

Cheniere Energy Partners, L.P.
Form 10-K
February 21, 2014

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, 2013

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 800
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)
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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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 x

Accelerated filer o

Non-accelerated filer o

Smaller reporting company o

(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 o No x

The aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately \$1.3 billion as of June 28, 2013.

The issuer had 57,078,848 common units, 145,333,334 Class B units and 135,383,831 subordinated units outstanding as of January 31, 2014.

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" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). 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 regarding future levels of domestic and international natural gas production, supply or consumption or future levels of liquefied natural gas ("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;
- statements regarding our anticipated LNG and natural gas marketing activities; 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.

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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, 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 capacity of up to 265,000 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 nominal production capacity of approximately 4.5 mtpa. 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. 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, 2014:

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;
 - utilizing capacity at the Sabine Pass LNG terminal for short-term and spot LNG purchases and sales until such capacity is used in connection with the Liquefaction Project;
- 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, 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 at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. 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. We are developing Trains 5 and 6 and commenced the regulatory approval process for these Trains in February 2013.

We have received authorization from the Federal Energy Regulatory Commission (the "FERC") to site, construct and operate Trains 1 through 4. We have also filed an application with the FERC for the approval to construct Trains 5 and 6. The Department of Energy (the "DOE") has granted Sabine Pass Liquefaction an order authorizing the export of up to the equivalent of 16 mtpa (approximately 803 Bcf/yr) of LNG to all nations with which trade is permitted for a 20-year term beginning on the earlier of the date of first export from Train 1 or August 7, 2017. The DOE further issued orders authorizing the export of an additional 503.3 Bcf/yr in total of domestically produced LNG from the Sabine Pass LNG terminal to free trade agreement ("FTA") countries providing for national treatment for trade in natural gas for a 20-year term.

As of December 31, 2013, the overall project completion for Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project were approximately 54% and 20%, 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 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, which has not yet received regulatory approval for construction. 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, 2013, 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 Aprovevisionamientos 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 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.

In addition, Cheniere Marketing has entered into an SPA (the "Cheniere Marketing SPA") with Sabine Pass Liquefaction to purchase, at Cheniere Marketing's option, up to 104,000,000 MMBtu/yr of LNG. Sabine Pass Liquefaction has the right each year during the term of the SPA to reduce the annual contract quantity based on its assessment of how much LNG it can produce in excess of that required for other customers. Cheniere Marketing may

purchase incremental LNG volumes at a price of 115% of Henry Hub plus up to \$3.00 per MMBtu for the most profitable 36,000,000 MMBtu of cargoes sold each year by Cheniere Marketing and then 20% of net profits of the remaining 68,000,000 MMBtu sold each year by Cheniere Marketing.

Natural Gas Transportation and Supply

For Sabine Pass Liquefaction's feed gas transportation requirements, Sabine Pass Liquefaction has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CTPL and other third party pipeline companies. Sabine Pass Liquefaction has entered into enabling agreements with third parties, and will continue to enter into such agreements in order to secure feed gas for the Liquefaction Project.

Construction

Trains 1 through 4 are being designed, constructed and commissioned by Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") using the ConocoPhillips Optimized Cascade® technology, a proven technology deployed in numerous LNG projects around the world. 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)") and together with the EPC Contract (Trains 1 and 2) the "EPC Contracts") 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, 2013. Total expected capital costs for Trains 1 through 4 are estimated to be between \$9.0 billion and \$10.0 billion before financing costs, including 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 \$100 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 burden 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 "EPAAct") 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 EPAAct, nothing in the EPAAct 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 the Liquefaction Project, including the siting, construction and operation of Trains 1 through 4. 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. 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 its 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 the 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. An 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 was submitted to the FERC by CTPL in April 2012. In February 2013, the FERC approved the proposed project, and in October 2013, the FERC issued an order denying petitioner's request for rehearing and stay of the approval. 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.

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, CTPL is not permitted to unduly discriminate or grant undue preference as to its 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 EAct 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 EAct, 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 or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud.

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 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 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 FTA 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 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 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 an additional 503.3 Bcf/yr of domestically produced LNG to non-FTA countries are pending.

Exports of natural gas to countries with which the United States has an FTA 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 countries with which the United States does not have an FTA 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 subject to regulation by the U.S. Department of Transportation ("DOT"), under the Pipeline and Hazardous Material Safety Act ("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 DOT 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 DOT issued a final rule (known as "Control Room Management Rule") requiring pipeline operators to write and institute certain control room procedures that address human factors and fatigue management.

