variable consideration received from customers during the years ended December 31, 2018 and 2017, respectively. All of our LNG revenues—affiliate were related to variable consideration received from customers during each of the years ended December 31, 2018 and 2017.

We have entered into contracts to sell LNG that are conditioned upon one or both of the parties achieving certain milestones such as reaching a final investment decision on a certain liquefaction Train, obtaining financing or achieving substantial completion of a Train and any related facilities. These contracts are considered completed contracts for revenue recognition purposes and are included in the transaction price above when the conditions are considered probable of being met.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 13—RELATED PARTY TRANSACTIONS

Below is a summary of our related party transactions as reported on our Consolidated Statements of Operations for the years ended December 31, 2018, 2017 and 2016 (in millions):

	Year Ended December 31,		
	2018	2017	2016
LNG revenues—affiliate			
Cheniere Marketing SPA and Cheniere Marketing Master SPA	$1,299	$1,389	$294
Other revenues—affiliate			
Contracts for Sale and Purchase of Natural Gas and LNG	—	—	1
Terminal Marine Services Agreement	—	—	3
Total other revenues—affiliate	—	—	4
Cost of sales—affiliate			
Fees under the Pre-commercial LNG Marketing Agreement	—	—	2

Operating and maintenance expense—affiliate			
Contracts for Sale and Purchase of Natural Gas and LNG	—	—	1
Services Agreements	117	94	51
Other agreements	—	6	—
Total operating and maintenance expense—affiliate	117	100	52
General and administrative expense—affiliate			
Services Agreements	73	80	90

As of December 31, 2018 and 2017, we had $114 million and $163 million, respectively, of accounts receivable—affiliate, primarily under the LNG terminal capacity agreements described below.

LNG Terminal Capacity Agreements

Terminal Use Agreements

SPL obtained approximately 2.0 Bcf/d of regasification capacity and other liquefaction support services under a TUA with SPLNG as a result of an assignment in July 2012 by Cheniere Investments of its rights, title and interest under its TUA with SPLNG. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million per year (the "TUA Fees"), continuing until at least May 2036.

In connection with this TUA, SPL is required to pay for a portion of the cost (primarily LNG inventory) to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal, which is recorded as operating and maintenance expense on our Consolidated Statements of Operations.

Cheniere Investments, SPL and SPLNG entered into the terminal use rights assignment and agreement (the "TURA") pursuant to which Cheniere Investments had the right to use SPL's reserved capacity under the TUA and had the obligation to pay the TUA Fees required by the TUA to SPLNG. However, the revenue earned by SPLNG from the TUA Fees and the loss incurred by Cheniere Investments under the TURA are eliminated upon consolidation of our Consolidated Financial Statements. We have guaranteed the obligations of SPL under its TUA and the obligations of

Cheniere Investments under the TURA.

In an effort to utilize Cheniere Investments' reserved capacity under the TURA during construction of the Liquefaction Project, Cheniere Marketing has entered into an amended and restated variable capacity rights agreement with Cheniere Investments (the "Amended and Restated VCRA") pursuant to which Cheniere Marketing is obligated to pay Cheniere Investments 80% of the expected gross margin of each cargo of LNG that Cheniere Marketing arranges for delivery to the Sabine Pass LNG terminal. Cheniere Investments recorded no revenues—affiliate from Cheniere Marketing during the years ended December 31, 2018, 2017 and 2016 related to the Amended and Restated VCRA.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Cheniere Marketing SPA

Cheniere Marketing has an SPA with SPL to purchase, at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers at a price of 115% of Henry Hub plus $3.00 per MMBtu of LNG.

Cheniere Marketing Master SPA

SPL has an agreement with Cheniere Marketing that allows the parties to sell and purchase LNG with each other by executing and delivering confirmations under this agreement. SPL executed a confirmation with Cheniere Marketing that obligates Cheniere Marketing in certain circumstances to buy LNG cargoes produced during the period while Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") has control of, and is commissioning, Train 5 of the Liquefaction Project.

Services Agreements

As of December 31, 2018 and 2017, we had $228 million and $36 million of advances to affiliates, respectively, under the services agreements described below. The non-reimbursement amounts incurred under these agreements are recorded in general and administrative expense—affiliate.

Cheniere Partners Services Agreement

We have a services agreement with Cheniere Terminals, a wholly owned subsidiary of Cheniere, pursuant to which Cheniere Terminals is entitled to a quarterly non-accountable overhead reimbursement charge of $3 million (adjusted for inflation) for the provision of various general and administrative services for our benefit. In addition, Cheniere Terminals is entitled to reimbursement for all audit, tax, legal and finance fees incurred by Cheniere Terminals that are necessary to perform the services under the agreement.

Cheniere Investments Information Technology Services Agreement

Cheniere Investments has an information technology services agreement with Cheniere, pursuant to which Cheniere Investments' subsidiaries receive certain information technology services. On a quarterly basis, the various entities receiving the benefit are invoiced by Cheniere Investments according to the cost allocation percentages set forth in the agreement. In addition, Cheniere is entitled to reimbursement for all costs incurred by Cheniere that are necessary to perform the services under the agreement.

SPLNG O&M Agreement

SPLNG has a long-term operation and maintenance agreement (the "SPLNG O&M Agreement") with Cheniere Investments pursuant to which SPLNG receives all necessary services required to operate and maintain the Sabine Pass LNG receiving terminal. SPLNG pays a fixed monthly fee of $130,000 (indexed for inflation) under the SPLNG O&M Agreement and the cost of a bonus equal to 50% of the salary component of labor costs in certain circumstances to be agreed upon between SPLNG and Cheniere Investments at the beginning of each operating year. In addition, SPLNG is required to reimburse Cheniere Investments for its operating expenses, which consist primarily of labor expenses. Cheniere Investments provides the services required under the SPLNG O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere. All payments received by Cheniere Investments under the SPLNG O&M Agreement are required to be remitted to such subsidiary.

SPLNG MSA

SPLNG has a long-term management services agreement (the “SPLNG MSA”) with Cheniere Terminals, pursuant to which Cheniere Terminals manages the operation of the Sabine Pass LNG receiving terminal, excluding those matters provided for under the SPLNG O&M Agreement. SPLNG pays a monthly fixed fee of $520,000 (indexed for inflation) under the SPLNG MSA.

SPL O&M Agreement

SPL has an operation and maintenance agreement (the “SPL O&M Agreement”) with Cheniere Investments pursuant to which SPL receives all of the necessary services required to construct, operate and maintain the Liquefaction Project. Before each

Train of the Liquefaction Project is operational, the services to be provided include, among other services, obtaining governmental approvals on behalf of SPL, preparing an operating plan for certain periods, obtaining insurance, preparing staffing plans and preparing status reports. After each Train is operational, the services include all necessary services required to operate and maintain the Train. Prior to the substantial completion of each Train of the Liquefaction Project, in addition to reimbursement of operating expenses, SPL is required to pay a monthly fee equal to 0.6% of the capital expenditures incurred in the previous month. After substantial completion of each Train, for services performed while the Train is operational, SPL will pay, in addition to the reimbursement of operating expenses, a fixed monthly fee of $83,333 (indexed for inflation) for services with respect to the Train. Cheniere Investments provides the services required under the SPL O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere. All payments received by Cheniere Investments under the SPL O&M Agreement are required to be remitted to such subsidiary.

SPL MSA

SPL has a management services agreement (the "SPL MSA") with Cheniere Terminals pursuant to which Cheniere Terminals manages the construction and operation of the Liquefaction Project, excluding those matters provided for under the SPL O&M Agreement. The services include, among other services, exercising the day-to-day management of SPL's affairs and business, managing SPL's regulatory matters, managing bank and brokerage accounts and financial books and records of SPL's business and operations, entering into financial derivatives on SPL's behalf and providing contract administration services for all contracts associated with the Liquefaction Project. Prior to the substantial completion of each Train of the Liquefaction Project, SPL pays a monthly fee equal to 2.4% of the capital expenditures incurred in the previous month. After substantial completion of each Train, SPL will pay a fixed monthly fee of $541,667 (indexed for inflation) for services with respect to such Train.

CTPL O&M Agreement

CTPL has an amended long-term operation and maintenance agreement (the "CTPL O&M Agreement") with Cheniere Investments pursuant to which CTPL receives all necessary services required to operate and maintain the Creole Trail Pipeline. CTPL is required to reimburse Cheniere Investments for its operating expenses, which consist primarily of labor expenses. Cheniere Investments provides the services required under the CTPL O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere. All payments received by Cheniere Investments under the CTPL O&M Agreement are required to be remitted to such subsidiary.

Agreement to Fund SPLNG's Cooperative Endeavor Agreements

SPLNG has executed Cooperative Endeavor Agreements ("CEAs") with various Cameron Parish, Louisiana taxing authorities that allowed them to collect certain annual property tax payments from SPLNG from 2007 through 2016. This ten-year initiative represented an aggregate commitment of $25 million in order to aid in their reconstruction efforts following Hurricane Rita. In exchange for SPLNG's advance payments of annual ad valorem taxes, Cameron Parish will grant SPLNG a dollar-for-dollar credit against future ad valorem taxes to be levied against the Sabine Pass LNG terminal starting in 2019. Beginning in September 2007, SPLNG entered into various agreements with Cheniere Marketing, pursuant to which Cheniere Marketing would pay SPLNG additional TUA revenues equal to any and all amounts payable by SPLNG to the Cameron Parish taxing authorities under the CEAs. In exchange for such amounts received as TUA revenues from Cheniere Marketing, SPLNG will make payments to Cheniere Marketing equal to ad valorem tax levied on our LNG terminal in the year the Cameron Parish dollar-for-dollar credit is applied.

On a consolidated basis, these advance tax payments were recorded to other non-current assets, and payments from Cheniere Marketing that SPLNG utilized to make the ad valorem tax payments were recorded as a long-term obligation. As of December 31, 2018, we had $3 million in due to affiliates and $22 million of other non-current liabilities—affiliate resulting from these payments received from Cheniere Marketing. As of December 31, 2017, we had $25 million of other non-current liabilities—affiliate resulting from these payments received from Cheniere Marketing.

Contracts for Sale and Purchase of Natural Gas and LNG

SPLNG is able to sell and purchase natural gas and LNG under agreements with Cheniere Marketing. Under these agreements, SPLNG purchases natural gas or LNG from Cheniere Marketing at a sales price equal to the actual purchase price paid by Cheniere Marketing to suppliers of the natural gas or LNG, plus any third-party costs incurred by Cheniere Marketing with respect to the receipt, purchase and delivery of natural gas or LNG to the Sabine Pass LNG terminal.

Terminal Marine Services Agreement

In connection with its tug boat lease, Tug Services entered into an agreement with a wholly owned subsidiary of Cheniere to provide its LNG cargo vessels with tug boat and marine services at the Sabine Pass LNG terminal. The agreement also provides that Tug Services shall contingently pay the wholly owned subsidiary of Cheniere a portion of its future revenues. Accordingly, Tug Services distributed $6 million, $3 million and zero to the wholly owned subsidiary of Cheniere during the years ended December 31, 2018, 2017 and 2016, respectively, which is recognized as part of the distributions to our general partner interest holders on the Consolidated Statements of Partners' Equity.

LNG Terminal Export Agreement

SPLNG and Cheniere Marketing have an LNG terminal export agreement that provides Cheniere Marketing the ability to export LNG from the Sabine Pass LNG terminal. SPLNG did not record any revenues associated with this agreement during the years ended December 31, 2018, 2017 and 2016.

State Tax Sharing Agreements

SPLNG has a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which SPLNG and Cheniere are required to file on a combined basis and to timely pay the combined state and local tax liability. If Cheniere, in its sole discretion, demands payment, SPLNG will pay to Cheniere an amount equal to the state and local tax that SPLNG would be required to pay if its state and local tax liability were calculated on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from SPLNG under this agreement; therefore, Cheniere has not demanded any such payments from SPLNG. The agreement is effective for tax returns due on or after January 1, 2008.

SPL has a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which SPL and Cheniere are required to file on a combined basis and to timely pay the combined state and local tax liability. If Cheniere, in its sole discretion, demands payment, SPL will pay to Cheniere an amount equal to the state and local tax that SPL would be required to pay if SPL's state and local tax liability were calculated on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from SPL under this agreement; therefore, Cheniere has not demanded any such payments from SPL. The agreement is effective for tax returns due on or after August 2012.

CTPL has a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which CTPL and Cheniere are required to file on a combined basis and to timely pay the combined state and local tax liability. If Cheniere, in its sole discretion, demands payment, CTPL will pay to Cheniere an amount equal to the state and local tax that CTPL would be required to pay if CTPL's state and local tax liability were calculated on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from CTPL under this agreement; therefore, Cheniere has not demanded any such payments from CTPL. The agreement is effective for tax returns due on or after May 2013.

