

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

FORM 10-K

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

For the fiscal year ended December 31, 2014

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 No. 001-33366

Cheniere Energy Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

20-5913059

(I.R.S. Employer Identification No.)

700 Milam Street, Suite 1900

Houston, Texas

(Address of principal executive offices)

77002

(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

(Title of Class)

NYSE MKT

(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 No

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

(Do not check if a smaller reporting company)

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

The aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately \$ 1.5 billion as of June 30, 2014.

The registrant had 57,079,973 common units, 145,333,334 Class B units and 135,383,831 subordinated units outstanding as of January 29, 2015.

Documents incorporated by reference: **None**

CHENIERE ENERGY PARTNERS, L.P.
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**CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS**

This annual report contains certain statements that are, or may be deemed to be, “forward-looking statements.” All statements, other than statements of historical facts, 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 Sabine Pass LNG, L.P. (“Sabine Pass LNG”), Sabine Pass Liquefaction, LLC (“Sabine Pass Liquefaction”) or Cheniere Creole Trail Pipeline, L.P. (“CTPL”);
- statements that we expect to commence or complete construction of our proposed liquefied natural gas (“LNG”) terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions 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 ability to enter into such transactions;
- statements relating to the construction of our natural gas liquefaction trains (“Trains”), including statements concerning the engagement of any engineering, procurement and construction (“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 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, 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 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 and capital expenditures, 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 fact, are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” “continue,” 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 due to factors described in this annual report and in the other reports and other information that we file with the Securities and Exchange Commission (“SEC”). These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

DEFINITIONS

As commonly used in the liquefied natural gas industry, to the extent applicable, and as used in this annual report, the following terms have the following meanings:

- *Bcf/d* means billion cubic feet per day;
- *Bcf/yr* means billion cubic feet per year;
- *Bcfe* means billion cubic feet equivalent;
- *Dthd* means dekatherms per day;
- *EPC* means engineering, procurement and construction;
- *Henry Hub* means 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;
- *LNG* means liquefied natural gas, a product of natural gas consisting primarily of methane (CH₄) that is in liquid form at near atmospheric pressure;
- *MMBtu* means million British thermal units, an energy unit;
- *MMBtu/d* means million British thermal units per day;
- *MMBtu/yr* means million British thermal units per year;
- *mtpa* means million metric tonnes per annum;
- *SPA* means an LNG sale and purchase agreement;
- *Tcf* means trillion cubic feet;
- *Tcf/yr* means trillion cubic feet per year;
- *Train* means a compressor train used in the industrial process to convert natural gas into LNG; and
- *TUA* means terminal use agreement.

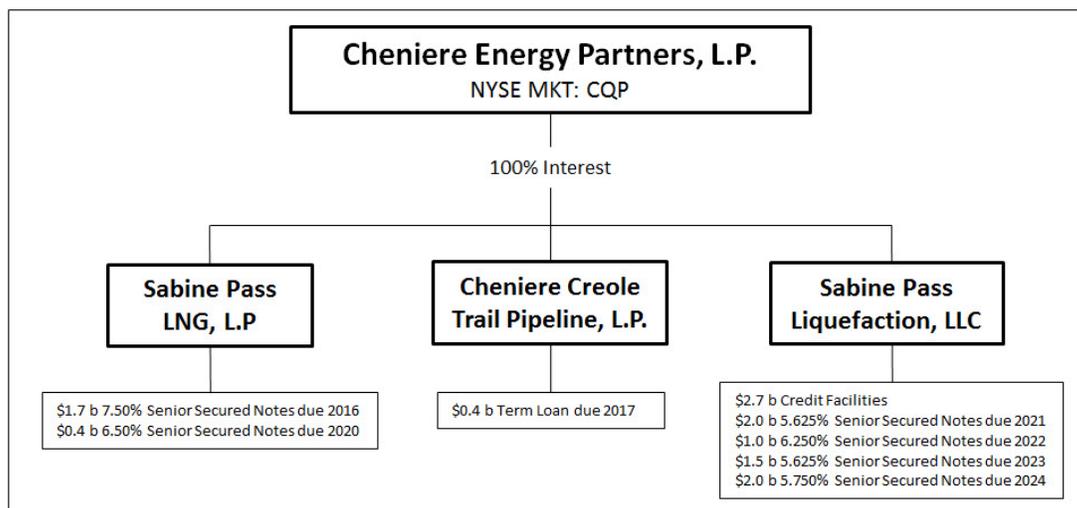
PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We are a publicly traded Delaware limited partnership (NYSE MKT: CQP) formed by Cheniere Energy, Inc. ("Cheniere") (NYSE MKT: LNG). Through our wholly owned subsidiary, Sabine Pass LNG, we own and operate the regasification facilities at the Sabine Pass LNG terminal located on the Sabine Pass deep water shipping channel less than four miles from the Gulf Coast. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We are developing and constructing natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through our wholly owned subsidiary, Sabine Pass Liquefaction. We plan to construct up to six Trains which are in various stages of development. Each Train is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. We also own the 94-mile Creole Trail Pipeline through our wholly owned subsidiary, CTPL, which interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines. Unless the context requires otherwise, references to "Cheniere Partners," "we," "us" and "our" refer to Cheniere Energy Partners, L.P. and its subsidiaries, including Sabine Pass LNG, Sabine Pass Liquefaction and CTPL.

The following diagram depicts our abbreviated capital structure, including our ownership of Sabine Pass LNG, Sabine Pass Liquefaction and CTPL, as of January 31, 2015:



LNG is 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. 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 justify economically the use of LNG. LNG is transported using large oceangoing LNG tankers specifically constructed for this purpose. LNG regasification facilities offload LNG from LNG tankers, store the LNG prior to processing, heat the LNG to return it to a gaseous state and deliver the resulting natural gas into pipelines for transportation to market.

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:

- completing construction and commencing operation of our Trains;
- developing and operating our Trains safely, efficiently and reliably;
- making LNG available to our long-term SPA customers to generate steady and reliable revenues and operating cash flows;
- safely maintaining and operating the Sabine Pass LNG terminal and the Creole Trail Pipeline;
- developing business relationships for the marketing of additional long-term and short-term agreements for additional LNG volumes at the Sabine Pass LNG terminal; 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

We have constructed and are operating regasification facilities at the Sabine Pass LNG terminal and are developing and constructing the Liquefaction Project. We have long-term leases for five tracts of land consisting of 1,044 acres.

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 Sabine Pass LNG'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 Sabine Pass LNG 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 Sabine Pass Liquefaction. Sabine Pass Liquefaction is obligated to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$250 million annually, continuing until at least 20 years after Sabine Pass Liquefaction delivers its first commercial cargo at the Liquefaction Project, which may occur as early as late 2015. In September 2012, Sabine Pass Liquefaction entered into a partial TUA assignment agreement with Total, whereby Sabine Pass Liquefaction will progressively gain access to Total's capacity and other services provided under Total's TUA with Sabine Pass LNG. This agreement will provide Sabine Pass Liquefaction with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to accommodate the development of Trains 5 and 6, provide increased flexibility in managing LNG cargo loading and unloading activity starting with the commencement of commercial operations of Train 3, and permit Sabine Pass Liquefaction to more flexibly manage its LNG storage capacity with the commencement of Train 1. Notwithstanding any arrangements between Total and Sabine Pass Liquefaction, payments required to be made by Total to Sabine Pass LNG will continue to be made by Total to Sabine Pass LNG in accordance with its TUA.

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

Liquefaction Facilities

The Liquefaction Project is being developed and constructed at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the Federal Energy Regulatory Commission (the "FERC") to site, construct and operate Trains 1 through 4. We commenced construction of Trains 1 and 2 and the related new facilities needed to treat, liquefy, store and export natural gas in August 2012. Construction of Trains 3 and 4 and the related facilities commenced in May 2013. On September 30, 2013, we filed an application with the FERC for the approval to site, construct and operate Trains 5 and 6.

The U.S. Department of Energy (the "DOE") has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to countries with which the United States has a free trade agreement providing for national treatment for trade in natural gas ("FTA countries") for a 30-year term, beginning on the earlier of the date of first export or September 7, 2020; and to all countries without a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted ("non-FTA countries") for a 20-year term, beginning on the earlier of the date of first export or August 7, 2017. The DOE further issued an order authorizing Sabine Pass Liquefaction to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. Additionally, the DOE further issued orders authorizing Sabine Pass Liquefaction to export an additional 503.3 Bcf/yr in total of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 20-year term. Sabine Pass Liquefaction's applications for authorization to export that same 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries are currently pending at the DOE.

As of December 31, 2014, the overall project completion percentages for Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project were approximately 81% and 54%, respectively, which are ahead of the contractual schedule. Based on our current construction schedule, we anticipate that Train 1 will produce LNG as early as late 2015, and Trains 2, 3 and 4 are expected to commence operations on a staggered basis thereafter.

The following table summarizes significant milestones and anticipated completion dates in the development of the Liquefaction Project:

Milestone	Target Date	
	Trains 1 - 4	Trains 5 & 6
DOE export authorization	Received	Received FTA Pending Non-FTA
Definitive commercial agreements	Completed	T5: Completed
- BG Gulf Coast LNG, LLC	16.0 mtpa	T6: 2015
- Gas Natural Fenosa	5.5 mtpa	
- KOGAS	3.5 mtpa	
- GAIL (India) Ltd.	3.5 mtpa	
- Total Gas & Power N.A.		2.0 mtpa
- Centrica plc		1.75 mtpa
EPC contract	Completed	2015
Financing	Completed	2015
- Equity commitments		
- Debt commitments		
FERC authorization	Completed	
- FERC Order		2015
- Certificate to commence construction		2015
Issue Notice to Proceed	Completed	2015
Commence operations	2015 - 2017	2018/2019

Customers

Sabine Pass Liquefaction has entered into four fixed price, 20-year SPAs with third parties that in the aggregate equate to 16 mtpa (approximately 807 Bcf/yr) of LNG that commence with the date of first commercial delivery for Trains 1 through 4, which are fully permitted. In addition, Sabine Pass Liquefaction has entered into two fixed price, 20-year SPAs with third parties for another 3.75 mtpa of LNG that commence with the date of first commercial delivery for Train 5. However, Sabine Pass Liquefaction has not yet received regulatory approval for construction of Train 5. Under the SPAs, the customers will purchase LNG from Sabine Pass Liquefaction for a price consisting of a fixed fee plus 115% of Henry Hub per MMBtu of LNG. 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 cargoes that are not delivered. A portion of the fixed fee will be subject to annual adjustment 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 commences upon the start of operations of the specified Train. As of December 31, 2014, Sabine Pass Liquefaction had the following third-party SPAs:

- BG Gulf Coast LNG, LLC (“BG”) has entered into an SPA that commences upon the date of first commercial delivery for Train 1 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of \$2.25 per MMBtu and includes additional annual contract quantities of 36,500,000 MMBtu, 34,000,000 MMBtu, and 33,500,000 MMBtu upon the date of first commercial delivery for Trains 2, 3 and 4, respectively, with a fixed fee of \$3.00 per MMBtu. The total expected annual contracted cash flow from BG from fixed fees is approximately \$723 million. In addition, Sabine Pass Liquefaction has agreed to make up to 500,000 MMBtu/d of LNG available to BG to the extent that Train 1 becomes commercially operable prior to the beginning of the first delivery window with a fixed fee of \$2.25 per MMBtu, if produced. The obligations of BG are guaranteed by BG Energy Holdings Limited, a company organized under the laws of England and Wales.
- Gas Natural Aproveisionamientos SDG S.A. (“Gas Natural Fenosa”) has entered into an SPA that commences upon the date of first commercial delivery for Train 2 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of \$2.49 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately \$454 million. In addition, Sabine Pass Liquefaction has agreed to make up to 285,000 MMBtu/d of LNG available to Gas Natural Fenosa to the extent that Train 2 becomes commercially operable prior to the beginning of the first delivery window with a fixed fee of \$2.49 per MMBtu, if produced. The obligations of Gas Natural Fenosa are guaranteed by

Gas Natural SDG S.A., a company organized under the laws of Spain.

- Korea Gas Corporation (“KOGAS”) has entered into an SPA that commences upon the date of first commercial delivery for Train 3 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of \$3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately \$548 million. KOGAS is organized under the laws of the Republic of Korea.
- GAIL (India) Limited (“GAIL”) has entered into an SPA that commences upon the date of first commercial delivery for Train 4 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of \$3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately \$548 million. GAIL is organized under the laws of India.
- Total has entered into an SPA that commences upon the date of first commercial delivery for Train 5 and includes an annual contract quantity of 104,750,000 MMBtu of LNG with a fixed fee of \$3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately \$314 million. The obligations of Total are guaranteed by Total S.A., a company organized under the laws of France.
- Centrica plc (“Centrica”) has entered into an SPA that commences upon the date of first commercial delivery for Train 5 and includes an annual contract quantity of 91,250,000 MMBtu of LNG with a fixed fee of \$3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately \$274 million. Centrica is organized under the laws of England and Wales.

In aggregate, the fixed fee portion to be paid by these customers is approximately \$2.3 billion annually for Trains 1 through 4, and \$2.9 billion annually if we make a positive final investment decision with respect to Train 5, with the applicable fixed fees starting from the commencement of commercial operations of the applicable Train. These fixed fees equal approximately \$411 million, \$564 million, \$650 million, \$648 million and \$588 million for each of Trains 1 through 5, respectively. The Total and Centrica SPAs contain certain conditions precedent, including, but not limited to, receiving regulatory approvals, securing necessary financing arrangements and making a final investment decision with respect to Train 5, which must be satisfied by June 30, 2015 or either party to the respective SPA may terminate its SPA.

In addition, Cheniere Marketing, LLC (“Cheniere Marketing”), a wholly owned subsidiary of Cheniere, has entered into an amended and restated SPA (the “Cheniere Marketing SPA”) with Sabine Pass Liquefaction to purchase, at Cheniere Marketing’s option, any LNG produced by Sabine Pass Liquefaction in excess of that required for other customers at a price of 115% of Henry Hub plus \$3.00 per MMBtu of LNG.

Natural Gas Transportation and Supply

For Sabine Pass Liquefaction’s natural gas feedstock transportation requirements, it has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. Sabine Pass Liquefaction has also entered into enabling agreements and long-term natural gas purchase agreements with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2014, we have secured up to approximately 2,162,000,000 MMBtu of natural gas feedstock through long-term natural gas purchase agreements.

Construction

Trains 1 through 4 are being designed, constructed and commissioned by Bechtel Oil, Gas and Chemicals, Inc. (“Bechtel”). Sabine Pass Liquefaction entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Train 1 and Train 2 (the “EPC Contract (Trains 1 and 2)”) and Train 3 and Train 4 (the “EPC Contract (Trains 3 and 4)”) 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 Sabine Pass Liquefaction to enter into a change order, or Sabine Pass Liquefaction agrees with Bechtel to a change order.

The total contract price of the EPC Contract (Trains 1 and 2) and the total contract price of the EPC Contract (Trains 3 and 4) are approximately \$4.1 billion and \$3.8 billion, respectively, reflecting amounts incurred under change orders through December 31, 2014. Total expected capital costs for Trains 1 through 4 are estimated to be between \$9.0 billion and \$10.0 billion before financing costs, and between \$12.0 billion and \$13.0 billion after financing costs, including, in each case, estimated owner’s costs and contingencies.

We will contemplate making a final investment decision to commence construction of Train 5 and Train 6 of the Liquefaction Project based upon, among other things, entering into an EPC contract, entering into acceptable commercial arrangements, receiving regulatory authorizations and obtaining adequate financing to construct the Trains.

Pipeline Facilities

CTPL owns the Creole Trail Pipeline, a 94-mile pipeline interconnecting the Sabine Pass LNG terminal with a number of large interstate pipelines. In December 2013, CTPL began construction of certain modifications to allow the Creole Trail Pipeline to be able to transport natural gas to the Sabine Pass LNG terminal. We estimate that the capital costs to modify the Creole Trail Pipeline will be approximately \$105 million. The modifications are expected to be in service in time for the commissioning and testing of Trains 1 and 2.

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 our cost of operations and construction, and failure to comply with such laws could result in substantial penalties.

Federal Energy Regulatory Commission

The design, construction and operation of our proposed liquefaction facilities, the export of LNG and the transportation of natural gas through the Creole Trail Pipeline are highly regulated activities. In order to site and construct the Sabine Pass LNG terminal, we received and are required to maintain authorization from the FERC under Section 3 of the Natural Gas Act of 1938 (“NGA”). The FERC’s approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to site, construct and operate our liquefaction facilities.

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 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. Subsequently, the FERC issued written approval to commence site preparation work for Trains 1 through 4. The FERC approval requires us to obtain certain additional FERC approvals as construction progresses. To date, we have been able to obtain these approvals as needed. On October 9, 2012, we applied to amend the FERC approval to reflect certain modifications to the Liquefaction Project, and on August 2, 2013, the FERC issued an order approving the modifications. On October 25, 2013, we applied to further amend the FERC approval, requesting authorization to increase the total LNG production capacity of Trains 1 through 4 from the currently authorized 803 Bcf/yr to 1,006 Bcf/yr so as to more accurately reflect the estimated maximum LNG production capacity. On February 20, 2014, the FERC issued an order granting the request. The need for these approvals has not materially affected our construction progress. The FERC’s approval to site, construct and operate Trains 5 and 6 also will be required. In this regard, on September 30, 2013, we filed an application with the FERC for authorization to add Trains 5 and 6 to the Liquefaction Project. Throughout the life of our proposed liquefaction facilities, we will be subject to regular reporting requirements to the FERC and the U.S. Department of Transportation regarding the operation and maintenance of our facilities.

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. 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 Dthd 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 began in December 2013.

In addition to the siting and construction authority with respect to LNG terminals under the NGA, the FERC is granted authority to approve, and if necessary, set “just and reasonable rates” for the transportation or sale of natural gas in interstate commerce. 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. 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. Under 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, or local distribution 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 for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

The EPAct amended the NGA to prohibit market manipulation, and increased civil and criminal penalties for any violations of the NGA and any rules, regulations or orders of the FERC, up to \$1.0 million per day per violation. In accordance with the EPAct, the FERC issued a final rule making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC’s jurisdiction, to defraud, make an untrue statement of material fact or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud or deceit upon any entity.

For a number of years the FERC has implemented certain rules referred to as Standards of Conduct aimed at ensuring that an interstate natural gas pipeline not provide certain affiliated entities with preferential access to transportation service or non-public information about such service. These rules have been subject to revision by the FERC from time to time, most recently in 2008 when the FERC issued a final rule, Order No. 717, on Standards of Conduct for Transmission Providers. Order No. 717, as amended, eliminated the concept of energy affiliates and adopted a “functional approach” that applies Standards of Conduct to individual officers and employees based on their job functions, not on the company or division in which the individual works. The general principles of the Standards of Conduct are non-discrimination, independent functioning, no conduit and transparency. These general principles govern the relationship between marketing function employees conducting transactions with affiliated pipeline companies and transportation function employees. CTPL has established the required policies and procedures to comply with the Standards of Conduct and is subject to audit by the FERC to review compliance, policies and its training programs.

DOE Export License

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term, beginning on the earlier of the date of first export or September 7, 2020; and to non-FTA countries for a 20-year term, beginning on the earlier of the date of first export or August 7, 2017. The DOE further issued an order authorizing Sabine Pass Liquefaction to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period.

Additionally, the DOE further issued three orders authorizing the export of an additional 503.3 Bcf/yr in total of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 20-year term. One order authorized the export of 101 Bcf/yr of domestically produced LNG pursuant to the SPA with Total, beginning on the earlier of the date of first export or July 11, 2021; the second order authorized the export of 88.3 Bcf/yr of domestically produced LNG pursuant to the SPA with Centrica, beginning on the earlier of the date of first export or July 12, 2021; and the third order authorized the export of 314 Bcf/yr of domestically produced LNG, beginning on the earlier of the date of first export or January 22, 2022. Additional applications to the DOE for permits to allow the export of the additional 503.3 Bcf/yr of domestically produced LNG to non-FTA countries are pending.

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 import LNG now or will do so by 2016 include Chile, Mexico, Singapore, South Korea and the Dominican Republic. 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.

Pipelines

The Creole Trail Pipeline is also subject to regulation by the U.S. Department of Transportation (“DOT”), under the Pipeline and Hazardous Material Safety Administration (“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 2010, the PHMSA issued a final rule (known as “Control Room Management/Human Factors Rule”) requiring pipeline operators to write and institute certain control room procedures that address human factors and fatigue management. In August 2011, the PHMSA issued an advanced notice of proposed rulemaking addressing whether changes are needed to the regulations governing the safety of gas transmission pipelines. Specifically, PHMSA is considering whether integrity management requirements should be changed, including whether the definition of “high consequence area” should be revised and whether additional restrictions should be placed on the use of specific pipeline assessment methods. The PHMSA is also considering whether to revise requirements for non-integrity management issues, such as mainline valves, corrosion control issues and the safety of gathering lines. This advanced notice of proposed rulemaking is still pending at the PHMSA.

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

Louisiana and Texas administer 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 remedies.

Pipeline Safety, Regulatory Certainty, and Jobs Creation Act of 2011

The Creole Trail Pipeline is also subject to the Pipeline Safety, Regulatory Certainty, and Jobs 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 \$200,000 per day (increased from the prior \$100,000), with a maximum of \$2 million 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 are subject to additional federal permits, orders, approvals and consultations required by other federal agencies, including the DOE, 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 (“Title V”) Operating Permit and the Prevention of Significant Deterioration (“PSD”) Permit, the latter two permits being issued by the LDEQ.

The application for revision of the Sabine Pass LNG terminal’s Section 10/404 Permit to authorize construction of Trains 1 through 4 was submitted in January 2011. The process included a public comment period which commenced in March 2011 and closed in April 2011. The revised Section 10/404 Permit was received from the USACE in March 2012. An application for a further revision to the Section 10/404 Permit, to address wetlands impacted by the construction of Trains 5 and 6, is currently pending before the USACE. We do not anticipate obtaining this permit until after FERC issues an order approving the expansion of the Liquefaction Project. In addition, a Section 10/404 permit application is pending with respect to the expansion of the Creole Trail Pipeline. Both of these permits, if issued, will require us to provide mitigation to compensate for the wetlands impacted by the respective projects. The application to amend the Sabine Pass LNG terminal’s existing Title V and PSD permits to authorize construction of Trains 1 through 4 was initially submitted in December 2010 and revised in March 2011. The process included a public comment period from June 2011 to August 2011 and a public hearing in August 2011. The final revised Title V and PSD permits were issued by the LDEQ in December 2011. Although these permits are final, a petition with the EPA has been filed pursuant to the Clean Air Act requesting that the EPA object to the Title V permit. The EPA has not ruled on this petition. In June 2012, we applied to the LDEQ for a further amendment to the Title V and PSD permits to reflect proposed modifications to the Liquefaction Project that were filed with the FERC in October 2012. The LDEQ issued the amended PSD and Title V permits in March 2013. These permits are final. In September 2013, we applied to the LDEQ for another amendment to its PSD and Title V permits seeking approval to, among other things, construct and operate Trains 5 and 6. We anticipate, but cannot guarantee, that the revised Title V and PSD permits authorizing, among other things, construction and operation of Trains 5 and 6 will be issued in the second quarter of 2015.

CTPL was issued Title V and PSD permits for the proposed modifications to the Creole Trail Pipeline system by the LDEQ in November 2013.

In August 2014, the Sabine Pass LNG terminal’s existing wastewater discharge permit was modified by LDEQ to authorize the discharge of wastewaters from the liquefaction facilities, including wastewaters generated with respect to the anticipated operations of Trains 5 and 6.

The Sabine Pass LNG terminal is subject to DOT safety regulations and standards for the transportation and storage of LNG and regulations of the U.S. Coast Guard relating to maritime safety and facility security.

Commodity Futures Trading Commission

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (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 certain swaps that the Commodity Futures Trading Commission (the “CFTC”) designated by rule to be cleared, (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, and (5) enhance the CFTC’s rulemaking and enforcement authority, including the authority to establish position limits on certain swaps and futures products. As required by the Dodd-Frank Act, the CFTC, the SEC and other regulators have been promulgating rules and regulations implementing the swaps regulatory provisions of the Dodd-Frank Act, although neither the CFTC nor the SEC has yet adopted all of the rules required by the Dodd-Frank Act. As a result of the Dodd-Frank Act’s provisions, the CFTC, in order to regulate excessive speculation in commodities, must adopt rules imposing new position limits on futures and options contracts and economically equivalent physical commodity swaps, on 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.

After a court vacated the final rules that the CFTC adopted imposing position limits on certain core futures and equivalent swaps contracts for physical commodities, including Henry Hub natural gas, the CFTC published in the Federal Register on December 12, 2013, proposed new position limits rules that would modify and expand the applicability of position limits on the amounts of core futures and equivalent swaps contracts of such types that market participants could hold, subject to exceptions for certain bona fide hedging transactions. An extended comment period on such proposed position limits rules has expired, but the CFTC has not yet acted to adopt the proposed rules.

Pursuant to rules adopted by the CFTC, six classes of over-the-counter (“OTC”) interest rate and credit default swaps must be cleared on a designated clearing organization and also must be executed on an exchange or swap execution facility. The CFTC has not yet proposed to designate any other classes of swaps, 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 we enter into to hedge our commercial risks, the mandatory clearing and exchange-trading requirements may apply to other market participants, such as our counterparties (who may be registered as Swap Dealers), and the application of such rules may change the cost and availability of the swaps that we use for hedging. For uncleared swaps, the CFTC or federal banking regulators may require our counterparties to require us to enter into credit support documentation with them and/or require us to post initial and variation margin with respect to our uncleared swaps. On September 24, 2014, the banking regulators published in the Federal Register proposed joint rules to establish minimum margin and capital requirements for registered Swap Dealers, Major Swap Participants, security-based Swap Dealers, and major security-based swap participants regulated by the banking regulators, although those requirements would not require collection of initial or variation margin from non-financial end users. On October 3, 2014, the CFTC published in the Federal Register similar proposed rules for initial and variation margin requirements. The proposed CFTC rules establish initial and variation margin requirements for Swap Dealers and Major Swap Participants, but do not require these entities to collect margin from non-financial end users. However, the proposed rules are not yet final and therefore the application of those provisions to us is uncertain at this time. On January 12, 2015, President Obama signed into law legislation modifying the Dodd-Frank Act and clarifying that any rules for the collection of initial or variation margin for uncleared swaps shall not apply to non-financial end users that qualify for the end user exception to clearing. Other provisions of the Dodd-Frank Act may also cause our derivatives counterparties to spin off some or all of their derivatives activities to a separate entity, and such separate entity, who could be our counterparty in future swaps, may not be as creditworthy as the current counterparty. The Dodd-Frank Act’s swaps regulatory provisions and the related rules may also adversely affect our existing derivative contracts and restrict our ability to monetize such contracts, cause us to restructure certain contracts, reduce the availability of derivatives to protect against risks or to optimize assets, adversely affect our ability to execute our hedging strategies and impact the liquidity of certain swaps products, all of which could increase our business costs.

Under the Commodity Exchange Act, the CFTC is directed generally to prevent manipulation and fraud in two markets: (a) physical commodities traded in interstate commerce, including physical energy and other commodities, as well as (b) financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-manipulation, anti-fraud and anti-disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Should we violate these laws and regulations, we could be subject to a CFTC 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 may impose substantial penalties for noncompliance and substantial liabilities for pollution. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial 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 fuel combustion sources as well as all fugitive emissions throughout LNG terminals. From time to time, Congress has considered proposed legislation directed at reducing GHG emissions, and the EPA has defined GHG emissions thresholds for requiring certain permits for new and existing industrial sources. 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, financial position, results of operations and cash flows.

Coastal Zone Management Act (“CZMA”)

The Sabine Pass LNG terminal is subject to the review and possible requirements of the CZMA throughout the construction of facilities located within the coastal zone. The CZMA is administered by the states (in Louisiana, by the Department of Natural Resources, and in Texas, by the General Land Office). 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 disposal of solid and hazardous wastes. 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

Endangered Species Act

The Sabine Pass LNG terminal may be restricted by requirements under the Endangered Species Act, which seeks to protect endangered or threatened animal, fish and plant species and designated habitats.

Market Factors and Competition

Sabine Pass LNG 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 Sabine Pass LNG has to replace any TUAs, it will compete with other then-existing LNG terminals for customers.

The Liquefaction Project currently does not experience competition with respect to Trains 1 through 5. Sabine Pass Liquefaction has entered into six fixed price, 20-year SPAs with third parties that will utilize substantially all of the liquefaction capacity available 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 Sabine Pass Liquefaction needs to replace any existing SPA or enter into new SPAs with respect to Train 6, Sabine Pass Liquefaction 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 has entered into nine third-party SPAs 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.

CTPL currently does not experience competition for its pipeline capacity because it is fully contracted with Sabine Pass Liquefaction. If and when CTPL has to replace any of its contracted pipeline capacity, it will compete with other interstate and/or intrastate pipelines that may connect with the Sabine Pass LNG terminal.

Our ability to enter into additional long-term sale and purchase agreements to underpin the development of additional Trains, sell any quantities of LNG available under the SPA with Cheniere Marketing, or develop new projects is subject to market factors, including 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, economic growth in developing countries, investment in energy infrastructure, the rate of fuel switching for power generation from coal, nuclear or oil to natural gas and access to 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 29 Tcf between 2012 and 2025, with LNG increasing its current share of approximately ten percent of the global market. Wood Mackenzie forecasts that global demand for LNG will increase by 85%, from approximately 237 mtpa, or 11.5 Tcf, in 2012, to 438 mtpa, or 21.4 Tcf, in 2025 and that LNG production from existing facilities and new facilities already under construction will be able to supply the market with 337 mtpa in 2025, resulting in a market need for construction of an additional 101 mtpa of LNG production. We believe our new project that does not already have capacity sold under long-term contracts is competitive and well-positioned to capture a portion of this incremental market need.

We have limited exposure to the recent decline in oil prices, even if it persists for more than 12 months, 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. To date we have contracted approximately 19.75 mtpa of aggregate production capacity for Trains 1 through 5 of the Liquefaction Project with third party customers. Train 6 has not been contracted to date. As of January 31, 2015, futures prices indicate that LNG exported from the U.S. continues to be competitive with LNG from alternative sources, supporting the need for additional long-term, medium-term and short-term contracting of LNG from our LNG 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, Sabine Pass LNG, Sabine Pass Liquefaction and CTPL. As of January 31, 2015, Cheniere and its subsidiaries had 642 full-time employees, including 371 employees who directly supported the Sabine Pass LNG terminal operations. See [Note 9—Related Party Transactions](#) in our Notes to Consolidated Financial Statements for a discussion of the services agreements pursuant to which general and administrative services are provided to Cheniere Partners, Sabine Pass LNG, Sabine Pass Liquefaction and CTPL.

Available Information

Our common units have been publicly traded since March 21, 2007, and are traded on the NYSE MKT 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 of 1934, as amended (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. In addition, the public may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports and other information regarding issuers, like us, that file electronically with the SEC.

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 significant debt could materially and adversely affect our business, financial condition and prospects.

As of December 31, 2014, we had \$9.0 billion of total debt outstanding on a consolidated basis (before debt discounts and debt premiums). We incur, and will incur, significant interest expense relating to the assets at the Sabine Pass LNG terminal and we anticipate needing to incur substantial additional debt and issue equity to finance the construction of Train 5 and 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. Furthermore, 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 net losses of \$410.0 million, \$258.1 million and \$175.4 million for the years ended December 31, 2014, 2013 and 2012, respectively. We will continue to incur significant capital and operating expenditures while we develop and construct the Liquefaction Project. We currently expect that we will not begin to receive any significant cash flows from the Liquefaction Project until late 2015, at the earliest. Any delays beyond the expected development period for Train 1 could cause, and could increase the level of, operating losses. 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 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 Trains 5 and 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 Chevron and Total, each of which has entered into a TUA with Sabine Pass LNG and agreed to pay us approximately \$125 million annually, and upon satisfaction of the conditions precedent to payment thereunder, by six third-party customers that have entered into SPAs with Sabine Pass Liquefaction and agreed to pay us an aggregate of \$2.9 billion annually in fixed fees. We are dependent on each customer's continued willingness and ability to perform its obligations under its SPA. We are also exposed to the credit risk of any guarantor of these customers' obligations under their respective TUA or SPA in the event that we must seek recourse under a guaranty. If any customer fails to perform its obligations under its TUA or SPA, 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 TUA or SPA.

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

Each of Sabine Pass LNG'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. Sabine Pass LNG may not be able to replace these TUAs on desirable terms, or at all, if they are terminated.

Each of Sabine Pass Liquefaction's SPAs contain various termination rights allowing our customers to terminate their SPAs, including, without limitation: (i) upon the occurrence of certain events of force majeure; (ii) if we fail to make available specified scheduled cargo quantities; (iii) delays in the commencement of commercial operations; and (iv) if the conditions precedent contained in the Total and Centrica SPAs are not met or waived by specified dates. We may not be able to replace these SPAs on desirable terms, or at all, if they are terminated.