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 (from the prior \$100,000), with a maximum of \$2 million for any related series of violations (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, 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 U.S. Army Corps of Engineers ("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. The USACE acted in the capacity as a cooperating agency in the FERC's NEPA review process. 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 by September 2014.

In April 2012, CTPL applied for new Title V and PSD permits for the proposed modifications to the Creole Trail Pipeline system, which were issued by the LDEQ in November 2013.

We will also need to obtain a modification to the Sabine Pass LNG terminal's existing wastewater discharge permit to authorize discharges from the liquefaction facilities prior to the commencement of operation of the Liquefaction Project.

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 newly established 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") determines, by rulemaking, must 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. This legislation requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the swaps regulatory provisions of the Dodd-Frank Act. The CFTC had adopted rules imposing new position limits on certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas, that market participants could hold with exceptions for certain bona fide hedging transactions.

The final rules that the CFTC adopted on November 18, 2011 imposing position limits on certain core futures and equivalent swaps contracts for physical commodities, including Henry Hub natural gas, were vacated by federal district court on September 28, 2012. On November 5, 2013, the CFTC proposed new position limits rules that would modify and expand the applicability of position limits on certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas, that market participants could hold with exceptions for certain bona fide hedging transactions. The CFTC has determined, by rule, that certain interest rate swaps and certain credit default swaps must be mandatorily cleared, but the CFTC

has not yet proposed rules determining 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 exchange-trading requirements for our swaps entered to hedge our commercial risks, these 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 adopt rules that would require our Swap Dealer counterparties to enter into credit support documentation with us and/or require us to post initial and variation margin; however, the CFTC's and other regulators' margin rules are not yet final and therefore the application of those provisions to us is uncertain at this time. Provisions from other titles 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, and impact the liquidity of certain swaps products, all of which could increase our business costs.

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. 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 proposed 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. 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 to discharge 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 LNG 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 one SPA 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 sell any seasonal quantities of LNG available from Trains 1 through 4, develop additional Trains, or develop other new projects is subject to a broader array of 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, based on our experience in the energy industry, that global demand for natural gas and LNG will increase significantly 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 more than 22.5 Tcf between 2010 and 2020, fueled by the growth of emerging economies. Wood Mackenzie forecasts that global demand for LNG will increase by 45%, or 5.14 Tcf, by 2020, from approximately 237 mtpa, or 11.5 Tcf/yr, in 2012, and reach a total of 532 mtpa, or 26 Tcf/yr, by 2030. As a result, the share of LNG in the global natural gas market is expected to increase as markets seek to improve security of supply by accessing a wide portfolio of producers that can readjust deliveries to meet the needs of changing markets.

While global natural gas consumption has been rising internationally, natural gas production in the United States has undergone a technological transformation that has resulted in a substantial increase in annual production capacity, decrease in the cost of production, and expansion of technically recoverable reserves.

Our ability to continue to develop new facilities in the United States will be driven in part by the continued success of the North American upstream natural gas sector in developing new reservoirs, continuing to drive down costs and producing higher valued condensates and natural gas liquids in conjunction with natural gas production. Any such facilities will compete with other international LNG export projects principally on a price basis. These projects generally require capital not only to build the marine, storage and liquefaction facilities, but also to drill wells and build processing and pipeline transportation infrastructure. Because we rely on the natural gas market and transportation infrastructure already existing in the United States, we generally require less capital expenditures than competing projects. Furthermore, because natural gas is purchased from the United States market at a Henry Hub related price, we can offer LNG for sale at an alternative price to crude oil prices, thereby providing customers with an opportunity to diversify their supply portfolios by geography and price index.

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 and Labor Relations

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, 2014, Cheniere and its subsidiaries had 423 full-time employees, including 235 employees who directly supported the Sabine Pass LNG terminal. See Note 12—"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. Cheniere considers its current employee relations to be favorable.

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 800, Houston, Texas 77002, and our telephone number is (713) 375-5000. Our internet address is <http://www.cheniereenergypartners.com>. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes and is not incorporated by reference into this Form 10-K.