NOTE 14—NET INCOME (LOSS) PER COMMON UNIT

Net income (loss) per common unit for a given period is based on the distributions that will be made to the unitholders with respect to the period plus an allocation of undistributed net income (loss) based on provisions of the partnership agreement, divided by the weighted average number of common units outstanding. Distributions paid by us are presented on the Consolidated Statements of Partners' Equity. On January 25, 2019, we declared a $0.59 distribution per common unit and subordinated unit and the related distribution to our general partner and IDR holders to be paid on February 14, 2019 to unitholders of record as of February 6, 2019 for the period from October 1, 2018 to December 31, 2018.

The two-class method dictates that net income (loss) for a period be reduced by the amount of available cash that will be distributed with respect to that period and that any residual amount representing undistributed net income be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income as if all of the net income for the period had been distributed in accordance with the partnership agreement. Undistributed income is allocated to participating securities based on the distribution waterfall for available cash specified in the partnership agreement. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units and other participating securities on a pro rata basis based on provisions of the partnership agreement. Distributions are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

The Class B units, which were mandatorily converted into our common units in accordance with the terms of our partnership agreement on August 2, 2017, were issued at a discount to the market price of the common units into which they were convertible. This discount, totaling $2,130 million, represented a beneficial conversion feature and was reflected as an increase in common and subordinated unitholders' equity and a decrease in Class B unitholders' equity to reflect the fair value of the Class B units at issuance on our Consolidated Statement of Partners' Equity. The beneficial conversion feature was considered a dividend that was distributed ratably with respect to any Class B unit from its issuance date through its conversion date, which resulted in an increase in Class B unitholders' equity and a decrease in common and subordinated unitholders' equity. We amortized the beneficial conversion feature through the mandatory conversion date of August 2, 2017 using the effective yield method, with a weighted average effective yield of 888.7% per year and 966.1% per year for Cheniere Holdings' previously held Class B units and Blackstone CQP Holdco's Class B units, respectively. The impact of the beneficial conversion feature was also included in earnings per unit for the years ended December 31, 2017 and 2016.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The following table provides a reconciliation of net income (loss) and the allocation of net income (loss) to the common units, the subordinated units, the general partner units and IDRs for purposes of computing basic and diluted net income (loss) per unit (in millions, except per unit data).

		Limited Partner Units				
	Total	Common Units	Class B Units	Subordinated Units	General Partner Units	IDR
Year Ended December 31, 2018						
Net income	$1,274					
Declared distributions	1,162	795	—	309	22	36
Assumed allocation of undistributed net income (1)	$112	79	—	31	2	—
Assumed allocation of net income		$874	$—	$ 340	$ 24	$36
Weighted average units outstanding		348.6	—	135.4		
Basic and diluted net income per unit		$2.51		$ 2.51		
Year Ended December 31, 2017						
Net income	$490					
Declared distributions	514	376	—	127	10	1
Amortization of beneficial conversion feature of Class B units	—	(594)	2,004	(1,410)	—	—
Assumed allocation of undistributed net loss (1)	$(24)	(17)	—	(7)	—	—
Assumed allocation of net income		$(235)	$2,004	$ (1,290)	$ 10	$1
Weighted average units outstanding		178.5	84.8	135.4		
Basic and diluted net loss per unit (2)		$(1.32)		$ (9.52)		
Year Ended December 31, 2016						
Net loss	$(171)					
Declared distributions	99	97	—	—	2	—
Amortization of beneficial conversion feature of Class B units	—	(29)	100	(71)	—	—
Assumed allocation of undistributed net loss	$(270)	(79)	—	(186)	(5)	—
Assumed allocation of net loss		$(11)	$100	$ (257)	$ (3)	$—
Weighted average units outstanding		57.1	145.3	135.4		
Basic and diluted net loss per unit (2)		$(0.20)		$ (1.90)		

(1) Under our partnership agreement, the IDRs participate in net income (loss) only to the extent of the amount of cash distributions actually declared, thereby excluding the IDRs from participating in undistributed net income (loss).

(2) Earnings per unit in the table may not recalculate exactly due to rounding because it is calculated based on whole numbers, not the rounded numbers presented.

NOTE 15—LEASES

During the years ended December 31, 2018, 2017 and 2016, we recognized rental expense for all operating leases of $16 million, $13 million and $11 million, respectively, related primarily to office space and land sites. Our land site leases for the Sabine Pass LNG terminal have initial terms varying up to 30 years with multiple options to renew up to an additional 60 years.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Future annual minimum lease payments, excluding inflationary adjustments, are as follows (in millions):

Years Ending December 31,	Operating Leases (1)
2019	$ 10
2020	10
2021	10
2022	10
2023	10
Thereafter	124
Total	$ 174

(1) Includes certain lease option renewals that are reasonably assured and payments for certain non-lease components.

NOTE 16—COMMITMENTS AND CONTINGENCIES

We have various contractual obligations which are recorded as liabilities in our Consolidated Financial Statements. Other items, such as certain purchase commitments and other executed contracts which do not meet the definition of a liability as of December 31, 2018, are not recognized as liabilities but require disclosures in our Consolidated Financial Statements.

LNG Terminal Commitments and Contingencies

Obligations under EPC Contracts

SPL has lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Train 5 and Train 6 of the Liquefaction Project. The EPC contract prices for Train 5 of the Liquefaction Project and Train 6 of the Liquefaction Project are approximately $3.1 billion and $2.5 billion, respectively, reflecting amounts incurred under change orders through December 31, 2018, and including estimated costs for an optional third marine berth. SPL has the right to terminate the EPC contracts for its convenience, in which case Bechtel will be paid (1) the portion of the contract price for the work performed, (2) costs reasonably incurred by Bechtel on account of such termination and demobilization and (3) a lump sum of up to $30 million depending on the termination date.

Obligations under SPAs

SPL has third-party SPAs which obligate SPL to purchase and liquefy sufficient quantities of natural gas to deliver contracted volumes of LNG to the customers' vessels, subject to completion of construction of specified Trains of the Liquefaction Project.

Obligations under LNG TUAs

SPLNG has third-party TUAs with Total and Chevron U.S.A. Inc. to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG terminal.

Obligations under Natural Gas Supply, Transportation and Storage Service Agreements

SPL primarily has index-based physical natural gas supply contracts to secure natural gas feedstock for the Liquefaction Project. The terms of these contracts range up to six years, some of which commence upon the satisfaction of certain conditions precedent. As of December 31, 2018, SPL has secured up to approximately 3,464 TBtu of natural gas feedstock through natural gas supply contracts, a portion of which are considered purchase obligations if the conditions precedent were met.

Additionally, SPL has transportation and storage service agreements for the Liquefaction Project. The initial terms of the transportation agreements range up to 20 years, with renewal options for certain contracts, and commence upon the occurrence of conditions precedent. The terms of the SPL storage service agreements range up to ten years.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

As of December 31, 2018, SPL's obligations under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent were met were as follows (in millions):

Years Ending December 31,	Payments Due (1)
2019	$ 2,465
2020	1,377
2021	1,010
2022	756
2023	641
Thereafter	1,652
Total	$ 7,901

(1) Pricing of natural gas supply contracts are variable based on market commodity basis prices adjusted for basis spread. Amounts included are based on prices and basis spreads as of December 31, 2018.

Services Agreements

We have certain services agreements with affiliates. See Note 13—Related Party Transactions for information regarding such agreements.

Restricted Net Assets

At December 31, 2018, our restricted net assets of consolidated subsidiaries were approximately $2.5 billion.

Other Commitments

State Tax Sharing Agreements

SPLNG, SPL and CTPL have state tax sharing agreements with Cheniere. See Note 13—Related Party Transactions for information regarding such agreements.

Other Agreements

In the ordinary course of business, we have entered into certain multi-year licensing and service agreements, none of which are considered material to our financial position. Additionally, we have various lease commitments, as disclosed in Note 15—Leases.

Legal Proceedings

We may in the future be involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management, as of December 31, 2018, there were no pending legal matters that would reasonably be expected to have a material impact on our operating results, financial position or cash flows.

91

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 17—CUSTOMER CONCENTRATION

The following table shows customers with revenues of 10% or greater of total revenues from external customers and customers with accounts receivable balances of 10% or greater of total accounts receivable from external customers:

	Percentage of Total Revenues from External Customers			Percentage of Accounts Receivable from External Customers	
	Year Ended December 31,			December 31,	
	2018	2017	2016	2018	2017
Customer A	28%	39%	52%	35%	39%
Customer B	21%	27%	*	23%	32%
Customer C	23%	23%	—%	30%	26%
Customer D	19%	—%	—%	8%	—%

* Less than 10%

The following table shows revenues from external customers attributable to the country in which the revenues were derived (in millions). We attribute revenues from external customers to the country in which the party to the applicable agreement has its principal place of business. Substantially all of our long-lived assets are located in the United States.

	Revenues from External Customers		
	Year Ended December 31,		
	2018	2017	2016
United States	$1,880	$1,441	$677
South Korea	1,168	666	—
Ireland	1,098	787	63
India	981	—	23
Other countries	—	21	39
Total	$5,127	$2,915	$802

NOTE 18—SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides supplemental disclosure of cash flow information (in millions):

	Year Ended December 31,		
	2018	2017	2016
Cash paid during the period for interest, net of amounts capitalized	$719	$510	$242

The balance in property, plant and equipment, net funded with accounts payable and accrued liabilities (including affiliate) was $263 million, $273 million and $267 million as of December 31, 2018, 2017 and 2016, respectively.

92

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 19—RECENT ACCOUNTING STANDARDS

The following table provides a brief description of a recent accounting standard that had not been adopted by us as of December 31, 2018:

Standard	Description	Expected Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2016-02, Leases (Topic 842), and subsequent amendments thereto	This standard requires a lessee to recognize leases on its balance sheet by recording a lease liability representing the obligation to make future lease payments and a right-of-use asset representing the right to use the underlying asset for the lease term. A lessee is permitted to make an election not to recognize lease assets and liabilities for leases with a term of 12 months or less. The standard also modifies the definition of a lease and requires expanded disclosures. This guidance may be early adopted, and may be adopted using either a modified retrospective approach to apply the standard at the beginning of the earliest period presented in the financial statements or an optional transition approach to apply the standard at the date of adoption with no retrospective adjustments to prior periods. Certain additional practical expedients are also available.	January 1, 2019	We will adopt this standard on January 1, 2019 using the optional transition approach to apply the standard at the beginning of the first quarter of 2019 with no retrospective adjustments to prior periods. The adoption of the standard will result in the recognition of right-of-use assets and lease liabilities for operating leases of approximately $100 million on our Consolidated Balance Sheets, with no material impact on our Consolidated Statements of Operations or Consolidated Statements of Cash Flows. The adoption of this standard will also result in additional disclosures including the significant judgments and assumptions used in applying the standard. When we adopt this standard we will elect the practical expedients to (1) carryforward prior conclusions related to lease identification and classification for existing leases, (2) combine lease and non-lease components of an arrangement for all classes of leased assets, (3) omit short-term leases with a term of 12 months or less from recognition on the balance sheet and (4) carryforward our existing accounting for land easements not previously accounted for as leases.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Additionally, the following table provides a brief description of recent accounting standards that were adopted by us during the reporting period:

Standard	Description	Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2014-09, Revenue from Contracts with Customers (Topic 606), and subsequent amendments thereto	This standard provides a single, comprehensive revenue recognition model which replaces and supersedes most existing revenue recognition guidance and requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard requires that the costs to obtain and fulfill contracts with customers should be recognized as assets and amortized to match the pattern of transfer of goods or services to the customer if expected to be recoverable. The standard also requires enhanced disclosures. This guidance may be adopted either retrospectively to each prior reporting period presented subject to allowable practical expedients ("full retrospective approach") or as a cumulative-effect adjustment as of the date of adoption ("modified retrospective approach").	January 1, 2018	We adopted this guidance on January 1, 2018, using the full retrospective method. The adoption of this guidance represents a change in accounting principle that will provide financial statement readers with enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The adoption of this guidance did not impact our previously reported Consolidated Financial Statements in any prior period nor did it result in a cumulative effect adjustment to retained earnings. See Note 12—Revenues from Contracts with Customers for additional disclosures.
ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory	This standard requires the immediate recognition of the tax consequences of intercompany asset transfers other than inventory. This guidance may be early adopted, but only at the beginning of an annual period, and must be adopted using a modified retrospective approach.	January 1, 2018	The adoption of this guidance did not have an impact on our Consolidated Financial Statements or related disclosures.