Our use of hedging arrangements may adversely affect our future results of operations 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 would 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 provisions of the Dodd-Frank Act and the rules adopted thereunder and other regulations that may have an effect on our derivatives could have an adverse impact on our ability to hedge risks associated with our business and on our results of operations and cash flows.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder by the CFTC and SEC 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 Sabine Pass LNG terminal and to secure natural gas feedstock for the Liquefaction Project. As mandated by the Dodd-Frank Act, the CFTC has proposed rules setting limits on the positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas, held by market participants, with exceptions for certain bona fide hedging transactions. If the position limits in the proposed rules or other similar position limits were imposed, our ability to execute our hedging strategies described above could be compromised.

Under the swaps regulatory provisions of the Dodd-Frank Act, and the rules adopted thereunder, we could have to clear on a designated 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 markets. The CFTC has designated six classes of interest rate swaps and credit default swaps for mandatory clearing, but has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. 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 failed to qualify for that exception as to any swap we enter into and had to clear that swap over a designated clearing organization, we may have to post margin with respect to such swap, our cost of entering into and maintaining such swap could increase and the flexibility we enjoy with respect to entering into uncleared OTC swaps could be diminished. In addition, 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 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. Moreover, the application of the mandatory clearing and trade execution requirements to other market participants, such as Swap Dealers, may change the cost and availability of the swaps that we use for hedging. Although the CFTC and federal banking regulators have proposed rules to require certain types of market participants to collect and post initial and variation margin with respect to uncleared swaps and such rules currently do not require the collection of margin from non-financial end users, if we did not qualify as a non-financial end user as to any of our swaps or the final rules adopted by the CFTC and the federal banking regulators required that the counterparties to our uncleared swaps collect margin from us, our cost of entering into and maintaining swaps would be increased. Provisions of the Dodd-Frank Act may also cause our derivatives counterparties to spin off some or all of their derivatives activities to a separate entity, which could be our counterparty in future swaps and which entity may not be as creditworthy as the current counterparty.

The Dodd-Frank Act's swaps regulatory provisions, the related rules described above and the record keeping, reporting and business conduct rules imposed by the Dodd-Frank Act on other swaps market participants, as well as the regulations imposing the Basel III capital requirements on certain swaps market participants, could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against certain risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and to execute our hedging strategies, and increase our exposure to less creditworthy counterparties. 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 results of operations and cash flows may become more volatile and could be otherwise adversely affected.

Risks Relating to Our Business

Operation of the Sabine Pass LNG terminal, the Liquefaction Project 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 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.

We may not be successful in implementing our proposed business strategy to provide liquefaction capabilities at the Sabine Pass LNG terminal adjacent to the existing regasification facilities.

The Liquefaction Project will require very significant financial resources, which may not be available on terms reasonably acceptable to us or at all. Our SPAs with Total and Centrica contain certain conditions precedent, including, but not limited to, receiving regulatory approvals, securing necessary financing arrangements and making a final investment decision to construct Train 5. If these conditions are not met by June 30, 2015, each of Total and Centrica may terminate its respective SPA.

It will take several years to construct our proposed liquefaction facilities, and we do not expect Train 1 to produce LNG until late 2015, at the earliest. Even if successfully constructed, our proposed liquefaction facilities would be subject to the operating risks described herein. Accordingly, there are many risks associated with the Liquefaction Project, and if we are not successful in implementing our business strategy, we may not be able to generate cash flows, which could have a material adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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 engineering, procurement and construction 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 do not have any prior experience in constructing liquefaction facilities, and no liquefaction facilities have been constructed and placed in service in the United States in over 40 years. 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.

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 engineering, procurement and construction 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 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 counterparties.

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. 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 additional Trains will be contingent on our ability to obtain additional funding. If we are unable to obtain sufficient funding, we may be unable to complete our business plan and our business may ultimately be unsuccessful.

We will require significant additional funding to be able to commence construction of Trains 5 and 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 additional Trains, 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 the applicable Train, which may 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. 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.

To maintain the cryogenic readiness of the Sabine Pass LNG terminal, Sabine Pass LNG may need to purchase and process LNG. Sabine Pass LNG's TUA customers, including Sabine Pass Liquefaction, have the obligation to procure LNG if necessary for the Sabine Pass LNG terminal to maintain its cryogenic state. If they fail to do so, Sabine Pass LNG may need to procure such LNG.

Sabine Pass LNG needs to maintain the cryogenic readiness of the Sabine Pass LNG terminal. Together with Sabine Pass Liquefaction, the two third-party TUA customers have the obligation to maintain minimum inventory levels, and, under certain circumstances, to procure LNG to maintain the cryogenic readiness of the terminal. In the event that aggregate minimum inventory levels are not maintained, Sabine Pass LNG has the right to procure a cryogenic readiness cargo to cure a minimum inventory condition, and to be reimbursed by each TUA customer for their allocable share of the LNG acquisition costs. If Sabine Pass LNG

is not able to obtain financing on acceptable terms, it will need to maintain sufficient working capital for such a purchase until it receives reimbursement for the allocable costs of the LNG from its TUA customers or sells the regasified LNG.

Sabine Pass LNG may be required to purchase natural gas to provide fuel at the Sabine Pass LNG terminal, which would increase operating costs and could have a material adverse effect on our results of operations.

Sabine Pass LNG's TUAs provide for an in-kind deduction of 2% of the LNG delivered to the Sabine Pass LNG terminal, which it uses primarily as fuel for revaporization and self-generated power and to cover natural gas unavoidably lost at the facility. There is a risk that this 2% in-kind deduction will be insufficient for these needs and that Sabine Pass LNG will have to purchase additional natural gas from third parties. Sabine Pass LNG will bear the cost and risk of changing prices for any such fuel.

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 Sabine Pass Liquefaction under the SPAs, all of which could adversely affect us.

In August and September of 2005, Hurricanes Katrina and Rita 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 coast, and the Sabine Pass LNG terminal experienced minor damage.

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 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 an order under Section 3 of the NGA authorizing the siting, construction and operation of four Trains, the FERC order requires us to obtain certain additional approvals in conjunction with ongoing construction and operations of our proposed liquefaction facilities. In addition, our application to the FERC under Section 3 of the NGA for authorization to site, construct and operate two additional Trains at the Liquefaction Project is currently pending. The environmental assessment by the FERC was issued in December 2014 and the public comment period has closed with comments from the Sierra Club (as an intervenor) and the EPA (as a cooperating agency). We also have pending applications with the DOE for authorization to export LNG to FTA and non-FTA countries in addition to the orders previously granted to us by the DOE. Authorizations obtained from other federal and state regulatory agencies also contain ongoing conditions, and additional approval and permit requirements may be imposed. We cannot control the outcome of the review and approval process. We do not know whether or when any such approvals or permits can be obtained, or whether or not 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, we may not be able to recover our investment in our projects. 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, financial condition, operating results, liquidity and prospects.

We are entirely dependent on Cheniere, including employees of Cheniere and its subsidiaries, for key personnel, and a loss of key personnel could have a material adverse effect on our business.

As of January 31, 2015, Cheniere and its subsidiaries had 642 full-time employees, including 371 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 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. 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 personnel and could require an increase in the wage and benefits packages that are offered, thereby increasing our operating costs.

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.

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 "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 Sabine Pass Liquefaction, which has a TUA with Sabine Pass LNG. In addition, Cheniere Marketing has entered into an SPA to purchase, at Cheniere Marketing's option, any LNG produced by Sabine Pass Liquefaction 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 a natural gas liquefaction facility near Corpus Christi, Texas and may 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 terminates 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 applicable liquefaction facility, 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 applicable liquefaction facility 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 our proposed liquefaction facilities, 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 our proposed liquefaction facilities. 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, financial condition, operating results, liquidity and prospects.

We will depend upon third-party pipelines and other facilities that will 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, financial condition, operating results, 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 liquefaction customers, we are required to deliver 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 delivery 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 operation of the Sabine Pass LNG terminal and construction of the Liquefaction Project is 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, which could divert natural gas from our proposed liquefaction facilities;
- 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 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 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 could adversely affect our customers and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Current operations at the Sabine Pass LNG terminal are dependent 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 recent 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.

Operations at our proposed liquefaction facilities 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 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 outside 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 LNG exported to these markets.

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 suppliers and merchants in such countries to import or export LNG from or to the United States. Furthermore, some foreign suppliers of LNG may have economic or other reasons to obtain their LNG from, or direct their LNG to, non-United States markets or from or to competitors' LNG 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, which can be or become available at a lower cost in certain markets.

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 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 our proposed liquefaction facilities 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 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 LNG 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 the Liquefaction Project. We cannot control the regulatory and permitting approvals or third parties' construction times, 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, including cyberterrorism, or military campaigns may adversely impact our business.

A terrorist, including cyberterrorist, 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 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, including cyberterrorism, 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.

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 and regulations that regulate and restrict, among other things, discharges to air, land and water, with particular respect to the protection of the environment and natural resources; the handling, storage and disposal of hazardous materials, hazardous waste, and petroleum products; and remediation associated with the release of hazardous substances. 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. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties or to capital expenditures related to pollution control equipment 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.

There are numerous regulatory approaches currently in effect or being considered to address GHG emissions, including possible future United States treaty commitments, new federal or state legislation that may impose a carbon emissions tax or establish a cap-and-trade program, and regulation by the EPA. In addition, as we consume natural gas at the Sabine Pass LNG terminal, a future carbon tax or other regulation may be imposed on us directly.

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 through the Sabine Pass deepwater shipping channel less than four miles from the Gulf Coast, 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 tariffs are subject to FERC regulation.

The Creole Trail Pipeline is subject to regulation by the FERC under the NGA and under the Natural Gas Policy Act of 1978. The FERC regulates the transportation of natural gas in interstate commerce, including the construction and operation of the Creole Trail Pipeline, the rates and terms of conditions of service and abandonment of facilities. Under the NGA, the rates charged by the Creole Trail Pipeline 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. If CTPL fails to comply with all applicable statutes, rules, regulations and orders, the Creole Trail Pipeline could be subject to substantial penalties and fines.

Our FERC gas tariffs, including our pro forma transportation agreements, must be filed and approved by the FERC. Before we enter into a transportation agreement with a shipper that contains a term that materially deviates from our tariff, we must seek the FERC's approval. The FERC may approve the material deviation in the transportation agreement; however, in that case, the materially deviating terms must be made available to our other similarly-situated customers. If CTPL fails to seek the FERC's approval of a transportation agreement that materially deviates from our tariff, or if the FERC audits our contracts and finds deviations that appear to be unduly discriminatory, the FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the EPAAct, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1.0 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 damage.

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 federal Office of Pipeline Safety 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, we are 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.

We are 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 we fail to comply with the Federal Office of Pipeline Safety's rules and related regulations and orders, we 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 2015 will be dependent upon one facility, the Sabine Pass LNG regasification facilities located in southern Louisiana. Due to our lack of asset and geographic diversification, an adverse development at the Sabine Pass LNG terminal, or in the LNG industry, would have a significantly greater impact on our financial condition and results of operations 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 LP, its Corpus Christi liquefaction project. 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 results of operations 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 results of operations.

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.

We are currently paying the initial quarterly distribution of \$0.425 on each of our common units and the related distribution on the general partner units. We are currently not paying any distributions on the subordinated units. The Class B units are not entitled to receive distributions until they convert into common units. As of December 31, 2014, we had 57,079,973 common units outstanding. The aggregate initial quarterly distribution on these common units and the related general partner units is approximately \$99 million per year. We are not currently generating sufficient operating surplus each quarter to pay the initial quarterly distribution on all of these units and therefore intend to use a portion of our accumulated operating surplus each quarter to enable us to make this distribution. We may not have sufficient operating surplus to continue paying the initial quarterly distribution on all of our common units before Trains 1 and 2 commence commercial operations, which is not expected to occur until at least 2016 or thereafter. Furthermore, if Trains 1 and 2 do not commence commercial operations as expected and the outstanding Class B units convert into common units, we may not have sufficient operating surplus to be able to pay the initial quarterly distribution on all common units then outstanding.

Accordingly, at least until Trains 1 and 2 commence commercial operations, 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 TUAs;
- performance by Sabine Pass LNG of its obligations under the TUAs;
- performance by, and the level of cash receipts received from, Cheniere Marketing under the 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 the ability of Sabine Pass LNG to pay distributions to us under the indentures governing the Sabine Pass LNG Senior Notes (the “Sabine Pass LNG Indentures”) as a result of requirements for a debt service reserve account, a debt payment account and satisfaction of a fixed charge coverage ratio and the ability of Sabine Pass Liquefaction to pay distributions to us under its credit facilities and the Sabine Pass Liquefaction 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 will 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, 2014, we had \$9.0 billion of total consolidated indebtedness (before debt discounts and debt premiums). We anticipate incurring additional consolidated indebtedness in the future, including by issuing additional notes of our subsidiaries, including Sabine Pass Liquefaction. 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 \$1.7 billion of our indebtedness will mature in 2016, \$400.0 million will mature in 2017, \$420.0 million will mature in 2020, \$2.0 billion will mature in 2021, \$1.0 billion will mature in 2022, \$1.5 billion will mature in 2023 and \$2.0 billion will mature in 2024. In addition, Sabine Pass Liquefaction’s \$2.7 billion credit facilities will mature on the earlier of May 28, 2020 or the second anniversary of the Train 4 completion date, as defined in Sabine Pass Liquefaction’s credit facilities. We are not generally required to make principal payments on any of our long-term indebtedness prior to maturity other than the Sabine Pass Liquefaction credit facilities. 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. Our TUAs with Total and Chevron, which provide substantially all of our current operating cash flows, will expire in 2029 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, 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, Sabine Pass LNG may not make distributions under the Sabine Pass LNG Indentures until, among other requirements, a deposit has been made in an interest payment account for one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment, a deposit has been made to a permanent debt service reserve fund for one semi-annual interest payment and a fixed charge coverage ratio test of 2:1 is satisfied. Sabine Pass LNG also is not permitted to make cash distributions if its consolidated cash flow is not at least twice its fixed charges, calculated as required in the Sabine Pass LNG Indentures. In order to satisfy this fixed charge coverage ratio test, we estimate that Sabine Pass LNG's consolidated cash flow, as defined in such indentures, must be greater than approximately \$340 million. Thus, TUA payments from Sabine Pass Liquefaction and either Chevron or Total are needed to satisfy the test. If the fixed charge coverage ratio test is not satisfied, Sabine Pass LNG will not be permitted by the Sabine Pass LNG Indentures to make distributions to us, which may prevent us from making distributions to our unitholders.

Sabine Pass Liquefaction is likewise restricted from making distributions under the agreements governing its indebtedness generally until, among other requirements, substantial completion of Trains 1 through 4 has occurred, 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 Sabine Pass LNG and Sabine Pass Liquefaction 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 9—Related Party Transactions](#) in 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.

We have not paid any distributions on our subordinated units with respect to the quarters ended on or after June 30, 2010. We may not have sufficient cash available for distributions on our subordinated units in the future. Any further reduction in the amount of cash available for distributions could impact our ability to pay the initial quarterly distribution on our common units in full or at all.

We may not be able to maintain or increase the distributions on our common units and recommence making distributions on our 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 proposed liquefaction facilities, that would result in sufficient cash flow to fully pay distributions to the subordinated unitholder and allow us to maintain or increase common 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, indirectly through Cheniere Energy Partners LP Holdings, LLC ("Cheniere Holdings"), 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 will 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 LP, 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 will 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 will 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, Class B 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. An affiliate of Cheniere owns 55.9% of our outstanding common units, Class B 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 may fluctuate significantly, and our unitholders could lose all or part of their investment.

The market price of our common units may fluctuate significantly as a result of a variety of factors, some of which are beyond our control, including:

- our quarterly distributions;
- 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;
- operating and unit price performance of companies that investors deem 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 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 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 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. An affiliate of Cheniere owns 11,963,488 common units, 135,383,831 subordinated units and 45,333,334 Class B units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier. 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. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service (“IRS”) on this matter.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, 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 to you.

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 are 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 Obama Administration 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. One such Obama Administration budget proposal for fiscal year 2016 would, if enacted, tax publicly traded partnerships with “fossil fuels” activities as corporations for U.S. federal income tax purposes beginning in 2021. Any modification to the U.S. federal income tax laws and interpretations thereof 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. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes 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. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to 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 change in tax treatment of our partnership, or 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.

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.

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.

Non-U.S. investors face unique tax issues from owning common units that may result in adverse tax consequences to them.

Non-U.S. investors who own common units will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income and distributions to non-U.S. investors will generally be reduced by withholding taxes at the highest applicable effective tax rate. The IRS has taken the position that a non-U.S. investor's gain on the sale of common units is subject to United States federal income tax.

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.

The sale or exchange of 50% or more of the total interest in our capital and profits during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same unit will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available as described below) for one fiscal year. Our technical termination could also result in a deferral of depreciation deductions allowable in computing our taxable income.

In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may result in more than 12 months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. Our technical termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership, we would be required to make new tax elections and we could be subject to penalties if we are unable to determine that a technical termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year, notwithstanding two partnership tax years.

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 loaned to a “short seller” to cover a short sale of 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 a unitholder whose common units are loaned to a “short seller” to cover a short sale of units 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 to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those 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 loan to a short seller are urged to consult with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing 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. In the opinion of management, as of December 31, 2014, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

ITEM 4. MINE SAFETY DISCLOSURE

None.

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 MKT under the symbol "CQP" commencing with our initial public offering on March 21, 2007. The table below presents the high and low sales prices per common unit, as reported by the NYSE MKT, and cash distributions to common unitholders for each quarter of 2013 and 2014.

Three Months Ended	High	Low	Cash Distributions Per Common Unit (1)	Cash Distributions Per Subordinated Unit (2)	Cash Distributions Per Class B Unit (3)
March 31, 2014	\$ 30.23	\$ 27.42	\$ 0.425	\$ —	\$ —
June 30, 2014	34.60	29.71	0.425	—	—
September 30, 2014	33.48	30.96	0.425	—	—
December 31, 2014	33.00	25.08	0.425	—	—
Three Months Ended					
March 31, 2013	\$ 27.41	\$ 21.53	\$ 0.425	\$ —	\$ —
June 30, 2013	31.25	24.35	0.425	—	—
September 30, 2013	31.12	25.62	0.425	—	—
December 31, 2013	33.00	25.57	0.425	—	—

- (1) We also paid cash distributions to our general partner with respect to its 2% general partner interest.
- (2) We have not paid distributions on our subordinated units since the distribution made with respect to the quarter ended March 31, 2010. See "Subordination Period" below.
- (3) Class B units are not entitled to cash distributions except in the event of a liquidation (or merger, combination or sale of substantially all of our assets). See "Class B Units" below.

A distribution for the quarter ended December 31, 2014 of \$0.425 per common unit was paid on February 13, 2015. In addition, we paid cash distributions to our general partner with respect to its 2% general partner interest.

As of January 29, 2015, we had (i) 57.1 million common units outstanding held by approximately 12 record owners and (ii) 145.3 million Class B units outstanding, of which 100.0 million Class B units were held by Blackstone CQP Holdco LP ("Blackstone") and 45.3 million Class B units were held by a majority owned subsidiary of Cheniere.

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 Sabine Pass LNG Indentures described in "Management's Discussion and Analysis of Financial Condition and Results of Operations" may prohibit Sabine Pass LNG from making cash distributions to us under certain circumstances, which could limit our ability to make distributions.

Upon the closing of our initial public offering, Cheniere received 135,383,831 subordinated units. Below is a description of our cash distribution policy regarding common, subordinated and Class B 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 Energy Partners LP Holdings, LLC owns all of the 135,383,831 subordinated units, representing 39.3% of the limited partner interests in us as of December 31, 2014. 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 have not paid distributions on our subordinated units since the distribution made with respect to the quarter ended March 31, 2010.

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 (assuming conversion of the Class B 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 (assuming conversion of the Class B 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 (assuming conversion of the Class B 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 incentive distribution rights 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 (assuming conversion of the Class B units), 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 (assuming conversion of the Class B 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 LNG sale and purchase agreements 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.

Class B Units

During 2012, Blackstone and Cheniere completed their purchases of Class B units for total consideration of \$1.5 billion and \$500.0 million, respectively. Proceeds from the financings are being used to fund a portion of the costs of developing, constructing and placing into service the Liquefaction Project. In May 2013, Cheniere purchased an additional 12.0 million Class B units for consideration of \$180.0 million in connection with our acquisition of the Creole Trail Pipeline Business described in [Note 3—Summary of Significant Accounting Policies](#). The Class B units are not entitled to cash distributions except in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets. The Class B units are subject to conversion, mandatorily or at the option of the holders of the Class B units under specified circumstances, into a number of common units based on the then-applicable conversion value of the Class B units. On a quarterly basis beginning on the initial purchase of the Class B units, and ending on the conversion date of the Class B units, the conversion value of the Class B units increases at a compounded rate of 3.5% per quarter, subject to an additional upward adjustment for certain equity and debt financings. The holders of Class B units have a preference over the holders of the subordinated units in the event of a liquidation (or merger, combination or sale of substantially all of our assets).

General Partner Units and Incentive Distribution Rights

Incentive distribution rights 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 incentive distribution rights but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

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. 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,				
	2014	2013	2012	2011	2010
	(in thousands, except per unit data)				
Statement of Operations Data:					
Revenues (including transactions with affiliates)	\$ 268,698	\$ 268,191	\$ 264,498	\$ 283,888	\$ 399,632
Expenses (including transactions with affiliates)	269,572	300,877	226,253	161,803	140,810
Income (loss) from operations	(874)	(32,686)	38,245	122,085	258,822
Interest expense, net	(177,032)	(178,400)	(171,646)	(173,590)	(174,016)
Net income (loss)	(410,036)	(258,117)	(175,431)	(53,560)	85,594
Net income (loss) per common unit	\$ (0.89)	\$ (0.03)	\$ 0.27	\$ 1.23	\$ 1.70
Weighted average units outstanding	57,079	54,235	33,470	27,910	26,416

	December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	\$ 248,830	\$ 351,032	\$ 419,292	\$ 81,415	\$ 53,349
Restricted cash and cash equivalents (current)	195,702	227,652	92,519	13,732	13,732
Non-current restricted cash and cash equivalents	544,465	1,025,056	272,425	82,394	82,394
Property, plant and equipment, net	8,978,356	6,383,939	3,219,592	2,044,020	2,094,752
Total assets	10,387,515	8,516,783	4,265,787	2,267,990	2,289,162
Long-term debt, net of discount	8,991,333	6,576,273	2,167,113	2,192,418	2,187,724
Total equity (deficit)	1,130,729	1,639,744	1,879,978	(14,411)	9,475

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 in "Financial Statements and Supplementary Data." 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 include 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 (NYSE MKT: CQP) formed by Cheniere Energy, Inc. ("Cheniere") (NYSE MKT: LNG). Through our wholly owned subsidiary, Sabine Pass LNG, L.P. ("Sabine Pass LNG") we own and operate the regasification facilities at the Sabine Pass LNG terminal located on the Sabine Pass deep water shipping channel less than four miles from the Gulf Coast. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcf, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We are developing and constructing natural gas liquefaction facilities (the "Liquefaction Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through our wholly owned subsidiary, Sabine Pass Liquefaction, LLC ("Sabine Pass Liquefaction"). We plan to construct up to six Trains, which are in various stages of development. Each Train is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. We also own the 94-mile Creole Trail Pipeline through our wholly owned subsidiary, Cheniere Creole Trail Pipeline, L.P. ("CTPL"), which interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines.

Overview of Significant Events

Our significant accomplishments since January 1, 2014 and through the filing date of this Form 10-K include the following:

- In April 2014, Sabine Pass Liquefaction entered into a \$325.0 million senior letter of credit and reimbursement agreement (the "Sabine Pass Liquefaction LC Agreement") that it is using for the issuance of letters of credit on behalf of Sabine Pass Liquefaction for certain working capital requirements related to the Liquefaction Project;
- In May 2014, Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion of 5.75% Senior Secured Notes due 2024 (the "2024 Sabine Pass Liquefaction Senior Notes") and \$0.5 billion of 5.625% Senior Secured Notes due 2023 (the "2023 Sabine Pass Liquefaction Senior Notes"). Net proceeds from the offering of approximately \$2.5 billion were used to repay Sabine Pass Liquefaction's outstanding indebtedness under the 2013 Liquefaction Credit Facilities (as defined below), and the remaining proceeds are being used to pay a portion of the capital costs associated with the construction of the first four Trains of the Liquefaction Project in lieu of the terminated portion of the commitments under the 2013 Liquefaction Credit Facilities; and
- In August 2014, Cheniere Marketing, LLC ("Cheniere Marketing"), a wholly owned subsidiary of Cheniere, entered into an amended and restated SPA to purchase, at Cheniere Marketing's option, any LNG produced by Sabine Pass Liquefaction in excess of that required for other customers at a price of 115% of Henry Hub plus \$3.00 per MMBtu of LNG.

Liquidity and Capital Resources

Cash and Cash Equivalents

As of December 31, 2014, we had \$248.8 million of cash and cash equivalents and \$740.2 million of current and non-current restricted cash and cash equivalents (which included current and non-current restricted cash and cash equivalents available to us, Sabine Pass Liquefaction and Sabine Pass LNG) designated for the following purposes: \$612.9 million for the Liquefaction Project, \$36.2 million for CTPL, and \$91.1 million for interest payments related to the Sabine Pass LNG Senior Secured Notes described below.

Sabine Pass LNG Terminal

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 Sabine Pass LNG'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 Sabine Pass LNG 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 Sabine Pass Liquefaction. Sabine Pass Liquefaction is obligated to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$250 million annually, continuing until at least 20 years after Sabine Pass Liquefaction delivers its first commercial cargo at the Liquefaction Project.

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

Liquefaction Facilities

The Liquefaction Project is being developed and constructed at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the Federal Energy Regulatory Commission (the "FERC") to site, construct and operate Trains 1 through 4. We commenced construction of Trains 1 and 2 and the related new facilities needed to treat, liquefy, store and export natural gas in August 2012. Construction of Trains 3 and 4 and the related facilities commenced in May 2013. On September 30, 2013, we filed an application with the FERC for the approval to site, construct and operate Trains 5 and 6.

The U.S. Department of Energy (the "DOE") has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to countries with which the United States has a free trade agreement providing for national treatment for trade in natural gas ("FTA countries") for a 30-year term, beginning on the earlier of the date of first export or September 7, 2020; and to all countries without a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted ("non-FTA countries") for a 20-year term, beginning on the earlier of the date of first export or August 7, 2017. The DOE further issued an order authorizing Sabine Pass Liquefaction to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. Additionally, the DOE further issued orders authorizing Sabine Pass Liquefaction to export an additional 503.3 Bcf/yr in total of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 20-year term. Sabine Pass Liquefaction's applications for authorization to export that same 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries are currently pending at the DOE.

As of December 31, 2014, the overall project completion percentages for Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project were approximately 81% and 54%, respectively, which are ahead of the contractual schedule. Based on our current construction schedule, we anticipate that Train 1 will produce LNG as early as late 2015, and Trains 2, 3 and 4 are expected to commence operations on a staggered basis thereafter.

Customers

Sabine Pass Liquefaction has entered into four fixed price, 20-year SPAs with third parties that in the aggregate equate to 16 mtpa (approximately 803 Bcf/yr) of LNG that commence with the date of first commercial delivery for Trains 1 through 4, which are fully permitted. In addition, Sabine Pass Liquefaction has entered into two fixed price, 20-year SPAs with third parties for another 3.75 mtpa of LNG that commence with the date of first commercial delivery for Train 5. However, Sabine Pass Liquefaction has not yet received regulatory approval for construction of Train 5. These two SPAs contain certain conditions precedent, including, but not limited to, receiving regulatory approvals, securing necessary financing arrangements and making a final investment decision with respect to Train 5, which must be satisfied by June 30, 2015 or either party to the respective SPA may terminate its SPA. Under the SPAs, the customers will purchase LNG from Sabine Pass Liquefaction for a price consisting of a fixed fee plus 115% of Henry Hub per MMBtu of LNG. 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 cargoes that are not delivered. A portion of the fixed fee will be subject to annual adjustment 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 commences upon the start of operations of the specified Train. In aggregate, the fixed fee portion to be paid by these customers is approximately \$2.3 billion annually for Trains 1 through 4, and \$2.9 billion annually if we make a positive final investment decision with respect to Train 5, with the applicable fixed fees starting from the commencement of commercial operations of the applicable Train. These fixed fees equal approximately \$411 million, \$564 million, \$650 million, \$648 million and \$588 million for each of Trains 1 through 5, respectively.

In addition, Cheniere Marketing has entered into an amended and restated SPA with Sabine Pass Liquefaction to purchase, at Cheniere Marketing's option, any LNG produced by Sabine Pass Liquefaction in excess of that required for other customers at a price of 115% of Henry Hub plus \$3.00 per MMBtu of LNG.

Natural Gas Transportation and Supply

For Sabine Pass Liquefaction's natural gas feedstock transportation requirements, Sabine Pass Liquefaction has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. Sabine Pass Liquefaction has also entered into enabling agreements and long-term natural gas purchase agreements with third parties in order to secure natural gas feedstock for the Liquefaction Project. As of December 31, 2014, we have secured up to approximately 2,162,000,000 MMBtu of natural gas feedstock through long-term natural gas purchase agreements.

Construction

Trains 1 through 4 are being designed, constructed and commissioned by Bechtel. Sabine Pass Liquefaction entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Train 1 and Train 2 (the "EPC Contract (Trains 1 and 2)") and EPC Contract (Trains 3 and 4) 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 Sabine Pass Liquefaction to enter into a change order, or Sabine Pass Liquefaction agrees with Bechtel to a change order.

The total contract price of the EPC Contract (Trains 1 and 2) and the total contract price of the EPC Contract (Trains 3 and 4) are approximately \$4.1 billion and \$3.8 billion, respectively, reflecting amounts incurred under change orders through December 31, 2014. Total expected capital costs for Trains 1 through 4 are estimated to be between \$9.0 billion and \$10.0 billion before financing costs and between \$12.0 billion and \$13.0 billion after financing costs, including, in each case, estimated owner's costs and contingencies.

Pipeline Facilities

CTPL owns the Creole Trail Pipeline, a 94-mile pipeline interconnecting the Sabine Pass LNG terminal with a number of large interstate pipelines. In December 2013, CTPL began construction of certain modifications to allow the Creole Trail Pipeline to be able to transport natural gas to the Sabine Pass LNG terminal. We estimate that the capital costs to modify the Creole Trail Pipeline will be approximately \$105 million. The modifications are expected to be in service in time for the commissioning and testing of Trains 1 and 2.

Final Investment Decision on Train 5 and Train 6

We will contemplate making a final investment decision to commence construction of Train 5 and Train 6 of the Liquefaction Project based upon, among other things, entering into an EPC contract, entering into acceptable commercial arrangements, receiving regulatory authorizations and obtaining adequate financing to construct the Trains.

Capital Resources

We currently expect that Sabine Pass Liquefaction's capital resources requirements with respect to Trains 1 through 4 will be financed through one or more of the following: borrowings, equity contributions from us and cash flows under the SPAs. We believe that with the net proceeds of borrowings, unfunded commitments under the 2013 Liquefaction Credit Facilities (as defined below) and cash flows from operations, we will have adequate financial resources available to complete Trains 1 through 4 and to meet our currently anticipated capital, operating and debt service requirements. We currently project that we will generate cash flow from the Liquefaction Project by late 2015, when Train 1 is anticipated to achieve initial LNG production.

Senior Secured Notes

As of December 31, 2014, our subsidiaries had six series of senior secured notes outstanding (collectively, the "Senior Notes"):

- \$1.7 billion of 7.50% Senior Secured Notes due 2016 issued by Sabine Pass LNG (the "2016 Sabine Pass LNG Senior Notes");
- \$0.4 billion of 6.50% Senior Secured Notes due 2020 issued by Sabine Pass LNG (the "2020 Sabine Pass LNG Senior Notes" and collectively with the 2016 Sabine Pass LNG Senior Notes, the "Sabine Pass LNG Senior Notes");
- \$2.0 billion of 5.625% Senior Secured Notes due 2021 issued by Sabine Pass Liquefaction (the "2021 Sabine Pass Liquefaction Senior Notes");
- \$1.0 billion of 6.25% Senior Secured Notes due 2022 issued by Sabine Pass Liquefaction (the "2022 Sabine Pass Liquefaction Senior Notes" and collectively with the 2021 Sabine Pass Liquefaction Senior Notes, the 2023 Sabine Pass Liquefaction Senior Notes and the 2024 Sabine Pass Liquefaction Senior Notes, the "Sabine Pass Liquefaction Senior Notes");
- \$1.5 billion of 2023 Sabine Pass Liquefaction Senior Notes;
and
- \$2.0 billion of 2024 Sabine Pass Liquefaction Senior Notes.