We will also make available to any unitholder, without charge, copies of our Annual Report on Form 10-K as filed with the SEC. For copies of this, or any other filing, please contact: Cheniere Energy Partners, L.P, Investor Relations Department, 700 Milam Street, Suite 800, 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, 2013, we had \$6.6 billion of total debt outstanding on a consolidated basis (before debt discounts and debt premiums). We 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 Trains 5 and 6 of the Liquefaction Project. Our ability to fund our capital expenditures and refinance our indebtedness will depend on our ability to access capital markets. Furthermore, our 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 \$258.1 million and \$175.4 million for the years ended December 31, 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 operations under any SPA 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 Sabine Pass LNG approximately \$125 million annually, and, upon

satisfaction of the conditions precedent to payment thereunder, by BG, Gas Natural Fenosa, KOGAS, GAIL, Total and Centrica, each of which has entered into an SPA with Sabine Pass Liquefaction and agreed to pay Sabine Pass Liquefaction approximately \$723 million, \$454 million, \$548 million, \$548 million, \$314 million and \$274 million annually, respectively. 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 ("NYMEX"), 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 could have an adverse impact on our ability to hedge risks associated with our business and on our results of operations and cash flows.

Title VII of the Dodd-Frank Act establishes federal oversight and regulation of the over-the-counter ("OTC") derivatives market and entities, such as us, that participate in that market. The provisions of that title of the Dodd-Frank Act and the rules of the CFTC and the SEC adopted and proposed to be adopted thereunder, regulate certain swaps entities, require clearing of certain swaps by clearing organizations and execution of certain swaps on contract markets or swap execution facilities, and require certain reporting and recordkeeping of swaps. They also give the CFTC the authority to establish 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. The CFTC's rules establishing position limits were vacated by a federal district court in September 2012. However, on November 5, 2013, the CFTC proposed new position limits

rules that would modify and expand the applicability of position limits on certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas, that market participants could hold with exceptions for certain bona fide hedging transactions.

The CFTC has designated certain interest rate swaps and certain credit default swaps for mandatory clearing and set compliance dates for three different categories of market participants who are parties to such swaps, the earliest of which was March 11, 2013 and the latest of which was September 9, 2013. The CFTC 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 to hedge our commercial risks, 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. In addition, for uncleared swaps, the CFTC or federal banking regulators may require our counterparties to require that we enter into credit support documentation and/or post initial and variation margin; however, the proposed margin rules are not yet final, and therefore the application of those provisions to us is uncertain at this time. 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 and the related rules 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 risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, 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. If there are changes in the global climate, storm frequency and intensity may increase; should it result in rising seas, our coastal operations may be impacted.

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. Approval of the FERC 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. 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 is currently pending and will be subject to an environmental assessment by the FERC and comment from the public and intervenors. 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, 2014, Cheniere and its subsidiaries had 423 full-time employees, including 235 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 its option, up to 104,000,000 MMBtu/yr of LNG. 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 the construction and operation 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.

Decreases in the demand for and price of LNG and natural gas could 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.

The development of domestic LNG facilities and projects generally is based on assumptions about the future availability of natural gas, price of natural gas and LNG, and the prospects for international natural gas and LNG markets. Natural gas 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:

- relatively minor changes in the supply of, and demand for, natural gas in relevant markets;
- political conditions in natural gas producing regions;
- the extent of domestic production and importation of natural gas in relevant markets;

the level of demand for LNG and natural gas in relevant markets, including the effects of economic downturns or upturns;

weather conditions;

the competitive position of natural gas as a source of energy compared with other energy sources; and

the effect of government regulation on the production, transportation and sale of 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 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.

Cyclical or other changes in the demand for LNG and natural gas may adversely affect our LNG businesses and the performance of our customers and could reduce our operating revenues and may cause us operating losses.

The economics of our LNG businesses could be subject to cyclical swings, reflecting alternating periods of under-supply and over-supply of LNG import or export capacity and available natural gas, principally due to the combined impact of several factors, including:

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;

reduced demand and lower prices for natural gas;

increased natural gas production deliverable by pipelines, which could suppress demand for LNG;

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;

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.

These factors could materially and adversely affect our ability, and the ability of our current and prospective customers, to procure supplies of LNG to be imported into North America, to procure customers for LNG or regasified LNG, or to procure natural gas to be liquefied and exported to international markets, at economical prices, or at all.

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 believe that there is sufficient capacity on the Creole Trail Pipeline to accommodate all of our natural gas supply requirements for Trains 1 and 2 of the Liquefaction Project but not for additional Trains. We have entered into transportation precedent agreements to secure firm pipeline transportation capacity with CTPL and other third party pipeline companies and plan to secure additional capacity, but we may not be able to do so on commercially reasonable terms or at all, which would 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;
- 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 or military campaigns may adversely impact our business.

A terrorist or military incident involving an LNG facility or 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 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; 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 greenhouse gases, 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 EPCRA, 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.

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 2014 will be dependent upon one facility, the Sabine Pass LNG receiving terminal 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.