NOTE 20—SUPPLEMENTAL GUARANTOR INFORMATION

Our CQP Senior Notes are jointly and severally guaranteed by each of our subsidiaries other than SPL (the "Guarantors") and, subject to certain conditions governing its guarantee, Sabine Pass LP (collectively with SPL, the "Non-Guarantors"). These guarantees are full and unconditional, subject to certain customary release provisions including (1) the sale, exchange, disposition or transfer (by merger, consolidation or otherwise) of the capital stock or all or substantially all of the assets of the Guarantors, (2) upon the liquidation or dissolution of a Guarantor, (3) following the release of a Guarantor from its guarantee obligations and (4) upon the legal defeasance or satisfaction and discharge of obligations under the CQP Indenture. See Note 11—Debt for additional information regarding the CQP Senior Notes.

The following is condensed consolidating financial information for Cheniere Partners ("Parent Issuer"), the Guarantors on a combined basis and the Non-Guarantors on a combined basis. The condensed consolidating financial information has been prepared using the same accounting policies as described in Note 3—Summary of Significant Accounting Policies, except for the investments in subsidiaries, which is accounted for using the equity method.

In lieu of Schedule I pursuant to the requirements of Rule 5-04 of Reg S-X, the condensed parent company financial statements are presented below in the Parent Issuer column. The condensed parent only financial statements have been provided in accordance with the rules and regulations of the SEC and should be read in conjunction with Cheniere Partners' Consolidated

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Financial Statements. Pursuant to the SEC rules and regulations, the condensed parent company financial statements do not include all of the financial information and notes normally included with financial statements prepared in accordance with GAAP.

Condensed Consolidating Balance Sheet
December 31, 2018
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets					
Cash and cash equivalents	$—	$ —	$ —	$ —	$ —
Restricted cash	779	6	756	—	1,541
Accounts and other receivables	1	1	346	—	348
Accounts receivable—affiliate	1	40	113	(40)	114
Advances to affiliate	—	104	210	(86)	228
Inventory	—	12	87	—	99
Other current assets	—	2	24	—	26
Other current assets—affiliate	—	—	21	(21)	—
Total current assets	781	165	1,557	(147)	2,356
Property, plant and equipment, net	79	2,128	13,209	(26)	15,390
Debt issuance costs, net	1	—	12	—	13
Non-current derivative assets	—	—	31	—	31
Investments in subsidiaries	2,544	440	—	(2,984)	—
Other non-current assets, net	—	26	158	—	184
Total assets	$3,405	$ 2,759	$ 14,967	$ (3,157)	$ 17,974
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities					
Accounts payable	$—	$ 4	$ 11	$ —	$ 15
Accrued liabilities	39	14	768	—	821
Due to affiliates	—	127	48	(126)	49
Deferred revenue	—	25	91	—	116
Deferred revenue—affiliate	—	22	—	(21)	1
Derivative liabilities	—	—	66	—	66
Total current liabilities	39	192	984	(147)	1,068
Long-term debt, net	2,566	—	13,500	—	16,066
Non-current derivative liabilities	—	—	14	—	14
Other non-current liabilities	—	1	3	—	4
Other non-current liabilities—affiliate	—	22	—	—	22
Partners' equity	800	2,544	466	(3,010)	800
Total liabilities and partners' equity	$3,405	$ 2,759	$ 14,967	$ (3,157)	$ 17,974

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Balance Sheet
December 31, 2017
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets					
Cash and cash equivalents	$—	$ —	$ —	$ —	$ —
Restricted cash	1,033	12	544	—	1,589
Accounts and other receivables	—	2	189	—	191
Accounts receivable—affiliate	—	36	163	(36)	163
Advances to affiliate	—	20	26	(10)	36
Inventory	—	10	85	—	95
Other current assets	8	3	54	—	65
Other current assets—affiliate	—	—	21	(21)	—
Total current assets	1,041	83	1,082	(67)	2,139
Property, plant and equipment, net	80	2,164	12,920	(25)	15,139
Debt issuance costs, net	20	—	18	—	38
Non-current derivative assets	14	—	17	—	31
Investments in subsidiaries	2,076	(63)	—	(2,013)	—
Other non-current assets, net	—	37	169	—	206
Total assets	$3,231	$ 2,221	$ 14,206	$ (2,105)	$ 17,553
LIABILITIES AND PARTNERS' EQUITY					
Current liabilities					
Accounts payable	$—	$ 4	$ 8	$ —	$ 12
Accrued liabilities	23	8	606	—	637
Due to affiliates	—	47	66	(45)	68
Deferred revenue	—	27	84	—	111
Deferred revenue—affiliate	—	22	—	(21)	1
Other current liabilities—affiliate	—	1	—	(1)	—
Total current liabilities	23	109	764	(67)	829
Long-term debt, net	2,569	—	13,477	—	16,046
Non-current derivative liabilities	—	—	3	—	3
Other non-current liabilities	—	11	—	—	11
Other non-current liabilities—affiliate	—	25	—	—	25
Partners' equity (deficit)	639	2,076	(38)	(2,038)	639
Total liabilities and partners' equity (deficit)	$3,231	$ 2,221	$ 14,206	$ (2,105)	$ 17,553

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Statement of Operations
Year Ended December 31, 2018
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues					
LNG revenues	$—	$ —	$ 4,827	$ —	$ 4,827
LNG revenues—affiliate	—	—	1,299	—	1,299
Regasification revenues	—	261	—	—	261
Regasification revenues—affiliate	—	258	—	(258)	—
Other revenues	—	39	—	—	39
Other revenues—affiliate	—	247	—	(247)	—
Total revenues	—	805	6,126	(505)	6,426
Operating costs and expenses					
Cost of sales (excluding depreciation and amortization expense shown separately below)	—	—	3,403	—	3,403
Cost of sales—affiliate	—	—	32	(32)	—
Operating and maintenance expense	—	67	342	—	409
Operating and maintenance expense—affiliate	—	151	423	(457)	117
Development expense	—	—	2	—	2
General and administrative expense	4	2	5	—	11
General and administrative expense—affiliate	12	25	50	(14)	73
Depreciation and amortization expense	2	74	349	(1)	424
Impairment expense and loss on disposal of assets	—	8	—	—	8
Total operating costs and expenses	18	327	4,606	(504)	4,447
Income (loss) from operations	(18)	478	1,520	(1)	1,979
Other income (expense)					
Interest expense, net of capitalized interest	(139)	(5)	(589)	—	(733)
Loss on modification or extinguishment of debt	(12)	—	—	—	(12)
Derivative gain, net	14	—	—	—	14
Equity earnings of subsidiaries	1,416	944	—	(2,360)	—
Other income	13	—	13	—	26
Total other income (expense)	1,292	939	(576)	(2,360)	(705)
Net income	$1,274	$ 1,417	$ 944	$ (2,361)	$ 1,274

97

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Statement of Operations
Year Ended December 31, 2017
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues					
LNG revenues	$—	$ —	$ 2,635	$ —	$ 2,635
LNG revenues—affiliate	—	—	1,389	—	1,389
Regasification revenues	—	260	—	—	260
Regasification revenues—affiliate	—	190	—	(190)	—
Other revenues	—	20	—	—	20
Other revenues—affiliate	—	218	—	(218)	—
Total revenues	—	688	4,024	(408)	4,304
Operating costs and expenses					
Cost of sales (excluding depreciation and amortization expense shown separately below)	—	1	2,317	2	2,320
Cost of sales—affiliate	—	—	23	(23)	—
Operating and maintenance expense	4	45	243	—	292
Operating and maintenance expense—affiliate	6	137	329	(372)	100
Development expense	—	1	2	—	3
General and administrative expense	4	1	7	—	12
General and administrative expense—affiliate	11	15	58	(4)	80
Depreciation and amortization expense	2	74	264	(1)	339
Other	—	2	—	—	2
Total operating costs and expenses	27	276	3,243	(398)	3,148
Income (loss) from operations	(27)	412	781	(10)	1,156
Other income (expense)					
Interest expense, net of capitalized interest	(111)	(9)	(494)	—	(614)
Loss on modification or extinguishment of debt	(25)	—	(42)	—	(67)
Derivative gain (loss), net	6	—	(2)	—	4
Equity earnings of subsidiaries	643	250	—	(893)	—
Other income	4	—	7	—	11
Total other income (expense)	517	241	(531)	(893)	(666)
Net income	$490	$ 653	$ 250	$ (903)	$ 490

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Statement of Operations
Year Ended December 31, 2016
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues					
LNG revenues	$—	$ —	$ 539	$ —	$ 539
LNG revenues—affiliate	—	—	294	—	294
Regasification revenues	—	259	—	—	259
Regasification revenues—affiliate	—	61	—	(61)	—
Other revenues	—	4	—	—	4
Other revenues—affiliate	—	163	—	(159)	4
Total revenues	—	487	833	(220)	1,100
Operating costs and expenses					
Cost of sales (excluding depreciation and amortization expense shown separately below)	—	—	416	(6)	410
Cost of sales—affiliate	—	—	7	(5)	2
Operating and maintenance expense	5	48	72	2	127
Operating and maintenance expense—affiliate	—	113	129	(190)	52
Development expense—affiliate	—	—	1	(1)	—
General and administrative expense	4	2	7	—	13
General and administrative expense—affiliate	12	15	68	(5)	90
Depreciation and amortization expense	1	72	83	—	156
Total operating costs and expenses	22	250	783	(205)	850
Income (loss) from operations	(22)	237	50	(15)	250
Other income (expense)					
Interest expense, net of capitalized interest	(23)	(148)	(186)	—	(357)
Loss on modification or extinguishment of debt	—	(20)	(52)	—	(72)
Derivative gain (loss), net	12	—	(6)	—	6
Equity losses of subsidiaries	(138)	(193)	—	331	—
Other income	—	1	1	—	2
Total other expense	(149)	(360)	(243)	331	(421)
Net loss	$(171)	$ (123)	$ (193)	$ 316	$ (171)

99

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2018
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash flows provided by operating activities	$714	$ 569	$ 1,423	$ (832)	$ 1,874
Cash flows from investing activities					
Property, plant and equipment, net	—	(34)	(771)	1	(804)
Investments in subsidiaries	(304)	(129)	—	433	—
Distributions received from affiliates, net	454	537	—	(991)	—
Net cash provided by (used in) investing activities	150	374	(771)	(557)	(804)
Cash flows from financing activities					
Proceeds from issuances of debt	1,100	—	—	—	1,100
Repayments of debt	(1,090)	—	—	—	(1,090)
Debt issuance and deferred financing costs	(8)	—	—	—	(8)
Debt extinguishment costs	(7)	—	—	—	(7)
Distributions to parent	—	(1,253)	(569)	1,822	—
Contributions from parent	—	304	129	(433)	—
Distributions to owners	(1,113)	—	—	—	(1,113)
Net cash used in financing activities	(1,118)	(949)	(440)	1,389	(1,118)
Net increase (decrease) in cash, cash equivalents and restricted cash	(254)	(6)	212	—	(48)
Cash, cash equivalents and restricted cash—beginning of period	1,033	12	544	—	1,589
Cash, cash equivalents and restricted cash—end of period	$779	$ 6	$ 756	$ —	$ 1,541

Balances per Condensed Consolidating Balance Sheet:

	December 31, 2018				
	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash and cash equivalents	$—	$ —	$ —	$ —	$ —
Restricted cash	779	6	756	—	1,541
Total cash, cash equivalents and restricted cash	$779	$ 6	$ 756	$ —	$ 1,541

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2017
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash flows provided by (used in) operating activities	$(101)	$ 431	$ 657	$ (10)	$ 977
Cash flows from investing activities					
Property, plant and equipment, net	—	(21)	(1,279)	10	(1,290)
Investments in subsidiaries	(245)	(7)	—	252	—
Distributions received from affiliates, net	1,431	782	—	(2,213)	—
Net cash provided by (used in) investing activities	1,186	754	(1,279)	(1,951)	(1,290)
Cash flows from financing activities					
Proceeds from issuances of debt	1,500	—	2,314	—	3,814
Repayments of debt	(1,470)	—	(703)	—	(2,173)
Debt issuance and deferred financing costs	(22)	—	(28)	—	(50)
Distributions to parent	—	(1,431)	(782)	2,213	—
Contributions from parent	—	245	7	(252)	—
Distributions to owners	(294)	—	—	—	(294)
Net cash provided by (used in) financing activities	(286)	(1,186)	808	1,961	1,297
Net increase (decrease) in cash, cash equivalents and restricted cash	799	(1)	186	—	984
Cash, cash equivalents and restricted cash—beginning of period	234	13	358	—	605
Cash, cash equivalents and restricted cash—end of period	$1,033	$ 12	$ 544	$ —	$ 1,589