Interest on the Senior Notes is payable semi-annually in arrears. Subject to permitted liens, the Sabine Pass LNG Senior Notes are secured on a *pari passu* first-priority basis by a security interest in all of Sabine Pass LNG's equity interests and substantially all of Sabine Pass LNG's operating assets. The Sabine Pass Liquefaction Senior Notes are secured on a first-priority basis by a security interest in all of the membership interests in Sabine Pass Liquefaction and substantially all of Sabine Pass Liquefaction's assets.

Sabine Pass LNG may redeem all or part of its 2016 Sabine Pass LNG Senior Notes at any time at a redemption price equal to 100% of the principal plus any accrued and unpaid interest plus the greater of:

- 1.0% of the principal amount of the 2016 Sabine Pass LNG Senior Notes;
or
- the excess of: a) the present value at such redemption date of (i) the redemption price of the 2016 Sabine Pass LNG Senior Notes plus (ii) all required interest payments due on the 2016 Sabine Pass LNG Senior Notes (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over b) the principal amount of the 2016 Sabine Pass LNG Senior Notes, if greater.

Sabine Pass LNG may redeem all or part of the 2020 Sabine Pass LNG Senior Notes at any time on or after November 1, 2016 at fixed redemption prices specified in the indenture governing the 2020 Sabine Pass LNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. Sabine Pass LNG may also, at its option, redeem all or part of the 2020 Sabine Pass LNG Senior Notes at any time prior to November 1, 2016, at a "make-whole" price set forth in the indenture governing the 2020 Sabine Pass LNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. At any time before November 1, 2015, Sabine Pass LNG may redeem up to 35% of the aggregate principal amount of the 2020 Sabine Pass LNG

Senior Notes at a redemption price of 106.5% of the principal amount of the 2020 Sabine Pass LNG Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the redemption date, in an amount not to exceed the net proceeds of one or more completed equity offerings as long as Sabine Pass LNG redeems the 2020 Sabine Pass LNG Senior Notes within 180 days of the closing date for such equity offering and at least 65% of the aggregate principal amount of the 2020 Sabine Pass LNG Senior Notes originally issued remains outstanding after the redemption.

At any time prior to November 1, 2020, with respect to the 2021 Sabine Pass Liquefaction Senior Notes; December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes; January 15, 2023, with respect to the 2023 Sabine Pass Liquefaction Senior Notes; or February 15, 2024, with respect to the 2024 Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction may redeem all or part of such series of the Sabine Pass Liquefaction Senior Notes at a redemption price equal to the “make-whole” price set forth in the common indenture governing the Sabine Pass Liquefaction Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. Sabine Pass Liquefaction may also at any time on or after November 1, 2020, with respect to the 2021 Sabine Pass Liquefaction Senior Notes; December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes; January 15, 2023, with respect to the 2023 Sabine Pass Liquefaction Senior Notes; or February 15, 2024, with respect to the 2024 Sabine Pass Liquefaction Senior Notes, redeem all or part of such series of the Sabine Pass Liquefaction Senior Notes at a redemption price equal to 100% of the principal amount of such series of the Sabine Pass Liquefaction Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

Under the indentures governing the Sabine Pass LNG Senior Notes (the “Sabine Pass LNG Indentures”), except for permitted tax distributions, Sabine Pass LNG may not make distributions until, among other requirements, deposits are made into debt service reserve accounts and a fixed charge coverage ratio test of 2:1 is satisfied. Under the common indenture governing the Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction may not make any distributions until, among other requirements, substantial completion of Trains 1 and 2 has occurred, deposits are made into debt service reserve accounts and a debt service coverage ratio test of 1.25:1.00 is satisfied. During the year ended December 31, 2014, Sabine Pass LNG made distributions of \$346.9 million, after satisfying all the applicable conditions in the Sabine Pass LNG Indentures.

The Sabine Pass Liquefaction Senior Notes are governed by a common indenture with restrictive covenants. Sabine Pass Liquefaction 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 Sabine Pass Liquefaction, including the Sabine Pass Liquefaction Senior Notes, the 2013 Liquefaction Credit Facilities and the Sabine Pass Liquefaction LC Agreement described below.

2013 Liquefaction Credit Facilities

In May 2013, Sabine Pass Liquefaction entered into four credit facilities aggregating \$5.9 billion (collectively, the “2013 Liquefaction Credit Facilities”). In conjunction with Sabine Pass Liquefaction’s issuance in May 2014 of the 2024 Sabine Pass Liquefaction Senior Notes and the additional issuance of the 2023 Sabine Pass Liquefaction Senior Notes (the “Additional 2023 Sabine Pass Liquefaction Senior Notes”), in an aggregate principal amount of \$2.5 billion before premium, Sabine Pass Liquefaction terminated approximately \$2.1 billion of commitments under the 2013 Liquefaction Credit Facilities. As a result, as of December 31, 2014, Sabine Pass Liquefaction has available commitments aggregating \$2.7 billion under the 2013 Liquefaction Credit Facilities, which will be used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 4 of the Liquefaction Project. The principal of the loans made under the 2013 Liquefaction Credit Facilities must be repaid in quarterly installments, commencing with the earlier of the last day of the first full calendar quarter after the Train 4 completion date, as defined in the 2013 Liquefaction Credit Facilities, or September 30, 2018. Loans under the 2013 Liquefaction Credit Facilities bear interest at a variable rate per annum equal to, at Sabine Pass Liquefaction’s election, the London Interbank Offered Rate (“LIBOR”) or the base rate plus the applicable margin. The applicable margins for LIBOR loans range from 2.3% to 3.0% prior to the completion of Train 4 and from 2.3% to 3.25% after such completion, depending on the applicable 2013 Liquefaction Credit Facility. The 2013 Liquefaction Credit Facilities also require Sabine Pass Liquefaction to pay a commitment fee calculated at a rate per annum equal to 40% of the applicable margin for LIBOR loans, multiplied by the average daily amount of undrawn commitments. Interest on LIBOR loans and the commitment fees are due and payable at the end of each LIBOR period and quarterly, respectively. Under the terms of the 2013 Liquefaction Credit Facilities, Sabine Pass Liquefaction is required to hedge not less than 75% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal.

2012 Liquefaction Credit Facility

In July 2012, Sabine Pass Liquefaction entered into a construction/term loan facility in an amount up to \$3.6 billion (the “2012 Liquefaction Credit Facility”), which was available to Sabine Pass Liquefaction in four tranches solely to fund the Liquefaction Project costs for Trains 1 and 2, the related debt service reserve account up to an amount equal to six months of scheduled debt service and the return of equity and affiliate subordinated debt funding to Cheniere or its affiliates up to an amount that would result in senior debt being no more than 65% of our total capitalization. Borrowings under the 2012 Liquefaction Credit Facility were based on LIBOR plus 3.50% during construction and 3.75% during operations. Sabine Pass Liquefaction was also required to pay commitment fees on the undrawn amount. The 2012 Liquefaction Credit Facility was amended and restated with the 2013 Liquefaction Credit Facilities and \$100.0 million of outstanding borrowings under the 2012 Liquefaction Credit Facility were repaid in full.

2017 CTPL Term Loan

CTPL has a \$400.0 million term loan facility (“2017 CTPL Term Loan”), which is being used to fund modifications to the Creole Trail Pipeline and for general business purposes. The 2017 CTPL Term Loan matures in 2017 when the full amount of the outstanding principal obligations must be repaid. CTPL’s loan may be repaid, in whole or in part, at any time without premium or penalty. As of December 31, 2014, CTPL had borrowed the full amount of \$400.0 million available under the 2017 CTPL Term Loan. Borrowings under the 2017 CTPL Term Loan bear interest at a variable rate per annum equal to, at CTPL’s election, LIBOR or the base rate, plus the applicable margin. The applicable margin for LIBOR loans is 3.25%. Interest on LIBOR loans is due and payable at the end of each LIBOR period.

Sabine Pass Liquefaction LC Agreement

In April 2014, Sabine Pass Liquefaction entered into the Sabine Pass Liquefaction LC Agreement that it uses for the issuance of letters of credit for certain working capital requirements related to the Liquefaction Project. Sabine Pass Liquefaction pays (a) a commitment fee in an amount equal to an annual rate of 0.75% of an amount equal to the unissued portion of letters of credit available pursuant to the Sabine Pass Liquefaction LC Agreement and (b) a letter of credit fee equal to an annual rate of 2.5% of the undrawn portion of all letters of credit issued under the Sabine Pass Liquefaction LC Agreement. If draws are made upon any letters of credit issued under the Sabine Pass Liquefaction LC Agreement, the amount of the draw will be deemed a loan issued to Sabine Pass Liquefaction. Sabine Pass Liquefaction is required to pay the full amount of this loan on or prior to the business day immediately succeeding the deemed issuance of the loan. These loans bear interest at a rate of 2.0% plus the base rate as defined in the Sabine Pass Liquefaction LC Agreement. As of December 31, 2014, Sabine Pass Liquefaction had issued letters of credit in an aggregate amount of \$9.5 million and no draws had been made upon any letters of credit issued under the Sabine Pass Liquefaction LC Agreement.

Sources and Uses of Cash

The following table summarizes (in thousands) the sources and uses of our cash and cash equivalents for the years ended December 31, 2014, 2013 and 2012. 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,		
	2014	2013	2012
Sources of cash and cash equivalents			
Proceeds from issuances of long-term debt	\$ 2,584,500	\$ 4,504,478	\$ 520,000
Use of restricted cash and cash equivalents for the acquisition of property, plant and equipment	2,669,332	3,119,632	1,114,742
Proceeds from sales of Class B units, net	—	—	1,887,342
Proceeds from sale of partnership common and general partner units	—	375,897	250,022
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	20,896	11,857
Operating cash flow	11,928	35,664	—
Total sources of cash and cash equivalents	5,265,760	8,056,567	3,783,963
Uses of cash and cash equivalents			
Property, plant and equipment, net	(2,645,553)	(3,120,643)	(1,118,787)
Investment in restricted cash and cash equivalents	(2,303,763)	(4,173,959)	(1,458,619)
Repayments of long-term debt	(177,000)	(100,000)	(550,000)
Debt issuance and deferred financing costs	(103,787)	(311,050)	(222,378)
Purchase of Creole Trail Pipeline Business from Cheniere, net	—	(313,892)	—
Distributions to owners	(98,979)	(91,386)	(57,821)
Operating cash flow	—	—	(37,741)
Other	(38,880)	(13,897)	(740)
Total uses of cash and cash equivalents	(5,367,962)	(8,124,827)	(3,446,086)
Net increase (decrease) in cash and cash equivalents	(102,202)	(68,260)	337,877
Cash and cash equivalents—beginning of period	351,032	419,292	81,415
Cash and cash equivalents—end of period	<u>\$ 248,830</u>	<u>\$ 351,032</u>	<u>\$ 419,292</u>

Proceeds from Issuances of Long-Term Debt, Debt Issuance and Deferred Financing Costs and Repayment of Long-Term Debt

In May 2014, Sabine Pass Liquefaction issued the 2024 Sabine Pass Liquefaction Senior Notes and the Additional 2023 Sabine Pass Liquefaction Senior Notes for total net proceeds of approximately \$2.5 billion. Debt issuance costs in the year ended December 31, 2014 primarily relate to up-front fees paid upon the closing of these offerings.

In February 2013 and April 2013, Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion, before premium, of the 2021 Sabine Pass Liquefaction Senior Notes. In April 2013, Sabine Pass Liquefaction also issued \$1.0 billion of the 2023 Sabine Pass Liquefaction Senior Notes. In November 2013, Sabine Pass Liquefaction also issued \$1.0 billion of the 2022 Sabine Pass Liquefaction Senior Notes. Net proceeds from those offerings were used to pay a portion of the capital costs incurred in connection with the construction of the Liquefaction Project. In May 2013, CTPL entered into the \$400.0 million 2017 CTPL Term Loan, which is being used to fund modifications to the Creole Trail Pipeline and for general business purposes. In June 2013, Sabine Pass Liquefaction borrowed \$100.0 million under the 2013 Liquefaction Credit Facilities. Debt issuance and deferred financing costs in the year ended December 31, 2013 primarily relate to up-front fees paid by Sabine Pass Liquefaction upon the closing of the 2013 Liquefaction Credit Facilities and the notes issued by Sabine Pass Liquefaction during the year.

In October 2012, Sabine Pass LNG issued \$420.0 million of the 2020 Notes. In July 2012, Sabine Pass Liquefaction entered into the 2012 Liquefaction Credit Facility with a syndicate of lenders. Sabine Pass Liquefaction borrowed \$100.0 million under the 2012 Liquefaction Credit Facility in August 2012 after meeting the required conditions precedent to the initial advance. Debt issuance costs primarily relate to \$212.8 million paid by Sabine Pass Liquefaction upon the closing of the 2012 Liquefaction Credit Facility.

During the year ended December 31, 2014 Sabine Pass Liquefaction repaid its \$177.0 million of borrowings under the 2013 Liquefaction Credit Facilities upon the issuance of the Additional 2023 Sabine Pass Liquefaction Senior Notes and the 2024 Sabine Pass Liquefaction Senior Notes. During the year ended December 31, 2013, the 2012 Liquefaction Credit Facility was amended and restated with the 2013 Liquefaction Credit Facilities and the \$100.0 million of outstanding borrowings under the 2012 Liquefaction Credit Facility were repaid in full.

During the fourth quarter of 2012, Sabine Pass LNG repurchased its \$550.0 million 7.25% Senior Secured Notes due 2013. Funds used for the repurchase included proceeds received from the 2020 Sabine Pass LNG Senior Notes that were issued in October 2012 and from an equity contribution from Cheniere Partners.

Uses of Restricted Cash and Cash Equivalents for the Acquisition of Property, Plant and Equipment and Property, Plant and Equipment, net

During the years ended December 31, 2014, 2013 and 2012, we used \$2,669.3 million, \$3,119.6 million and \$1,114.7 million, respectively, of restricted cash and cash equivalents for investing activities to primarily fund \$2,645.6 million, \$3,120.6 million and \$1,118.8 million, respectively, of construction costs for Trains 1 through 4 of the Liquefaction Project. Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project satisfied the criteria for capitalization in June 2012 and May 2013, respectively. Accordingly, costs associated with the construction of Trains 1 through 4 of the Liquefaction Project have been recorded as construction-in-process since those dates.

Proceeds from Sales of Class B Units

During the year ended December 31, 2012, we issued and sold an aggregate of 133.3 million Class B units to Cheniere and Blackstone CQP Holdco LP (“Blackstone”) at a price of \$15.00 per Class B unit, resulting in total net proceeds of \$1,887.3 million.

Proceeds from the Sale of Partnership Common and General Partner Units

In the year ended December 31, 2013, we received \$375.9 million in proceeds from the sale of Cheniere Partners common and general partner units primarily related to the sale of 17.6 million common units to institutional investors in February 2013. We used the proceeds from this offering to purchase the Creole Trail Pipeline Business (described below).

In September 2012, we sold 8.0 million common units in an underwritten public offering at a price of \$25.07 per common unit for net cash proceeds of \$194.0 million. We also received \$11.1 million in net cash proceeds from our general partner in connection with the exercise of its right to maintain its 2% ownership interest in us during the year ended December 31, 2012.

Contributions to Creole Trail Pipeline Business from Cheniere, net

Contributions to Creole Trail Pipeline Business from Cheniere, net relate to equity contributions provided by Cheniere to the entities owning the Creole Trail Pipeline that we purchased in May 2013. The acquisition has been accounted for as a transfer of net assets between entities under common control. During the year ended December 31, 2013, Cheniere contributed \$20.9 million to the Creole Trail Pipeline entities that we acquired.

Operating Cash Flow

Cash provided by operations was \$11.9 million and \$35.7 million in the years ended December 31, 2014 and 2013, respectively. This decrease in cash provided by operating activities was primarily a result of increased cash outflows during 2014 related to the settlement of interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 Liquefaction Credit Facilities.

Cash provided by operations was \$35.7 million in the year ended December 31, 2013, whereas cash used in operations was \$37.7 million in the year ended December 31, 2012. The increase in operating cash flow from 2012 to 2013 was primarily due to decreased interest expense in the year ended December 31, 2013 as a result of the reduction of our indebtedness outstanding in 2012.

Investment in Restricted Cash and Cash Equivalents, Net of Uses of Restricted Cash and Cash Equivalents

In the year ended December 31, 2014, we invested \$2,303.8 million in restricted cash and cash equivalents primarily related to the net proceeds from the 2024 Sabine Pass Liquefaction Senior Notes and Additional 2023 Sabine Pass Liquefaction Senior Notes issued in May 2014. In the year ended December 31, 2013, we invested \$4,174.0 million in restricted cash and cash equivalents primarily related to the net proceeds from the 2021 Sabine Pass Liquefaction Senior Notes and 2023 Sabine Pass Liquefaction Senior Notes issued in 2013 and from the sale of common units by Cheniere Partners as described above. During 2012, we invested \$1,458.6 million in restricted cash and cash equivalents from primarily the proceeds of Class B unit sales.

Repayment of Long-Term Debt

During the year ended December 31, 2014, Sabine Pass Liquefaction repaid \$177.0 million of borrowings under the 2013 Liquefaction Credit Facilities upon the issuance of the Additional 2023 Sabine Pass Liquefaction Senior Notes and the 2024 Sabine Pass Liquefaction Senior Notes. During the year ended December 31, 2013, the 2012 Liquefaction Credit Facility was amended and restated with the 2013 Liquefaction Credit Facilities and the \$100.0 million of outstanding borrowings under the 2012 Liquefaction Credit Facility were repaid in full. During the fourth quarter of 2012, Sabine Pass LNG repurchased its \$550.0 million 7.25% Senior Secured Notes due 2013 (the "2013 Notes"). Funds used for the repurchase included proceeds received from the 2020 Notes and from an equity contribution from us.

Purchase of the Creole Trail Pipeline Business, net

In May 2013, we completed the acquisition of Cheniere's ownership in CTPL and Cheniere Pipeline GP Interests, LLC (collectively, the "Creole Trail Pipeline Business") for \$480.0 million and reimbursed Cheniere \$13.9 million for certain expenditures incurred prior to the closing date. Concurrent with the Creole Trail Pipeline Business acquisition closing, we issued 12.0 million Class B units to Cheniere for aggregate consideration of \$180.0 million pursuant to a unit purchase agreement with Cheniere Class B Units Holdings, LLC, a wholly owned subsidiary of Cheniere. As a result of the two transactions, we paid Cheniere net cash of \$313.9 million.

Distributions to Owners

During the years ended December 31, 2014, 2013 and 2012, we distributed \$99.0 million, \$91.4 million and \$57.8 million, respectively, to our common unitholders and general partner. The increased amount of distributions each year is attributable to additional issued and outstanding common and general partner units as a result of our sale of additional common and general partner units, as described above.

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 year ended December 31, 2014:

Date Paid	Period Covered by Distribution	Distribution Per Common Unit	Total Distribution (in thousands)			
			Common Units	Subordinated Units	Class B Units	General Partner Units
February 14, 2014	October 1, 2013 - December 31, 2013	\$ 0.425	\$ 24,259	\$ —	\$ —	\$ 495
May 15, 2014	January 1, 2014 - March 31, 2014	0.425	24,259	—	—	495
August 14, 2014	April 1, 2014 - June 30, 2014	0.425	24,259	—	—	495
November 14, 2014	July 1, 2014 - September 30, 2014	0.425	24,259	—	—	495

On January 22, 2015, we declared a \$0.425 distribution per common unit and the related distribution to our general partner to be paid to owners of record on February 2, 2015 for the fourth quarter of 2014.

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 the amended and restated VCRA. The ending of the subordination period and conversion of the subordinated units into common units will depend upon future business development.

In 2012 and 2013, we issued Class B units, a new class of equity interests representing limited partner interests in us, in connection with the development of the Liquefaction Project. The Class B units are not entitled to cash distributions except in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets. The Class B units are subject to conversion, mandatorily or at the option of the holders of the Class B units under specified circumstances, into a number of common units based on the then-applicable conversion value of the Class B units. On a quarterly basis beginning on the initial purchase of the Class B units and ending on the conversion date of the Class B units, the conversion value of the Class B units increases at a compounded rate of 3.5% per quarter, subject to an additional upward adjustment for certain equity and debt financings. The accreted conversion ratio of the Class B units owned by Cheniere and Blackstone was 1.41 and 1.39, respectively, as of December 31, 2014. The Class B units will mandatorily convert into common units on the first business day following the record date with respect to Cheniere Partners' first distribution (the "Mandatory Conversion Date") after the earlier of the substantial completion date of Train 3 of the Liquefaction Project or August 9, 2017, although if a notice to proceed is given to Bechtel for Train 3 prior to August 9, 2017, the Mandatory Conversion Date will be the substantial completion date of Train 3. The notice to proceed was given to Bechtel on May 28, 2013. Cheniere Partners currently expects the substantial completion date of Train 3 to occur before March 31, 2017. If the Class B units are not mandatorily converted by July 2019, the holders of the Class B units have the option to convert the Class B units into common units at that time.

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, 2014 (in thousands):

	Payments Due for Years Ended December 31,				
	Total	2015	2016 - 2017	2018 - 2019	Thereafter
Construction and purchase obligations (1)	\$ 1,935,067	\$ 1,143,399	\$ 791,668	\$ —	\$ —
Long-term debt (2)	8,985,500	—	2,065,500	—	6,920,000
Interest payments (2)	3,527,087	573,945	1,004,513	870,527	1,078,102
Operating lease obligations (3)	208,744	10,261	20,741	5,305	172,437
Other obligation	4,125	4,125	—	—	—
Total (4)	\$ 14,660,523	\$ 1,731,730	\$ 3,882,422	\$ 875,832	\$ 8,170,539

- (1) Construction and purchase obligations primarily relate to the EPC Contract (Trains 1 and 2) and the EPC Contract (Trains 3 and 4). A discussion of these obligations can be found at [Note 11—Commitments and Contingencies](#) of our Notes to Consolidated Financial Statements.
- (2) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2014. See [Note 8—Long-Term Debt](#) of our Notes to Consolidated Financial Statements.
- (3) Operating lease obligations primarily relate to land site and tug leases related to the Sabine Pass LNG terminal. Minimum lease payments have not been reduced by a minimum sublease rental of \$24.4 million due in the future under non-cancelable tug boat subleases. A discussion of these obligations can be found in [Note 10—Leases](#) of our Notes to Consolidated Financial Statements.
- (4) Obligations arising through intercompany service agreements have not been included in this total. A discussion of these obligations can be found in [Note 9—Related Party Transactions](#) of our Notes to Consolidated Financial Statements. On November 20, 2013, our general partner, which had been performing services under operation and maintenance agreements with Sabine Pass Liquefaction, Sabine Pass LNG and CTPL, assigned its rights and obligations under those agreements to Cheniere Investments.

Results of Operations

2014 vs. 2013

Our consolidated net loss increased \$151.9 million, from \$258.1 million in the year ended December 31, 2013, to \$410.0 million in the year ended December 31, 2014. The increase in net loss was primarily a result of decreased derivative gain, net, which was partially offset by decreased general and administrative expense—affiliate and decreased loss on early extinguishment of debt.

Derivative gain, net decreased \$201.5 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013 primarily as a result of a decrease in long-term LIBOR during the year ended December 31, 2014, as compared to an increase in long-term LIBOR during the year ended December 31, 2013, and the early settlement of interest rate swaps in connection with the early extinguishment of a portion of the 2013 Liquefaction Credit Facilities in May 2014. General and administrative expense—affiliate decreased \$28.5 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of decreased costs incurred to manage the construction of Trains 1 through 4 of the Liquefaction Project, which resulted from a management services agreement in which we are required to pay a monthly fee based upon the capital expenditures incurred in the previous month for Trains 1 through 4 until substantial completion of each Train. Loss on early extinguishment of debt decreased \$17.2 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, due to the write-off of debt issuance costs in connection with the early extinguishment of \$2.1 billion of commitments under the 2013 Liquefaction Credit Facilities in May 2014, as compared to the write-off of debt issuance costs and deferred commitment fees in connection with the early extinguishment of a portion of the commitments under the 2012 Liquefaction Credit Facility in April 2013 and the 2013 Liquefaction Credit Facilities in November 2013.

There was no significant change to interest expense, net in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of our capitalization of interest costs incurred which were directly related to the construction of the first four Trains of the Liquefaction Project. For the years ended December 31, 2014 and 2013, we incurred \$580.2 million and \$414.0 million of total interest cost, respectively, of which we capitalized and deferred \$403.2 million and \$235.6 million, respectively.

2013 vs. 2012

Our consolidated net loss was \$258.1 million in 2013 compared to a net loss of \$175.4 million in 2012. The increase in net loss was primarily a result of loss on early extinguishment of debt, increased general and administrative expense (including affiliate expense) and increased operating and maintenance expense (including affiliate expense), which was partially offset by increased derivative gain and decreased development expense (including affiliate expense).

Loss on early extinguishment of debt increased \$89.0 million in 2013 as compared to 2012 primarily as a result of issuances of the Sabine Pass Liquefaction Senior Notes that resulted in the termination of a portion of the commitments under the 2012 Liquefaction Credit Facility and the 2013 Liquefaction Credit Facilities. Our general and administrative expense (including affiliate expense) increased \$68.0 million in 2013 as compared to 2012 primarily as a result of increased costs incurred to manage the construction of Trains 1 through 4 of the Liquefaction Project, which resulted from a management services agreement entered into by Sabine Pass Liquefaction, in which Sabine Pass Liquefaction is required to pay a wholly owned subsidiary of Cheniere a monthly fee based upon the capital expenditures incurred in the previous month for the Liquefaction Project. Operating and maintenance expense (including affiliate expense) increased \$34.4 million in 2013 as compared to 2012 primarily as a result of the loss incurred to purchase LNG to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal, increased LNG terminal maintenance and repair costs, increased fuel costs at the Sabine Pass LNG terminal and increased costs to manage the operation and maintenance of the regasification facilities at the Sabine Pass LNG terminal. We anticipate continuing to incur a similar amount of terminal use agreement maintenance expense until minimum inventory quantities are maintained, which we expect to occur in 2015. Derivative gain increased \$83.4 million in 2013 as compared to 2012 primarily as a result of the change in fair value of Sabine Pass Liquefaction's interest rate derivatives to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 Liquefaction Credit Facilities. Development expense (including affiliate expense) decreased \$27.5 million in 2013 as compared to 2012 primarily as a result of Trains 1 and 2 of the Liquefaction Project satisfying the criteria for capitalization in June 2012 and Trains 3 and 4 of the Liquefaction Project satisfying the criteria for capitalization in May 2013.

Off-Balance Sheet Arrangements

As of December 31, 2014, we had no “off-balance sheet arrangements” that may have a current or future material effect on our consolidated financial position or results of operations.

Summary of Critical Accounting Estimates

The preparation of Consolidated Financial Statements in conformity with generally accepted accounting principles in the United States (“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 value of properties, plant and equipment, asset retirement obligations (“AROs”) and fair values. 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.

Fair Value

When necessary or required by GAAP, we estimate fair value for derivatives, long-lived assets for impairment testing, initial measurements of AROs and financial instruments that require fair value disclosure, including cash and cash equivalents, restricted cash and cash equivalents, accounts receivable, accounts payable and debt. When we are required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, we use the cost, income or market valuation approaches depending on the quality of information available to support management’s assumptions. The cost approach is based on management’s best estimate of the current asset replacement cost. The income approach is based on management’s best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management’s best assumptions regarding prices and other relevant information from market transactions involving comparable assets. Such evaluations involve significant judgment and the results are based on expected future events or conditions, such as sales prices, estimates of future LNG production, development, construction and operating costs and the timing thereof, future net cash flows, economic and regulatory climates and other factors, most of which are often outside of management’s control. However, assumptions used reflect a market participant’s view of long-term prices, costs and other factors, and are consistent with assumptions used in our business plans and investment decisions.

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 techniques.

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

Gains and losses on derivative instruments are recognized currently 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 commodity prices and interest rates change.

Impairment of Long-Lived Assets

A long-lived asset is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may be greater than its future net undiscounted cash flows. Impairment, if any, is measured as the excess of an asset's carrying amount over its estimated fair value. We use a variety of fair value measurement techniques when market information for the same or similar assets does not exist. Projections of future operating results and cash flows may vary significantly from results. Management reviews its estimates of cash flows on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment.

Recent Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") amended its guidance on revenue recognition. The core principle of this amendment is that an entity should 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. This guidance is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period, with earlier adoption not permitted. This guidance can be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. We are currently evaluating the impact of the provisions of this guidance on our consolidated financial position, results of operations and cash flows.

In August 2014, the FASB issued authoritative guidance that requires an entity's management to evaluate, for each reporting period, whether there are conditions and events that raise substantial doubt about the entity's ability to continue as a going concern within one year after the financial statements are issued. Additional disclosures are required if management concludes that conditions or events raise substantial doubt about the entity's ability to continue as a going concern. This guidance is effective for annual reporting periods ending after December 15, 2016, and for annual periods and interim periods thereafter, with earlier adoption permitted. The adoption of this guidance is not expected to have an impact on our consolidated financial position, results of operations or cash flows.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Cash Investments

We have cash investments that we manage based on internal investment guidelines that emphasize liquidity and preservation of capital. Such cash investments are stated at historical cost, which approximates fair market value on our Consolidated Balance Sheets.

Marketing and Trading Commodity Price Risk

We have entered into certain commodity derivative instruments to hedge the exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory ("LNG Inventory Derivatives"). We use one-day value at risk ("VaR") with a 95% confidence interval and other methodologies for market risk measurement and control purposes of our LNG Inventory Derivatives. The VaR is calculated using the Monte Carlo simulation method. The VaR related to our LNG Inventory Derivatives was \$30,000 as of December 31, 2014.

We have entered into certain commodity derivative instruments consisting of natural gas purchase agreements to secure natural gas feedstock for the Liquefaction Project ("Term Gas Supply Derivatives"). In order to test the sensitivity of the fair value of the Term Gas Supply Derivatives to changes in underlying commodity prices, management modeled a 10% change in the Henry Hub price for natural gas. As of December 31, 2014, we estimated the fair value of our Term Gas Supply Derivatives to be \$0.3 million. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would have resulted in a change in the fair value of the Term Gas Supply Derivatives of \$0.4 million as of December 31, 2014.

Interest Rate Risk

We have entered into interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 Liquefaction Credit Facilities (“Interest Rate Derivatives”). In order to test the sensitivity of the fair value of the Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward 1-month LIBOR curve across the full 7-year term of the Interest Rate Derivatives. This 10% change in interest rates would have resulted in a change in the fair value of our Interest Rate Derivatives of \$16.5 million as of December 31, 2014.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY PARTNERS, L.P.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheet of Cheniere Energy Partners, L.P. and subsidiaries (the Partnership) as of December 31, 2014, and the related consolidated statements of operations, comprehensive loss, partners' equity, and cash flows for the year then ended. In connection with our audit of the consolidated financial statements, we also have audited financial statement schedule (Schedule I) for the year ended December 31, 2014. These consolidated financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2014, and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule for the year ended December 31, 2014, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cheniere Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2015, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Houston, Texas
February 19, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Cheniere Energy Partners, L.P.'s internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cheniere Energy Partners, L.P.'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, 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.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cheniere Energy Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2014, and the related consolidated statements of operations, comprehensive loss, partners' equity, and cash flows for the year then ended, and our report dated February 19, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Houston, Texas
February 19, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of Cheniere Energy Partners GP, LLC, and
Unitholders of Cheniere Energy Partners, L.P.