Balances per Condensed Consolidating Balance Sheet:

	December 31, 2017				
	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash and cash equivalents	$—	$ —	$ —	$ —	$ —
Restricted cash	1,033	12	544	—	1,589
Total cash, cash equivalents and restricted cash	$1,033	$ 12	$ 544	$ —	$ 1,589

101

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2016
(in millions)

	Parent Issuer	Guarantors	Non-Guarantors	Eliminations	Consolidated
Cash flows provided by (used in) operating activities	$ (53)	$ 181	$ (130)	$ 2	$ —
Cash flows from investing activities					
Property, plant and equipment, net	—	(7)	(2,306)	(2)	(2,315)
Investments in subsidiaries	(2,429)	(1)	—	2,430	—
Distributions received from affiliates, net	218	—	—	(218)	—
Other	—	(6)	(32)	—	(38)
Net cash used in investing activities	(2,211)	(14)	(2,338)	2,210	(2,353)
Cash flows from financing activities					
Proceeds from issuances of debt	2,560	—	5,443	—	8,003
Repayments of debt	—	(2,486)	(2,765)	—	(5,251)
Debt issuance and deferred financing costs	(73)	—	(42)	—	(115)
Debt extinguishment costs	—	(14)	—	—	(14)
Distributions to parent	—	(218)	—	218	—
Contributions from parent	—	2,429	1	(2,430)	—
Distributions to owners	(99)	—	—	—	(99)
Net cash provided by (used in) financing activities	2,388	(289)	2,637	(2,212)	2,524
Net increase (decrease) in cash, cash equivalents and restricted cash	124	(122)	169	—	171
Cash, cash equivalents and restricted cash—beginning of period	110	135	189	—	434
Cash, cash equivalents and restricted cash—end of period	$ 234	$ 13	$ 358	$ —	$ 605

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

Summarized Quarterly Financial Data—(in millions, except per unit amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2018:				
Revenues	$1,593	$1,407	$1,529	$1,897
Income from operations	508	455	492	524
Net income	335	281	307	351
Net income per common unit—basic and diluted (1)	0.67	0.55	0.60	0.69
Year ended December 31, 2017:				
Revenues	$891	$992	$903	$1,518
Income from operations	219	200	197	540
Net income	47	46	23	374
Net income (loss) per common unit—basic and diluted (1)	(0.80)	(3.71)	(1.10)	0.76

(1) The sum of the quarterly net income (loss) per common unit may not equal the full year amount as the undistributed income and loss allocations and computations of the weighted average common units outstanding for basic and diluted common units outstanding for each quarter and the full year are performed independently.

103

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Based on their evaluation as of the end of the fiscal year ended December 31, 2018, our general partner's principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are (1) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our Management's Report on Internal Control Over Financial Reporting is included in our Consolidated Financial Statements on page 59 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF OUR GENERAL PARTNER AND CORPORATE GOVERNANCE

Management of Cheniere Partners

Cheniere Partners GP, as our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. The directors of our general partner are elected by the sole member of the general partner. Unitholders are not entitled to elect the directors of our general partner or to participate directly or indirectly in our management or operations.

Audit Committee

The board of directors of our general partner has appointed an audit committee composed of Lon McCain, chairman, Oliver G. Richard, III and Vincent Pagano, Jr., each of whom is an independent director and satisfies the additional independence and other requirements for audit committee members provided for in the listing standards of the NYSE American and the Exchange Act. In addition, the board of directors of our general partner has determined that Lon McCain and Oliver G. Richard, III meet the qualifications of a “financial expert” and are “financially sophisticated” as such terms are defined by the SEC and the NYSE American, respectively.

The audit committee assists the board of directors of our general partner in its oversight of the integrity of our Consolidated Financial Statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all audit services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee. Our audit committee charter is posted at http://www.cheniere.com/about-us/cheniere-partners/governance-and-ethics/.

Conflicts Committee

Under our partnership agreement, the board of directors of our general partner has appointed a conflicts committee composed of the independent directors, Vincent Pagano, Jr., chairman, Lon McCain, Oliver G. Richard, III and James R. Ball, to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of a conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be security holders, officers or employees of our general partner, directors, officers, or employees of affiliates of the general partner or holders of any ownership interest in us other than common units or other publicly traded units and must meet the independence standards established by the NYSE American, the Exchange Act and other federal securities laws. Any matter approved by the conflicts committee is 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 that it may owe us or our unitholders.

CMI SPA Committee

The board of directors of our general partner has formed a CMI SPA Committee, composed of James Ball, chairman, Eric Bensaude and John-Paul Munfa, to approve LNG sales entered into between Cheniere Marketing and SPL.

Other

We do not have a nominating committee because the directors of our general partner manage our operations.

We also do not have a compensation committee. We have no employees, directors or officers. We are managed by our general partner, Cheniere Partners GP. Our general partner has paid no cash compensation to its executive officers since its inception. All of the executive officers of our general partner are also executive officers of Cheniere. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. Cheniere does not allocate this compensation between services for us and services for Cheniere and its affiliates.

Directors and Executive Officers of Our General Partner

The following sets forth information, as of February 20, 2019, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. The appointments of Messrs. Meier, Munfa and Welch to the board of directors of our general partner were made pursuant to the rights of Blackstone CQP Holdco under the Third Amended and Restated Limited Liability Company Agreement of our general partner to appoint certain directors to the board of directors of our general partner.

Name	Age	Election Date	Position with Our General Partner
Jack A. Fusco	56	May 2016	Chairman of the Board and President and Chief Executive Officer
Michael J. Wortley	42	January 2014	Director and Executive Vice President and Chief Financial Officer
Eric Bensaude	52	September 2016	Director
Doug Shanda	49	September 2016	Director and Senior Vice President, Operations
Philip Meier	60	July 2013	Director
John-Paul Munfa	37	February 2015	Director
Jamie Welch	52	August 2017	Director
James R. Ball	68	September 2012	Director
Lon McCain	71	March 2007	Director
Vincent Pagano, Jr.	68	December 2012	Director
Oliver G. Richard, III	66	September 2012	Director

Jack A. Fusco

Chairman of the Board and President and Chief Executive Officer of our general partner

Mr. Fusco serves as a director and President and Chief Executive Officer of Cheniere; Chief Executive Officer of SPL and a manager and President and Chief Executive Officer of the general partner of SPLNG. Mr. Fusco served as Chairman, President and Chief Executive Officer of Cheniere Energy Partners LP Holdings, LLC (“Cheniere Holdings”) from June 2016 to September 2018. Mr. Fusco served as the Executive Chairman of Calpine Corporation (“Calpine”) from May 2014 through May 2016, Chief Executive Officer of Calpine from August 2008 to May 2014, President of Calpine from August 2008 to December 2012 and director of Calpine from August 2008 to March 2018. From July 2004 to February 2006, Mr. Fusco served as the Chairman and Chief Executive Officer of Texas Genco LLC. From 2002 through July 2004, Mr. Fusco was an exclusive energy investment advisor for Texas Pacific Group. From November 1998 until February 2002, he served as founder, President and Chief Executive Officer of Orion Power Holdings, Inc. Prior to his founding of Orion Power Holdings, Inc., Mr. Fusco was a Vice President at Goldman Sachs Power, an affiliate of Goldman, Sachs & Co. Prior to joining Goldman, Sachs & Co., Mr. Fusco was employed by Pacific Gas & Electric Company or its affiliates in various engineering and management roles for approximately 13 years. Mr. Fusco obtained a Bachelor of Science degree in Mechanical Engineering from California State University, Sacramento. Mr. Fusco served as a director on the board of Foster Wheeler Ltd., a global engineering and construction contractor and power equipment supplier, until February 2009 and on the board of Graphics Packaging Holdings, a paper and packaging company, until 2008. It was determined that Mr. Fusco should serve as a director of our general partner because of his prior experience leading successful energy industry companies and his perspective as President and Chief Executive Officer of Cheniere.

Michael J. Wortley

Executive Vice President and Chief Financial Officer and a Director of our general partner and a member of the Executive Committee

Mr. Wortley has served as Chief Financial Officer of Cheniere since January 2014 and as Executive Vice President of Cheniere since September 2016. Mr. Wortley served as Senior Vice President of Cheniere from January 2014 to September 2016. Mr. Wortley also served as a director and Chief Financial Officer of Cheniere Holdings from January 2014 to September 2018 and Executive Vice President from September 2016 to September 2018. Mr. Wortley served as Vice President–Strategy and Risk of Cheniere from January 2013 to January 2014 and as Vice

President–Business Development of Cheniere and President of Corpus Christi Liquefaction, LLC, a wholly owned subsidiary of Cheniere, from September 2011 to January 2013. Mr. Wortley served as Cheniere's Vice President–Strategic Planning from January 2009 to September 2011 and Manager–Strategic New Business from August 2007 to January 2009. Mr. Wortley is also Chief Financial Officer of the general partner of SPLNG and a manager and Chief Financial Officer of SPL. Prior to joining Cheniere in February 2005, Mr. Wortley spent five years in oil and gas corporate development, mergers, acquisitions and divestitures with Anadarko Petroleum Corporation ("Anadarko"), a publicly traded oil and gas exploration and production company. Mr. Wortley began his career with Union Pacific Resources Corporation, a publicly traded oil and gas exploration and production company subsequently acquired by Anadarko. Mr. Wortley received a

B.B.A. in Finance from Southern Methodist University. It was determined that Mr. Wortley should serve as a director of our general partner because of his financial expertise and his perspective as Chief Financial Officer of Cheniere and certain of its affiliates. Other than Cheniere Holdings, Mr. Wortley has not held any other directorship positions in the past five years.

Eric Bensaude
Director of our general partner and a member of the CMI SPA Committee
Mr. Bensaude joined Cheniere in September 2013 and currently serves as Managing Director, Commercial Operations and Asset Optimization of Cheniere Marketing Ltd., a subsidiary of Cheniere. Mr. Bensaude also serves as Senior Vice President, Commercial Operations of SPL. Mr. Bensaude has more than 20 years of experience in the energy, oil and natural gas trading and marketing business. Prior to joining Cheniere, Mr. Bensaude served as Head of Global LNG at EDF Trading where he set up and ran the LNG trading and marketing department and General Manager for natural gas and LNG origination. Prior to EDF Trading, Mr. Bensaude was an Associate at Booz Allen & Hamilton in the Energy Practice, working on a variety of gas & power assignments. Mr. Bensaude started his career in energy as a trader of middle distillates for Total and previously served as the representative for the French bank, Société Générale, in Canton, People's Republic of China. He held the position of Vice-Chairman of the European Federation of Energy Traders Gas Committee while at EDF Trading. Mr. Bensaude holds an MBA from ESSEC, business school in France, and studied Mandarin at Paris 7 Jussieu. It was determined that Mr. Bensaude should serve as a director of our general partner because of his experience in the energy, oil and natural gas trading and marketing industry. Mr. Bensaude has not held any other directorship positions in the past five years.

Doug Shanda
Senior Vice President, Operations and a Director of our general partner
Mr. Shanda joined Cheniere in October 2012 as Vice President, Sabine Pass Operations leading the effort to prepare for liquefaction operations. His role was expanded to include Corpus Christi Operations in 2015. Mr. Shanda currently serves as Senior Vice President, Operations of Cheniere. Mr. Shanda also serves as President of SPL and Senior Vice President, Operations of Corpus Christi Liquefaction, LLC. Mr. Shanda also served as a director of Cheniere Holdings from September 2016 to September 2018 and Senior Vice President, Operations from August 2017 to September 2018. Mr. Shanda is responsible for safe, reliable operations at Cheniere's terminals. Mr. Shanda has been professionally involved in the power, chemical, petrochemical, refining and LNG industries for over 25 years. Mr. Shanda is currently a director of Cheniere Energy Partners GP, LLC. Prior to joining Cheniere, Mr. Shanda served as the Senior Project Engineer, Technical Manager and Plant Manager of the PERU LNG liquefaction plant in Melchorita, Peru where he was responsible for the overall management of the facility including production, marine, maintenance, technical services, EHS, security and administration. Mr. Shanda has over 25 years of experience in project management and operations management. Mr. Shanda has a B.S. degree in Electrical Engineering from Iowa State University. It was determined that Mr. Shanda should serve as a director of our general partner because of his background in the LNG industry. Other than Cheniere Holdings, Mr. Shanda has not held any other directorship positions in the past five years.

Philip Meier
Director of our general partner and a member of the Executive Committee
Mr. Meier is president of Meier Consulting LLC and is currently providing technical and project management advice to Blackstone CQP Holdco with respect to the Liquefaction Project. From 2007 to 2012, Mr. Meier was Senior Vice President Projects with Woodside Energy, an oil and gas company in Perth, Western Australia, where he was accountable for delivery of all Woodside construction projects (both LNG and offshore). Prior to this, he spent 25 years with Bechtel at various levels culminating as Project Manager of Egyptian LNG Train 2. Mr. Meier received a BSCE from Rensselaer Polytechnic Institute and an M.B.A. in Finance and International Business from the University of Houston. It was determined that Mr. Meier should serve as a director of our general partner because of his international experience and expertise in the LNG industry. Mr. Meier has not held any other directorship positions in the past five years.

John-Paul Munfa
Director of our general partner and a member of the CMI SPA Committee and the Executive Committee
Mr. Munfa is a Managing Director in the Private Equity Group of Blackstone Group, an investment and advisory firm. Mr. Munfa joined Blackstone Group in 2004 and was an employee in its Restructuring & Reorganization and Private Equity Groups from 2004 to 2009. Mr. Munfa re-joined Blackstone Group in 2011 after receiving an M.B.A. from Stanford University's Graduate School of Business. Mr. Munfa also received an A.B. in Economics from Harvard University. It was determined that Mr. Munfa should serve as a director of our general partner because of his significant investment experience with Blackstone Group. Mr. Munfa has not held any other directorship positions in the past five years.

Jamie Welch
Director of our general partner and a member of the Executive Committee
Mr. Welch currently serves as the President and Chief Financial Officer of EagleClaw Midstream Ventures LLC. Mr. Welch was the Group Chief Financial Officer and Head of Business Development for the Energy Transfer Equity, L.P. ("ETE") family from June 2013 to February 2016. Mr. Welch also served on the Board of Directors of ETE, Energy Transfer Partners and Sunoco Logistics from June 2013 to February 2016. Before joining ETE, Mr. Welch was Head of the EMEA Investment Banking Department and Head of the Global Energy Group at Credit Suisse. He was also a member of the Investment Banking Division Global Management Committee and the EMEA Operating Committee. Mr. Welch joined Credit Suisse First Boston in 1997 from Lehman Brothers Inc. in New York, where he was a Senior Vice President in the global utilities and project finance group. Prior to that he was an attorney with Milbank, Tweed, Hadley & McCloy (New York) and a barrister and solicitor with Minter Ellison in Melbourne, Australia. It was determined that Mr. Welch should serve as a director of our general partner because of his understanding of energy-related corporate finance gained through his experience in the investment banking and legal fields.

James R. Ball
Director of our general partner, Chairman of the CMI SPA Committee and the Executive Committee and a member of the Conflicts Committee
Mr. Ball has served as a senior advisor to Tachebois Limited, an energy and equities advisory firm, since 2011. Mr. Ball served as a non-executive director of Gas Strategies Group Ltd, a professional services company providing commercial energy advisory services ("GSG"), from September 2011 to June 2013. From 1988 until August 2011, he also served as an executive director of GSG. Mr. Ball is a Fellow of the Energy Institute and Companion of the Institute of Gas Engineers and Managers. Mr. Ball received a B.A. in Economics from the University of Colorado and a Master of Science from City University Business School (now Cass Business School). It was determined that Mr. Ball should serve as a director of our general partner because of his background as an advisor in the energy industry. Mr. Ball has not held any other directorship positions in the past five years.

Lon McCain
Director of our general partner, Chairman of the Audit Committee and a member of the Conflicts Committee
Mr. McCain was Executive Vice President and Chief Financial Officer of Ellora Energy Inc., a private, independent exploration and production company from July 2009 to August 2010. Prior to that, he was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a publicly traded exploration and production company, from 2001 until the sale of that company to Kerr-McGee Corporation in 2004. From 1992 until joining Westport, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He is currently on the board of directors of Contango Oil and Gas Company, a publicly traded oil and natural gas exploration and production company into which Crimson Exploration, Inc. was merged effective October 2, 2013. Mr. McCain served on the Board of Crimson Exploration, Inc. from 2005 until the merger with Contango. Mr. McCain also currently serves on the board of directors of Continental Resources, Inc., a publicly traded oil and natural gas exploration and production company. Mr. McCain received a B.S. in Business Administration and a Masters of Business Administration/Finance from the University of Denver. Mr. McCain was also an Adjunct Professor of Finance at the University of Denver from 1982 to 2005. It was determined that Mr. McCain should serve as a director of our general partner because of his experience as a chief financial officer for energy companies and his background as an investment banker in the energy industry.

Vincent Pagano, Jr.
Director of our general partner, Chairman of the Conflicts Committee and a member of the Audit Committee
Mr. Pagano served as a senior corporate partner of Simpson Thacher & Bartlett LLP, a law firm, with a focus on capital markets transactions and public company advisory matters from 1981 until his retirement at the end of 2012. Mr. Pagano currently also serves as a director of L3 Technologies, Inc. (formerly known as L-3 Communications

Holdings, Inc.), a publicly traded defense company, and Hovnanian Enterprises, Inc., a publicly traded homebuilding company. Mr. Pagano earned his law degree, cum laude, from Harvard Law School and his B.S. in Engineering, summa cum laude, from Lehigh University and an M.S. in Engineering from the University of California, Berkeley. It was determined that Mr. Pagano should serve as a director of our general partner because of his capital markets expertise and his experience as an advisor to public companies on a variety of corporate matters.

Oliver G. Richard, III
Director of our general partner and a member of the Audit Committee and Conflicts Committee
Mr. Richard is the owner and president of Empire of the Seed, LLC, a private consulting firm in the energy and management industries. Mr. Richard has served as Chairman of Cleanfuel USA, an alternative vehicular fuel company, since September 2007.

Mr. Richard served as Chairman, President and Chief Executive Officer of Columbia Energy Group, a natural gas company, from 1995 until 2000. Mr. Richard was a Commissioner on the FERC from 1982 until 1985. Mr. Richard currently serves as a director of Buckeye Partners, L.P., a publicly traded petroleum product pipeline and terminal company, and American Electric Power Company, Inc., a publicly traded electric utility. Mr. Richard received a B.S. in Journalism and a J.D. from Louisiana State University and a Master of Law in Taxation from Georgetown University. It was determined that Mr. Richard should serve as a director of our general partner because of his extensive background in the energy industry, including his experience in both the public and private sectors of the energy industry.

Code of Ethics

Our Code of Business Conduct and Ethics covers a wide range of business practices and procedures and furthers our fundamental principles of honesty, loyalty, fairness and forthrightness. The Code of Business Conduct and Ethics was approved by the directors of our general partner. Our Code of Business Conduct and Ethics, which is applicable to all of our directors, officers and employees, is posted at http://www.cheniere.com/about-us/cheniere-partners/governance-and-ethics/. We posted a revised Code of Business Conduct and Ethics on our website in November 2018 and intend to post any further changes to or waivers of our Code of Business Conduct and Ethics for the executive officers of our general partner on our website.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Exchange Act requires the directors and executive officers of our general partner and persons who own more than 10% of a registered class of our equity securities to file initial reports of ownership and reports of changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from the directors and executive officers of our general partner (or otherwise based on our knowledge), we believe that all Section 16(a) filing requirements were met during 2018 in a timely manner.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Our general partner has paid no cash compensation to its executive officers since its inception. All of the executive officers of our general partner are also executive officers of Cheniere. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. Cheniere does not allocate this compensation between services for us and services for Cheniere and its affiliates. Instead, an affiliate of Cheniere provides us various general and administrative services for our benefit, such as technical, commercial, regulatory, financial, accounting, treasury, tax and legal staffing and related support services, pursuant to a services agreement for which we pay a quarterly non-accountable overhead reimbursement charge of $3 million (adjusted for inflation). For a description of the services agreement, see Note 13—Related Party Transactions of our Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

In 2007, the board of directors of our general partner adopted the Cheniere Energy Partners, L.P. Long-Term Incentive Plan for employees, consultants and directors of our general partner, employees of its affiliates and consultants to its subsidiaries. The purpose of the plan is to enhance attraction and retention of qualified individuals who are essential for the successful operation of our partnership and to encourage them to align their interests with our interests through an equity ownership stake in us. The plan allows for the grant of options, restricted units, phantom units and unit appreciation rights. Up to 1,250,000 units may be granted under the plan. The only awards that have been granted under the plan have been made to the non-management directors of our general partner in the form of phantom units to be settled, at the director’s election, in common units, cash or in equal amounts over a four-year vesting period.

Compensation Committee Report

As discussed above, the board of directors of our general partner does not have a compensation committee. In fulfilling its responsibilities, the board of directors of our general partner, acting in lieu of a compensation committee, has reviewed and discussed the Compensation Discussion and Analysis with management. Based on this review and discussion, the board of directors of our general partner recommended that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

By the members of the board of directors of our general partner:
Jack A. Fusco
Michael J. Wortley
Eric Bensaude
Doug Shanda
Philip Meier
John-Paul Munfa
Jamie Welch
James R. Ball
Lon McCain
Vincent Pagano, Jr.
Oliver G. Richard, III

Compensation Committee Interlocks and Insider Participation

As discussed above, the board of directors of our general partner does not have a compensation committee. If any compensation is to be paid to our general partners' officers, the compensation would be reviewed and approved by the entire board of directors of our general partner because they perform the functions of a compensation committee in the event such committee is needed. None of the directors or executive officers of our general partner served as a member of a compensation committee of another entity that has or has had an executive officer who served as a member of the board of directors of our general partner during 2018.

Director Compensation

On July 22, 2014, the board of directors of our general partner approved an annual fee of $70,000 to each non-management director of our general partner for services as a director effective pro-rata as of the date of the approval. Also approved were annual fees of $30,000 for the chairman of the audit committee; $15,000 for the members of the audit committee other than the chairman; $10,000 for the chairman of the conflicts committee; $2,500 per meeting for the members of the conflicts committee, including the chairman; $10,000 for the chairman of the executive committee; $2,500 per meeting for the non-employee members of the executive committee, including the chairman; and $30,000 for the chairman of the CMI SPA Committee. All directors' fees are pro-rated from the date of election to the board and are payable quarterly.

In addition to the annual fees paid to the non-management directors, Messrs. Ball, McCain, Pagano and Richard each receive 3,000 phantom units annually. Vesting will occur for one-fourth of the phantom units on each anniversary of the grant date beginning on the first anniversary of the grant date. Upon vesting, the phantom units will be payable, at the director's election, in common units, cash in an amount equal to the fair market value of a common unit on such date, or an equal amount of both. The directors receive no distributions, and no distributions accrue, on the outstanding phantom units. Mr. Welch serves as Senior Advisor of Blackstone Group and Mr. Munfa serves as a Managing Director in the Private Equity Group of Blackstone Group, and they do not receive additional compensation for service as directors. Mr. Meier and Meier Consulting LLC entered into a letter agreement, dated June 14, 2013 (the "Meier Consulting Letter Agreement"), with Blackstone CQP Holdco pursuant to which Mr. Meier agreed to provide consulting services to Blackstone CQP Holdco relating to the development, construction and operation of the Liquefaction Project. For a further description of the Meier Consulting Letter Agreement, see "Related-Party Transactions-Arrangements involving Mr. Meier and Meier Consulting LLC" below. Mr. Meier receives no additional compensation for his service as a director.

The following table shows the compensation paid for service as a member of the board of directors of our general partner for the 2018 fiscal year:

Name	Fees Earned or Paid in Cash	Unit Awards (1)	Option Awards	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
Jack A. Fusco (2)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Michael J. Wortley (2)	—	—	—	—	—	—	—
Eric Bensaude (2)	—	—	—	—	—	—	—
Doug Shanda (2)	—	—	—	—	—	—	—
Philip Meier (3)	—	—	—	—	—	—	—
John-Paul Munfa (4)	—	—	—	—	—	—	—
Jamie Welch (4)	—	—	—	—	—	—	—
James R. Ball (5)	112,500	115,920	—	—	—	—	228,420
Lon McCain (6)	102,500	105,090	—	—	—	—	207,590
Vincent Pagano, Jr. (7)	97,500	110,790	—	—	—	—	208,290
Oliver G. Richard, III (8)	87,500	115,920	—	—	—	—	203,420

(1) Reflects aggregate grant date fair value. The phantom units are to be settled, at the director's election, in common units, cash, or an equal amount of both. The units are valued using the closing unit price on the date of grant and are revalued on a quarterly basis through the date of vesting.