We have audited the accompanying consolidated balance sheet of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2013, and the related consolidated statements of operations, comprehensive loss, partners' equity, and cash flows for each of the two years in the period ended December 31, 2013. Our audits also included the financial statement schedule for each of the two years in the period ended December 31, 2013 listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cheniere Energy Partners, L.P. and subsidiaries at December 31, 2013, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ ERNST & YOUNG LLP

Ernst & Young LLP

Houston, Texas
February 21, 2014

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)

	December 31,	
	2014	2013
ASSETS		
Current assets		
Cash and cash equivalents	\$ 248,830	\$ 351,032
Restricted cash and cash equivalents	195,702	227,652
Accounts receivable	310	40
Advances to affiliate	27,323	14,737
LNG inventory	4,293	10,430
Prepaid expenses and other	6,411	5,957
Other—affiliate	3,651	3,280
Total current assets	486,520	613,128
Non-current restricted cash and cash equivalents	544,465	1,025,056
Property, plant and equipment, net	8,978,356	6,383,939
Debt issuance costs, net	241,909	313,944
Non-current derivative assets	11,744	98,123
Other non-current assets	124,521	82,593
Total assets	\$ 10,387,515	\$ 8,516,783
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	\$ 8,598	\$ 10,146
Accrued liabilities	136,578	170,052
Due to affiliates	19,660	45,547
Deferred revenue	26,655	26,593
Derivative liabilities	23,247	13,484
Other	18	65
Total current liabilities	214,756	265,887
Long-term debt, net	8,991,333	6,576,273
Non-current deferred revenue	13,500	17,500
Other non-current liabilities	2,452	193
Other non-current liabilities—affiliate	34,745	17,186
Commitments and contingencies		
Partners' equity		
Common unitholders' interest (57.1 million units issued and outstanding at December 31, 2014 and 2013)	495,597	711,771
Class B unitholders' interest (145.3 million units issued and outstanding at December 31, 2014 and 2013)	(38,216)	(38,216)
Subordinated unitholders' interest (135.4 million units issued and outstanding at December 31, 2014 and 2013)	648,414	931,074
General partner's interest (2% interest with 6.9 million units issued and outstanding at December 31, 2014 and 2013)	24,934	35,115
Total partners' equity	1,130,729	1,639,744
Total liabilities and partners' equity	\$ 10,387,515	\$ 8,516,783

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Year Ended December 31,		
	2014	2013	2012
Revenues			
Revenues	\$ 265,740	\$ 265,251	\$ 256,361
Revenues—affiliate	2,958	2,940	8,137
Total revenues	268,698	268,191	264,498
Operating costs and expenses			
Operating and maintenance expense	64,208	59,957	36,292
Operating and maintenance expense—affiliate	21,115	29,304	18,540
Depreciation expense	58,601	57,486	57,788
Development expense	9,319	11,322	37,559
Development expense—affiliate	1,153	1,402	2,677
General and administrative expense	13,807	11,570	12,316
General and administrative expense—affiliate	101,369	129,836	61,081
Total operating costs and expenses	269,572	300,877	226,253
Income (loss) from operations	(874)	(32,686)	38,245
Other income (expense)			
Interest expense, net	(177,032)	(178,400)	(171,646)
Loss on early extinguishment of debt	(114,335)	(131,576)	(42,587)
Derivative gain (loss), net	(118,012)	83,448	58
Other income	217	1,097	499
Total other expense	(409,162)	(225,431)	(213,676)
Net loss	\$ (410,036)	\$ (258,117)	\$ (175,431)
Net loss attributable to the Creole Trail Pipeline Business	—	(18,150)	(25,295)
Net loss attributable to partners	\$ (410,036)	\$ (239,967)	\$ (150,136)
Basic and diluted net income (loss) per common unit	\$ (0.89)	\$ (0.03)	\$ 0.27
Weighted average number of common units outstanding used for basic and diluted net income (loss) per common unit calculation	57,079	54,235	33,470

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(in thousands)

	Year Ended December 31,		
	2014	2013	2012
Net loss	\$ (410,036)	\$ (258,117)	\$ (175,431)
Other comprehensive income (loss)			
Loss on settlements of interest rate cash flow hedges retained in other comprehensive income	—	(30)	(136)
Change in fair value of interest rate cash flow hedges	—	21,297	(27,104)
Losses reclassified into earnings as a result of discontinuance of cash flow hedge accounting	—	5,973	—
Total other comprehensive income (loss)	—	27,240	(27,240)
Comprehensive loss	<u>\$ (410,036)</u>	<u>\$ (230,877)</u>	<u>\$ (202,671)</u>

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

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
(in thousands)

	Common Unitholders' Interest		Class B Unitholders' Interest		Subordinated Unitholder's Interest		General Partner's Interest		Accumulated Other Comprehensive (Income) Loss	Creole Trail Pipeline Business Equity	Total Partners' Equity
	Units	Amount	Units	Amount	Units	Amount	Units	Amount			
Balance at December 31, 2011	31,003	\$ (52,774)	—	\$ —	135,384	\$ (479,197)	3,396	\$ (13,048)	\$ —	\$ 530,608	\$ (14,411)
Net loss	—	(28,351)	—	—	—	(114,678)	—	(7,107)	—	(25,295)	(175,431)
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	—	—	—	—	—	—	—	—	11,857	11,857
Sale of common and general partner units	8,485	204,878	—	—	—	—	2,894	45,144	—	—	250,022
Distributions	—	(56,665)	—	—	—	—	—	(1,156)	—	—	(57,821)
Non-cash contributions	—	—	—	—	—	—	—	5,663	—	—	5,663
Interest rate cash flow hedges	—	—	—	—	—	—	—	—	(27,240)	—	(27,240)
Sale of Class B units	—	—	133,333	1,887,339	—	—	—	—	—	—	1,887,339
Beneficial conversion feature of Class B units	—	386,473	—	(1,950,000)	—	1,563,527	—	—	—	—	—
Amortization of beneficial conversion feature of Class B units	—	(5,149)	—	25,319	—	(20,170)	—	—	—	—	—
Balance at December 31, 2012	39,488	448,412	133,333	(37,342)	135,384	949,482	6,290	29,496	(27,240)	517,170	1,879,978
Net loss	—	(67,263)	—	—	—	(167,905)	—	(4,799)	—	(18,150)	(258,117)
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	—	—	—	—	—	—	—	—	20,896	20,896
Acquisition of the Creole Trail Pipeline Business	—	—	—	—	—	—	—	—	—	(519,916)	(519,916)
Excess of acquired assets over the purchase price	—	2,022	—	—	—	22,880	—	1,124	—	—	26,026
Issuance of Class B units associated with acquisition of Creole Trail Pipeline Business	—	—	12,000	179,126	—	—	—	—	—	—	179,126
Sale of common and general partner units	17,590	364,775	—	—	—	—	604	11,122	—	—	375,897
Distributions	—	(89,558)	—	—	—	—	—	(1,828)	—	—	(91,386)
Interest rate cash flow hedges	—	—	—	—	—	—	—	—	27,240	—	27,240
Beneficial conversion feature of Class B units	—	53,383	—	(180,000)	—	126,617	—	—	—	—	—
Balance at December 31, 2013	57,078	711,771	145,333	(38,216)	135,384	931,074	6,894	35,115	—	—	1,639,744
Net loss	—	(119,175)	—	—	—	(282,660)	—	(8,201)	—	—	(410,036)
Distributions	—	(97,035)	—	—	—	—	—	(1,980)	—	—	(99,015)
Issuance of common units as compensation to non-management directors	2	36	—	—	—	—	—	—	—	—	36
Balance at December 31, 2014	57,080	\$495,597	145,333	\$ (38,216)	135,384	\$ 648,414	6,894	\$ 24,934	\$ —	\$ —	\$ 1,130,729

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 thousands)

	Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities			
Net loss	\$ (410,036)	\$ (258,117)	\$ (175,431)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation	58,601	57,486	57,498
Use of restricted cash and cash equivalents for certain operating activities	148,972	171,345	75,060
Non-cash LNG inventory write-downs	24,461	26,900	9,393
Non-cash LNG inventory—affiliate write-downs	—	—	11,025
Amortization of debt issuance costs and discount	14,264	14,948	9,057
Total (gains) losses on derivatives, net	117,701	(84,296)	(1,095)
Net cash from settlement of derivative instruments	(21,581)	579	476
Loss on early extinguishment of debt	114,335	131,576	1,470
Other	15	—	3,496
Changes in operating assets and liabilities:			
Accounts and interest receivable	(293)	4	481
Accounts receivable—affiliate	(503)	(1,083)	(1,690)
Accounts payable and accrued liabilities	3,949	(2,384)	2,214
Due to affiliates	(15,842)	26,091	2,425
Deferred revenue	(3,938)	(3,947)	(4,089)
Advances to affiliate	(12,586)	(9,281)	(4,764)
LNG inventory	(18,325)	(30,863)	(11,545)
LNG inventory—affiliate	—	—	(11,076)
Other, net	(4,919)	(7,672)	(646)
Other, net—affiliate	17,653	4,378	—
Net cash provided by (used in) operating activities	11,928	35,664	(37,741)
Cash flows from investing activities			
Property, plant and equipment, net	(2,645,553)	(3,120,643)	(1,118,787)
Use of restricted cash and cash equivalents for the acquisition of property, plant and equipment	2,669,332	3,119,632	1,114,742
Purchase of Creole Trail Pipeline Business, net	—	(313,892)	—
Other	(38,880)	(13,897)	(740)
Net cash used in investing activities	(15,101)	(328,800)	(4,785)
Cash flows from financing activities			
Proceeds from issuances of long-term debt	2,584,500	4,504,478	520,000
Proceeds from sale of partnership common and general partner units	—	375,897	250,022
Proceeds from sale of Class B units, net	—	—	1,887,342
Contributions to Creole Trail Pipeline Business from Cheniere, net	—	20,896	11,857
Investment in restricted cash and cash equivalents	(2,303,763)	(4,173,959)	(1,458,619)
Debt issuance and deferred financing costs	(103,787)	(311,050)	(222,378)
Repayments of long-term debt	(177,000)	(100,000)	(550,000)
Distributions to owners	(98,979)	(91,386)	(57,821)
Net cash provided by (used in) financing activities	(99,029)	224,876	380,403
Net increase (decrease) in cash and cash equivalents	(102,202)	(68,260)	337,877
Cash and cash equivalents—beginning of period	351,032	419,292	81,415
Cash and cash equivalents—end of period	\$ 248,830	\$ 351,032	\$ 419,292

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—NATURE OF OPERATIONS

We are a publicly traded Delaware limited partnership (NYSE MKT: CQP) formed by Cheniere Energy, Inc. (“Cheniere”). Through our wholly owned subsidiary, Sabine Pass LNG, L.P. (“Sabine Pass LNG”), we own and operate the regasification facilities at the Sabine Pass LNG terminal located on the Sabine Pass deep water shipping channel less than four miles from the Gulf Coast. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. We are developing and constructing natural gas liquefaction facilities (the “Liquefaction Project”) at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through our wholly owned subsidiary, Sabine Pass Liquefaction, LLC (“Sabine Pass Liquefaction”). We plan to construct up to six Trains which are in various stages of development. Each Train is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. We also own the 94-mile Creole Trail Pipeline through our wholly owned subsidiary, Cheniere Creole Trail Pipeline, L.P. (“CTPL”), which interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines.

As of December 31, 2014, Cheniere owned 100% of our general partner interest and 80.1% of Cheniere Energy Partners LP Holdings, LLC (“Cheniere Holdings”) which owned 12.0 million of our common units, 45.3 million of our Class B units and 135.4 million of our subordinated units.

Unless the context requires otherwise, references to “Cheniere Partners,” “we,” “us” and “our” refer to Cheniere Energy Partners, L.P. and its consolidated subsidiaries, including Sabine Pass LNG, Sabine Pass Liquefaction and CTPL.

NOTE 2—UNITHOLDERS’ EQUITY

The common units, Class B 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 common units have the right to receive initial quarterly distributions of \$0.425 plus any arrearages thereon, before any distribution is made to the holders of the subordinated units. The 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, 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. The higher percentages range from 15% up to 50%.

During 2012, Blackstone CQP Holdco LP (“Blackstone”) and Cheniere completed their purchases of newly created Cheniere Partners Class B units (“Class B units”) for total consideration of \$1.5 billion and \$500.0 million, respectively. Proceeds from the financings were used to fund a portion of the costs of developing, constructing and placing into service the first two natural gas liquefaction trains (“Trains”) of the Liquefaction Project. In May 2013, Cheniere purchased an additional 12.0 million Class B units for consideration of \$180.0 million in connection with our acquisition of the Creole Trail Pipeline Business described in [Note 1—Nature of Operations](#). In 2013, Cheniere formed Cheniere Holdings to hold its limited partner interests in us. The Class B units are subject to conversion, mandatorily or at the option of the Class B unitholders under specified circumstances, into a number of common units based on the then-applicable conversion value of the Class B units. The Class B units are not entitled to cash distributions except in the event of our liquidation or a merger, consolidation or other combination of us with another person or the sale of all or substantially all of our assets. On a quarterly basis beginning on the initial purchase of the Class B units and ending on the conversion date of the Class B units, the conversion value of the Class B units increases at a compounded rate of 3.5% per quarter, subject to additional upward adjustment for certain equity and debt financings. The accreted conversion ratio

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

of the Class B units owned by Cheniere Holdings and Blackstone was 1.41 and 1.39, respectively, as of December 31, 2014. We expect the Class B units to mandatorily convert into common units within 90 days of the substantial completion date of Train 3 of the Liquefaction Project, which we currently expect to occur before March 31, 2017. If the Class B units are not mandatorily converted by July 2019, the holders of the Class B units have the option to convert the Class B units into common units at that time.

NOTE 3—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements were prepared in accordance with generally accepted accounting principles in the United States (“GAAP”). The Consolidated Financial Statements include the accounts of Cheniere Energy Partners, L.P. and its majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

In May 2013, we completed the acquisition of Cheniere’s ownership interests in CTPL and Cheniere Pipeline GP Interests, LLC (collectively, “the Creole Trail Pipeline Business”), thereby providing us with ownership of a 94-mile pipeline interconnecting the Sabine Pass LNG terminal with a large number of interstate pipelines. We acquired the Creole Trail Pipeline Business for \$480.0 million and reimbursed Cheniere \$13.9 million for certain expenditures incurred prior to the closing date. Concurrent with the Creole Trail Pipeline Business acquisition closing, we issued 12.0 million Class B units to Cheniere for aggregate consideration of \$180.0 million pursuant to a unit purchase agreement with Cheniere Class B Units Holdings, LLC, a wholly owned subsidiary of Cheniere. As a result of the two transactions, we paid Cheniere net cash of \$313.9 million.

These Consolidated Financial Statements include our accounts and the assets, liabilities and operations of the Creole Trail Pipeline Business. The effect of including the prior results of the Creole Trail Pipeline Business is reported as net loss attributable to Creole Trail Pipeline Business in our Consolidated Statement of Operations and Creole Trail Pipeline Business equity in our Consolidated Balance Sheets and Consolidated Statements of Partners’ Equity. This purchase has been accounted for as a transfer of net assets between entities under common control.

We recognize transfers of net assets between entities under common control at Cheniere’s historical basis in the net assets sold. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information. The difference between the purchase price and Cheniere’s basis in the net assets sold, if any, is recognized as an adjustment to partners’ equity.

Subsequent to the Creole Trail Pipeline Business acquisition, we control CTPL’s operating and financial decisions and policies and have consolidated CTPL in our financial statements. Our Consolidated Financial Statements and all other financial information included in this report assume that our acquisition of the Creole Trail Pipeline Business from Cheniere had occurred at the date when the Creole Trail Pipeline Business met the accounting requirements for entities under common control (the date of our inception since both we and the Creole Trail Pipeline Business were formed by Cheniere). Net income (loss) attributable to the Creole Trail Pipeline Business for periods prior to the acquisition is not allocated to the common units for purposes of calculating net income (loss) per common unit. See [Note 13—Net Income \(Loss\) Per Common Unit](#) for an adjusted net income (loss) per common unit that includes pre-acquisition date net losses of the Creole Trail Pipeline Business.

Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications had no effect on our overall consolidated financial position, results of operations or cash flows.

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 value of property, plant and equipment, collectability of accounts receivable, 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.

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

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 techniques 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 commodity derivatives and interest rate derivatives as disclosed in [Note 6—Derivative Instruments](#). The carrying amount of cash and cash equivalents, restricted cash and cash equivalents, 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, 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 8—Long-Term Debt](#), are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments. Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination, intangible assets and AROs.

Revenue Recognition

LNG regasification capacity reservation fees are recognized as revenue over the term of the TUAs. Advance capacity reservation fees are initially deferred and amortized over a 10-year period as a reduction of a customer's regasification capacity reservation fees payable under its TUA. Under each of these TUAs, Sabine Pass LNG is entitled to retain 2% of LNG delivered for each customer's account at the Sabine Pass LNG terminal, which is recognized as revenues as Sabine Pass LNG performs the services set forth in each customer's TUA.

Cash and Cash Equivalents

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

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents consist 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.

Amounts that are designated as restricted cash and cash equivalents are contractually restricted as to usage or withdrawal and will not become available to us as cash and cash equivalents. For these amounts, we have presented increases and decreases as "Investments in (uses of) restricted cash and cash equivalents" in our Consolidated Statements of Cash Flows. These amounts that represent non-cash transactions within our Consolidated Statements of Cash Flows present the effect of sources and uses of restricted cash and cash equivalents as they relate to the changes to assets and liabilities in our Consolidated Balance Sheets. Restricted cash and cash equivalents are presented on a gross basis within each of those categories so as to reconcile the change in non-cash activity that occurs on the balance sheet from period to period.

LNG Inventory

LNG inventory and LNG inventory—affiliate are recorded at cost and are subject to lower of cost or market ("LCM") adjustments at the end of each period. LNG inventory—affiliate represents LNG inventory purchased under a related party LNG lease agreement with Cheniere Marketing, LLC ("Cheniere Marketing"), a wholly owned subsidiary of Cheniere, as described in [Note 9—Related Party Transactions](#). LNG inventory and LNG inventory—affiliate costs are determined using the average cost method. Our LCM adjustments primarily related to LNG inventory purchased to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal that are recorded in operating and maintenance expense on our Consolidated Statements of Operations. Recoveries of losses resulting from interim period LCM adjustments are recorded when market price

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

recoveries occur on the same inventory in the same fiscal year. These recoveries are recognized as gains in later interim periods with such gains not exceeding previously recognized losses.

During the years ended December 31, 2014, 2013 and 2012, we recognized \$24.5 million, \$26.9 million and \$9.4 million, respectively, as operating and maintenance expense as a result of LCM adjustments primarily related to LNG inventory purchased to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal. During the years ended December 31, 2014, 2013 and 2012, we recognized zero, zero and \$11.0 million, respectively, as a result of LCM adjustments to our LNG inventory—affiliate.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of our LNG terminals and related pipelines once the individual project meets the following criteria: (i) regulatory approval has been received, (ii) financing for the project is available and (iii) 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 and related pipelines.

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 intangible LNG assets. The costs of lease options are amortized over the life of the lease once obtained. If no lease is obtained, the costs are expensed.

We capitalize interest and other related debt costs during the construction period of our LNG terminal. Upon commencement of operations, capitalized interest, as a component of the total cost, will be amortized over the estimated useful life of the asset.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction activities, major renewals and betterments that extend the useful life of an asset are capitalized, while expenditures for maintenance and repairs and general and administrative activities are charged to expense as incurred. Interest costs incurred on debt obtained for the construction of property, plant and equipment are capitalized as construction-in-process over the construction period or related debt term, whichever is shorter. 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 other operating costs and expenses.

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. In performing this test, an undiscounted cash flow analysis is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value. We have recorded no impairments related to property, plant and equipment for 2014, 2013 or 2012.

Regulated Natural Gas Pipelines

The Creole Trail Pipeline is subject to the jurisdiction of the Federal Energy Regulatory Commission ("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,

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

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 commodity price and interest rate 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 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 current 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 as of December 31, 2014 and 2013.

From time to time, we have elected cash flow hedge accounting for derivatives that we use to hedge the exposure to volatility in floating-rate interest payments. Changes in fair value of derivative instruments designated as cash flow hedges, to the extent the hedge is effective, are recognized in accumulated other comprehensive loss on our Consolidated Balance Sheets. We reclassify gains and losses on the hedges from accumulated other comprehensive loss into interest expense in our Consolidated Statements of Operations as the hedged item is recognized. Any change in the fair value resulting from ineffectiveness is recognized immediately as derivative gain (loss) on our Consolidated Statements of Operations. We use regression analysis to determine whether we expect a derivative to be highly effective as a cash flow hedge, prior to electing hedge accounting and also to determine whether all derivatives designated as cash flow hedges have been effective. We perform these effectiveness tests prior to designation for all new hedges and on a quarterly basis for all existing hedges. We calculate the actual amount of ineffectiveness on our cash flow hedges using the “dollar offset” method, which compares changes in the expected cash flows of the hedged transaction to changes in the value of expected cash flows from the hedge. We discontinue hedge accounting when our effectiveness tests indicate that a derivative is no longer highly effective as a hedge; when the derivative expires or is sold, terminated or exercised; when the hedged item matures, is sold or repaid; or when we determine that the occurrence of the hedged forecasted transaction is not probable. When we discontinue hedge accounting but continue to hold the derivative, prospective changes in fair value of the derivative instrument are recorded in income. Once we conclude that the hedged forecasted transaction becomes probable of not occurring, the amount remaining in accumulated other comprehensive loss pertaining to the previously designated derivatives is reclassified out of accumulated other comprehensive loss and into income.

See [Note 6—Derivative Instruments](#) of our Notes to Consolidated Financial Statements for additional details about our derivative instruments.

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

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. 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 as an other current asset and not netted within the derivative fair value. 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 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.

Sabine Pass LNG has entered into certain long-term TUAs with unaffiliated third parties for regasification capacity at the Sabine Pass LNG terminal. Sabine Pass LNG is dependent on the respective counterparties' creditworthiness and their willingness to perform under their respective TUAs. Sabine Pass LNG 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 AA.

Sabine Pass Liquefaction has entered into six fixed price 20-year SPAs with six unaffiliated third parties. Sabine Pass Liquefaction is dependent on the respective counterparties' creditworthiness and their willingness to perform under their respective SPAs.

Long-Term Debt

Our debt consists of 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 balance sheet at par value adjusted for unamortized discount or premium. Discounts, premiums and costs directly related to the issuance of debt are amortized over the life of the debt and are recorded in interest expense, net using the effective interest method. Gains and losses on the extinguishment of debt are recorded in gains and losses on the 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 debt issuance costs on our Consolidated Balance Sheets and are being 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 early 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. Our recognition of AROs is described below.

Currently, the Sabine Pass LNG terminal is our only constructed and operating 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 zero. Therefore, we have not recorded an ARO associated with the Sabine Pass LNG terminal.

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

Currently, the Creole Trail Pipeline is our only constructed and operating natural gas 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. Therefore, we have concluded that due to advanced technology associated with current natural gas pipelines and our intent to operate the Creole Trail Pipeline as long as supply and demand for natural gas exists in the United States, we have not recorded an ARO associated with the Creole Trail Pipeline.

Income Taxes

We are not subject to federal, state or foreign income taxes, as the partners are taxed individually on their allocable share of taxable income. At December 31, 2014, the tax basis of our assets and liabilities was \$216.3 million less than the reported amounts of our assets and liabilities.

In November 2006, Sabine Pass LNG and Cheniere entered into a state tax sharing agreement. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which Sabine Pass LNG 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, Sabine Pass LNG will pay to Cheniere an amount equal to the state and local tax that Sabine Pass LNG would be required to pay if Sabine Pass LNG's state and local tax liability were computed on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from Sabine Pass LNG under this agreement; therefore, Cheniere has not demanded any such payments from Sabine Pass LNG. The agreement is effective for tax returns due on or after January 1, 2008.

In August 2012, Sabine Pass Liquefaction and Cheniere entered into a state tax sharing agreement. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which Sabine Pass Liquefaction 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, Sabine Pass Liquefaction will pay to Cheniere an amount equal to the state and local tax that Sabine Pass Liquefaction would be required to pay if Sabine Pass Liquefaction's state and local tax liability were computed on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from Sabine Pass Liquefaction under this agreement; therefore, Cheniere has not demanded any such payments from Sabine Pass Liquefaction. The agreement is effective for tax returns due on or after August 2012.

In May 2013, CTPL and Cheniere entered into a state tax sharing agreement. 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 computed 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.

Business Segment

Our LNG terminal business is our only operating business segment in which separate financial information is produced and evaluated by our chief operating decision maker in deciding how to allocate resources. Our LNG terminal business segment consists of the operational regasification and pipeline facilities at the Sabine Pass LNG terminal and the adjacent Liquefaction Project. The Sabine Pass LNG terminal includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters, vaporizers with regasification capacity of approximately 4.0 Bcf/d and pipeline facilities (including the Creole Trail Pipeline) interconnecting the Sabine Pass LNG terminal with a number of large interstate pipelines. The Liquefaction Project is adjacent to the existing regasification facilities at the Sabine Pass LNG terminal.

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NOTE 4—RESTRICTED CASH AND CASH EQUIVALENTS

Restricted cash and cash equivalents consist 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. Restricted cash and cash equivalents include the following:

Sabine Pass LNG Senior Notes Debt Service Reserve

Sabine Pass LNG has consummated private offerings of an aggregate principal amount of \$1,665.5 million, before discount, of 7.50% Senior Secured Notes due 2016 (the “2016 Sabine Pass LNG Senior Notes”) and \$420.0 million of 6.50% Senior Secured Notes due 2020 (the “2020 Sabine Pass LNG Senior Notes”). Collectively, the 2016 Sabine Pass LNG Senior Notes and the 2020 Sabine Pass LNG Senior Notes are referred to as the “Sabine Pass LNG Senior Notes.” Under the indentures governing the Sabine Pass LNG Senior Notes (the “Sabine Pass LNG Indentures”), except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied, including: (i) there must be on deposit in an interest payment account an amount equal to one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment, and (ii) there must be on deposit in a permanent debt service reserve fund an amount equal to one semi-annual interest payment. Distributions are permitted only after satisfying the foregoing funding requirements, a fixed charge coverage ratio test of 2:1 and other conditions specified in the Sabine Pass LNG Indentures.

As of both December 31, 2014 and 2013, we classified \$15.0 million as current restricted cash and cash equivalents for the payment of current interest due. As of both December 31, 2014 and 2013, we classified the permanent debt service reserve fund of \$76.1 million as non-current restricted cash and cash equivalents. These cash accounts are controlled by a collateral trustee and, therefore, are shown as restricted cash and cash equivalents on our Consolidated Balance Sheets.

Sabine Pass Liquefaction Reserve

In July 2012, Sabine Pass Liquefaction entered into a construction/term loan facility in an amount up to \$3.6 billion (the “2012 Liquefaction Credit Facility”). During 2013, Sabine Pass Liquefaction entered into four credit facilities aggregating \$5.9 billion (collectively, the “2013 Liquefaction Credit Facilities”), which amended and restated the 2012 Liquefaction Credit Facility. Under the terms and conditions of the 2012 Liquefaction Credit Facility Sabine Pass Liquefaction was required, and under the 2013 Liquefaction Credit Facilities Sabine Pass Liquefaction is required, to deposit all cash received into reserve accounts controlled by a collateral trustee. Therefore, all of Sabine Pass Liquefaction’s cash and cash equivalents are shown as restricted cash and cash equivalents on our Consolidated Balance Sheets.

During 2013, Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion, before premium, of 5.625% Senior Secured Notes due 2021 (the “2021 Sabine Pass Liquefaction Senior Notes”), \$1.0 billion of 6.25% Senior Secured Notes due 2022 (the “2022 Sabine Pass Liquefaction Senior Notes”) and \$1.0 billion of 5.625% Senior Secured Notes due 2023 (the “2023 Sabine Pass Liquefaction Senior Notes”). During 2014, Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion of 5.75% Senior Secured Notes due 2024 (the “2024 Sabine Pass Liquefaction Senior Notes”) and collectively with the 2021 Sabine Pass Liquefaction Senior Notes, the 2022 Sabine Pass Liquefaction Senior Notes and the 2023 Sabine Pass Liquefaction Senior Notes, the “Sabine Pass Liquefaction Senior Notes”) and additional 2023 Sabine Pass Liquefaction Senior Notes (the “Additional 2023 Sabine Pass Liquefaction Senior Notes”) in an aggregate principal amount of \$0.5 billion, before premium.

As of December 31, 2014 and 2013, we classified \$155.8 million and \$192.1 million, respectively, as current restricted cash and cash equivalents held by Sabine Pass Liquefaction for the payment of current liabilities related to the Liquefaction Project and \$457.1 million and \$867.6 million, respectively, as non-current restricted cash and cash equivalents held by Sabine Pass Liquefaction for future Liquefaction Project construction costs.

CTPL Reserve

In May 2013, CTPL entered into a \$400.0 million term loan facility (the “2017 CTPL Term Loan”). As of December 31, 2014 and 2013, we classified \$24.9 million and \$20.5 million, respectively, as current restricted cash and cash equivalents held by CTPL for the payment of current liabilities and \$11.3 million and \$81.4 million, respectively, as non-current restricted cash and cash equivalents held by CTPL because such funds may only be used for modifications of the 94-mile Creole Trail Pipeline, which interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines, in order to enable bi-directional

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
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natural gas flow and for the payment of interest during construction of such modifications. The restricted cash reserved to pay interest during construction is controlled by a collateral agent, and can only be released by the collateral agent upon satisfaction of certain terms and conditions.

See [Note 8—Long-Term Debt](#) for additional details about our long-term debt.

NOTE 5—PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consists of LNG terminal costs and fixed assets, as follows (in thousands):

	December 31,	
	2014	2013
LNG terminal costs		
LNG terminal	\$ 2,240,233	\$ 2,225,412
LNG terminal construction-in-process	7,082,732	4,448,541
LNG site and related costs, net	141	149
Accumulated depreciation	(348,907)	(291,265)
Total LNG terminal costs, net	8,974,199	6,382,837
Fixed assets		
Computer and office equipment	1,105	612
Vehicles	1,507	907
Machinery and equipment	1,508	1,490
Furniture and fixtures	1,375	373
Other	2,505	590
Accumulated depreciation	(3,843)	(2,870)
Total fixed assets, net	4,157	1,102
Property, plant and equipment, net	\$ 8,978,356	\$ 6,383,939

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 15 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
Regasification processing equipment (recondensers, vaporization and vents)	30
Sendout pumps	20
Others	15-30

Fixed Assets

Our fixed assets 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 6—DERIVATIVE INSTRUMENTS

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

- commodity derivatives to hedge the exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory (“LNG Inventory Derivatives”);
- commodity derivatives to hedge the exposure to price risk attributable to future purchases of natural gas to be utilized as fuel to operate the Sabine Pass LNG terminal (“Fuel Derivatives”);
- commodity derivatives consisting of natural gas purchase agreements to secure natural gas feedstock for the Liquefaction Project (“Term Gas Supply Derivatives”); and

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- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 Liquefaction Credit Facilities (“Interest Rate Derivatives”).

The following table (in thousands) shows the fair value of our derivative assets and liabilities that are required to be measured at fair value on a recurring basis as of December 31, 2014 and 2013, which are classified as prepaid expenses and other, non-current derivative assets and other current liabilities in our Consolidated Balance Sheets.

	Fair Value Measurements as of							
	December 31, 2014				December 31, 2013			
	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
LNG Inventory Derivatives asset (liability)	\$ —	\$ 1,216	\$ —	\$ 1,216	\$ —	\$ (161)	\$ —	\$ (161)
Fuel Derivatives asset	—	—	—	—	—	27	—	27
Term Gas Supply Derivatives asset	—	—	342	342	—	—	—	—
Interest Rate Derivatives asset (liability)	—	(12,036)	—	(12,036)	—	84,639	—	84,639

The estimated fair values of our LNG Inventory Derivatives and Fuel Derivatives are the amounts at which the instruments could be exchanged currently between willing parties. We value these derivatives using observable commodity price curves and other relevant data. We value our Interest Rate Derivatives using valuations based on the initial trade prices. Using an income-based approach, subsequent valuations are based on observable inputs to the valuation model including interest rate curves, risk adjusted discount rates, credit spreads and other relevant data.

The fair value of Sabine Pass Liquefaction’s Term Gas Supply Derivatives is developed through the use of internal models which are impacted by inputs that are unobservable in the marketplace. As a result, the fair value of Sabine Pass Liquefaction’s Term Gas Supply Derivatives is designated as Level 3 within the valuation hierarchy. The curves used to generate the fair value of the Term Gas 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 particular Term Gas Supply Derivative contract may exceed the period for which such information is available, resulting in a Level 3 classification. In these instances, 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. Internal fair value models that include contractual pricing with a fixed basis include fixed basis amounts for delivery at locations for which no market currently exists. Internal fair value models also include conditions precedent to the respective long-term natural gas purchase agreements. As of December 31, 2014, the majority of Sabine Pass Liquefaction’s Term Gas Supply Derivatives existed within markets for which the pipeline infrastructure has not been developed to accommodate marketable physical gas flow and our internal fair value models were based on a market price that equated to our own contractual pricing due to the inactive and unobservable market as well as the conditions precedent and their impact on the uncertainty in the timing of our actual receipt of the physical volumes associated with each forward. The fair value of the Term Gas 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. We estimated the fair value of Sabine Pass Liquefaction’s Term Gas Supply Derivatives to be \$0.3 million as of December 31, 2014.

There were no transfers into or out of Level 3 for the years ended December 31, 2014 and 2013. As all of Sabine Pass Liquefaction’s Term Gas Supply Derivatives are either purely index-priced or index-priced with a fixed basis, we do not believe that a significant change in market commodity prices would have a material impact on our Level 3 fair value measurements. The following table (in thousands, except natural gas basis spread) includes quantitative information for the unobservable inputs as of December 31, 2014:

	Net Fair Value Asset	Valuation Technique	Significant Unobservable Input	Significant Unobservable Inputs Range
Term Gas Supply Derivatives	\$342	Basis Spread plus Liquid Location	Basis Spread	\$ (0.350) - \$0.035

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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.

Commodity Derivatives

We recognize all commodity derivative instruments that qualify for derivative accounting treatment, including our LNG Inventory Derivatives, Fuel Derivatives and Term Gas Supply Derivatives (collectively, “Commodity Derivatives”), as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exception. For transactions in which we have elected the normal purchase normal sale exception, gains and losses are not reflected on our Consolidated Statements of Operations until the period of delivery. For those instruments accounted for as derivatives, including our LNG Inventory Derivatives, Term Gas Supply Derivatives and certain of our Fuel Derivatives, changes in fair value are reported in earnings.