(2) Mr. Fusco served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2018. Mr. Wortley served as an executive officer of our general partner and as an executive officer of Cheniere during fiscal year 2018. Mr. Bensaude served as an officer of Cheniere Marketing Ltd., a subsidiary of Cheniere during fiscal year 2018. Mr. Shanda served as an officer of our general partner and as an executive officer of Cheniere during fiscal year 2018. Cheniere compensates these officers for the performance of their duties as employees of Cheniere, which includes managing our partnership. They do not receive additional compensation for service as directors.

(3) Mr. Meier is compensated by Blackstone CQP Holdco pursuant to the Meier Consulting Letter Agreement and received no additional compensation for service as a director. For a further description of the Meier Consulting Letter Agreement, see "Related-Party Transactions-Arrangements involving Mr. Meier and Meier Consulting LLC" below.

(4) Mr. Welch serves as Senior Advisor to Blackstone Group and Mr. Munfa is a Managing Director in the Private Equity Group of Blackstone Group. They do not receive additional compensation for service as directors.

(5) Mr. Ball was granted 3,000 phantom units in 2018 with a grant date fair value of $115,920. In addition, Mr. Ball received $28,980 in cash and 2,250 common units on account of 3,000 phantom units granted in earlier years that vested in 2018. As of December 31, 2018, he held 7,500 phantom units and 9,375 common units for a total of 16,875 units.

(6) Mr. McCain was granted 3,000 phantom units in 2018 with a grant date fair value of $105,090. In addition, Mr. McCain received $39,409 in cash and 1,875 common units on account of 3,000 phantom units granted in earlier years that vested in 2018. As of December 31, 2018, he held 7,500 phantom units and 5,250 common units for a total of 12,750 units.

(7) Mr. Pagano was granted 3,000 phantom units in 2018 with a grant date fair value of $110,790. In addition, Mr. Pagano received $55,395 in cash and 1,500 common units on account of 3,000 phantom units granted in earlier years that vested in 2018. As of December 31, 2018, he held 7,500 phantom units and 4,125 common units for a total of 11,625 units.

(8) Mr. Richard was granted 3,000 phantom units in 2018 with a grant date fair value of $115,920. In addition, Mr. Richard received $14,490 in cash and 2,625 common units on account of 3,000 phantom units granted in earlier years that vested in 2018. As of December 31, 2018, he held 7,500 phantom units and 7,125 common units for a total of 14,625 units.

Indemnification of Directors

We have entered into indemnification agreements with each of our directors, which provide for indemnification with respect to all expenses and claims that a director incurs as a result of actions taken, or not taken, on our behalf while serving as a director, officer, employee, controlling person, agent or fiduciary of Cheniere Partners GP or any of our subsidiaries. Pursuant to the agreements, no indemnification will generally be provided (1) for claims brought by the director, except for a claim of indemnity under the indemnification agreement, if we approve the bringing of such claim, or if the Delaware Limited Liability Company Act requires providing indemnification because our director has been successful on the merits of such claim, (2) for claims under Section 16(b) of the Exchange Act, or (3) if there has been a final judgment entered by a court determining that the director acted in bad faith, engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful. Indemnification will be provided to the extent permitted by law, Cheniere Partners GP's certificate of formation and limited liability company agreement, and to a greater extent if, by law, the scope of coverage is expanded after the date of the indemnification agreements. In all events, the scope of coverage will not be less than what was in existence on the date of the indemnification agreements.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT, AND RELATED UNITHOLDER MATTERS

The limited partner interest in our partnership is divided into units. As of February 20, 2019, the following units were outstanding: 348.6 million common units and 135.4 million subordinated units. In addition, as of February 20, 2019, there were 9.9 million general partner units outstanding.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities, and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Except as indicated by footnote, the address for the beneficial owners listed below is 700 Milam Street, Suite 1900, Houston, Texas 77002.

Owners of More than Five Percent of Outstanding Units

The following table shows the beneficial owners known by us to own more than five percent of our common units, subordinated units and/or general partner units as of February 20, 2019:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned		Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned		Percentage of Total Securities Beneficially Owned	
Cheniere Energy, Inc. (1)	104,488,671	30	%	135,383,831	100	%	51	%
Blackstone Group (2)	4,382,079	1	%	—	—		1	%
Blackstone CQP Holdco (2)	198,978,886	57	%	—	—		40	%

(1) Cheniere Energy, Inc. also owns 9,877,400 of our general partner units.

(2) Information is based on the Schedule 13D/A filed with the SEC on August 11, 2017 by the Blackstone Group, L.P., Blackstone CQP Common Holdco L.P., Blackstone CQP Common Holdco GP LLC, Blackstone Energy Management Associates L.L.C., Blackstone EMA L.L.C., Blackstone Management Associates VI L.L.C., BMA VI L.L.C., Blackstone Holdings III L.P., Blackstone Holdings III GP L.P., Blackstone Holdings III GP Management L.L.C., GSO Credit Alpha Fund AIV-2 LP, GSO Coastline Credit Partners LP, GSO Credit-A Partners LP, GSO Palmetto Opportunistic Investment Partners LP, GSO Special Situations Fund LP, GSO Special Situations Master Fund LP, GSO Special Situations Overseas Master Fund Ltd., Blackstone Holdings I L.P., Blackstone Holdings II L.P., Blackstone Holdings I/II GP Inc., GSO Capital Partners LP, GSO Advisor

Holdings LLC, GSO Palmetto Opportunistic Associates LLC, GSO Credit-A Associates LLC, GSO Holdings I L.L.C., Blackstone Group Management L.L.C., Stephen A. Schwarzman, Bennett J. Goodman and J. Albert Smith III and a Form 4 filed with the SEC on January 2, 2018 by the Blackstone Group, L.P. Blackstone CQP Common Holdco L.P. is the record holder of 2,011,447 common units. GSO Credit-A Partners LP and GSO Palmetto Opportunistic Investment Partners LP are the record holders of 953,855 and 953,855 common units, respectively. GSO Credit Alpha Fund AIV-2 LP is the record owner of 462,922 common units. Blackstone CQP Holdco is the record holder of 198,978,886 common units. The address of the various persons identified in this footnote is 345 Park Avenue, New York, New York 10154.

Directors and Executive Officers

The following table sets forth information with respect to our common units beneficially owned as of February 20, 2019, by each director and executive officer of our general partner and by all current directors and executive officers of our general partner as a group. On February 20, 2019, the current directors and executive officers of Cheniere Partners beneficially owned an aggregate of 37,513 common units (less than 1% of the outstanding common units at the time).

The table also presents information with respect to Cheniere Energy, Inc.'s common stock beneficially owned as of February 20, 2019, by each current director and executive officer of our general partner and by all directors and executive officers of our general partner as a group. As of February 20, 2019, Cheniere Energy, Inc. had 257.4 million shares of common stock outstanding.

	Cheniere Energy Partners, L.P.		Cheniere Energy, Inc.	
Name of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Jack A. Fusco (1)	—	— %	803,307 (1)	*%
Michael J. Wortley	—	—	535,011	*
Eric Bensaude	—	—	—	—
Doug Shanda	2,850	*	148,445	*
Philip Meier (2)	—	—	—	—
John-Paul Munfa (2)	—	—	—	—
Jamie Welch (2)	8,788	*	—	—
James R. Ball	9,375	*	—	—
Lon McCain	5,250	*	—	—
Vincent Pagano, Jr.	4,125	*	—	—
Oliver G. Richard, III	7,125	*	—	—
All current directors and executive officers as a group (11 persons)	37,513	*%	1,486,763	*%

* Less than 1%

(1) Includes 169,378 shares held by trust.

(2) Messrs. Meier, Munfa and Welch were appointed as directors of our general partner pursuant to the rights of Blackstone CQP Holdco under the Third Amended and Restated Limited Liability Company Agreement of our general partner to appoint certain directors to the board of directors of our general partner.

Equity Compensation Plan Information

In 2007, the board of directors of our general partner adopted the Cheniere Energy Partners, L.P. Long-Term Incentive Plan. The following table provides certain information as of December 31, 2018 with respect to this plan:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	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 the first column) (2)
Equity compensation plans approved by security holders	—	N/A	—
Equity compensation plans not approved by security holders	16,500	N/A	1,210,250
Total	16,500	N/A	1,210,250

(1) The phantom units that have been granted are payable, at the director's election, in common units, in cash at the time of vesting in an amount equal to the fair market value of a common unit on such date or an equal amount of both.

(2) The number of securities remaining available for issuance does not include securities reserved for issuance upon the vesting of unvested phantom units issued to directors for which such directors have made an irrevocable election to receive common units in lieu of cash.

For more information regarding the Long-Term Incentive Plan, see "Compensation Discussion and Analysis."

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Related-Party Transactions

Prior to the completion of our initial public offering of common units in 2007, the managers of our general partner approved the distributions and payments to be made to our general partner and its affiliates in connection with our ongoing operations and, in the event of, our liquidation. During our operational stage, we will generally make cash distributions to our unitholders, including our affiliates, as described in Part II, Item 5, of this annual report on Form 10-K. Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Procedures for Review, Approval and Ratification of Transactions with Related Persons

Under the audit committee charter, the audit committee of our general partner is required to review and approve all transactions or series of related financial transactions, arrangements or relationships between the partnership and any related-party, if the amount involved exceeds $120,000 and such transactions have not been reviewed by the conflicts committee of our general partner. The following related-party transactions are in addition to those related-party transactions described in Note 13—Related Party Transactions of our Notes to Consolidated Financial Statements which is herein incorporated by reference. Except as described below, such related-party transactions were approved by the members of the board of directors of our general partner, which includes each member of the audit committee.

In determining whether to approve or ratify a related party transaction, the audit committee of our general partner will apply the following standards and such other standards it deems appropriate:

- whether the related party transaction is on terms no less favorable than the terms generally available to an unaffiliated third-party under the same or similar circumstances;
- whether the transaction is material to the Company or the related party; and
- the extent of the related person’s interest in the transaction.

In addition, pursuant to our Code of Business Conduct and Ethics approved by the board of directors of our general partner, the directors, officers and employees of our general partner are expected to bring to the attention of the Compliance Officer any conflict or potential conflict of interest. If a conflict or potential conflict of interest arises between us and a director, officer or any of our affiliates, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of our limited partnership agreement.

Arrangements involving Mr. Meier and Meier Consulting LLC

As noted above, Blackstone CQP Holdco, Mr. Meier and Meier Consulting LLC entered into the Meier Consulting Letter Agreement, pursuant to which Mr. Meier agreed to provide consulting services to Blackstone CQP Holdco relating to the development, construction and operation of the Liquefaction Project. As compensation for the consulting services, Blackstone CQP Holdco agreed to pay Mr. Meier an annual base consulting fee of $375,000 per year and an annual performance consulting fee in Blackstone CQP Holdco's discretion, which was $375,000 in 2018. The consulting arrangement between Blackstone CQP Holdco and Mr. Meier may be terminated by Blackstone for cause or by either party upon 30 days' advance written notice.

We entered into a letter agreement with Blackstone CQP Holdco (the "Blackstone Consultant Letter Agreement"), dated June 23, 2013, pursuant to which we agreed to reimburse Blackstone CQP Holdco for (a) 25% of the fees of Mr. Meier described in the Meier Consulting Letter Agreement and (b) 25% of the expenses of Mr. Meier incurred in connection with his consulting services relating to the Liquefaction Project which are either to be paid or reimbursed by Blackstone CQP Holdco pursuant to the Meier Consulting Letter Agreement. We did not reimburse Blackstone CQP Holdco for any fees and expenses with respect to 2018 under the Blackstone Consultant Letter Agreement.