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

	Balance Sheet Location	Fair Value Measurements as of	
		December 31, 2014	December 31, 2013
LNG Inventory Derivatives asset (liability)	Prepaid expenses and other	\$ 1,216	\$ (161)
Fuel Derivatives asset	Prepaid expenses and other	—	27
Term Gas Supply Derivatives asset	Prepaid expenses and other	76	—
Term Gas Supply Derivatives asset	Non-current derivative assets	586	—
Term Gas Supply Derivatives liability	Other current liabilities	(53)	—
Term Gas Supply Derivatives liability	Other non-current liabilities	(267)	—

The following table (in thousands) shows the changes in the fair value and settlements and location of our Commodity Derivatives recorded on our Consolidated Statements of Operations during the years ended December 31, 2014, 2013 and 2012

	Income Statement Location	Year Ended December 31,		
		2014	2013	2012
LNG Inventory Derivatives gain (loss)	Revenues	\$ (31)	\$ (463)	\$ 1,036
LNG Inventory Derivatives gain	Derivative gain (loss), net	1,108	476	—
Fuel Derivatives gain (loss) (1)	Derivative gain (loss), net	281	181	(622)
Term Gas Supply Derivatives gain (2)	Operating and maintenance expense	342	—	—

- (1) Excludes settlements of hedges of the exposure to price risk attributable to future purchases of natural gas to be utilized as fuel to operate the Sabine Pass LNG terminal for which Sabine Pass LNG has elected the normal purchase normal sale exception from derivative accounting and has recorded as operating and maintenance expense.
- (2) There were no settlements during the reporting period.

LNG Inventory and Fuel Derivatives

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 where our Fuel Derivatives or our LNG Inventory Derivatives are in an asset position. Except for the fuel hedges with our affiliate described below, 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. We are required by these financial institutions to use margin deposits as credit support for our commodity derivative activities. We had a collateral call of \$1.1 million and a collateral deposit of \$0.9 million for such contracts, which have not been reflected in the derivative fair value tables but are included in prepaid expenses and other current assets in our Consolidated Balance Sheets as of December 31, 2014 and 2013, respectively.

During the second quarter of 2013, Sabine Pass LNG began to enter into forward contracts under an International Swaps and Derivatives Association master agreement with Cheniere Marketing, a wholly owned subsidiary of Cheniere, to hedge the exposure to price risk attributable to future purchases of natural gas to be utilized as fuel to operate the Sabine Pass LNG terminal. Sabine Pass LNG elected to account for these physical hedges of future fuel purchases as normal purchase normal sale transactions,

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exempt from fair value accounting. Sabine Pass LNG had not posted collateral with Cheniere Marketing for such forward contracts as of December 31, 2014 and 2013.

Term Gas Supply Derivatives

We have entered into index-based physical natural gas supply contracts to secure natural gas feedstock for the Liquefaction Project. The terms of these contracts range from approximately one to seven years and commence upon the occurrence of conditions precedent, including the date of first commercial operation of specified Trains of the Liquefaction Project. We recognize our natural gas purchase agreements as either assets or liabilities and measure those instruments at fair value. Changes in the fair value of Sabine Pass Liquefaction's Term Gas Supply Derivatives are reported in earnings.

As of December 31, 2014, the majority of Sabine Pass Liquefaction's Term Gas Supply Derivatives existed within markets for which the pipeline infrastructure has not been developed to accommodate marketable physical gas flow and its internal fair value models were based on a market price that equated to its own contractual pricing due to the inactive and unobservable market as well as the conditions precedent and their impact on the uncertainty in the timing of our actual receipt of the physical volumes associated with each forward. As of December 31, 2014, the forward notional natural gas buy position of Sabine Pass Liquefaction's Term Gas Supply Derivatives was approximately 1,249.4 million MMBtu.

Interest Rate Derivatives

In August 2012 and June 2013, Sabine Pass Liquefaction entered into Interest Rate Derivatives to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2012 Liquefaction Credit Facility and the 2013 Liquefaction Credit Facilities, respectively. The Interest Rate Derivatives hedge a portion of the expected outstanding borrowings over the term of the 2013 Liquefaction Credit Facilities.

Sabine Pass Liquefaction designated the Interest Rate Derivatives entered into in August 2012 as hedging instruments, which was required in order to qualify for cash flow hedge accounting. As a result of this cash flow hedge designation, we recognized the Interest Rate Derivatives entered into in August 2012 as an asset or liability at fair value, and reflected changes in fair value through other comprehensive income in our Consolidated Statements of Comprehensive Loss. Any hedge ineffectiveness associated with the Interest Rate Derivatives entered into in August 2012 was recorded immediately as derivative gain (loss) in our Consolidated Statements of Operations. The realized gain (loss) on the Interest Rate Derivatives entered into in August 2012 was recorded as an (increase) decrease in interest expense on our Consolidated Statements of Operations to the extent not capitalized as part of the Liquefaction Project. The effective portion of the gains or losses on our Interest Rate Derivatives entered into in August 2012 recorded in other comprehensive income would have been reclassified to earnings as interest payments on the 2012 Liquefaction Credit Facility impact earnings. In addition, amounts recorded in other comprehensive income are also reclassified into earnings if it becomes probable that the hedged forecasted transaction will not occur.

Sabine Pass Liquefaction did not elect to designate the Interest Rate Derivatives entered into in June 2013 as cash flow hedging instruments, and changes in fair value are recorded as derivative gain (loss) within our Consolidated Statements of Operations.

During the first quarter of 2013, Sabine Pass Liquefaction determined that it was no longer probable that the forecasted variable interest payments on the 2012 Liquefaction Credit Facility would occur in the time period originally specified based on the continued development of our financing strategy for the Liquefaction Project, and in particular, the Sabine Pass Liquefaction Senior Notes described in [Note 8—Long-Term Debt](#). As a result, all of the Interest Rate Derivatives entered into in August 2012 were no longer effective hedges, and the remaining portion of hedge relationships that were designated cash flow hedges as of December 31, 2012, were de-designated as of February 1, 2013. For de-designated cash flow hedges, changes in fair value prior to their de-designation date were recorded as other comprehensive income (loss) within our Consolidated Balance Sheets, and changes in fair value subsequent to their de-designation date were recorded as derivative gain (loss) within our Consolidated Statements of Operations.

In June 2013, Sabine Pass Liquefaction concluded that the hedged forecasted transactions associated with the Interest Rate Derivatives entered into in connection with the 2012 Liquefaction Credit Facility had become probable of not occurring based on the issuances of the Sabine Pass Liquefaction Senior Notes, the closing of the 2013 Liquefaction Credit Facilities, the additional Interest Rate Derivatives executed in June 2013, and Sabine Pass Liquefaction's intention to continue to issue fixed rate debt to refinance the 2013 Liquefaction Credit Facilities. As a result, the amount remaining in accumulated other comprehensive income

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(“AOCI”) pertaining to the previously designated Interest Rate Derivatives was reclassified out of AOCI and into income. We have presented the changes in fair value and settlements subsequent to the reclassification date separate from interest expense as derivative gain (loss), net in our Consolidated Statements of Operations.

In May 2014, Sabine Pass Liquefaction settled a portion of its Interest Rate Derivatives and recognized a derivative loss of \$9.3 million within our Consolidated Statements of Operations in conjunction with the termination of approximately \$2.1 billion of commitments under the 2013 Liquefaction Credit Facilities as discussed in [Note 8—Long-Term Debt](#).

At December 31, 2014, Sabine Pass Liquefaction had the following Interest Rate Derivatives outstanding:

	Initial Notional Amount	Maximum Notional Amount	Effective Date	Maturity Date	Weighted Average Fixed Interest Rate Paid	Variable Interest Rate Received
Interest Rate Derivatives - Not Designated	\$20.0 million	\$2.5 billion	August 14, 2012	July 31, 2019	1.98%	One-month LIBOR

The following table (in thousands) shows the fair value of our Interest Rate Derivatives:

	Balance Sheet Location	Fair Value Measurements as of	
		December 31, 2014	December 31, 2013
Interest Rate Derivatives - Not Designated	Non-current derivative assets	\$ 11,158	\$ 98,123
Interest Rate Derivatives - Not Designated	Other current liabilities	(23,194)	(13,484)

The following table (in thousands) details the effect of our Interest Rate Derivatives included in Other Comprehensive Income (“OCI”) and AOCI for the years ended December 31, 2014, 2013 and 2012:

	Gain (Loss) in OCI	Gain (Loss) Reclassified from AOCI into Interest Expense (Effective Portion)	Losses Reclassified into Earnings as a Result of Discontinuance of Cash Flow Hedge Accounting
December 31, 2012			
Interest Rate Derivatives - Designated	\$ (21,290)	\$ —	\$ —
Interest Rate Derivatives - De-designated	(5,814)	—	—
Interest Rate Derivatives - Settlements	(136)	—	—
December 31, 2013			
Interest Rate Derivatives - Designated	21,297	—	—
Interest Rate Derivatives - De-designated	—	—	5,807
Interest Rate Derivatives - Settlements	(30)	—	166
December 31, 2014			
Interest Rate Derivatives - Designated	—	—	—
Interest Rate Derivatives - De-designated	—	—	—
Interest Rate Derivatives - Settlements	—	—	—

The following table (in thousands) shows the changes in the fair value and settlements of our Interest Rate Derivatives—Not Designated recorded in derivative gain (loss), net on our Consolidated Statements of Operations during the years ended December 31, 2014, 2013 and 2012

	Year Ended December 31,		
	2014	2013	2012
Interest Rate Derivatives - Not Designated	\$ (119,401)	\$ 88,596	\$ 679

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Balance Sheet Presentation

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

Offsetting Derivative Assets (Liabilities)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets	Gross Amounts Not Offset in the Consolidated Balance Sheets		Net Amount
				Derivative Instrument	Cash Collateral Received (Paid)	
As of December 31, 2014:						
LNG Inventory Derivatives	\$ 1,216	\$ 1,132	\$ 84	\$ —	\$ —	\$ 84
Term Gas Supply Derivatives	662	—	662	—	—	662
Term Gas Supply Derivatives	(320)	—	(320)	—	—	(320)
Interest Rate Derivatives - Not Designated	11,158	—	11,158	—	—	11,158
Interest Rate Derivatives - Not Designated	(23,194)	—	(23,194)	—	—	(23,194)
As of December 31, 2013:						
LNG Inventory Derivatives	(161)	(161)	—	—	—	—
Fuel Derivatives	27	—	27	—	—	27
Interest Rate Derivatives - Not Designated	98,123	—	98,123	—	—	98,123
Interest Rate Derivatives - Not Designated	(13,484)	—	(13,484)	—	—	(13,484)

NOTE 7—ACCRUED LIABILITIES

As of December 31, 2014 and 2013, accrued liabilities consisted of the following (in thousands):

	December 31,	
	2014	2013
Interest expense and related debt fees	\$ 112,858	\$ 80,151
LNG liquefaction costs	22,014	83,127
LNG terminal costs	1,077	1,612
Other	629	5,162
Total accrued liabilities	\$ 136,578	\$ 170,052

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NOTE 8—LONG-TERM DEBT

As of December 31, 2014 and 2013, our long-term debt consisted of the following (in thousands):

	December 31,	
	2014	2013
Long-term debt		
2016 Sabine Pass LNG Senior Notes	\$ 1,665,500	\$ 1,665,500
2020 Sabine Pass LNG Senior Notes	420,000	420,000
2021 Sabine Pass Liquefaction Senior Notes	2,000,000	2,000,000
2022 Sabine Pass Liquefaction Senior Notes	1,000,000	1,000,000
2023 Sabine Pass Liquefaction Senior Notes	1,500,000	1,000,000
2024 Sabine Pass Liquefaction Senior Notes	2,000,000	—
2013 Liquefaction Credit Facilities	—	100,000
2017 CTPL Term Loan	400,000	400,000
Total long-term debt	8,985,500	6,585,500
Long-term debt premium (discount)		
2016 Sabine Pass LNG Senior Notes	(8,998)	(13,693)
2021 Sabine Pass Liquefaction Senior Notes	10,177	11,562
2023 Sabine Pass Liquefaction Senior Notes	7,089	—
2017 CTPL Term Loan	(2,435)	(7,096)
Total long-term debt, net	\$ 8,991,333	\$ 6,576,273

For the years ended December 31, 2014, 2013 and 2012 we incurred \$580.2 million, \$414.0 million and \$206.8 million of total interest cost, respectively, of which we capitalized and deferred \$403.2 million, \$233.0 million and \$35.1 million, respectively, of interest cost, including amortization of debt issuance costs, primarily related to the construction of the first four Trains of the Liquefaction Project.

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt as of December 31, 2014 (in thousands):

	Payments Due for the Years Ended December 31,				
	Total	2015	2016 to 2017	2018 to 2019	Thereafter
Debt:					
2016 Notes	\$ 1,665,500	\$ —	\$ 1,665,500	\$ —	\$ —
2020 Notes	420,000	—	—	—	420,000
2021 Sabine Pass Liquefaction Senior Notes	2,000,000	—	—	—	2,000,000
2022 Sabine Pass Liquefaction Senior Notes	1,000,000	—	—	—	1,000,000
2023 Sabine Pass Liquefaction Senior Notes	1,500,000	—	—	—	1,500,000
2024 Sabine Pass Liquefaction Senior Notes	2,000,000	—	—	—	2,000,000
2017 CTPL Term Loan	400,000	—	400,000	—	—
Total Debt	\$ 8,985,500	\$ —	\$ 2,065,500	\$ —	\$ 6,920,000

Sabine Pass LNG Senior Notes

As of both December 31, 2014 and 2013, Sabine Pass LNG had an aggregate principal amount of \$1,665.5 million, before discount, of the 2016 Sabine Pass LNG Senior Notes and \$420.0 million of the 2020 Sabine Pass LNG Senior Notes outstanding. Borrowings under the 2016 Sabine Pass LNG Senior Notes and 2020 Sabine Pass LNG Senior Notes bear interest at a fixed rate of 7.50% and 6.50%, respectively. The terms of the Sabine Pass LNG Senior Notes are substantially similar. Interest on the Sabine Pass LNG Senior Notes is payable semi-annually in arrears. Subject to permitted liens, the Sabine Pass LNG Senior Notes are secured on a first-priority basis by a security interest in all of Sabine Pass LNG's equity interests and substantially all of its operating assets.

Sabine Pass LNG may redeem all or part of the 2016 Sabine Pass LNG Senior Notes at any time, and from time to time, at a redemption price equal to 100% of the principal plus any accrued and unpaid interest plus the greater of:

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- 1.0% of the principal amount of the 2016 Sabine Pass LNG Senior Notes;
or
- the excess of: a) the present value at such redemption date of (i) the redemption price of the 2016 Sabine Pass LNG Senior Notes plus (ii) all required interest payments due on the 2016 Sabine Pass LNG Senior Notes (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the Treasury Rate as of such redemption date plus 50 basis points; over b) the principal amount of the 2016 Sabine Pass LNG Senior Notes, if greater.

Sabine Pass LNG may redeem all or part of the 2020 Sabine Pass LNG Senior Notes at any time on or after November 1, 2016, at fixed redemption prices specified in the indenture governing the 2020 Sabine Pass LNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. Sabine Pass LNG may also, at its option, redeem all or part of the 2020 Sabine Pass LNG Senior Notes at any time prior to November 1, 2016, at a “make-whole” price set forth in the indenture governing the 2020 Sabine Pass LNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. At any time before November 1, 2015, Sabine Pass LNG may redeem up to 35% of the aggregate principal amount of the 2020 Sabine Pass LNG Senior Notes at a redemption price of 106.5% of the principal amount of the 2020 Sabine Pass LNG Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the redemption date, in an amount not to exceed the net proceeds of one or more completed equity offerings as long as Sabine Pass LNG redeems the 2020 Sabine Pass LNG Senior Notes within 180 days of the closing date for such equity offering and at least 65% of the aggregate principal amount of the 2020 Sabine Pass LNG Senior Notes originally issued remains outstanding after the redemption.

Under the Sabine Pass LNG Indentures, except for permitted tax distributions, Sabine Pass LNG may not make distributions until certain conditions are satisfied as described in [Note 4—Restricted Cash and Cash Equivalents](#). During the years ended December 31, 2014, 2013 and 2012 Sabine Pass LNG made distributions of \$346.9 million, \$348.9 million and \$333.5 million, respectively, after satisfying all the applicable conditions in the Sabine Pass LNG Indentures.

Sabine Pass Liquefaction Senior Notes

In February 2013 and April 2013, Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion, before premium, of the 2021 Sabine Pass Liquefaction Senior Notes. In April 2013 and May 2014, Sabine Pass Liquefaction issued an aggregate principal amount of \$1.5 billion, before premium, of the 2023 Sabine Pass Liquefaction Senior Notes. Borrowings under the 2021 Sabine Pass Liquefaction Senior Notes and 2023 Sabine Pass Liquefaction Senior Notes bear interest at a fixed rate of 5.625%. In November 2013, Sabine Pass Liquefaction issued an aggregate principal amount of \$1.0 billion of the 2022 Sabine Pass Liquefaction Senior Notes. Borrowings under the 2022 Sabine Pass Liquefaction Senior Notes bear interest at a fixed rate of 6.25%. In May 2014, Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion of the 2024 Sabine Pass Liquefaction Senior Notes. Borrowings under the 2024 Sabine Pass Liquefaction Senior Notes bear interest at a fixed rate of 5.75%. Interest on the Sabine Pass Liquefaction Senior Notes is payable semi-annually in arrears.

The terms of the 2021 Sabine Pass Liquefaction Senior Notes, the 2022 Sabine Pass Liquefaction Senior Notes, the 2023 Sabine Pass Liquefaction Senior Notes and the 2024 Sabine Pass Liquefaction Senior Notes are governed by a common indenture (the “Sabine Pass Liquefaction Indenture”). The Sabine Pass Liquefaction Indenture contains customary terms and events of default and certain covenants that, among other things, limit Sabine Pass Liquefaction’s ability and the ability of Sabine Pass Liquefaction’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 Sabine Pass Liquefaction’s restricted subsidiaries, restrict dividends or other payments by restricted subsidiaries, incur liens, enter into transactions with affiliates, consolidate, merge, sell or lease all or substantially all of Sabine Pass Liquefaction’s assets and enter into certain LNG sales contracts. Subject to permitted liens, the Sabine Pass Liquefaction Senior Notes are secured on a *pari passu* first-priority basis by a security interest in all of the membership interests in Sabine Pass Liquefaction and substantially all of Sabine Pass Liquefaction’s assets. Sabine Pass Liquefaction may not make any distributions until, among other requirements, substantial completion of Trains 1 and 2 has occurred, deposits are made into debt service reserve accounts and a debt service coverage ratio for the prior 12-month period and a projected debt service coverage ratio for the upcoming 12-month period of 1.25:1.00 are satisfied.

At any time prior to November 1, 2020, with respect to the 2021 Sabine Pass Liquefaction Senior Notes; December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes; January 15, 2023, with respect to the 2023 Sabine Pass Liquefaction Senior Notes; or February 15, 2024, with respect to the 2024 Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction may redeem all or part of such series of the Sabine Pass Liquefaction Senior Notes at a redemption price equal to the “make-whole” price set forth in the Sabine Pass Liquefaction Indenture, plus accrued and unpaid interest, if any, to the date of redemption. Sabine Pass Liquefaction may also at any time on or after November 1, 2020, with respect to the 2021 Sabine Pass

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Liquefaction Senior Notes; December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes; January 15, 2023, with respect to the 2023 Sabine Pass Liquefaction Senior Notes; or February 15, 2024, with respect to the 2024 Sabine Pass Liquefaction Senior Notes, redeem all or part of such series of the Sabine Pass Liquefaction Senior Notes at a redemption price equal to 100% of the principal amount of such series of the Sabine Pass Liquefaction Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

2013 Liquefaction Credit Facilities

In May 2013, Sabine Pass Liquefaction entered into the 2013 Liquefaction Credit Facilities aggregating \$5.9 billion. The 2013 Liquefaction Credit Facilities are being used to fund a portion of the costs of developing, constructing and placing into operation the first four Trains of the Liquefaction Project. The 2013 Liquefaction Credit Facilities will mature on the earlier of May 28, 2020 or the second anniversary of the completion date of the first four Trains of the Liquefaction Project, as defined in the 2013 Liquefaction Credit Facilities. Borrowings under the 2013 Liquefaction Credit Facilities may be refinanced, in whole or in part, at any time without premium or penalty, except for interest rate hedging and interest rate breakage costs. Sabine Pass Liquefaction made an initial \$100.0 million borrowing under the 2013 Liquefaction Credit Facilities in June 2013 after meeting the required conditions precedent, and in May 2014, Sabine Pass Liquefaction repaid its borrowings under the 2013 Liquefaction Credit Facilities upon the issuance of the Additional 2023 Sabine Pass Liquefaction Senior Notes and the 2024 Sabine Pass Liquefaction Senior Notes. As of December 31, 2014 and 2013, Sabine Pass Liquefaction had \$2.7 billion and \$4.9 billion, respectively, of available commitments under the 2013 Liquefaction Credit Facilities.

Borrowings under the 2013 Liquefaction Credit Facilities bear interest at a variable rate per annum equal to, at Sabine Pass Liquefaction's election, the London Interbank Offered Rate ("LIBOR") or the base rate, plus the applicable margin. The applicable margins for LIBOR loans range from 2.3% to 3.0% prior to the completion of Train 4 and from 2.3% to 3.25% after such completion, depending on the applicable 2013 Liquefaction Credit Facility. Interest on LIBOR loans is due and payable at the end of each LIBOR period. The 2013 Liquefaction Credit Facilities required Sabine Pass Liquefaction to pay certain up-front fees to the agents and lenders in the aggregate amount of approximately \$144 million and provide for a commitment fee calculated at a rate per annum equal to 40% of the applicable margin for LIBOR loans, multiplied by the average daily amount of the undrawn commitment due quarterly in arrears. Annual administrative fees must also be paid to the agent and the trustee. The principal of the loans made under the 2013 Liquefaction Credit Facilities must be repaid in quarterly installments, commencing with the earlier of the last day of the first full calendar quarter after the Train 4 completion date, as defined in the 2013 Liquefaction Credit Facilities, or September 30, 2018. Scheduled repayments are based upon an 18-year amortization profile, with the remaining balance due upon the maturity of the 2013 Liquefaction Credit Facilities.

Under the terms and conditions of the 2013 Liquefaction Credit Facilities, all cash held by Sabine Pass Liquefaction is controlled by a collateral agent. These funds can only be released by the collateral agent upon satisfaction of certain terms and conditions related to the use of proceeds, and are classified as restricted on our Consolidated Balance Sheets.

The 2013 Liquefaction Credit Facilities contain conditions precedent for any subsequent borrowings, as well as customary affirmative and negative covenants. The obligations of Sabine Pass Liquefaction under the 2013 Liquefaction Credit Facilities are secured by substantially all of the assets of Sabine Pass Liquefaction as well as all of the membership interests in Sabine Pass Liquefaction on a *pari passu* basis with the Sabine Pass Liquefaction Senior Notes.

Under the terms of the 2013 Liquefaction Credit Facilities, Sabine Pass Liquefaction is required to hedge not less than 75% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal. See [Note 6—Derivative Instruments](#).

In November 2013, in conjunction with Sabine Pass Liquefaction's issuance of the 2022 Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction terminated approximately \$885 million of commitments under the 2013 Liquefaction Credit Facilities. This termination resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2013 Liquefaction Credit Facilities of \$43.3 million in November 2013.

In May 2014, in conjunction with Sabine Pass Liquefaction's issuance of the 2024 Sabine Pass Liquefaction Senior Notes and the Additional 2023 Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction terminated approximately \$2.1 billion of commitments under the 2013 Liquefaction Credit Facilities. This termination resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2013 Liquefaction Credit Facilities of \$114.3 million in May 2014.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
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2012 Liquefaction Credit Facility

In July 2012, Sabine Pass Liquefaction entered into the 2012 Liquefaction Credit Facility with a syndicate of lenders. The 2012 Liquefaction Credit Facility was intended to be used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 and 2 of the Liquefaction Project. Borrowings under the 2012 Liquefaction Credit Facility were based on LIBOR plus 3.50% during construction and LIBOR plus 3.75% during operations. Sabine Pass Liquefaction was also required to pay commitment fees on the undrawn amount. In May 2013, the 2012 Liquefaction Credit Facility was amended and restated with the 2013 Liquefaction Credit Facilities and \$100.0 million of outstanding borrowings under the 2012 Liquefaction Credit Facility were repaid in full.

Under the terms of the 2012 Liquefaction Credit Facility, Sabine Pass Liquefaction was required to hedge not less than 75% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal. See [Note 6—Derivative Instruments](#).

In conjunction with the issuance of the 2021 Sabine Pass Liquefaction Senior Notes in February 2013 and the issuances of \$500.0 million of additional 2021 Sabine Pass Liquefaction Senior Notes and 2023 Sabine Pass Liquefaction Senior Notes in April 2013, approximately \$1.4 billion of commitments under the 2012 Liquefaction Credit Facility were terminated. The termination of these commitments in April 2013 and the amendment and restatement of the 2012 Liquefaction Credit Facility with the 2013 Liquefaction Credit Facilities in May 2013 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2012 Liquefaction Credit Facility of \$88.3 million during the year ended December 31, 2013.

2017 CTPL Term Loan

In May 2013, CTPL entered into the 2017 CTPL Term Loan, which is being used to fund modifications to the Creole Trail Pipeline and for general business purposes. CTPL incurred \$10.0 million of direct lender fees that were recorded as a debt discount. The 2017 CTPL Term Loan matures in 2017 when the full amount of the outstanding principal obligations must be repaid. CTPL's loans may be repaid, in whole or in part, at any time without premium or penalty. As of December 31, 2014, CTPL had borrowed the full amount of \$400.0 million available under the 2017 CTPL Term Loan.

Borrowings under the 2017 CTPL Term Loan bear interest at a variable rate per annum equal to, at CTPL's election, LIBOR or the base rate, plus the applicable margin. The applicable margin for LIBOR loans is 3.25%. Interest on LIBOR loans is due and payable at the end of each LIBOR period.

Under the terms and conditions of the 2017 CTPL Term Loan, all cash reserved to pay interest during construction is controlled by a collateral agent. These funds can only be released by the collateral agent upon satisfaction of certain terms and conditions, and are classified as restricted on our Consolidated Balance Sheets. CTPL is also required to pay annual fees to the administrative and collateral agents.

The 2017 CTPL Term Loan contains customary affirmative and negative covenants. The obligations of CTPL under the 2017 CTPL Term Loan are secured by a first priority lien on substantially all of the personal property of CTPL and all of the general partner and limited partner interests in CTPL.

Cheniere Partners has guaranteed (i) the obligations of CTPL under the 2017 CTPL Term Loan if the maturity of the CTPL loans is accelerated following the termination by Sabine Pass Liquefaction of a transportation precedent agreement in limited circumstances and (ii) the obligations of Cheniere Energy Investments, LLC ("Cheniere Investments"), Cheniere Partners' wholly owned subsidiary, in connection with its obligations under an equity contribution agreement (a) to pay operating expenses of CTPL until CTPL receives revenues under a service agreement with Sabine Pass Liquefaction and (b) to fund interest payments on the CTPL loans after the funds in an interest reserve account have been exhausted.

Sabine Pass Liquefaction LC Agreement

In April 2014, Sabine Pass Liquefaction entered into a \$325.0 million senior letter of credit and reimbursement agreement (the "Sabine Pass Liquefaction LC Agreement") that it uses for the issuance of letters of credit for certain working capital requirements related to the Liquefaction Project. Sabine Pass Liquefaction pays (a) a commitment fee in an amount equal to an annual rate of 0.75% of an amount equal to the unissued portion of letters of credit available pursuant to the Sabine Pass Liquefaction LC Agreement and (b) a letter of credit fee equal to an annual rate of 2.5% of the undrawn portion of all letters of credit issued.

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under the Sabine Pass Liquefaction LC Agreement. If draws are made upon any letters of credit issued under the Sabine Pass Liquefaction LC Agreement, the amount of the draw will be deemed a loan issued to Sabine Pass Liquefaction. Sabine Pass Liquefaction is required to pay the full amount of this loan on or prior to the business day immediately succeeding the deemed issuance of the loan. These loans bear interest at a rate of 2.0% plus the base rate as defined in the Sabine Pass Liquefaction LC Agreement. As of December 31, 2014, Sabine Pass Liquefaction had issued letters of credit in an aggregate amount of \$9.5 million and no draws had been made upon any letters of credit issued under the Sabine Pass Liquefaction LC Agreement.

Fair Value Disclosures

The following table (in thousands) shows the carrying amount and estimated fair value of our long-term debt:

	December 31, 2014		December 31, 2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
2016 Sabine Pass LNG Senior Notes, net of discount (1)	\$ 1,656,502	\$ 1,718,621	\$ 1,651,807	\$ 1,868,607
2020 Sabine Pass LNG Senior Notes (1)	420,000	428,400	420,000	432,600
2021 Sabine Pass Liquefaction Senior Notes, net of premium (1)	2,010,177	1,985,050	2,011,562	1,961,273
2022 Sabine Pass Liquefaction Senior Notes (1)	1,000,000	1,020,000	1,000,000	982,500
2023 Sabine Pass Liquefaction Senior Notes, net of premium (1)	1,507,089	1,476,947	1,000,000	935,000
2024 Sabine Pass Liquefaction Senior Notes (1)	2,000,000	1,970,000	—	—
2013 Liquefaction Credit Facilities (2)	—	—	100,000	100,000
2017 CTPL Term Loan, net of discount (3)	397,565	400,000	392,904	400,000

- (1) The Level 2 estimated fair value was based on quotations obtained from broker-dealers who make markets in these and similar instruments based on the closing trading prices on December 31, 2014 and 2013, as applicable.
- (2) The Level 3 estimated fair value approximates the carrying amount because the interest rates are variable and reflective of market rates and Sabine Pass Liquefaction had the ability to call this debt at any time without penalty.
- (3) The Level 3 estimated fair value approximates the principal amount because the interest rates are variable and reflective of market rates and CTPL has the ability to call this debt at any time without penalty.

NOTE 9—RELATED PARTY TRANSACTIONS

LNG Terminal Capacity Agreements

Terminal Use Agreement

Sabine Pass Liquefaction obtained approximately 2.0 Bcf/d of regasification capacity under a TUA with Sabine Pass LNG as a result of an assignment in July 2012 by Cheniere Investments, our wholly owned subsidiary, of its rights, title and interest under its TUA with Sabine Pass LNG. Sabine Pass Liquefaction is obligated to make monthly capacity payments to Sabine Pass LNG aggregating approximately \$250 million per year, continuing until at least 20 years after Sabine Pass Liquefaction delivers its first commercial cargo at the Liquefaction Project, which may occur as early as late 2015.

In connection with this TUA, Sabine Pass Liquefaction 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. During the years ended December 31, 2014, 2013 and 2012, we recorded \$26.1 million, \$26.6 million and \$10.1 million, respectively, as operating and maintenance expense related to this obligation.

Cheniere Investments, Sabine Pass Liquefaction and Sabine Pass LNG entered into the terminal use rights assignment and agreement (“TURA”) pursuant to which Cheniere Investments has the right to use Sabine Pass Liquefaction’s reserved capacity under the TUA and has the obligation to make the monthly capacity payments required by the TUA to Sabine Pass LNG. However, the revenue earned by Sabine Pass LNG from the capacity payments made under the TUA and the loss incurred by Cheniere Investments under the TURA are eliminated upon consolidation of our financial statements. We have guaranteed the obligations of Sabine Pass Liquefaction under its TUA and the obligations of Cheniere Investments under the TURA.

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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. We recorded revenues—affiliate from Cheniere Marketing of zero, zero and \$4.9 million during the years ended December 31, 2014, 2013 and 2012, respectively, related to the amended and restated VCRA.

Cheniere Marketing SPA

Cheniere Marketing has entered into an amended and restated SPA with Sabine Pass Liquefaction to purchase, at Cheniere Marketing's option, any LNG produced by Sabine Pass Liquefaction in excess of that required for other customers at a price of 115% of Henry Hub plus \$3.00 per MMBtu of LNG.

Services Agreements

As of December 31, 2014 and 2013, we had \$27.3 million and \$14.7 million of advances to affiliates, respectively, under the services agreements described below. During the years ended December 31, 2014, 2013 and 2012, we recorded general and administrative expense—affiliate of \$101.4 million, \$129.8 million and \$61.1 million, respectively, and operating and maintenance expense—affiliate of \$21.1 million, \$29.3 million and \$18.5 million, respectively, under the services agreements described below.

Cheniere Partners Services Agreement

We have entered into a services agreement with Cheniere LNG Terminals, LLC ("Cheniere Terminals"), a wholly owned subsidiary of Cheniere, pursuant to which we pay Cheniere Terminals a quarterly non-accountable overhead reimbursement charge of \$2.8 million (adjusted for inflation) for the provision of various general and administrative services for our benefit. In addition, we reimburse Cheniere Terminals for all audit, tax, legal and finance fees incurred by Cheniere Terminals that are necessary to perform the services under the agreement.

Sabine Pass LNG O&M Agreement

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

Sabine Pass LNG MSA

Sabine Pass LNG has entered into a long-term management services agreement (the "Sabine Pass LNG 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 Sabine Pass LNG O&M Agreement. Sabine Pass LNG is required to pay Cheniere Terminals a monthly fixed fee of \$520,000 (indexed for inflation).

Sabine Pass Liquefaction O&M Agreement

Sabine Pass Liquefaction has entered into an operation and maintenance agreement (the "Liquefaction O&M Agreement") with Cheniere Investments pursuant to which Sabine Pass Liquefaction receives all of the necessary services required to construct, operate and maintain the liquefaction facilities. Before the liquefaction facilities are operational, the services to be provided include, among other services, obtaining governmental approvals on behalf of Sabine Pass Liquefaction, preparing an operating plan for certain periods, obtaining insurance, preparing staffing plans and preparing status reports. After the liquefaction facilities are operational, the services include all necessary services required to operate and maintain the liquefaction facilities. Before the liquefaction facilities are operational, in addition to reimbursement of operating expenses, Sabine Pass Liquefaction is required

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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 liquefaction facilities are operational, Sabine Pass Liquefaction 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 such Train. Cheniere Investments provides the services required under the Liquefaction O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere.

Sabine Pass Liquefaction MSA

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

CTPL O&M Agreement

CTPL has entered into 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 the counterparty for its operating expenses, which consist primarily of labor expenses. In November 2013, the CTPL O&M Agreement was assigned by Cheniere Energy Partners GP, LLC to Cheniere Investments. Cheniere Investments provides the services required under the CTPL O&M Agreement pursuant to a secondment agreement with a wholly owned subsidiary of Cheniere.

CTPL MSA

CTPL has entered into a management services agreement (the “CTPL MSA”) with Cheniere Terminals pursuant to which Cheniere Terminals manages the modification and operation of the Creole Trail Pipeline, excluding those matters provided for under the CTPL O&M Agreement. The services include, among other services, exercising the day-to-day management of CTPL’s affairs and business, managing CTPL’s regulatory matters, managing bank and brokerage accounts and financial books and records of CTPL’s business and operations, and providing contract administration services for all contracts associated with the liquefaction facilities. CTPL pays a monthly fee equal to 3.0% of the capital expenditures to enable bi-directional natural gas flow on the Creole Trail Pipeline incurred in the previous month.

LNG Lease Agreement

In September 2011, Cheniere Investments entered into an agreement in the form of a lease (the “LNG Lease Agreement”) with Cheniere Marketing that enables Cheniere Investments to supply the Sabine Pass LNG terminal with LNG to maintain proper LNG inventory levels and temperature. The LNG Lease Agreement also enables Cheniere Investments to hedge the exposure to variability in expected future cash flows of the LNG inventory. Under the terms of the LNG Lease Agreement, Cheniere Marketing funds all activities related to the purchase and hedging of the LNG, and Cheniere Investments reimburses Cheniere Marketing for all costs and assumes full price risk associated with these activities.

As a result of Cheniere Investments assuming full price risk associated with the LNG Lease Agreement, LNG inventory purchased by Cheniere Marketing under this arrangement is classified as LNG inventory—affiliate, which is included in other—affiliate on our Consolidated Balance Sheets. This amount is recorded at cost and subject to LCM adjustments at the end of each period. LNG inventory—affiliate cost is determined using the average cost method. Recoveries of losses resulting from interim period LCM adjustments are made due to market price recoveries on the same LNG inventory—affiliate in the same fiscal year and are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. Gains or losses on the sale of LNG inventory—affiliate and LCM adjustments are recorded as revenues on our Consolidated Statements of Operations. As of December 31, 2014, we had no LNG inventory—affiliate recorded on our Consolidated Balance Sheets under the LNG Lease Agreement, and as of December 31, 2013, we had 41,000 MMBtu of LNG inventory—affiliate recorded at \$130,000 in other—affiliate on our Consolidated Balance Sheets under the LNG Lease Agreement.

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Cheniere Marketing has entered into financial derivatives, on our behalf, to hedge the exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory under the LNG Lease Agreement. The fair value of these derivative instruments at December 31, 2014 and 2013 was zero and \$0.2 million, respectively, and was classified as other current assets and other current liabilities, respectively, on our Consolidated Balance Sheets. Changes in the fair value of these derivative instruments are classified as revenues on our Consolidated Statements of Operations. We recorded losses of \$31,000 and \$0.5 million and revenues of \$1.0 million related to LNG inventory—affiliate derivatives in the years ended December 31, 2014, 2013 and 2012 respectively.

Agreement to Fund Sabine Pass LNG’s Cooperative Endeavor Agreements (“CEAs”)

In July 2007, Sabine Pass LNG executed CEAs with various Cameron Parish, Louisiana taxing authorities that allow them to collect certain annual property tax payments from Sabine Pass LNG in 2007 through 2016. This ten-year initiative represents an aggregate commitment of up to \$25.0 million and Sabine Pass LNG will make resources available to the Cameron Parish taxing authorities on an accelerated basis in order to aid in their reconstruction efforts following Hurricane Rita. In exchange for Sabine Pass LNG’s advance payments of annual ad valorem taxes, Cameron Parish will grant Sabine Pass LNG a dollar for dollar credit against future ad valorem taxes to be levied against the Sabine Pass LNG terminal starting in 2019. In September 2007, Sabine Pass LNG entered into an agreement with Cheniere Marketing, pursuant to which Cheniere Marketing would pay Sabine Pass LNG additional TUA revenues equal to any and all amounts payable under the CEAs in exchange for a similar amount of credits against future TUA payments it would owe Sabine Pass LNG under its TUA starting in 2019. In June 2010, Cheniere Marketing assigned its TUA to Cheniere Investments and concurrently entered into a variable capacity rights agreement (“VCRA”), allowing Cheniere Marketing to utilize Cheniere Investments’ capacity under the TUA after the assignment. In July 2012, Cheniere Investments entered into the amended and restated VCRA with Cheniere Marketing in order for Cheniere Investments to utilize during construction of the Liquefaction Project the capacity rights granted under the TURA. Cheniere Marketing will continue to fund the CEAs during the term of the amended and restated VCRA and, in exchange, Cheniere Marketing will receive the benefit of any future credits.

On a consolidated basis, these advance tax payments were recorded to other non-current assets, and payments from Cheniere Marketing that Sabine Pass LNG utilized to make the ad valorem tax payments were recorded as a long-term obligation. As of December 31, 2014 and 2013, we had \$19.6 million and \$17.2 million, respectively, of other non-current assets resulting from Sabine Pass LNG’s ad valorem tax payments and non-current liabilities—affiliate resulting from these payments received from Cheniere Marketing.

Contracts for Sale and Purchase of Natural Gas and LNG

Sabine Pass LNG is able to sell and purchase natural gas and LNG under agreements with Cheniere Marketing. Under these agreements, Sabine Pass LNG purchases natural gas or LNG from Cheniere Marketing at a sales price equal to the actual purchase cost paid by Cheniere Marketing to suppliers of the natural gas or LNG, plus any third-party costs incurred by Cheniere Marketing in respect of the receipt, purchase and delivery of natural gas or LNG to the Sabine Pass LNG terminal. As a result, Sabine Pass LNG records the purchases of natural gas and LNG from Cheniere Marketing to be utilized as fuel to operate the Sabine Pass LNG terminal as operating and maintenance expense.

Sabine Pass LNG recorded operating and maintenance expense of \$3.3 million, \$3.3 million and \$2.8 million for natural gas purchased from Cheniere Marketing under these agreements in the years ended December 31, 2014, 2013 and 2012 respectively.

Sabine Pass LNG recorded revenues—affiliate of \$0.7 million, \$14.7 million and \$2.8 million for natural gas sold to Cheniere Marketing under these agreements in the years ended December 31, 2014, 2013 and 2012 respectively.

LNG Terminal Export Agreement

In January 2010, Sabine Pass LNG and Cheniere Marketing entered into an LNG Terminal Export Agreement that provides Cheniere Marketing the ability to export LNG from the Sabine Pass LNG terminal. Sabine Pass LNG recorded revenues—affiliate of zero, zero, and \$0.3 million pursuant to this agreement in the years ended December 31, 2014, 2013 and 2012, respectively.

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Tug Boat Lease Sharing Agreement

In connection with its tug boat lease, Sabine Pass Tug Services, LLC, a wholly owned subsidiary of Sabine Pass LNG (“Tug Services”), entered into a tug sharing 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. Tug Services recorded revenues—affiliate of \$2.8 million pursuant to this agreement in each of the years ended December 31, 2014, 2013 and 2012.

State Tax Sharing Agreement

In May 2013, CTPL entered into a state tax sharing agreement with Cheniere. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which we 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, we will pay to Cheniere an amount equal to the state and local tax that we would be required to pay if our 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 us under this agreement; therefore, Cheniere has not demanded any such payments from us. The agreement is effective for tax returns due on or after May 2013.

NOTE 10—LEASES

During the years ended December 31, 2014, 2013 and 2012, we recognized rental expense for all operating leases of \$10.5 million, \$10.0 million and \$10.0 million, respectively.

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

Year ending December 31,	Lease Payments (2)
2015	\$ 10,261
2016	10,340
2017	10,401
2018	2,988
2019	2,318
Thereafter (1)	172,437
Total	\$ 208,745

(1) Includes certain lease option renewals as they are reasonably assured.

(2) Lease payments for Sabine Pass LNG’s tug boat lease represent its lease payment obligation and do not take into account the \$24.4 million of sublease payments Sabine Pass LNG will receive from its customers that effectively offset these lease payment obligations, as discussed below.

Land Leases

We recognized \$2.2 million, \$2.2 million and \$2.3 million of site lease expense on our Consolidated Statements of Operations in 2014, 2013 and 2012, respectively, under the following LNG site leases:

In January 2005, Sabine Pass LNG exercised its options and entered into three land leases for the site of the Sabine Pass LNG terminal. The leases have an initial term of 30 years, with options to renew for six 10-year extensions with similar terms as the initial term. In February 2005, two of the three leases were amended, thereby increasing the total acreage under lease to 853 acres. In July 2012, Sabine Pass LNG entered into an additional land lease, thereby increasing the total acreage under lease to 883 acres. The annual lease payments are adjusted for inflation every 5 years based on a consumer price index, as defined in the lease agreements.

In November 2011, Sabine Pass Liquefaction entered into a land lease of 80.7 acres to be used as the laydown area during the construction of the Liquefaction Project. The lease has an initial term of 5 years, with options to renew for five 1-year extensions with similar terms as the initial term.

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

In December 2011, Sabine Pass Liquefaction entered into a land lease of 80.6 acres to be used for the site of the Liquefaction Project. The lease has an initial term of 30 years, with options to renew for six 10-year extensions with similar terms as the initial term. The annual lease payment is adjusted for inflation every 5 years based on a consumer price index, as defined in the lease agreement.

Tug Boat Lease

In the second quarter of 2009, Sabine Pass LNG acquired a lease (the “Tug Agreement”) for the use of tug boats and marine services for the Sabine Pass LNG terminal. The term of the Tug Agreement commenced in January 2008 for a period of 10 years, with an option to renew two additional, consecutive terms of 5 years each. We have determined that the Tug Agreement contains a lease for the tugs specified in the Tug Agreement. In addition, we have concluded that the tug lease contained in the Tug Agreement is an operating lease, and as such, the equipment component of the Tug Agreement will be charged to expense over the term of the Tug Agreement as it becomes payable.

In connection with this lease acquisition, Tug Services entered into a tug sharing agreement (the “Tug Sharing Agreement”) with Total Gas & Power North America, Inc. (“Total”), Chevron U.S.A. Inc. (“Chevron”) and a wholly owned subsidiary of Cheniere to provide their LNG cargo vessels with tug boat and marine services at the Sabine Pass LNG terminal and effectively offset the cost of the Tug Agreement. The Tug Sharing Agreement provides for each of our customers to pay Tug Services an annual service fee.

NOTE 11—COMMITMENTS AND CONTINGENCIES

Obligations under LNG TUAs

Sabine Pass LNG has entered into third-party TUAs with Total and Chevron to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG terminal.

Obligations under Bechtel EPC Contract

Sabine Pass Liquefaction has entered into lump sum turnkey EPC contracts for Trains 1 and 2 (the “EPC Contract (Trains 1 and 2)”) and Trains 3 and 4 (the “EPC Contract (Trains 3 and 4)”) with Bechtel Oil, Gas and Chemicals, Inc. (“Bechtel”) in November 2011 and December 2012, respectively.

The EPC Contract (Trains 1 and 2) provides that Sabine Pass Liquefaction will pay Bechtel a contract price of \$3.9 billion, which is subject to adjustment by change order. Sabine Pass Liquefaction has the right to terminate the EPC Contract (Trains 1 and 2) for its convenience, in which case Bechtel will be paid (i) the portion of the contract price for the work performed, (ii) costs reasonably incurred by Bechtel on account of such termination and demobilization, and (iii) a lump sum of up to \$30.0 million depending on the termination date.

The EPC Contract (Trains 3 and 4) provides for (i) the procurement, engineering, design, installation, training, commissioning and placing into service of Trains 3 and 4 of the Liquefaction Project and related facilities and (ii) certain modifications and improvements to Trains 1 and 2 and the Sabine Pass LNG terminal. The EPC Contract (Trains 3 and 4) provides that Sabine Pass Liquefaction will pay Bechtel a contract price of \$3.8 billion, which is subject to adjustment by change order. Sabine Pass Liquefaction has the right to terminate the EPC Contract (Trains 3 and 4) for its convenience, in which case Bechtel will be paid (i) the portion of the contract price for the work performed, (ii) costs reasonably incurred by Bechtel on account of such termination and demobilization, and (iii) a lump sum of up to \$30.0 million depending on the termination date.

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

Obligations under SPAs

Sabine Pass Liquefaction has entered into third-party SPAs with four customers which obligates Sabine Pass Liquefaction to purchase natural gas in sufficient quantities, liquefy the natural gas purchased, and deliver 834.0 million MMBtu per year of LNG to the customers' vessels, subject to completion of construction of each of the first four Trains of the Liquefaction Project as specified in the customers' SPAs. In addition, Sabine Pass Liquefaction has entered into third-party SPAs with two customers to purchase natural gas in sufficient quantities, liquefy the natural gas purchased, and deliver 196.0 million MMBtu per year of LNG to the customers' vessels, subject to completion of regulatory approvals, securing adequate financing, reaching a positive final investment decision to construct the relevant infrastructure, and construction of the fifth Train of the Liquefaction Project.

Services Agreements

We have entered into certain services agreements with affiliates. See [Note 9—Related Party Transactions](#) for information regarding such agreements.

Restricted Net Assets

At December 31, 2014, our restricted net assets of consolidated subsidiaries were approximately \$903 million.

Other Commitments

State Tax Sharing Agreements

In November 2006, Sabine Pass LNG and Cheniere entered into a state tax sharing agreement. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which Sabine Pass LNG 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, Sabine Pass LNG will pay to Cheniere an amount equal to the state and local tax that Sabine Pass LNG would be required to pay if Sabine Pass LNG's state and local tax liability were computed on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from Sabine Pass LNG under this agreement; therefore, Cheniere has not demanded any such payments from Sabine Pass LNG. The agreement is effective for tax returns due on or after January 1, 2008.

In August 2012, Sabine Pass Liquefaction and Cheniere entered into a state tax sharing agreement. Under this agreement, Cheniere has agreed to prepare and file all state and local tax returns which Sabine Pass Liquefaction 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, Sabine Pass Liquefaction will pay to Cheniere an amount equal to the state and local tax that Sabine Pass Liquefaction would be required to pay if Sabine Pass Liquefaction's state and local tax liability were computed on a separate company basis. There have been no state and local taxes paid by Cheniere for which Cheniere could have demanded payment from Sabine Pass Liquefaction under this agreement; therefore, Cheniere has not demanded any such payments from Sabine Pass Liquefaction. The agreement is effective for tax returns due on or after August 2012.

In May 2013, CTPL and Cheniere entered into a state tax sharing agreement. 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 computed 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.

Cooperative Endeavor Agreements

In July 2007, Sabine Pass LNG executed CEAs with various Cameron Parish, Louisiana taxing authorities. See [Note 9—Related Party Transactions](#) for information regarding such agreements.

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

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, 2014, there were no threatened or pending legal matters that would have a material impact on our consolidated results of operations, financial position or cash flows.

NOTE 12—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2014	2013	2012
Cash paid during the year for interest, net of amounts capitalized and deferred	\$ 130,578	\$ 120,908	\$ 160,273
Balance in property, plant and equipment, net funded with accounts payable and accrued liabilities (including affiliate)	124,741	166,252	99,680
Class B units issued in connection with Creole Trail Pipeline Business acquisition	—	180,000	—

NOTE 13—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 23, 2015, we declared a \$0.425 distribution per common unit and the related distribution to our general partner to be paid on February 13, 2015 to owners of record as of February 2, 2015 for the period from October 1, 2014 to December 31, 2014.

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. Historical income (losses) attributable to a company that was purchased from an entity under common control are allocated to the predecessor owner in accordance with the terms 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 were issued at a discount to the market price of the common units into which they are convertible. This discount totaling \$2,130.0 million represents a beneficial conversion feature and is 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 Statements of Partners' Equity. The beneficial conversion feature is considered a dividend that will be distributed ratably with respect to any Class B unit from its issuance date through its conversion date, resulting in an increase in Class B unitholders' equity and a decrease in common and subordinated unitholders' equity. We amortize the beneficial conversion feature assuming a conversion date of June 2017 and August 2017 for Cheniere Holdings' and Blackstone's Class B units, respectively, although actual conversion may occur prior to or after these assumed dates. We are amortizing using the effective yield method with a weighted average effective yield of 888.7% per year and 966.1% per year for Cheniere Holdings' and Blackstone's Class B units, respectively. The impact of the beneficial conversion feature is also included in earnings per unit for the years ended December 31, 2014, 2013 and 2012.

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

The following is a schedule by years, based on the capital structure as of December 31, 2014, of the anticipated impact to the capital accounts in connection with the amortization of the beneficial conversion feature (in thousands):

	<u>Common Units</u>	<u>Class B Units</u>	<u>Subordinated Units</u>
2015	\$ (232)	\$ 781	\$ (549)
2016	(29,564)	99,685	(70,121)
2017	(594,390)	2,004,209	(1,409,819)

Under our partnership agreement, the incentive distribution rights (“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). We did not allocate earnings or losses to IDR holders for the purpose of the two class method earnings per unit calculation for any of the periods presented. 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 and Creole Trail Pipeline Business for purposes of computing net income (loss) per unit (in thousands, except per unit data). The following table also provides net income (loss) per unit, as adjusted, assuming the common units, subordinated units and the general partner had participated in the pre-acquisition date net losses of the Creole Trail Pipeline Business.

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 and the subordinated units for purposes of computing net income (loss) per unit (in thousands, except per unit data):

	Total	Limited Partner Units			General Partner	Creole Trail Pipeline Business
		Common Units	Class B Units	Subordinated Units		
Year Ended December 31, 2014						
Net loss	\$ (410,036)					
Declared distributions	99,015	97,036	—	—	1,979	
Assumed allocation of undistributed net loss	<u>\$ (509,051)</u>	<u>(147,952)</u>	<u>—</u>	<u>(350,918)</u>	<u>(10,181)</u>	<u>—</u>
Assumed allocation of net loss		<u>\$ (50,916)</u>	<u>\$ —</u>	<u>\$ (350,918)</u>	<u>\$ (8,202)</u>	<u>\$ —</u>
Weighted average units outstanding		57,079	145,333	135,384		
Net loss per unit		<u>\$ (0.89)</u>	<u>\$ —</u>	<u>\$ (2.59)</u>		
Year Ended December 31, 2013						
Net loss	\$ (258,117)					
Declared distributions	99,015	97,035	—	—	1,980	
Assumed allocation of undistributed net loss	<u>\$ (357,132)</u>	<u>(98,522)</u>	<u>—</u>	<u>(233,680)</u>	<u>(6,780)</u>	<u>(18,150)</u>
Assumed allocation of net loss		<u>\$ (1,487)</u>	<u>\$ —</u>	<u>\$ (233,680)</u>	<u>\$ (4,800)</u>	<u>\$ (18,150)</u>
Assumed allocation of net loss adjusted for the Creole Trail Pipeline Business		<u>\$ (6,762)</u>	<u>\$ —</u>	<u>\$ (246,192)</u>	<u>\$ (5,163)</u>	
Weighted average units outstanding		54,235	140,500	135,384		
Net loss per unit		<u>\$ (0.03)</u>	<u>\$ —</u>	<u>\$ (1.73)</u>		
Net loss per unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business		<u>\$ (0.12)</u>	<u>\$ —</u>	<u>\$ (1.82)</u>		
Year Ended December 31, 2012						
Net loss	\$ (175,431)					
Declared distributions	61,501	60,271	—	—	1,230	
Amortization of beneficial conversion feature of Class B Units	—	(5,149)	25,319	(20,170)		
Assumed allocation of undistributed net loss	<u>\$ (236,932)</u>	<u>(46,061)</u>	<u>—</u>	<u>(157,917)</u>	<u>(7,659)</u>	<u>(25,295)</u>
Assumed allocation of net loss		<u>\$ 9,061</u>	<u>\$ 25,319</u>	<u>\$ (178,087)</u>	<u>\$ (6,429)</u>	<u>\$ (25,295)</u>
Assumed allocation of net loss adjusted for the Creole Trail Pipeline Business		<u>\$ 3,463</u>	<u>\$ 25,319</u>	<u>\$ (197,278)</u>	<u>\$ (6,935)</u>	
Weighted average units outstanding		33,470	43,303	135,384		
Net income (loss) per unit		<u>\$ 0.27</u>	<u>\$ 0.58</u>	<u>\$ (1.32)</u>		
Net income (loss) per unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business		<u>\$ 0.10</u>	<u>\$ 0.58</u>	<u>\$ (1.46)</u>		

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

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2014:				
Revenues	\$ 67,221	\$ 67,328	\$ 67,590	\$ 66,559
Income (loss) from operations	5,086	(7,726)	(2,056)	3,822
Net loss	(69,733)	(226,224)	(43,240)	(70,839)
Basic and diluted net income (loss) per common unit (1)	\$ (0.06)	\$ (0.85)	\$ 0.08	\$ (0.06)
Year ended December 31, 2013:				
Revenues	\$ 66,108	\$ 67,637	\$ 67,447	\$ 66,999
Income (loss) from operations	5,670	(20,427)	(23,357)	5,428
Net loss	(51,733)	(47,010)	(98,108)	(61,266)
Basic and diluted net income (loss) per common unit (1)	\$ 0.10	\$ 0.11	\$ (0.20)	\$ (0.01)
Net income (loss) per common unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business—basic and diluted (1)	\$ 0.04	\$ 0.06	\$ (0.20)	\$ (0.01)

(1) The sum of the quarterly net income (loss) per common unit may not equal the full year amount as the 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.

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, 2014, 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 (i) 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 (ii) 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 56 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

Compliance Disclosure

Pursuant to Section 13(r) of the Exchange Act, if during the fiscal year ended December 31, 2014, we or any of our affiliates had engaged in certain transactions with Iran or with persons or entities designated under certain executive orders, we would be required to disclose information regarding such transactions in our Annual Report on Form 10-K as required under Section 219 of the Iran Threat Reduction and Syria Human Rights Act of 2012 ("ITRA"). During the fiscal year ended December 31, 2014, we did not engage in any transactions with Iran or with persons or entities related to Iran.

Blackstone CQP Holdco LP, an affiliate of The Blackstone Group L.P. ("Blackstone Group"), is a holder of approximately 29% of the outstanding equity interests of Cheniere Partners and has three representatives on the Board of Directors of Cheniere Partners' general partner. Accordingly, Blackstone Group may be deemed an "affiliate" of Cheniere Partners, as that term is defined in Exchange Act Rule 12b-2. We have received notice from Blackstone that it may include in its Annual Report on Form 10-K for the fiscal year ended December 31, 2014 disclosures pursuant to ITRA regarding one of its portfolio companies that may be deemed to be an affiliate of Blackstone Group. Because of the broad definition of "affiliate" in Exchange Act Rule 12b-2, this portfolio company of Blackstone Group, through Blackstone Group's ownership of Cheniere Partners, may also be deemed to be an affiliate of ours.

We have received notice from Blackstone Group that Travelport Limited ("Travelport") has engaged in the following activities: as part of its global business in the travel industry, Travelport provides certain passenger travel-related GDS and airline IT services to Iran Air and airline IT services to Iran Air Tours. The gross revenues and net profits attributable to such activities by Travelport during the fiscal year ended December 31, 2014 have not been reported by Travelport. Blackstone Group has informed us that Travelport intends to continue these business activities with Iran Air and Iran Air Tours as such activities are either exempt from applicable sanctions prohibitions or specifically licensed by the Office of Foreign Assets Control.

In our Form 10-Q reports for the quarterly periods ended on March 31, 2014, June 30, 2014 and September 30, 2014, we disclosed, under “Item 5. Other Information—Compliance Disclosure” in each such report, as amended, activities as required by Section 13(r) of the Exchange Act as transactions or dealings with the government of Iran that have not been specifically authorized by a U.S. federal department or agency. Such disclosures are incorporated herein by reference.

PART III

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

Management of Cheniere Energy Partners, L.P.

Cheniere Energy Partners GP, LLC (“Cheniere 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 MKT 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 MKT, respectively.

The audit committee assists the board of directors of our general partner in its oversight of the integrity of our 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 www.cheniere.com/corporate/audit_committee_charter_CQP.pdf.

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 MKT, 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.

Other

We do not have a nominating committee because the directors of our general partner manage our operations. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis. Unitholders are not entitled to elect the directors of our general partner or to participate directly or indirectly in our management or operations.

We also do not have a compensation committee. We have no employees, directors or officers. We are managed by our general partner, Cheniere 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

We have no employees, directors or officers. We are managed by our general partner, Cheniere GP. The following sets forth information, as of January 29, 2015, regarding the individuals who currently serve on the board of directors and as executive officers of our general partner. Charif Souki has served as a director of the general partner since 2006. Meg Gentle and Lon McCain have served as directors of the general partner since 2007. Keith Teague has served as a director of the general partner since 2008. Messrs. Ball, Foley, Klimczak, Pagano and Richard were elected as directors of the general partner in 2012. Philip Meier was elected a director of the general partner in July 2013. Michael Wortley was elected as a director of the general partner in January 2014. The appointments of Messrs. Foley, Klimczak and Meier to the board of directors of our general partner were made pursuant to the rights of Blackstone 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	Position with Our General Partner
Charif Souki	62	Director, Chairman of the Board and Chief Executive Officer
R. Keith Teague	50	Director, President and Chief Operating Officer
Michael J. Wortley	38	Director, Senior Vice President and Chief Financial Officer
James R. Ball	64	Director
David I. Foley	47	Director
Meg A. Gentle	40	Director
Sean T. Klimczak	38	Director
Lon McCain	66	Director
Philip Meier	55	Director
Vincent Pagano, Jr.	64	Director
Oliver G. Richard, III	62	Director

Charif Souki is Chairman of the Board of Directors and Chief Executive Officer of our general partner and has held such positions since January 2007. Mr. Souki, a co-founder of Cheniere, is Chairman of Cheniere's board of directors and Chief Executive Officer and President of Cheniere. In addition, Mr. Souki is Chairman, Chief Executive Officer, President and a director of Cheniere Energy Partners LP Holdings, LLC. Mr. Souki is also Chief Executive Officer of Sabine Pass Liquefaction, LLC and Chief Executive Officer and a manager of the general partner of Sabine Pass LNG, L.P. Since December 2002, Mr. Souki has been the Chief Executive Officer of Cheniere, and he was also President of Cheniere from that time until April 2005. He was re-elected as President in April 2008. From June 1999 to December 2002, he was Chairman of the board of directors of Cheniere and an independent investment banker. From September 1997 until June 1999, he was co-chairman of the board of directors of Cheniere, and he served as Secretary of Cheniere from July 1996 until September 1997. Mr. Souki has over 20 years of independent investment banking experience in the oil and gas industry and has specialized in providing financing for small capitalization companies with an emphasis on the oil and gas industry. Mr. Souki received a B.A. from Colgate University and an M.B.A. from Columbia University. It was determined that Mr. Souki should serve as a director of our general partner because he is the Chief Executive Officer of Cheniere, Cheniere GP, Sabine Pass Liquefaction and the general partner of Sabine Pass LNG, L.P. and is responsible for developing the companies' overall strategy and vision and implementing the business plans. In addition, with 20 years of experience as an investment banker specializing in the oil and gas industry, Mr. Souki brings a unique perspective to the board of directors of the general partner. Mr. Souki has not held any other directorship positions in the past five years.

R. Keith Teague is President and Chief Operating Officer and a director of our general partner and has held such positions since June 2008. He has served as Executive Vice President-Asset Group of Cheniere since February 2014 and served as Senior Vice President-Asset Group from April 2008 to February 2014. Prior to April 2008, he served as Vice President-Pipeline Operations since May 2006. Mr. Teague has also served as President of CQH Holdings Company, LLC (formerly known as Cheniere Pipeline Company), a wholly owned subsidiary of Cheniere, since January 2005. In addition, Mr. Teague is a director of Cheniere Energy Partners LP Holdings, LLC and President and a director of Sabine Pass Liquefaction, LLC. Mr. Teague is also President of the general partner of Sabine Pass LNG, L.P. and is responsible for the development, construction and operation of Cheniere's LNG terminal and pipeline assets. Mr. Teague began his career with Cheniere in February 2004 as Director of Facility Planning. Prior to joining Cheniere, Mr. Teague served as the Director of Strategic Planning for the CMS Panhandle Companies from December 2001 until September 2003. He began his career with Texas Eastern Transmission Corporation where he managed pipeline operations and facility expansion. Mr. Teague received a B.S. in civil engineering from Louisiana Tech University and an M.B.A.

from Louisiana State University. With Mr. Teague's knowledge and expertise relating to the Sabine Pass LNG terminal, it was determined that he should serve as a director of our general partner. Mr. Teague has not held any other directorship positions in the past five years.

Michael J. Wortley is Chief Financial Officer and a director of our general partner and has held such positions since January 2014. Mr. Wortley is Senior Vice President and Chief Financial Officer of Cheniere. He is also Chief Financial Officer and a director of Cheniere Energy Partners LP Holdings, LLC, a subsidiary of Cheniere. In addition, Mr. Wortley is the Chief Financial Officer of Sabine Pass Liquefaction and of the general partner of Sabine Pass LNG, L.P. He served as Vice President, Strategy and Risk of Cheniere from January 2013 to January 2014. Prior to January 2013, he served as Vice President–Business Development of Cheniere and President of Corpus Christi Liquefaction, LLC, a wholly owned subsidiary of Cheniere, since September 2011. Prior to September 2011, Mr. Wortley served as Cheniere's Vice President – Strategic Planning since January 2009 and its Manager – Strategic New Business since August 2007. 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, a publicly traded oil and gas exploration and production company. Mr. Wortley began his career as an Internal Auditor 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. degree 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. Mr. Wortley has not held any other directorship positions in the past five years.

James R. Ball is a director of our general partner, Chairman of the Executive Committee and a member of the Conflicts Committee. 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. Since 2011, Mr. Ball has served as a senior advisor to Tachebois Limited, an energy and equities advisory firm. 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.

David I. Foley is a director of our general partner. In addition, Mr. Foley is a director of Cheniere. Mr. Foley is a Senior Managing Director in the Private Equity Group of The Blackstone Group L.P., an investment and advisory firm, and Chief Executive Officer of Blackstone Energy Partners L.P. Prior to joining Blackstone in 1995, Mr. Foley was an employee of AEA Investors Inc., a private equity investment firm, from 1991 to 1993 and a consultant with The Monitor Company, a business management consulting firm, from 1989 to 1991. Mr. Foley received a B.A. and a Master of Arts in economics from Northwestern University and a Master of Business Administration from Harvard Business School. It was determined that Mr. Foley should serve as a director of our general partner because of his financial expertise and his experience in the energy industry. Mr. Foley currently serves as a director of Kosmos Energy Ltd.