Independent Directors

Because we are a limited partnership, the NYSE American does not require our general partner's board of directors to be composed of a majority of directors who meet the criteria for independence required by NYSE American. The board of our general partner has determined that Messrs. Ball, McCain, Pagano and Richard are independent directors in accordance with the following NYSE American independence standards. A director would not be independent if any of the following relationships exists:

- a director who is, or during the past three years was, employed by the partnership, general partner or by any parent or subsidiary of the partnership or general partner, other than prior employment as an interim executive officer (provided the interim employment did not last longer than one year);
- a director who accepts, or has an immediate family member who accepts, any compensation from the partnership, general partner or any parent or subsidiary of the partnership or general partner in excess of $120,000 during any twelve consecutive-month period within the three years preceding the determination of independence, other than compensation for board or committee services, or compensation paid to an immediate family member who is a non-executive employee of the partnership, general partner or any parent or subsidiary of the partnership or general partner, among other exceptions;
- a director who is an immediate family member of an individual who is, or at any time during the past three years was, employed by the partnership, general partner or any parent or subsidiary of the partnership or general partner as an executive officer;
- a director who is, or has an immediate family member who is, a partner in, or a controlling shareholder or an executive officer of, any organization to which the partnership, general partner or any parent or subsidiary of the partnership or general partner made, or from which the partnership, general partner or any parent or subsidiary of the partnership or general partner received, payments (other than those arising solely from investments in our common units or payments under non-discretionary charitable contribution matching programs) that exceed 5% of the organization's consolidated gross revenues for that year, or $200,000, whichever is more, in any of the most recent three fiscal years;
- a director who is, or has an immediate family member who is, employed as an executive officer of another entity where at any time during the most recent three fiscal years any of the executive officers of the partnership, general partner or any parent or subsidiary of the partnership or general partner serves on the compensation committee of such other entity; or
-

a director who is, or has an immediate family member who is, a current partner of the outside auditor of the partnership, general partner or parent or subsidiary of the partnership or general partner, or was a partner or employee of the outside auditor of the partnership, general partner or any parent or subsidiary of the partnership or general partner who worked on our audit at any time during any of the past three years.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

KPMG LLP served as our independent auditor for the fiscal years ended December 31, 2018 and 2017. The following table sets forth the fees paid to KPMG LLP for professional services rendered for 2018 and 2017 (in millions):

	Fiscal 2018	Fiscal 2017
Audit Fees	$ 3	$ 3

Audit Fees—Audit fees for 2018 and 2017 include fees associated with the integrated audit of our annual Consolidated Financial Statements, reviews of our interim Consolidated Financial Statements and services performed in connection with registration statements and debt offerings, including comfort letters and consents.

Audit-Related Fees—There were no audit-related fees in 2018 and 2017.

Tax Fees—There were no tax fees in 2018 and 2017.

Other Fees—There were no other fees in 2018 and 2017.

Auditor Pre-Approval Policy and Procedures

Under the audit committee’s charter, the audit committee is required to review and approve in advance all audit and lawfully permitted non-audit services to be provided by the independent accountants and the fees for such services. Pre-approval of non-audit services (other than review and attestation services) shall not be required if such services fall within exceptions established by the SEC. All audit and non-audit services provided to us during the fiscal years ended December 31, 2018 and 2017 were pre-approved.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Exhibits

(1) Financial Statements—Cheniere Energy Partners, L.P.:

Management's Report to the Unitholders of Cheniere Energy Partners, L.P.	59
Reports of Independent Registered Public Accounting Firm	60
Consolidated Balance Sheets	62
Consolidated Statements of Operations	63
Consolidated Statements of Partners' Equity	64
Consolidated Statements of Cash Flows	65
Notes to Consolidated Financial Statements	66
Supplemental Information to Consolidated Financial Statements—Quarterly Financial Data	103

(2) Financial Statement Schedules:

All financial statement schedules have been omitted because they are not required, are not applicable, or the required information has been included elsewhere within this Form 10-K.

(3) Exhibits:

Certain of the agreements filed as exhibits to this Form 10-K contain representations, warranties, covenants and conditions by the parties to the agreements that have been made solely for the benefit of the parties to the agreement. These representations, warranties, covenants and conditions:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other parties in connection with the negotiation of the agreements, which disclosures are not necessarily reflected in the agreements;
- may apply standards of materiality that differ from those of a reasonable investor; and
- were made only as of specified dates contained in the agreements and are subject to subsequent developments and changed circumstances.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time. These agreements are included to provide you with information regarding their terms and are not intended to provide any other factual or disclosure information about the Company or the other parties to the agreements. Investors should not rely on them as statements of fact.

Exhibit No.	Description
2.1	Contribution and Conveyance Agreement, by and among the Partnership, Cheniere LNG Holdings, LLC, Cheniere Partners GP, Cheniere Investments, Sabine Pass LNG-GP, Inc. and Sabine Pass LNG-LP, LLC, effective as of March 26, 2007 (Incorporated by reference to Exhibit 10.4 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 26, 2007)
2.2	

Amended and Restated Purchase and Sale Agreement, dated as of August 9, 2012, by and among the Partnership, Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and Cheniere (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)

Exhibit No.	Description
3.1	Certificate of Limited Partnership of the Partnership (Incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006)
3.2	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated as of February 14, 2017 (Incorporated by reference to Exhibit 3.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on February 21, 2017)
3.3	Certificate of Formation of Cheniere Partners GP (Incorporated by reference to Exhibit 3.3 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006)
3.4	Third Amended and Restated Limited Liability Company Agreement of Cheniere Partners GP, dated as of August 9, 2012 (Incorporated by reference to Exhibit 3.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
4.1	Form of common unit certificate (Included as Exhibit A to Exhibit 3.2 above)
4.2	Indenture, dated as of February 1, 2013, by and among SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on February 4, 2013)
4.3	Form of 5.625% Senior Secured Note due 2021 (Included as Exhibit A-1 to Exhibit 4.2 above)
4.4	First Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013)
4.5	Second Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013)
4.6	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.5 above)
4.7	Third Supplemental Indenture, dated as of November 25, 2013, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on November 25, 2013)
4.8	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.7 above)
4.9	Fourth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.10	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.9 above)
4.11	Fifth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.12	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.11 above)
4.13	Sixth Supplemental Indenture, dated as of March 3, 2015, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 3, 2015)
4.14	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.13 above)
4.15	Seventh Supplemental Indenture, dated as of June 14, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on June 14, 2016)
4.16	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.15 above)
4.17	Eighth Supplemental Indenture, dated as of September 19, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 23, 2016)
4.18	Ninth Supplemental Indenture, dated as of September 23, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 23, 2016)

4.19	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.18 above)
4.20	Tenth Supplemental Indenture, dated as of March 6, 2017, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 6, 2017)
4.21	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.20 above)

Exhibit No.	Description
4.22	Indenture, dated as of February 24, 2017, between SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on February 27, 2017)
4.23	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.22 above)
4.24	Indenture, dated as of September 18, 2017, between the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 18, 2017)
4.25	First Supplemental Indenture, dated as of September 18, 2017, between the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 18, 2017)
4.26	Form of 5.250% Senior Note due 2025 (Included as Exhibit A-1 to Exhibit 4.25 above)
4.27	Second Supplemental Indenture, dated as of September 11, 2018, among the Partnership, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 12, 2018)
4.28	Form of 5.625% Senior Note due 2026 (Included as Exhibit A-1 to Exhibit 4.27 above)
10.1	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and SPLNG (Incorporated by reference to Exhibit 10.1 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.2	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and SPLNG (Incorporated by reference to Exhibit 10.40 to Cheniere's Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)
10.3	Amendment of LNG Terminal Use Agreement, dated June 15, 2010, by and between Total Gas & Power North America, Inc. and SPLNG (Incorporated by reference to Exhibit 10.2 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 6, 2010)
10.4	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and SPLNG (Incorporated by reference to Exhibit 10.2 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.5	Parent Guarantee, dated as of November 5, 2004, by Total S.A. in favor of SPLNG (Incorporated by reference to Exhibit 10.3 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.6	Letter Agreement, dated September 11, 2012, between Total Gas & Power North America, Inc. and SPLNG (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.7	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and SPLNG (Incorporated by reference to Exhibit 10.4 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.8	Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A. Inc. and SPLNG (Incorporated by reference to Exhibit 10.28 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.9	Amendment of LNG Terminal Use Agreement, dated June 16, 2010, by and between Chevron U.S.A. Inc. and SPLNG (Incorporated by reference to Exhibit 10.3 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 6, 2010)
10.10	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and SPLNG (Incorporated by reference to Exhibit 10.5 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)

10.11	Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to SPLNG (Incorporated by reference to Exhibit 10.12 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.12	Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between SPL and SPLNG (Incorporated by reference to Exhibit 10.1 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.13	Letter Agreement, dated May 28, 2013, by and between SPL and SPLNG (Incorporated by reference to Exhibit 10.1 to SPLNG's Quarterly Report on Form 10-Q (SEC File No. 333-138916), filed on August 2, 2013)

Exhibit No.	Description
10.14	Guarantee Agreement, dated as of July 31, 2012, by the Partnership in favor of SPLNG (Incorporated by reference to Exhibit 10.2 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.15	Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, among SPL, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015)
10.16	Omnibus Amendment, dated as of September 24, 2015, to the Second Amended and Restated Common Terms Agreement among SPL, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent (Incorporated by reference to Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015)
10.17	Administrative Amendment to the Second Amended and Restated Common Terms Agreement, dated as of December 31, 2015, among SPL, Société Générale, as the Commercial Banks Facility Agent, The Korea Development Bank, New York Branch, as the KSURE Covered Facility Agent and Shinhan Bank New York Branch, as KEXIM Facility Agent (Incorporated by reference to Exhibit 10.7 to the Partnership's Quarterly Report on Form 10-Q (File No. 001-33366), filed on May 5, 2016)
10.18	Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, among SPL, as Borrower, The Bank of Nova Scotia, as Senior Issuing Bank and Senior Facility Agent, ABN Amro Capital USA LLC, HSBC Bank USA, National Association and ING Capital LLC, as Senior Issuing Banks, Société Générale, as Swing Line Lender and Common Security Trustee, and the senior lenders party thereto from time to time (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 11, 2015)
10.19	Third Omnibus Amendment, dated as of May 23, 2018 to (a) the Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, by and among SPL, Société Générale, as the Common Security Trustee and as the Intercreditor Agent, The Bank of Nova Scotia, and each other party thereto from time to time and (b) the Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, by and among SPL, Société Générale as the Swing Line Lender and as the Common Security Trustee, The Bank of Nova Scotia as the Senior Issuing Bank and Senior Facility Agent and the other agents and lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.3 to the Partnership's Registration Statement on Form S-4 (SEC File No. 333-225684) filed on June 15, 2018)
10.20	Fourth Omnibus Amendment, dated as of September 17, 2018, to (a) the Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, by and among SPL, as Borrower, Société Générale, as the Common Security Trustee and as the Intercreditor Agent, The Bank of Nova Scotia, as the Secured Debt Holder Group Representative for the Working Capital Debt and other Secured Debt Holder Group Representatives party thereto from time to time, the Secured Hedge Representatives and the Secured Gas Hedge Representatives party thereto from time to time and (b) the Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, by and among SPL, as Borrower, Société Générale as the Swing Line Lender and as the Common Security Trustee, The Bank of Nova Scotia as the Senior Issuing Bank and Senior Facility Agent and the other agents and lenders from time to time party thereto (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 8, 2018)
10.21	Credit and Guaranty Agreement, dated as of February 25, 2016, among the Partnership, as Borrower, certain subsidiaries of the Partnership, as Subsidiary Guarantors, the lenders from time to time party thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Issuing Bank, Administrative Agent and Coordinating Lead Arranger, and certain arrangers and other participants (Incorporated by reference to Exhibit 10.1 to the

	Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 2, 2016)
10.22	Administrative Amendment, dated August 7, 2017, to the Credit and Guaranty Agreement among the Partnership, as Borrower, certain subsidiaries of the Partnership, as Subsidiary Guarantors, the lenders from time to time party thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 9, 2017)
10.23	Second Amendment and Consent, dated as of May 23, 2018, amending and modifying the Credit and Guaranty Agreement, dated as of February 25, 2016 by and among the Partnership, MUFG Bank, Ltd., as Administrative Agent, the Lenders party thereto from time to time and each other Person party thereto from time to time (Incorporated by reference to Exhibit 10.2 to the Partnership's Registration Statement on Form S-4 (SEC File No. 333-225684) filed on June 15, 2018)

Exhibit No.	Description
10.24	Depositary Agreement, dated as of February 25, 2016, among the Partnership, as Borrower, certain subsidiaries of the Partnership, as Subsidiary Guarantors, MUFG Union Bank, N.A., as Collateral Agent and Depositary Bank (Incorporated by reference to Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 2, 2016)
10.25	Omnibus Amendment and Waiver, dated as of October 14, 2016, to (a) the Credit and Guaranty Agreement, dated as of February 25, 2016 among the Partnership, as Borrower, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent, the lenders party thereto from time to time, and each other person party thereto from time to time and to (b) the Depositary Agreement, dated as of February 25, 2016, among Borrower, MUFG Union Bank, N.A., as Collateral Agent and Depositary Agent and each other person party thereto from time to time (Incorporated by reference to Exhibit 10.27 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 24, 2017)
10.26	Second Omnibus Amendment, dated as of September 28, 2017 to (a) the Credit and Guaranty Agreement, dated as of February 25, 2016, as amended by the Omnibus Amendment and Waiver, dated October 14, 2016, by and among the Partnership as Borrower, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent, the lenders party thereto from time to time, and each other person party thereto from time to time, to (b) the Depositary Agreement, dated as of February 25, 2016, as amended by the Omnibus Amendment and Waiver, dated October 14, 2016, by and among Borrower, MUFG Union Bank, N.A., as Collateral Agent and Depositary Agent and each other person party thereto from time to time and to (c) the Intercreditor Agreement, dated as of February 25, 2016 by and among the Borrower, the Administrative Agent, the Collateral Agent, and each other person party thereto from time to time (Incorporated by reference to Exhibit 10.20 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 21, 2018)
10.27	Registration Rights Agreement, dated as of September 11, 2018, among the Partnership, the guarantors party thereto and J.P. Morgan Securities LLC (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on September 12, 2018)
10.28†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.3 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on March 26, 2007)
10.29†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (2012 Reload Award) (Incorporated by reference to Exhibit 10.9 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.30†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.8 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.31†	Form of Amendment to Phantom Units Agreement (Incorporated by reference to Exhibit 10.7 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.32†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Units Settlement) (Incorporated by reference to Exhibit 10.41 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 20, 2015)
10.33†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Reload Units Settlement) (Incorporated by reference to Exhibit 10.42 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 20, 2015)
10.34†	Form of Indemnification Agreement for officers and/or directors of Cheniere Partners GP (Incorporated by reference to Exhibit 10.42 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 19, 2016)
10.35	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on