Meg A. Gentle is a director of our general partner. Ms. Gentle is also a director of Cheniere Holdings. In addition, Ms. Gentle has served as Executive Vice President-Marketing of Cheniere since February 2014 and served as Senior Vice President-Marketing of Cheniere from June 2013 to February 2014. She previously served as Senior Vice President and Chief Financial Officer of Cheniere and our general partner from March 2009 to June 2013 and Senior Vice President of our general partner from June 2008 to March 2009. She served as Senior Vice President - Strategic Planning and Finance for Cheniere from February 2008 to March 2009. Prior to that time, she served as Cheniere's Vice President of Strategic Planning since September 2005 and Manager of Strategic Planning since June 2004. Prior to joining Cheniere, Ms. Gentle spent eight years in energy market development, economic evaluation and long-range planning. She conducted international business development and strategic planning for Anadarko Petroleum Corporation, an oil and natural gas exploration and production company, for six years and energy market analysis for Pace Global Energy Services, an energy management and consulting firm, for two years. Ms. Gentle received her B.A. in economics and international affairs from James Madison University and an M.B.A. from Rice University. It was determined that Ms. Gentle should serve as a director of our general partner because of her experience with strategic planning and finance in the energy industry and because of the perspective she brings as the former Chief Financial Officer of Cheniere, Cheniere GP and the general partner of Sabine Pass LNG, L.P. Ms. Gentle has not held any other directorship positions in the past five years.

Sean T. Klimczak is a director of our general partner. In addition, Mr. Klimczak is a director of Sabine Pass Liquefaction, LLC. Mr. Klimczak is a Senior Managing Director in the Private Equity Group of The Blackstone Group L.P., an investment and advisory firm. Prior to joining Blackstone in 2005, Mr. Klimczak was an Associate at Madison Dearborn Partners, a private equity investment firm, from 2001 to 2003 and an employee in the Mergers & Acquisitions department of the Investment Banking

division of Morgan Stanley, a financial services firm, from 1998 to 2001. Mr. Klimczak received a B.B.A. in finance and business economics from Notre Dame and a Master of Business Administration from Harvard Business School. It was determined that Mr. Klimczak should serve as a director of our general partner because of his significant investment experience with Blackstone. Mr. Klimczak has not held any other directorship positions in the past five years.

Lon McCain is a director of our general partner and serves as the Chairman of the Audit Committee and a member of the Conflicts Committee. He 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. During the past five years, he served as a director of Transzap, Inc., a privately held provider of digital data and electronic payment solutions. 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.

Philip Meier is a director of our general partner. Mr. Meier is president of Meier Consulting LLC and is currently providing technical and project management advice to Blackstone 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.

Vincent Pagano, Jr. is a director of our general partner and serves as Chairman of the Conflicts Committee and as 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 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. Mr. Pagano currently also serves as a director of L-3 Communications Holdings, Inc., a publicly traded defense company, and Hovnanian Enterprises, Inc., a publicly traded homebuilding company.

Oliver G. Richard, III is a director of our general partner and serves as a member of the Audit Committee and Conflicts Committee. Mr. Richard has served as Chairman of Cleanfuel USA, an alternative vehicular fuel company, since September 2007 and, for the past five years, he has been the owner and president of Empire of the Seed LLC, a private consulting firm in the energy and management industries. 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 Federal Energy Regulatory Commission from 1982 until 1985. 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. 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.

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 is posted at www.cheniere.com. We also intend

to post any 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 2014 in a timely manner, except that Messrs. Ball and Richard each had one late Form 4 filing relating to the vesting of two prior grants of phantom units and a new grant of phantom units.

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, 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 non-accountable overhead reimbursement charge of \$2.8 million per quarter (indexed for inflation). For a description of the services agreement, see [Note 9—Related Party Transactions](#) of our Notes to Consolidated Financial Statements.

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:

Charif Souki
R. Keith Teague
Michael J. Wortley
James R. Ball
David I. Foley
Meg A. Gentle
Sean T. Klimczak
Lon McCain
Philip Meier
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 2014.

Director Compensation

On May 29, 2007, the board of directors of our general partner approved an annual fee of \$50,000 to each non-management director of our general partner for services as a director. 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; and \$5,000 for the chairman of the conflicts committee. 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; and \$2,500 per meeting for the non-employee members of the executive committee, including the chairman. 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, Mr. Ball received retroactive meeting fees of \$25,000 for his service on the Executive Committee and the special CMI SPA Committee of the Board. In addition to the annual fees paid to the non-management directors, when they joined the board of directors Messrs. Ball, McCain, Pagano and Richard each received 12,000 phantom units pursuant to the terms of the Cheniere Energy Partners, L.P. Long-Term Incentive Plan. The grant date for each grant is as follows: May 29, 2007 for Mr. McCain, September 7, 2012 for Messrs. Ball and Richard and December 7, 2012 for Mr. Pagano. Each of these directors will receive an additional 3,000 phantom units annually on each anniversary of the grant date. 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. Foley is a Senior Managing Director and Mr. Klimczak is a Managing Director in the Private Equity Group of The Blackstone Group L.P. 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 Holding Company L.P. ("Blackstone") pursuant to which Mr. Meier agreed to provide consulting services to Blackstone 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 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 2014 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
Charif Souki (2)	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
R. Keith Teague (2)	—	—	—	—	—	—	—
Michael J. Wortley (2)	—	—	—	—	—	—	—
H. Davis Thames (2)	—	—	—	—	—	—	—
James R. Ball (3)	87,038	98,040	—	—	—	—	185,078
David I. Foley (4)	—	—	—	—	—	—	—
Meg A. Gentle (2)	—	—	—	—	—	—	—
Sean T. Klimczak (4)	—	—	—	—	—	—	—
Lon McCain (5)	86,359	100,980	—	—	—	—	187,339
Philip Meier (6)	—	—	—	—	—	—	—
Vincent Pagano, Jr. (7)	77,948	89,310	—	—	—	—	167,258
Oliver G. Richard, III (8)	71,359	98,040	—	—	—	—	169,399

- (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. Souki and Mr. Teague served as executive officers of our general partner and as executive officers of Cheniere during fiscal year 2014. Ms. Gentle served as an executive officer of Cheniere during fiscal year 2014. Mr. Wortley served as an executive officer of our general partner and as an executive officer of Cheniere since January 2014. Mr. Thames served as an executive officer of our general partner and as an executive officer of Cheniere until January 2014. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. They do not receive additional compensation for service as directors.
- (3) Mr. Ball was granted 3,000 phantom units in 2014 with a grant date fair value of \$98,040. In addition, Mr. Ball received \$98,040 in cash and 750 common units on account of 3,750 phantom units granted in earlier years that vested in September 2014. As of December 31, 2014, he held 11,250 phantom units and 750 common units.
- (4) Messrs. Foley and Klimczak are Senior Managing Directors in the Private Equity Group of The Blackstone Group L.P. and they do not receive additional compensation for service as directors.
- (5) Mr. McCain was granted 3,000 phantom units in 2014 with a grant date fair value of \$100,980. In addition, Mr. McCain received \$100,980 in cash on account of 3,000 phantom units granted in earlier years that vested in May 2014. As of December 31, 2014, he held 7,500 phantom units.
- (6) Mr. Meier is compensated by Blackstone 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.
- (7) Mr. Pagano was granted 3,000 phantom units in 2014 with a grant date fair value of \$89,310. In addition, Mr. Pagano received \$100,474 in cash and 375 common units on account of 3,750 phantom units granted in earlier years that vested in December 2014. As of December 31, 2014, he held 11,250 phantom units and 375 common units.
- (8) Mr. Richard was granted 3,000 phantom units in 2014 with a grant date fair value of \$98,040. In addition, Mr. Richard received \$122,550 in cash on account of 3,750 phantom units granted in earlier years that vested in September 2014. As of December 31, 2014, he held 11,250 phantom 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 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 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 January 29, 2015, the following units were outstanding: 57,079,973 common units, 135,383,831 subordinated units and 145,333,334 Class B units. In addition, as of January 29, 2015, there were 6,893,819 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, Class B units, subordinated units and/or general partner units as of January 29, 2015:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Class B Units Beneficially Owned	Percentage of Class B Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Securities Beneficially Owned
Cheniere Energy, Inc. (1)	11,963,488	21%	45,333,334	31%	135,383,831	100%	58%
Cheniere Energy Partners LP Holdings, LLC	11,963,488	21%	45,333,334	31%	135,383,831	100%	56%
Blackstone CQP Holdco LP (2)	—	—	100,000,000	69%	—	—	29%

(1) Cheniere Energy, Inc. is the parent company of Cheniere Energy Partners LP Holdings, LLC and may, therefore, be deemed to beneficially own the units held by Cheniere Energy Partners LP Holdings, LLC. Cheniere Energy, Inc. owns approximately 80% of the outstanding common shares of Cheniere Energy Partners LP Holdings, LLC, as well as the sole share of that entity authorized to elect its directors. Cheniere Energy, Inc. also owns 6,893,819 of our general partner units.

(2) The address is 345 Park Avenue, 44th floor, New York, New York 10154.

Directors and Executive Officers

The following table sets forth information with respect to our common units owned of record and beneficially as of January 29, 2015, by each director and executive officer of our general partner and by all directors and executive officers of our general

partner as a group. On January 29, 2015, the directors and executive officers of Cheniere Partners beneficially owned an aggregate of 410,760 common units (approximately 1% of the outstanding common units at the time).

The table also presents the ownership of common shares of Cheniere Energy Partners LP Holdings, LLC and shares of common stock of Cheniere Energy, Inc. owned of record or beneficially as of January 29, 2015, by each director and executive officer of our general partner and by all directors and executive officers of our general partner as a group. Cheniere Energy Partners LP Holdings, LLC owns a majority interest in Cheniere Partners. Cheniere Energy, Inc. owns a majority interest in Cheniere Energy Partners LP Holdings, LLC. As of January 29, 2015, Cheniere Energy Partners LP Holdings, LLC had 231,700,000 common shares outstanding and Cheniere Energy, Inc. had 236,710,964 shares of common stock outstanding.

Name of Beneficial Owner	Cheniere Energy Partners, L.P.		Cheniere Energy Partners LP Holdings, LLC		Cheniere Energy, Inc.	
	Amount and Nature of Beneficial Ownership	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class	Amount and Nature of Beneficial Ownership	Percent of Class
Charif Souki	400,100 (1)	1%	—	—	5,176,327 (2)	2%
R. Keith Teague	—	—	—	—	737,221	*
Meg A. Gentle	8,035	*	—	—	1,383,370	1%
James R. Ball	750	*	—	—	—	—
David I. Foley (3)	—	—	—	—	—	—
Sean T. Klimczak (3)	—	—	—	—	—	—
Lon McCain	—	—	—	—	—	—
Vincent Pagano, Jr.	375	*	—	—	—	—
Michael J. Wortley (4)	1,000	*	—	—	425,787 (5)	*
H. Davis Thames (4)(6)	500	*	—	—	785,416	*
Philip Meier	—	—	—	—	—	—
Oliver G. Richard, III	—	—	—	—	—	—
All directors and executive officers as a group (12 persons)	410,760	1%	—	—	8,508,121	4%

* Less than 1%

- (1) Includes 400,100 units held by Mr. Souki's wife.
- (2) Includes 300,000 shares held by trust. Some of the shares held by Mr. Souki have been pledged as collateral.
- (3) Messrs. Foley and Klimczak were appointed as directors of our general partner pursuant to an investors' rights agreement entered into in connection with Blackstone CQP Holdco LP's purchase of Class B units.
- (4) As of January 14, 2014, Mr. Wortley replaced Mr. Thames as Chief Financial Officer and a director of our general partner.
- (5) Includes 1,500 shares issuable upon exercise of currently exercisable stock options held by Mr. Wortley.
- (6) Includes information reported to us as of March 7, 2014. Mr. Thames left Cheniere on March 7, 2014 and is no longer required to report his holding pursuant to Section 16(a) of the Exchange Act.

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, 2014 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	—	N/A	1,235,000
Total	—	N/A	1,235,000

- (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.

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 9—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 Chief 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.

ISDA Master Agreement

In September 2007, Cheniere Marketing and Sabine Pass LNG entered into an International Swaps and Derivatives Association (“ISDA”) Master Agreement that provides Sabine Pass LNG with the ability to hedge its future price risk from time to time. The ISDA Master Agreement was entered into in the event Sabine Pass LNG chooses to hedge some of its LNG purchases or gas sales and elects to implement such hedges through Cheniere Marketing, which already has ISDA agreements in place with third parties and accounts with futures brokers. There are no current transactions under this agreement. No amounts were paid to Cheniere Marketing under this agreement during the year ended December 31, 2014.

LNG Terminal Export Agreement

In January 2010, Sabine Pass LNG and Cheniere Marketing entered into an LNG Terminal Export Agreement that provides Cheniere Marketing the ability to export LNG from the Sabine Pass LNG terminal. Sabine Pass LNG recorded revenues—affiliate of zero pursuant to this agreement in the year ended December 31, 2014.

The following related-party transactions were not approved by the board of directors or audit committee of our general partner:

Letter Agreement regarding the Cooperative Endeavor Agreement and Payment in Lieu of Taxes Agreement

In July 2007, Sabine Pass LNG entered into Cooperative Endeavor Agreements with various Cameron Parish, Louisiana taxing authorities and a related agreement with Cheniere Marketing, each as described in [Note 9—Related Party Transactions](#) of our Notes to Consolidated Financial Statements. During the year ended December 31, 2014, Cheniere Marketing paid Sabine Pass LNG \$2.5 million under the agreement.

Temporary Pipeline Compressor Sharing Agreement

In August 2010, Sabine Pass LNG entered into an agreement with its TUA customers, including Cheniere Investments, to share in the cost for the installation and operation of a temporary pipeline compressor at the Sabine Pass LNG terminal. Sabine Pass LNG recorded costs of zero under this agreement in the year ended December 31, 2014. During the year ended December 31, 2014, Sabine Pass LNG recorded revenues—affiliate from Cheniere Investments of zero pursuant to this agreement.

Arrangements involving Mr. Meier and Meier Consulting LLC

As noted above, Blackstone, 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 relating to the development, construction and operation of the Liquefaction Project. As compensation for the consulting services, Blackstone agreed to pay Mr. Meier an annual base consulting fee of \$375,000 per year and an annual performance consulting fee of up to \$200,000 per year in Blackstone’s discretion. The annual performance consulting fee with respect to 2014 was \$125,000. The consulting arrangement between Blackstone and Mr. Meier may be terminated by Blackstone for cause or by either party upon 30 days’ advance written notice.

In addition, Blackstone agreed to pay Mr. Meier the following fees upon the substantial completion of each of Trains 1 through 4 of the Liquefaction Project, provided Mr. Meier continues to provide consulting services through such time: (a) upon the substantial completion of Train 1, an amount equal to the product of (1) 83,333, (2) 15% and (3) the fair market value of one of our common units as of that date; (b) upon the substantial completion of Train 2, an amount equal to the product of (1) 83,333, (2) 15% and (3) the fair market value of one of our common units as of that date; (c) upon the substantial completion of Train 3, an amount equal to the product of (1) 83,333, (2) 30% and (3) the fair market value of one of our common units as of that date; and (d) upon the substantial completion of Train 4, an amount equal to (1) the product of 83,333 and the fair market value of one of our common units as of that date, less (2) the sum of all payments made with respect to the substantial completion of each of Trains 1 through 3.

We entered into a letter agreement with Blackstone (the “Blackstone Consultant Letter Agreement”), dated June 23, 2013, pursuant to which we agreed to reimburse Blackstone 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 pursuant to the Meier Consulting Letter Agreement. We did not reimburse Blackstone for any fees and expenses with respect to 2014 under the Blackstone Consultant Letter Agreement.

Independent Directors

Because we are a limited partnership, the NYSE MKT 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 MKT. The board of our general partner has determined that Messrs. Ball, McCain, Pagano and Richard are independent directors in accordance with the following NYSE MKT 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 year ended December 31, 2014 and Ernst & Young LLP served as our independent auditor for the fiscal year ended December 31, 2013. The following table (in thousands) sets forth the fees paid to the respective independent auditors for professional services rendered for 2014 and 2013:

	Fiscal 2014	Fiscal 2013
Audit Fees	\$ 2,190	\$ 2,875

Audit Fees—Audit fees for 2014 and 2013 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, consents and due diligence on SEC comment letters.

There were no audit-related, tax or other fees in 2014 and 2013.

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, 2014 and 2013 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.	56
Reports of Independent Registered Public Accounting Firm—KPMG LLP	57
Report of Independent Registered Public Accounting Firm—Ernst & Young LLP	59
Consolidated Balance Sheets	60
Consolidated Statements of Operations	61
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Consolidated Statements of Partners’ Equity	63
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Supplemental Information to Consolidated Financial Statements—Quarterly Financial Data	93

(2) Financial Statement Schedules:

Schedule I—Condensed Financial Information of Registrant for the years ended December 31, 2014, 2013 and 2012	118
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(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 (Incorporated by reference to Exhibit 10.4 to Cheniere Energy Partners, L.P.’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 Cheniere Energy Partners, L.P., Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.2 to Cheniere Energy Partners, L.P.’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 Cheniere Energy Partners, L.P. (Incorporated by reference to Exhibit 3.1 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on December 21, 2006)
3.2	Third Amended and Restated Agreement of Limited Partnership of Cheniere Energy Partners, L.P., dated as of August 9, 2012 (Incorporated by reference to Exhibit 3.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
3.3	Certificate of Formation of Cheniere Energy Partners GP, LLC (Incorporated by reference to Exhibit 3.3 to Cheniere Energy Partners, L.P.'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 Energy Partners GP, LLC, dated as of August 9, 2012 (Incorporated by reference to Exhibit 3.2 to Cheniere Energy Partners, L.P.'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 November 9, 2006, between Sabine Pass LNG, L.P., as issuer, and The Bank of New York, as trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
4.3	Form of 7.50% Senior Secured Note due 2016 (Included as Exhibit A1 to Exhibit 4.2 above)
4.4	Indenture, dated as of October 16, 2012, by and among Sabine Pass LNG, L.P., 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 Sabine Pass LNG L.P.'s Current Report on Form 8-K (SEC File No. 001-138916), filed on October 19, 2012)
4.5	Form of 6.5% Senior Secured Note due 2020 (Included as Exhibit A1 to Exhibit 4.4 above)
4.6	Indenture, dated as of February 1, 2013, by and among Sabine Pass Liquefaction, LLC, 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 Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on February 4, 2013)
4.7	First Supplemental Indenture, dated as of April 16, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366, filed on April 16, 2013)
4.8	Second Supplemental Indenture, dated as of April 16, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.2 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366, filed on April 16, 2013)
4.9	Third Supplemental Indenture, dated as of November 25, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366, filed on November 25, 2013)
4.10	Fourth Supplemental Indenture, dated as of May 20, 2014, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.11	Fifth Supplemental Indenture, dated as of May 20, 2014, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.2 to Cheniere Energy Partners, L.P.'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 2021 (Included as Exhibit A-1 to Exhibit 4.6 above)
4.13	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.8 above)
4.14	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.9 above)
4.15	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.10 above)
10.1	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to Cheniere Energy, Inc.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.40 to Cheniere Energy, Inc.'s Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005)

Exhibit No.	Description
10.3	Amendment of LNG Terminal Use Agreement, dated June 15, 2010, by and between Total Gas & Power North America, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to Cheniere Energy, Inc.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to Cheniere Energy, Inc.'s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004)
10.5	Parent Guaranty, dated as of November 5, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to Cheniere Energy, Inc.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to Cheniere Energy, Inc.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.28 to Sabine Pass LNG, L.P.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to Cheniere Energy, Inc.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to Cheniere Energy, Inc.'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 Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to Sabine Pass LNG, L.P.'s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.12	Second Amended and Restated Terminal Use Agreement, dated as of July 31, 2012, between Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.1 to Sabine Pass LNG, L.P.'s Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.13	Guarantee Agreement, dated as of July 31, 2012, by Cheniere Energy Partners, L.P. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to Sabine Pass LNG, L.P.'s Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.14	Letter Agreement, dated May 28, 2013, by and between Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.1 to Sabine Pass LNG, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 333-138916), filed on August 2, 2013)
10.15	Collateral Trust Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, Sabine Pass LNG-GP, Inc. and Sabine Pass LNG-LP, LLC (Incorporated by reference to Exhibit 10.1 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.16	Amended and Restated Parity Lien Security Agreement, dated November 9, 2006, by and between Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.2 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.17	Third Amended and Restated Multiple Indebtedness Mortgage, Assignment of Rents and Leases and Security Agreement, dated November 9, 2006, between Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.3 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.18	Amended and Restated Parity Lien Pledge Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., Sabine Pass LNG-GP, Inc., Sabine Pass LNG-LP, LLC and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.4 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)
10.19	Security Deposit Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, and The Bank of New York, as depository agent (Incorporated by reference to Exhibit 10.5 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006)

Exhibit No.	Description
10.20	Amended and Restated Common Terms Agreement, dated as of May 28, 2013, among Sabine Pass Liquefaction, LLC, as borrower, the Secured Debt Holder Group Representatives, Secured Hedge Representatives and Secured Gas Hedge Representatives from time to time party thereto, and Société Générale, as the common security trustee and intercreditor agent (Incorporated by reference to Exhibit 10.5 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.21	KEXIM Direct Facility Agreement, dated as of May 28, 2013, among Sabine Pass Liquefaction, LLC, as borrower, KEB NY Financial Corp., as the KEXIM Facility Agent, Société Générale, as the common security trustee, and The Export-Import Bank of Korea (Incorporated by reference to Exhibit 10.2 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.22	KEXIM Covered Facility Agreement, dated as of May 28, 2013, among Sabine Pass Liquefaction, LLC, as borrower, KEB NY Financial Corp., as the KEXIM Facility Agent, Société Générale, as the common security trustee, The Export-Import Bank of Korea and the other lenders from time to time party thereto (Incorporated by reference to Exhibit 10.3 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.23	KSURE Covered Facility Agreement, dated as of May 28, 2013, among Sabine Pass Liquefaction, LLC, as borrower, The Korea Development Bank, New York Branch, as the KSURE Covered Facility Agent, Société Générale, as the common security trustee, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.4 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.24	Credit Agreement, dated as of May 28, 2013, among Cheniere Creole Trail Pipeline, L.P., as borrower, the lenders party thereto from time to time, Morgan Stanley Senior Funding, Inc., as administrative agent, The Bank of New York Mellon, as collateral agent, and The Bank of New York Mellon, as depositary bank (Incorporated by reference to Exhibit 10.6 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.25	Amended and Restated Credit Agreement (Term Loan A), dated as of May 28, 2013, among Sabine Pass Liquefaction, LLC, as borrower, Société Générale, as the commercial banks facility agent and common security trustee, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on 8-K (SEC File No. 001-33366), filed on May 29, 2013)
10.26	Senior Letter of Credit and Reimbursement Agreement, dated as of April 21, 2014, among Sabine Pass Liquefaction, LLC, as Borrower, The Bank of Nova Scotia, as Senior Issuing Bank and Senior LC Facility Administrative Agent, Société Générale, as Common Security Trustee and the lenders named therein, as Senior LC Lenders (Incorporated by reference to Exhibit 10.1 to Sabine Pass Liquefaction, LLC's Current Report on Form 8-K (SEC File No. 333-192373), filed on April 25, 2014)
10.27†	Form of Director Units Option Agreement for employees and consultants (four-year) (Incorporated by reference to Exhibit 10.41 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.28†	Form of Phantom Units Agreement for employees, consultants and directors (four-year) (Incorporated by reference to Exhibit 10.44 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.29†	Form of Phantom Units Agreement for employees, consultants and directors (three-year) (Incorporated by reference to Exhibit 10.45 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.30†	Form of Restricted Units Agreement for employees, consultants and directors (four-year) (Incorporated by reference to Exhibit 10.40 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.31†	Form of Restricted Units Agreement for employees, consultants and directors (three-year) (Incorporated by reference to Exhibit 10.39 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.32†	Form of Units Option Agreement for employees and consultants (four-year) (Incorporated by reference to Exhibit 10.43 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.33†	Form of Units Option Agreement for employees and consultants (three-year) (Incorporated by reference to Exhibit 10.42 to Cheniere Energy Partners, L.P.'s Registration Statement on Form S-1 (SEC File No. 333-139572), filed on March 2, 2007)
10.34†	Cheniere Energy Partners, L.P. 2007 Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.3 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on March 26, 2007)

Exhibit No.	Description
10.35†	Form of Phantom Units Agreement (Incorporated by reference to Exhibit 10.2 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on June 4, 2007)
10.36†	Summary of Compensation for Independent Directors (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on June 4, 2007)
10.37†	Form of Indemnification Agreement for officers and/or directors of Cheniere Energy Partners GP, LLC (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on April 6, 2009)
10.38†	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 Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.39†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.8 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.40†	Form of Amendment to Phantom Units Agreement (Incorporated by reference to Exhibit 10.7 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.41*†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Units Settlement)
10.42*†	Form of Phantom Units Agreement under the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (Reload Units Settlement)
10.43†	Meg Gentle's Assignment Letter, dated July 30, 2013 (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on July 30, 2013)
10.44	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement, dated October 23, 2007 (Incorporated by reference to Exhibit 10.7 to Cheniere Energy, Inc.'s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.45	LNG Lease Agreement, dated June 24, 2008, between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to Cheniere Energy, Inc.'s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 11, 2008)
10.46	LNG Lease Agreement, dated September 30, 2011, by and between Cheniere Marketing, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.3 to Cheniere Energy, Inc.'s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2011)
10.47	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to the a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on November 14, 2011)
10.48	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0001 EPC Terms and Conditions, dated May 1, 2012, (ii) the Change Order CO-0002 Heavies Removal Unit, dated May 23, 2012, (iii) the Change Order CO-0003 LNTP, dated June 6, 2012, (iv) the Change Order CO-0004 Addition of Inlet Air Humidification, dated July 10, 2012, (v) the Change Order CO-0005 Replace Natural Gas Generators with Diesel Generators, dated July 10, 2012, (vi) the Change Order CO-0006 Flange Reduction and Valve Positioners, dated June 20, 2012, and (vii) the Change Order CO-0007 Relocation of Temporary Facilities, Power Poles Relocation Reimbursement, and Duck Blind Road Improvement Reimbursement, dated July 13, 2012 (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 3, 2012)
10.49	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0008 Delay in Full Placement of Insurance, dated July 27, 2012, (ii) the Change Order CO-0009 HAZOP Action Items, dated July 31, 2012, (iii) the Change Order CO-00010 Fuel Provisional Sum, dated August 8, 2012, (iv) the Change Order CO-00011 Currency Provisional Sum, dated August 8, 2012, (v) the Change Order CO-00012 Delay in NTP, dated August 8, 2012, and (vi) the Change Order CO-00013 Early EPC Work Credit, dated August 29, 2012 (Incorporated by reference to Exhibit 10.2 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)

Exhibit No.	Description
10.50	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00014 Bundle of Changes, dated September 5, 2012, (ii) the Change Order CO-00015 Static Mixer, Air Cooler Walkways, etc., dated November 8, 2012, (iii) the Change Order CO-0016 Delay in Full Placement of Insurance, dated October 29, 2012, (iv) the Change Order CO-00017 Condensate Header, dated December 3, 2012 and (v) the Change Order CO-00018 Increase in Power Requirements, dated January 17, 2013 (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 10.26 to Cheniere Energy Partners, L.P.'s Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.51	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00019 Delete Tank 6 Scope of Work, dated February 27, 2013 and (ii) the Change Order CO-00020 Modification to Builder's Risk Insurance Sum Insured Value, dated March 14, 2013 (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 10.2 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013)
10.52	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00021 Increase to Insurance Provisional Sum, dated April 17, 2013, (ii) the Change Order CO-00022 Removal of LNG Static Mixer Scope, dated May 8, 2013, (iii) the Change Order CO-00023 Revised LNG Rundown Line, dated May 30, 2013, (iv) the Change Order CO-00024 Reroute Condensate Header, Substation HVAC Stacks, Inlet Metering Station Pile Driving, dated June 11, 2013 and (v) the Change Order CO-00025 Feed Gas Connection Modifications, dated June 11, 2013 (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 10.45 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (SEC File No. 333-191298), filed on October 18, 2013)
10.53	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00026 Bundle of Changes, dated June 28, 2013, (ii) the Change Order CO-00027 16" Water Pumps, dated July 12, 2013, (iii) the Change Order CO-00028 HRU Operability, dated July 26, 2013, (iv) the Change Order CO-00029 Belleville Washers, dated August 14, 2013 and (v) the Change Order CO-00030 Soils Preparation Provisional Sum Transfer, dated August 29, 2013 (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 Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 8, 2013)
10.54	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00031 LNG Intake Pump Replacement Scope Reduction/OSBL Additional Piling for the Cathodic Protection Rectifier Platform and Drum Storage Shelter dated October 15, 2013 (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 10.35 to Sabine Pass Liquefaction, LLC's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on January 28, 2014)
10.55	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00032 Intra-Plant Feed Gas Header and Jefferson Davis Electrical Distribution, dated January 9, 2014, (ii) the Change Order CO-00033 Revised EPC Agreement Attachments S & T, dated March 24, 2014 and (iii) the Change Order CO-00034 Greenfield/Brownfield Demarcation Adjustment, dated February 19, 2014 (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 Sabine Pass Liquefaction, LLC's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 1, 2014)
10.56	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00035 Resolution of FERC Open Items, Additional FERC Support Hours and Greenfield/Brownfield Milestone Adjustment, dated May 9, 2014 (Incorporated by reference to Exhibit 10.3 to Sabine Pass Liquefaction, LLC's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 31, 2014)

Exhibit No.	Description
10.57	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00036 Future Tie-Ins and Jeff Davis Invoices, dated July 9, 2014 (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 10.23 to Sabine Pass Liquefaction, LLC's Registration on Form S-4 (SEC File No. 333-198358) filed on August 26, 2014)
10.58	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00037 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated October 31, 2014 and (ii) the Change Order CO-00038 Control Room Modifications and Miscellaneous Items, dated January 6, 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 10.26 to Sabine Pass Liquefaction LLC's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2015)
10.59	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated December 20, 2012, by and between Sabine Pass Liquefaction, LLC 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 Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on December 27, 2012)
10.60	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0001 Electrical Station HVAC Stacks, dated June 4, 2013, (ii) the Change Order CO-0002 Revised LNG Rundown Line, dated May 30, 2013, (iii) the Change Order CO-0003 Currency Provisional Sum Closure, dated May 30, 2013 and (iv) the Change Order CO-0004 Fuel Provisional Sum Closure, dated June 4, 2013 (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 10.48 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (SEC File No. 333-191298), filed on October 18, 2013)
10.61	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0005 Credit to EPC Contract Value for TSA Work, dated June 24, 2013, (ii) the Change Order CO-0006 HRU Operability with Lean Gas & Controls Upgrade and Ultrasonic Meter Configuration and Calibration, (iii) the Change Order CO-0007 Additional Belleville Washers, dated August 15, 2013, (iv) the Change Order CO-0008 GTG Switchgear Arrangement/Upgrade Fuel Gas Heater System, dated August 26, 2013, (iv) the Change Order CO-0009 Soils Preparation Provisional Sum Transfer and Closure, dated August 26, 2013 (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 10.49 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (SEC File No. 333-191298), filed on October 18, 2013)
10.62	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00010 Insurance Provisional Sum Adjustment, dated January 23, 2014, (ii) the Change Order CO-00011 Additional Stage 2 GTGs, dated January 23, 2014, (iii) the Change Order CO-0012 Lien and Claim Waiver Modification, dated March 24, 2014 and (iv) the Change Order CO-00013 Revised Stage 2 EPC Agreement Attachments S&T, dated March 24, 2014 (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 10.2 to Sabine Pass Liquefaction, LLC's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 1, 2014)
10.63	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00014 Additional 13.8kv Circuit Breakers and Misc. Items, dated July 14, 2014 (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 10.28 to Sabine Pass Liquefaction, LLC's Registration on Form S-4 (SEC File No. 333-198358) filed on August 26, 2014)

Exhibit No.	Description
10.64	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00015 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated October 31, 2014 (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 10.32 to Sabine Pass Liquefaction LLC's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2015)
10.65	LNG Sale and Purchase Agreement (FOB), dated November 21, 2011, between Sabine Pass Liquefaction, LLC (Seller) and Gas Natural Aproveisionamientos SDG S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on November 21, 2011)
10.66	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated April 3, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Gas Natural Aproveisionamientos SDG S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013)
10.67	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between Sabine Pass Liquefaction, LLC (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on December 12, 2011)
10.68	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between Sabine Pass Liquefaction, LLC (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.18 to Cheniere Energy Partners, L.P.'s Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.69	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between Sabine Pass Liquefaction, LLC (Seller) and BG Gulf Coast LNG, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on January 26, 2012)
10.70	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between Sabine Pass Liquefaction, LLC (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on January 30, 2012)
10.71	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.19 to Cheniere Energy Partners, L.P.'s Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.72	LNG Sale and Purchase Agreement (FOB), dated December 14, 2012, between Sabine Pass Liquefaction, LLC (Seller) and Total Gas & Power North America, Inc. (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on December 17, 2012)
10.73	LNG Sale and Purchase Agreement (FOB), dated March 22, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Centrica plc (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on March 25, 2013)
10.74	LNG Sale and Purchase Agreement (FOB), dated December 4, 2013, between Sabine Pass Liquefaction, LLC (Seller) and PT PERTAMINA (PERSERO) (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on December 5, 2013)
10.75	Omnibus Agreement, dated December 4, 2013, among Cheniere Energy, Inc., Corpus Christi Liquefaction, LLC and PT PERTAMINA (PERSERO) (Incorporated by reference to Exhibit 10.2 to Cheniere Energy, Inc.'s Current Report on Form 8-K (SEC File No. 001-16383), filed on December 5, 2013)
10.76	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between Sabine Pass Liquefaction, LLC and Cheniere Marketing, LLC (Incorporated by reference to Exhibit 10.1 to Sabine Pass Liquefaction's Current Report on Form 8-K (SEC File No. 333-192373), filed on August 11, 2014)
10.77	Management Services Agreement, dated May 14, 2012, by and between Cheniere LNG Terminals, LLC and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.6 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.78	Operation and Maintenance Agreement (Sabine Pass Liquefaction Facilities), dated May 14, 2012, by and among Cheniere LNG O&M Services, LLC, Cheniere Energy Partners GP, LLC and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.5 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)