	Form 8-K/A (SEC File No. 001-33366), filed on July 1, 2015)
10.36	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00001 Currency and Fuel Provisional Sum Adjustment, dated June 25, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015)

Exhibit No.	Description
10.37	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00002 Credit to EPC Contract Value for TSA Work, dated September 17, 2015 (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on October 30, 2015)
10.38	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00003 Perimeter Fencing Scope Removal, East Meter Piping Scope Change, Additional Bathroom Facilities, dated November 18, 2015 (Incorporated by reference to Exhibit 10.45 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2016)
10.39	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00004 DOE Regulation Change Impacts, RECON Schedule Change, Addition of Dry Flare Connection, Fuel Gas Supply Transfer to Train 5 and East Meter Fuel Gas, dated February 18, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 5, 2016)
10.40	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00005 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated March 16, 2016, (ii) the Change Order CO-00006 Additional Bechtel Hours to Support RECON, Temporary Access Rd., Addition of Flash Liquid Expander, Removal of Vibration Monitor System, To-Date Reconciliation of Soils Preparation Provisional Sum, dated March 22, 2016, (iii) the Change Order CO-00007 Additional Support for FERC Document Requests, dated May 10, 2016, (iv) the Change Order CO-00008 Water System Scope Changes and Seal Design & Seal Gas Modification, dated May 4, 2016, (v) the Change Order CO-00009 Re-Orientation of PSV Bypass Valves, dated May 17, 2016 and (vi) the Change Order CO-00010 Deletion of Chlorine Analyzer, dated June 15, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on August 9, 2016)
10.41	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00011 Site Drainage Design Change: Professional Service Hours, dated July 26, 2016 (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on November 3, 2016)
10.42	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00012 Addition of Check Valves to Condensate Lines and Change of Tie-in Point, dated September 12, 2016, (ii) the Change Order CO-00013 LNG Rundown Line Reroute, dated September 12, 2016, (iii) the Change Order CO-00014 Pre-EPC HAZOP Action Item Closure, dated September 27, 2016, (iv) the Change Order CO-00015 Study for Enclosed Ground Flare and Process Flare, dated September 27, 2016, (v) the Change Order CO-00016 Upgrades to Gas Turbine Generators, dated October 19, 2016 and (vi) the Change Order CO-00017 Site Drainage Design Change: Temporary Drainage Implementation, dated December 1, 2016 (Incorporated by reference to Exhibit 10.59 to SPL's Registration Statement on Form S-4 (SEC File No. 333-215882), filed on February 3, 2017)
10.43	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00018 Stage 3 Process Flare Modification, dated March

	10, 2017, (ii) the Change Order CO-00019 Site Drainage Design Change: Permanent Drainage Implementation, dated March 10, 2017 and (iii) the Change Order CO-00020 Soils Provisional Sum Partial True-up RECON 2, dated March 13, 2017 (Incorporated by reference to Exhibit 10.64 to SPL's Registration Statement on Form S-4 (SEC File No. 333-218646), filed on June 9, 2017)
10.44	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00021 Soils Preparation Provisional Sum Partial True-Up RECON 3, dated August 24, 2017 (Incorporated by reference to Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 9, 2017)

Exhibit No.	Description
10.45	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00022 OSHA Handrail and Guardrail Modifications, dated October 24, 2017, (ii) the Change Order CO-00023 Operating Spare Part Provisional Sum Closeout, dated October 31, 2017 and (iii) the Change Order CO-00024, dated November 28, 2017 (Incorporated by reference to Exhibit 10.41 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 21, 2018)
10.46	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00025 BOG and LNG Rundown, dated January 19, 2018, (ii) the Change Order CO-00026 Design Analysis of Existing East & West Jetty Piping and Structure for Simultaneous Loading, dated February 1, 2018, (iii) the Change Order CO-00027 Performance and Attendance Bonus (PAB) Transfer from Stage 2, dated February 1, 2018 and (iv) the Change Order CO-00028 Existing Jetty Structural Steel Supply, dated February 27, 2018 (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 4, 2018)
10.47	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00029 Existing Jetty Structural Steel Analysis – Tanks 104 & 105, dated March 28, 2018, (ii) the Change Order CO-00030 Train 5 JT Valve PV-16002 Internals Modification, Eaton Switchgear Bus Repairs & Inspection Isometrics, dated April 18, 2018, (iii) the Change Order CO-00031 Blind and Spacer Set for Feed Gas Header, dated April 18, 2018 and (iv) the Change Order CO-00032 Additional GTG Testing, dated April 18, 2018 (Incorporated by reference to Exhibit 10.1 to the Partnership's Registration Statement on S-4 (SEC File No. 333-225684), filed on June 15, 2018)
10.48	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00033 System Inspection Isometrics, dated May 24, 2018, (ii) the Change Order CO-00034 Site Evacuation, dated May 31, 2018, (iii) the Change Order CO-00035 Stage 3 - Existing & Stages 1 and 2 Liquefaction Facility Labor Provisional Sum True-Up, dated June 7, 2018 and (iv) the Change Order CO-00036 General Electric, Instrument and Valve Spares, dated June 7, 2018 (Incorporated by reference to Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 9, 2018)
10.49*	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00037 Soils Preparation Provisional Sum Closeout, dated November 29, 2018
10.50	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on November 9, 2018)
10.51	LNG Sale and Purchase Agreement (FOB), dated November 21, 2011, between SPL (Seller) and Gas Natural Aprovisionamientos SDG S.A. (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on November 21, 2011)
10.52	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated April 3, 2013, between SPL (Seller) and Gas Natural Aprovisionamientos SDG S.A. (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form

	10-Q (SEC File No. 001-33366), filed on May 3, 2013)
10.53	Amendment of LNG Sale and Purchase Agreement (FOB), dated January 12, 2017, between SPL (Seller) and Gas Natural Fenosa LNG GOM, Limited (assignee of Gas Natural Aprovisionamientos SDG S.A.) (Buyer) (Incorporated by reference to Exhibit 10.3 to SPL's Registration Statement on Form S-4 (SEC File No. 333-215882), filed on February 3, 2017)
10.54	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between SPL (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on December 12, 2011)
10.55	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.18 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)

123

Exhibit No.	Description
10.56	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between SPL (Seller) and BG Gulf Coast LNG, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on January 26, 2012)
10.57	Letter agreement, dated May 12, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB) between SPL and BG Gulf Coast LNG, LLC dated January 25, 2012 (Incorporated by reference to Exhibit 10.7 to SPL's Registration Statement on Form S-4 (SEC File No. 333-215882), filed on February 3, 2017)
10.58	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between SPL (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on January 30, 2012)
10.59	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL(Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.19 to the Partnership's Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.60	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL (Seller) and Cheniere Marketing, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to SPL's Current Report on Form 8-K (SEC File No. 333-192373), filed on August 11, 2014)
10.61	Letter agreement, dated December 8, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC) (Incorporated by reference to Exhibit 10.14 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 24, 2017)
10.62	Management Services Agreement, dated May 14, 2012, by and between Cheniere Terminals and SPL (Incorporated by reference to Exhibit 10.6 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.63	Amendment to Management Services Agreement, dated September 28, 2015, between Cheniere Terminals and SPL (Incorporated by reference to Exhibit 10.8 to Amendment No. 1 to SPL's Quarterly Report on Form 10-Q/A (SEC File No. 333-192373), filed on November 9, 2015)
10.64	Amended and Restated Management Services Agreement, dated as of August 9, 2012, by and between Cheniere Terminals and SPLNG (Incorporated by reference to Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.65	Management Services Agreement, dated May 27, 2013, by and between Cheniere Terminals and CTPL (Incorporated by reference to Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 2, 2013)
10.66	Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated May 14, 2012, by and between Cheniere LNG O&M Services, LLC, Cheniere Partners GP and SPL (Incorporated by reference to Exhibit 10.5 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.67	Assignment and Assumption Agreement (Sabine Pass Liquefaction O&M Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments (Incorporated by reference to Exhibit 10.76 to Amendment No. 4 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on December 2, 2013)
10.68	Amendment to Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated September 28, 2015, by and among Cheniere LNG O&M Services, LLC, Cheniere Investments and SPL (Incorporated by reference to Exhibit 10.7 to Amendment No. 1 to SPL's Quarterly Report on Form 10-Q/A (SEC File No. 333-192373), filed on November 9, 2015)
10.69	Amended and Restated Operation and Maintenance Agreement (Sabine Pass LNG Facilities), dated as of August 9, 2012, by and among Cheniere Partners GP, Cheniere LNG O&M Services, LLC, and SPLNG (Incorporated by reference to Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)

10.70	Assignment and Assumption Agreement (Sabine Pass LNG O&M Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments (Incorporated by reference to Exhibit 10.75 to Amendment No. 4 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on December 2, 2013)
10.71	Amended and Restated Management and Administrative Services Agreement, dated as of August 9, 2012, by and between Cheniere Terminals, the Partnership and Cheniere (Incorporated by reference to Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)

Exhibit No.	Description
10.72	Amended and Restated Operation and Maintenance Services Agreement (Cheniere Creole Trail Pipeline), dated May 27, 2013, by and between CTPL and Cheniere Partners GP (Incorporated by reference to Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 2, 2013)
10.73	Assignment and Assumption Agreement (Creole Trail O&M Agreement), dated as of November 20, 2013, between Cheniere Partners GP and Cheniere Investments (Incorporated by reference to Exhibit 10.74 to Amendment No. 4 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on December 2, 2013)
10.74	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement with eleven Cameron Parish taxing authorities, dated October 23, 2007, by and between Cheniere Marketing, Inc. and SPLNG (Incorporated by reference to Exhibit 10.7 to Cheniere's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.75	Amended and Restated Services and Secondment Agreement, dated as of August 9, 2012, between Cheniere LNG O&M Services, LLC and Cheniere Partners GP (Incorporated by reference to Exhibit 10.3 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.76	Assignment and Assumption Agreement (Services and Secondment Agreement), dated as of November 20, 2013, by and between Cheniere Partners GP and Cheniere Investments (Incorporated by reference to Exhibit 10.73 to Amendment No. 4 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on December 2, 2013)
10.77	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among Cheniere, Cheniere Partners GP, the Partnership, Cheniere Class B Units Holdings, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time (Incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 001-33366), filed on August 6, 2012)
21.1*	Subsidiaries of the Partnership
23.1*	Consent of KPMG LLP
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2*	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1**	Certification by 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 by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.
** Furnished herewith.
† Management contract or compensatory plan or arrangement.

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.

CHENIERE ENERGY PARTNERS, L.P.

By: Cheniere Energy Partners GP, LLC,
its general partner

By: /s/ Jack A. Fusco
Jack A. Fusco
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 25, 2019

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 general partner of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Jack A. Fusco Jack A. Fusco	President and Chief Executive Officer, Chairman of the Board (Principal Executive Officer)	February 25, 2019
/s/ Michael J. Wortley Michael J. Wortley	Executive Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 25, 2019
/s/ Leonard Travis Leonard Travis	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2019
/s/ Eric Bensaude Eric Bensaude	Director	February 25, 2019
/s/ Doug Shanda Doug Shanda	Director	February 25, 2019
/s/ Philip Meier Philip Meier	Director	February 25, 2019
/s/ John-Paul Munfa John-Paul Munfa	Director	February 25, 2019
/s/ Jamie Welch Jamie Welch	Director	February 25, 2019
/s/ James R. Ball James R. Ball	Director	February 25, 2019
/s/ Lon McCain	Director	February 25, 2019

Lon McCain

/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 25, 2019
/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 25, 2019

127