Exhibit No.	Description
10.79	Assignment and Assumption Agreement (Sabine Pass Liquefaction O&M Agreement), dated as of November 20, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.76 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (File No. 333-191298) filed on December 2, 2013)
10.80	Amended and Restated Management and Administrative Services Agreement, dated as of August 9, 2012, by and between Cheniere Energy Partners, L.P., Cheniere LNG Terminals, LLC and Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.4 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.81	Amended and Restated Management Services Agreement, dated as of August 9, 2012, by and between Cheniere LNG Terminals, LLC and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.6 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.82	Amended and Restated Operation and Maintenance Agreement (Sabine Pass LNG Facilities), dated as of August 9, 2012, by and among Cheniere LNG O&M Services, LLC, Cheniere Energy Partners GP, LLC and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.83	Assignment and Assumption Agreement (Sabine Pass LNG O&M Agreement), dated as of November 20, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.75 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (File No. 333-191298) filed on December 2, 2013)
10.84	Amended and Restated Services and Secondment Agreement, dated as of August 9, 2012, between Cheniere LNG O&M Services, LLC and Cheniere Energy Partners GP, LLC (Incorporated by reference to Exhibit 10.3 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012)
10.85	Assignment and Assumption Agreement (Services and Secondment Agreement), dated as of November 20, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.73 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (File No. 333-191298) filed on December 2, 2013)
10.86	Amended and Restated Operation and Maintenance Services Agreement, dated May 27, 2013, by and between Cheniere Energy Partners GP, LLC and Cheniere Creole Trail Pipeline, L.P. (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366) filed on August 2, 2013)
10.87	Assignment and Assumption Agreement (Creole Trail O&M Agreement), dated as of November 20, 2013, between Cheniere Energy Partners GP, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.74 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (File No. 333-191298) filed on December 2, 2013)
10.88	Management Services Agreement, dated May 27, 2013, by and between Cheniere LNG Terminals, LLC and Cheniere Creole Trail Pipeline, L.P. (Incorporated by reference to Exhibit 10.2 to Cheniere Energy Partners, L.P.'s Quarterly Report on Form 10-Q (SEC File No. 001-33366) filed on August 2, 2013)
10.89	Waiver and Assignment of O&M Agreement; Amendment to Common Terms Agreement, dated November 20, 2013 (Incorporated by reference to Exhibit 10.77 to Cheniere Energy Partners LP Holdings, LLC's Registration Statement on Form S-1 (File No. 333-191298) filed on December 2, 2013)
10.90	Payment Deferral Agreement (O&M Agreement), dated March 27, 2014, between Cheniere Energy Investments, LLC and Cheniere LNG O&M Services, LLC (Incorporated by reference to Exhibit 10.5 to Cheniere Energy, Inc.'s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 1, 2014)
10.91	Class B Unit Purchase Agreement, dated as of May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, LLC (Incorporated by reference to Exhibit 10.2 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.92	First Amendment to Class B Unit Purchase Agreement, dated as of August 9, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere Class B Units Holdings, LLC (Incorporated by reference to Exhibit 10.3 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
10.93	Subscription Agreement, dated May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, LLC (Incorporated by reference to Exhibit 10.4 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)
10.94	Unit Purchase Agreement, dated May 14, 2012, by and among Cheniere Energy Partners, L.P., Cheniere Energy, Inc. and Blackstone CQP Holdco LP (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)

Exhibit No.	Description
10.95	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among Cheniere Energy, Inc., Cheniere Energy Partners, L.P., Cheniere Energy Partners GP, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on 8-K (SEC File No. 001-33366), filed on August 6, 2012)
10.96	Letter Agreement, dated as of August 9, 2012, among Cheniere Energy, Inc., Cheniere Energy Partners, L.P. and Blackstone CQP Holdco LP (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012)
21.1*	Subsidiaries of Cheniere Energy Partners, L.P.
23.1*	Consent of KPMG LLP
23.2*	Consent of Ernst & Young LLP
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and Rule 15d-14(a) under the Exchange Act
31.2*	Certification by Chief Financial Officer required by Rule 13a-14(a) and Rule 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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED BALANCE SHEETS
(in thousands)

		December 31,	
		2014	2013
ASSETS			
Current assets			
Cash and cash equivalents		\$ 222,130	\$ 314,782
Accounts receivable—affiliates		9,568	—
Prepaid expenses and other		104	112
Total current assets		<u>231,802</u>	<u>314,894</u>
Investment in affiliates		902,612	1,328,613
Other		123	—
Total assets		<u>\$ 1,134,537</u>	<u>\$ 1,643,507</u>
LIABILITIES AND PARTNERS' EQUITY			
Current liabilities			
Accrued liabilities—affiliates		\$ 3,033	\$ 3,135
Other current liabilities		775	628
Total current liabilities		<u>3,808</u>	<u>3,763</u>
Commitments and contingencies			
Partners' equity		<u>1,130,729</u>	<u>1,639,744</u>
Total liabilities and partners' equity		<u>\$ 1,134,537</u>	<u>\$ 1,643,507</u>

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

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
(in thousands)

	Year Ended December 31,		
	2014	2013	2012
Operating costs and expenses	\$ 3,383	\$ 3,041	\$ 7,074
Operating costs and expenses—affiliates	11,556	11,376	11,188
Loss from operations	(14,939)	(14,417)	(18,262)
Interest expense, net	—	—	12
Interest income	162	242	235
Equity loss of affiliates	(395,259)	(243,942)	(157,416)
Net loss	\$ (410,036)	\$ (258,117)	\$ (175,431)
Other comprehensive income (loss) attributable to affiliates	—	27,240	(27,240)
Comprehensive loss	\$ (410,036)	\$ (230,877)	\$ (202,671)

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

CHENIERE ENERGY PARTNERS, L.P.
CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities	\$ (24,416)	\$ (13,056)	\$ (17,508)
Cash flows from investing activities			
Investment in subsidiaries	(77,847)	(405,452)	(1,785,866)
Distributions received from affiliates, net	108,625	369,726	61,529
Purchase of Creole Trail Pipeline Business, net	—	(313,892)	—
Other	—	—	3
Net cash provided by (used in) investing activities	30,778	(349,618)	(1,724,334)
Cash flows from financing activities:			
Proceeds from sale of Class B units	—	—	1,887,342
Distributions to owners	(99,014)	(91,386)	(57,821)
Proceeds from sale of partnership common and general partner units	—	375,897	250,021
Deferred financing costs	—	—	(874)
Net cash provided by (used in) financing activities	(99,014)	284,511	2,078,668
Net increase (decrease) in cash and cash equivalents	(92,652)	(78,163)	336,826
Cash and cash equivalents—beginning of year	314,782	392,945	56,119
Cash and cash equivalents—end of year	\$ 222,130	\$ 314,782	\$ 392,945

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

CHENIERE ENERGY PARTNERS, L.P.

NOTES TO CONDENSED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The condensed financial statements represent the financial information required by Securities and Exchange Commission Regulation S-X 5-04 for Cheniere Energy Partners, L.P. (“Cheniere Partners”).

A substantial amount of Cheniere Partners’ operating, investing, and financing activities are conducted by its affiliates. In the condensed financial statements, Cheniere Partners’ investments in affiliates are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded in the balance sheets. The gain (loss) from operations of the affiliates is reported on a net basis as equity in net gains (losses) of affiliates.

In May 2013, we acquired Cheniere Energy, Inc.’s (“Cheniere”) ownership interest in Cheniere Creole Trail Pipeline, L.P. (“CTPL”) and Cheniere Pipeline GP Interest, LLC (collectively, the “Creole Trail Pipeline Business”), thereby providing us with ownership of a 94-mile pipeline interconnecting the Sabine Pass LNG terminal with a number of large interstate pipelines. The effect on reported equity on including the prior results of the Creole Trail Pipeline Business is reported as Investment in affiliates in our Condensed Balance Sheet and Equity loss of affiliates in our Condensed Statement of Operations. The purchase has been accounted for as a transfer of net assets between entities under common control. We recognize transfers of net assets between entities under common control at Cheniere’s historical basis in the net assets sold. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information.

The condensed financial statements should be read in conjunction with Cheniere Partners’ Consolidated Financial Statements.

NOTE 2—GUARANTEES

Guarantees on Behalf of CTPL

In May 2013, CTPL entered into the 2017 CTPL Term Loan, which is being used to fund modifications to the Creole Trail Pipeline and for general business purposes. CTPL incurred \$10.0 million of direct lender fees that were recorded as a debt discount. The 2017 CTPL Term Loan matures in 2017 when the full amount of the outstanding principal obligations must be repaid. CTPL’s loans may be repaid, in whole or in part, at any time without premium or penalty. As of December 31, 2014, CTPL had borrowed the full amount of \$400.0 million available under the 2017 CTPL Term Loan. Cheniere Partners has guaranteed on behalf of CTPL all principal, interest, costs, fees and expenses owed under the 2017 CTPL Term Loan.

NOTE 3—SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Non-cash capital contributions (1)	\$ (395,259)	\$ (225,792)	\$ (132,121)
Non-cash capital contributions related to the Creole Trail Pipeline Business (1)	—	(18,150)	(25,295)

(1) Amounts represent equity gains (losses) of affiliates not funded by Cheniere Partners.

PHANTOM UNITS AGREEMENT

*Pursuant to the terms of the
Cheniere Energy Partners, L.P. Long-Term Incentive Plan*

1. **Grant of Phantom Units.** Subject to and in accordance with the terms and conditions of this document, Cheniere Energy Partners GP, LLC, a Delaware limited liability company (“Company”), hereby awards to _____ (“Participant”) _____ phantom units, which are notional units of common units (“Units”) of Cheniere Energy Partners, L.P. (the “Partnership”) (the “Phantom Units”). This Phantom Units Agreement (“Phantom Units Agreement”) is dated as of _____, 20___. The Phantom Units are awarded pursuant to and to implement in part the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (as amended and in effect from time to time, the “Plan”) and are subject to the restrictions, forfeiture provisions and other terms and conditions of the Plan, which is hereby incorporated herein and is made a part hereof, and this Phantom Units Agreement. By execution of this Phantom Units Agreement, Participant agrees to be bound by all of the terms, provisions, conditions and limitations of the Plan as implemented by the Phantom Units Agreement, together with all rules and determinations from time to time issued by the Committee pursuant to the Plan. All capitalized terms have the meanings set forth in the Plan unless otherwise specifically provided herein. All references to specified paragraphs pertain to paragraphs of this Phantom Units Agreement unless otherwise provided.

2. **Risk of Forfeiture.** Participant shall immediately forfeit all rights to any Phantom Units which have not vested and with respect to which the restrictions thereon have not lapsed in the event of the termination, resignation, or removal of Participant from employment with or services to Company and its Affiliates under circumstances that do not cause Participant to become fully vested, and the restrictions on such Phantom Units to lapse, under the terms of the Plan and this Phantom Units Agreement.

3. **Restricted Period; Vesting.** Subject to the provisions of this Phantom Units Agreement including, without limitation, the provisions of Paragraph 4, Participant shall vest in his or her rights to the Phantom Units and the restrictions imposed thereon shall lapse as follows: 25% of the Phantom Units shall vest on the first anniversary of the date hereof, an additional 25% of the Phantom Units shall vest on the second anniversary of the date hereof, an additional 25% of the Phantom Units shall vest on the third anniversary of the date hereof and the remainder of the Phantom Units shall vest on the fourth anniversary of the date hereof. The period from the date hereof until the Phantom Units have become one hundred percent (100%) vested and the restrictions thereon have lapsed shall be referred to as the “Restricted Period.” If an installment of the vesting and release of Phantom Units from the Restricted Period covers a fractional Phantom Unit, such installment will be rounded to the next lower Phantom Unit, except the final installment, which will be for the balance of the total Phantom Units.

4. **Termination of Employment or Services; Change in Control.** Except as provided otherwise in this Paragraph 4, if Participant’s service with Company and its Affiliates shall be terminated for any reason, any unvested Phantom Units outstanding at the time of such termination and all rights thereunder shall be forfeited without payment under Paragraph 5 or 7 and no further vesting shall occur; provided however, that any Phantom Units not then vested shall vest upon the death or Disability of Participant. For purposes of this Phantom Units Agreement, the term “Disability” as it relates to Participant shall mean that Participant is “disabled” as described in accordance with Treasury Regulation Section 1.409A-3(i)(4) and Section 409A(a)(2)(C) of the Code.

In the event of a Change in Control, any Phantom Units not then vested shall vest upon the involuntary termination of Participant from service with Company and its Affiliates by the Company or an Affiliate without Cause within one (1) year from the effective date of such Change in Control. For purposes of this Phantom Units Agreement, the term "Cause" shall mean the commission of an act of fraud or intentional misrepresentation or an act of embezzlement, misappropriation or conversion of assets or opportunities of the Company or any Affiliate.

5. **Time and Form of Payment.** To the extent a Phantom Unit shall become fully vested and the restrictions imposed thereon shall have lapsed pursuant to Paragraph 3 or Paragraph 4, Participant shall receive payment for such vested Phantom Unit in the form of a Unit, the value of which will be based on the Fair Market Value of the Unit on the applicable vesting date. The issuance of a Unit in settlement of a vested Phantom Unit shall be made as soon as administratively practicable following the applicable vesting date, but in no event later than the thirtieth (30th) day following the date on which vesting occurs and the restrictions lapse with respect to such Phantom Unit. Should Participant die before receiving all Units required to be issued under this Paragraph 5 in settlement of vested Phantom Units, such Units shall be issued to Participant's estate. Participant's right to any payments in the form of Units described in this Paragraph 5 shall not rise above those of a general creditor of Company.

6. **Transferability.** Phantom Units shall not be transferable (by operation of law or otherwise) by Participant or any other person claiming through or under Participant, other than by Participant's will or the laws of descent or distribution. Any attempt to sell, assign, transfer, pledge, exchange, hypothecate, or otherwise dispose of any Phantom Units shall be void and unenforceable.

7. **Ownership Rights and Distribution Equivalent Rights.** A Phantom Unit is a notional Unit of Company and, as a result, does not provide or give rise to any right to a Unit or to receive the Fair Market Value of a Unit except as specifically provided in the Plan and this Phantom Units Agreement. During the Restricted Period, any distribution in the form of cash paid or delivered by the Partnership on a Unit shall not entitle Participant to an equal amount of cash with respect to each Phantom Unit.

8. **Adjustment of Units.** In the event of any distribution (whether in the form of cash, Common Units, other securities, or other property), recapitalization, split, reverse split, reorganization, merger, consolidation, split-up, spin-off, combination, repurchase, or exchange of Units or other securities of Partnership, issuance of warrants or other rights to purchase Units or other securities of Partnership, or other similar transaction or event affects the Units, then the Committee shall, in such manner as it may deem equitable, make adjustments to the terms and provisions of this Phantom Units Agreement pursuant to Section 4(c) of the Plan in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the Plan.

9. **Certain Restrictions.** By executing this Phantom Units Agreement, Participant agrees that if at the time of delivery of Units in settlement of the Phantom Units awarded hereunder any sale of the Units is not covered by an effective registration statement filed under the Securities Act of 1933 ("Act"), the Units so delivered may contain such legends as Company shall require and Participant will acquire the Units for Participant's own account and without a view to resale or distribution in violation of the Act or any other securities law, and upon any such acquisition Participant will enter into such written representations, warranties and agreements as Company may reasonably request in order to comply with the Securities Act of 1933 or any other securities law or with this Phantom Units Agreement. Participant agrees that Company shall not be obligated to take any affirmative action in order to cause the Phantom Units subject to this Phantom Units Agreement to comply with any law, rule or regulation.

10. **Amendment and Termination.** This Phantom Units Agreement may not be terminated by the Company at any time without the written consent of Participant. This Phantom Units Agreement may be amended in writing by Company and Participant, provided Company may amend this Phantom Units Agreement unilaterally (i) if the amendment does not adversely affect Participant's rights hereunder in any material respect, (ii) if Company determines that an amendment is necessary to comply with Rule 16b-3 under the Exchange Act or other applicable law, or (iii) if Company determines that an amendment is necessary to meet the requirements of the Code or to prevent adverse tax consequences to Participant. No amendment or termination of the Plan will adversely affect the rights and privileges of Participant under this Phantom Units Agreement or to the Phantom Units granted hereunder without the written consent of Participant.

11. **No Guarantee of Service.** Neither this Phantom Units Agreement nor the award of Phantom Units hereunder shall confer upon Participant any right with respect to continuance of employment or other service with Company or any Affiliate, nor shall it interfere in any way with any right Company or any Affiliate would otherwise have to terminate such Participant's employment or other service at any time.

12. **Section 409A of the Code.** This Phantom Units Agreement is intended to be written, administered, interpreted and construed in a manner such that no payment or benefits provided under the Phantom Units Agreement become subject to (a) the gross income inclusion set forth within Section 409A(a)(1)(A) of the Code or (b) the interest and additional tax set forth within Section 409A(a)(1)(B) of the Code (collectively, "Section 409A Penalties"), including, where appropriate, the construction of defined terms to have meanings that would not cause the imposition of Section 409A Penalties. Notwithstanding anything to the contrary in this Phantom Units Agreement, to the maximum extent permitted by applicable law, the payments payable to Participant pursuant to this Phantom Units Agreement shall be made in reliance upon Treasury Regulation Section 1.409A-1(b)(4) (relating to short-term deferrals). However, with respect to any amounts payable to Participant under this Phantom Units Agreement in connection with a termination of Participant's service with Company that would be considered "non-qualified deferred compensation" under Section 409A of the Code, in no event shall a termination of service be considered to have occurred under this Phantom Units Agreement unless such termination constitutes the Participant's "separation from service" with Company as such term is defined in Treasury Regulation Section 1.409A-1(h), and any successor provision thereto. For purposes of Section 409A of the Code (including, without limitation, for purposes of Treasury Regulation Section 1.409A-2(b)(2)(iii)), each payment that Participant may be eligible to receive under this Phantom Units Agreement shall be treated as a separate and distinct payment and shall not collectively be treated as a single payment. Notwithstanding anything to the contrary contained in this Phantom Units Agreement, with respect to any amounts payable to Participant under this Phantom Units Agreement during a specified period of time following the occurrence of a payment event, the actual date of payment during such specified period will be determined by Company, in its sole and absolute discretion.

13. **Additional Tax Matters.** Company shall have the right to (i) make deductions from the number of Units otherwise deliverable upon vesting of the Phantom Units and satisfaction of the conditions precedent under this Phantom Units Agreement in an amount sufficient to satisfy withholding of any federal, state or local taxes required by law, or (ii) take such other action as may be necessary or appropriate to satisfy any such tax withholding obligations.

14. **Community Interest of Spouse.** The community interest, if any, of any spouse of Participant in any Phantom Units shall be subject to all of the terms, conditions and restrictions of this Phantom Units Agreement and the Plan.

15. **Severability.** In the event that any provision of this Phantom Units Agreement shall be held illegal, invalid, or unenforceable for any reason, such provision shall be fully severable, but shall not affect

the remaining provisions of this Phantom Units Agreement, and this Phantom Units Agreement shall be construed and enforced as of the illegal, invalid, or unenforceable provision had never been included herein.

16. **Governing Law.** This Phantom Units Agreement shall be construed in accordance with the laws of the State of Delaware to the extent federal law does not supersede and preempt Delaware law.

COMPANY:

CHENIERE ENERGY PARTNERS GP, LLC

By: _____

Printed Name: _____

Title: _____

PARTICIPANT:

By: _____

(Signature)

PHANTOM UNITS AGREEMENT

*Pursuant to the terms of the
Cheniere Energy Partners, L.P. Long-Term Incentive Plan*

1. **Grant of Phantom Units.** Subject to and in accordance with the terms and conditions of this document, Cheniere Energy Partners GP, LLC, a Delaware limited liability company (“Company”), hereby awards to _____ (“Participant”) _____ phantom units, which are notional units of common units (“Units”) of Cheniere Energy Partners, L.P. (the “Partnership”) (the “Phantom Units”). This Phantom Units Agreement (“Phantom Units Agreement”) is dated as of _____, 20___. The Phantom Units are awarded pursuant to and to implement in part the Cheniere Energy Partners, L.P. Long-Term Incentive Plan (as amended and in effect from time to time, the “Plan”) and are subject to the restrictions, forfeiture provisions and other terms and conditions of the Plan, which is hereby incorporated herein and is made a part hereof, and this Phantom Units Agreement. By execution of this Phantom Units Agreement, Participant agrees to be bound by all of the terms, provisions, conditions and limitations of the Plan as implemented by the Phantom Units Agreement, together with all rules and determinations from time to time issued by the Committee pursuant to the Plan. All capitalized terms have the meanings set forth in the Plan unless otherwise specifically provided herein. All references to specified paragraphs pertain to paragraphs of this Phantom Units Agreement unless otherwise provided.

2. **Risk of Forfeiture.** Participant shall immediately forfeit all rights to any Phantom Units which have not vested and with respect to which the restrictions thereon have not lapsed in the event of the termination, resignation, or removal of Participant from employment with or services to Company and its Affiliates under circumstances that do not cause Participant to become fully vested, and the restrictions on such Phantom Units to lapse, under the terms of the Plan and this Phantom Units Agreement.

3. **Restricted Period; Vesting.** Subject to the provisions of this Phantom Units Agreement including, without limitation, the provisions of Paragraph 4, Participant shall vest in his or her rights to the Phantom Units and the restrictions imposed thereon shall lapse as follows: 25% of the Phantom Units shall vest on the first anniversary of the date hereof, an additional 25% of the Phantom Units shall vest on the second anniversary of the date hereof, an additional 25% of the Phantom Units shall vest on the third anniversary of the date hereof and the remainder of the Phantom Units shall vest on the fourth anniversary of the date hereof. The period from the date hereof until the Phantom Units have become one hundred percent (100%) vested and the restrictions thereon have lapsed shall be referred to as the “Restricted Period.”

4. **Termination of Employment or Services; Change in Control.** Except as provided otherwise in this Paragraph 4, if Participant’s service with Company and its Affiliates shall be terminated for any reason, any unvested Phantom Units outstanding at the time of such termination and all rights thereunder shall be forfeited without payment under Paragraph 5 or 7 and no further vesting shall occur; provided however, that any Phantom Units not then vested shall vest upon the death or Disability of Participant. For purposes of this Phantom Units Agreement, the term “Disability” as it relates to Participant shall mean that Participant is “disabled” as described in accordance with Treasury Regulation Section 1.409A-3(i)(4) and Section 409A(a)(2)(C) of the Code.

In the event of a Change in Control, any Phantom Units not then vested shall vest upon the involuntary termination of Participant from service with Company and its Affiliates by the Company or an Affiliate without Cause within one (1) year from the effective date of such Change in Control. For purposes of this

Phantom Units Agreement, the term “Cause” shall mean the commission of an act of fraud or intentional misrepresentation or an act of embezzlement, misappropriation or conversion of assets or opportunities of the Company or any Affiliate.

5. **Time and Form of Payment.** To the extent a Phantom Unit shall become fully vested and the restrictions imposed thereon shall have lapsed pursuant to Paragraph 3 or Paragraph 4, Participant shall receive a single sum cash payment in an amount equal to the Fair Market Value of a Unit on the applicable vesting date. Such payment shall be made as soon as administratively practicable following the applicable vesting date, but in no event later than the thirtieth (30th) day following the date on which vesting occurs and the restrictions lapse with respect to such Phantom Unit. Should Participant die before receiving all amounts payable under this Paragraph 5, such amounts shall be paid to his estate. Participant’s right to any amounts described in this Paragraph 5 shall not rise above those of a general creditor of Company.

6. **Transferability.** Phantom Units shall not be transferable (by operation of law or otherwise) by Participant or any other person claiming through or under Participant, other than by Participant’s will or the laws of descent or distribution. Any attempt to sell, assign, transfer, pledge, exchange, hypothecate, or otherwise dispose of any Phantom Units shall be void and unenforceable.

7. **Ownership Rights and Distribution Equivalent Rights.** A Phantom Unit is a notional Unit of Company and, as a result, does not provide or give rise to any right to a Unit or to receive the Fair Market Value of a Unit except as specifically provided in the Plan and this Phantom Units Agreement. During the Restricted Period, any distribution in the form of cash paid or delivered by the Partnership on a Unit shall not entitle Participant to an equal amount of cash with respect to each Phantom Unit.

8. **Adjustment of Units.** In the event of any distribution (whether in the form of cash, Common Units, other securities, or other property), recapitalization, split, reverse split, reorganization, merger, consolidation, split-up, spin-off, combination, repurchase, or exchange of Units or other securities of Partnership, issuance of warrants or other rights to purchase Units or other securities of Partnership, or other similar transaction or event affects the Units, then the Committee shall, in such manner as it may deem equitable, make adjustments to the terms and provisions of this Phantom Units Agreement pursuant to Section 4(c) of the Plan in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the Plan.

9. **Certain Restrictions.** By executing this Phantom Units Agreement, Participant agrees that Participant will enter into such written representations, warranties and agreements as Company may reasonably request in order to comply with the Securities Act of 1933 or any other securities law or with this Phantom Units Agreement. Participant agrees that Company shall not be obligated to take any affirmative action in order to cause the Phantom Units subject to this Phantom Units Agreement to comply with any law, rule or regulation.

10. **Amendment and Termination.** This Phantom Units Agreement may not be terminated by the Company at any time without the written consent of Participant. This Phantom Units Agreement may be amended in writing by Company and Participant, provided Company may amend this Phantom Units Agreement unilaterally (i) if the amendment does not adversely affect Participant’s rights hereunder in any material respect, (ii) if Company determines that an amendment is necessary to comply with Rule 16b-3 under the Exchange Act or other applicable law, or (iii) if Company determines that an amendment is necessary to meet the requirements of the Code or to prevent adverse tax consequences to Participant. No amendment or termination of the Plan will adversely affect the rights and privileges of Participant under this Phantom Units Agreement or to the Phantom Units granted hereunder without the written consent of Participant.

11. **No Guarantee of Service.** Neither this Phantom Units Agreement nor the award of Phantom Units hereunder shall confer upon Participant any right with respect to continuance of employment or other service with Company or any Affiliate, nor shall it interfere in any way with any right Company or any Affiliate would otherwise have to terminate such Participant's employment or other service at any time.

12. **Section 409A of the Code.** This Phantom Units Agreement is intended to be written, administered, interpreted and construed in a manner such that no payment or benefits provided under the Phantom Units Agreement become subject to (a) the gross income inclusion set forth within Section 409A(a)(1)(A) of the Code or (b) the interest and additional tax set forth within Section 409A(a)(1)(B) of the Code (collectively, "Section 409A Penalties"), including, where appropriate, the construction of defined terms to have meanings that would not cause the imposition of Section 409A Penalties. Notwithstanding anything to the contrary in this Phantom Units Agreement, to the maximum extent permitted by applicable law, the payments payable to Participant pursuant to this Phantom Units Agreement shall be made in reliance upon Treasury Regulation Section 1.409A-1(b)(4) (relating to short-term deferrals). However, with respect to any amounts payable to Participant under this Phantom Units Agreement in connection with a termination of Participant's service with Company that would be considered "non-qualified deferred compensation" under Section 409A of the Code, in no event shall a termination of service be considered to have occurred under this Phantom Units Agreement unless such termination constitutes the Participant's "separation from service" with Company as such term is defined in Treasury Regulation Section 1.409A-1(h), and any successor provision thereto. For purposes of Section 409A of the Code (including, without limitation, for purposes of Treasury Regulation Section 1.409A-2(b)(2)(iii)), each payment that Participant may be eligible to receive under this Phantom Units Agreement shall be treated as a separate and distinct payment and shall not collectively be treated as a single payment. Notwithstanding anything to the contrary contained in this Phantom Units Agreement, with respect to any amounts payable to Participant under this Phantom Units Agreement during a specified period of time following the occurrence of a payment event, the actual date of payment during such specified period will be determined by Company, in its sole and absolute discretion.

13. **Community Interest of Spouse.** The community interest, if any, of any spouse of Participant in any Phantom Units shall be subject to all of the terms, conditions and restrictions of this Phantom Units Agreement and the Plan.

14. **Severability.** In the event that any provision of this Phantom Units Agreement shall be held illegal, invalid, or unenforceable for any reason, such provision shall be fully severable, but shall not affect the remaining provisions of this Phantom Units Agreement, and this Phantom Units Agreement shall be construed and enforced as of the illegal, invalid, or unenforceable provision had never been included herein.

15. **Governing Law.** This Phantom Units Agreement shall be construed in accordance with the laws of the State of Delaware to the extent federal law does not supersede and preempt Delaware law.

COMPANY:

CHENIERE ENERGY PARTNERS GP, LLC

By: _____

Printed Name: _____

Title: _____

PARTICIPANT:

By: _____

(Signature)

List of Subsidiaries or Other Related Entities of the Company

<u>Name</u>	<u>Where Incorporated</u>
Cheniere Creole Trail Pipeline, L.P.	Delaware
Cheniere Energy Investments, LLC	Delaware
Cheniere Midstream Services, LLC	Delaware
Cheniere NGL Pipeline, LLC	Delaware
Cheniere Pipeline GP Interests, LLC	Delaware
Sabine Pass Liquefaction Expansion, LLC	Delaware
Sabine Pass Liquefaction, LLC	Delaware
Sabine Pass LNG-GP, LLC	Delaware
Sabine Pass LNG-LP, LLC	Delaware
Sabine Pass LNG, L.P.	Delaware
Sabine Pass Tug Services, LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We consent to the incorporation by reference in the registration statements (Nos. 333-183780 and 333-183986) on Form S-3 and the registration statement (No. 333-151155) on Form S-8 of Cheniere Energy Partners, L.P. and subsidiaries of our reports dated February 19, 2015, with respect to the consolidated balance sheet of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2014, and the related consolidated statement of operations, comprehensive loss, partners' equity, and cash flows for the year then ended, and the related financial statement schedule (Schedule I) for the year ended December 31, 2014, and the effectiveness of internal control over financial reporting as of December 31, 2014, which reports appear in the December 31, 2014 annual report on Form 10-K of Cheniere Energy Partners, L.P. and subsidiaries.

/s/ KPMG LLP

KPMG LLP

Houston, Texas
February 19, 2015

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We consent to the incorporation by reference in the Registration Statements (Form S-3 No. 333-183780 and 333-183986 and Form S-8 No. 333-151155) of our report dated February 21, 2014, with respect to the consolidated financial statements and schedule of Cheniere Energy Partners, L.P. and subsidiaries, included in this Annual Report (Form 10-K) of Cheniere Energy Partners, L.P. and subsidiaries for the year ended December 31, 2014.

/s/ ERNST & YOUNG LLP

Ernst & Young LLP

Houston, Texas
February 19, 2015

**CERTIFICATION BY CHIEF EXECUTIVE OFFICER PURSUANT TO
RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Charif Souki, certify that:

1. I have reviewed this annual report on Form 10-K of Cheniere Energy Partners, LP.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2015

/s/ Charif Souki

Charif Souki

Chief Executive Officer of

Cheniere Energy Partners GP, LLC, the general partner of

Cheniere Energy Partners, L.P.

**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT**

I, Michael J. Wortley, certify that:

1. I have reviewed this annual report on Form 10-K of Cheniere Energy Partners, LP.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 19, 2015

/s/ Michael J. Wortley

Michael J. Wortley

Chief Financial Officer of

Cheniere Energy Partners GP, LLC, the general partner of

Cheniere Energy Partners, L.P.

**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**

In connection with the Annual Report of Cheniere Energy Partners, LP. (the "Partnership") on Form 10-K for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charif Souki, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934;
and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

Date: February 19, 2015

/s/ Charif Souki

Charif Souki

Chief Executive Officer of

Cheniere Energy Partners GP, LLC, the general partner of

Cheniere Energy Partners, L.P.

**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**

In connection with the Annual Report of Cheniere Energy Partners, LP. (the "Partnership") on Form 10-K for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael J. Wortley, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934;
and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Partnership.

Date: February 19, 2015

/s/ Michael J. Wortley

Michael J. Wortley
Chief Financial Officer of
Cheniere Energy Partners GP, LLC, the general partner of
Cheniere Energy Partners, L.P.