We may engage in operations or make substantial commitments and investments located, or enter into agreements with counterparties located, outside the United States, which would expose us to political, governmental and economic instability and foreign currency exchange rate fluctuations.

Conducting operations or making commitments and investments located, or entering into agreements with counterparties located, outside of the United States will cause us to be affected by economic, political and governmental conditions in the countries where we engage in business. Any disruption caused by these factors could harm our business. Risks associated with operations, commitments and investments outside of the United States include the risks of:

- currency fluctuations;
- war;
- expropriation or nationalization of assets;
- renegotiation or nullification of existing contracts;
- changing political conditions;
- changing laws and policies affecting trade, taxation and investment;
- multiple taxation due to different tax structures; and
- the general hazards associated with the assertion of sovereignty over certain areas in which operations are conducted.

Because our reporting currency is the United States dollar, any of our operations conducted outside the United States or denominated in foreign currencies would face additional risks of fluctuating currency values and exchange rates, hard currency shortages and controls on currency exchange. We would be subject to the impact of foreign currency fluctuations and exchange rate changes on our reporting for results from those operations in our consolidated financial statements.

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;

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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 proposed 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.

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, 2013, we had 57,078,848 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, 2013, we had \$6.6 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 and \$1.0 billion will mature in 2023. In addition, Sabine Pass Liquefaction's \$5.0 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 12—"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;

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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 proposed liquefaction project at Corpus Christi, Texas, its proposed 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 proposed 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;

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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;

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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, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity-level taxation. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. 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 and the amount of cash available for distribution to our unitholders.

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

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our common units as a means to measure fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the

Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of 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, 2013, 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 daily closing sales prices per common unit, as reported by the NYSE MKT, and cash distributions to common unitholders for each quarter of 2012 and 2013.

	High	Low	Cash Distributions Per Common Unit (1)	Cash Distributions Per Subordinated Unit (2)	Cash Distributions Per Class B Unit (3)
Three Months Ended					
March 31, 2013	\$27.37	\$21.60	\$ 0.425	\$ —	\$ —
June 30, 2013	30.99	25.05	0.425	—	—
September 30, 2013	31.04	26.20	0.425	—	—
December 31, 2013	31.82	26.00	0.425	—	—
Three Months Ended					
March 31, 2012	\$24.70	\$18.05	\$ 0.425	—	—
June 30, 2012	27.14	19.81	0.425	—	—
September 30, 2012	26.58	22.67	0.425	—	—
December 31, 2012	23.22	17.87	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, 2013 of \$0.425 per common unit was paid on February 14, 2014. In addition, we paid cash distributions to our general partner with respect to its 2% general partner interest.

As of January 31, 2014, we had (i) 57.1 million common units outstanding held by approximately 11 record owners and (ii) 145.3 Class B units outstanding, of which 100.0 million Class B units were held by Blackstone CQP Holdco LP 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 Indentures described in "Management's Discussion and Analysis of Financial Condition and Results of Operation" 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, 2013. 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 CQP Holdco LP ("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 Cheniere Partners' 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 a liquidation (or merger, combination or sale of 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

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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,				
	2013	2012	2011	2010	2009
	(in thousands)				
Statement of Operations Data:					
Revenues (including transactions with affiliates)	\$268,191	\$264,498	\$283,888	\$399,632	\$417,824
Expenses (including transactions with affiliates)	300,877	226,253	161,803	140,810	111,366
Income (loss) from operations	(32,686)	38,245	122,085	258,822	306,458
Interest Expense, net	(178,400)	171,646	173,590	174,016	147,200
Net income (loss)	(258,117)	(175,431)	(53,560)	85,594	165,314
Net income (loss) per common unit	(0.03)	0.27	1.23	1.70	1.13
Weighted average units outstanding	54,235	33,470	27,910	26,416	26,416
Cash Flow Data:					
Cash flows provided by (used in) operating activities	35,664	(37,741)	6,840	99,844	227,695
Cash flows provided by (used in) investing activities	(328,800)	(4,785)	(8,448)	(5,104)	90,822
Cash flows provided by (used in) financing activities	224,876	380,403	29,674	(158,933)	(200,982)
	December 31,				
	2013	2012	2011	2010	2009
	(in thousands)				
Balance Sheet Data:					

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Cash and cash equivalents	\$351,032	\$419,292	\$81,415	\$53,349	\$117,542
Restricted cash and cash equivalents (current)	227,652	92,519	13,732	13,732	\$13,732
Non-current restricted cash and cash equivalents	1,025,056	272,425	82,394	82,394	82,394
Property, plant and equipment, net	6,383,939	3,219,592	2,044,020	2,094,752	2,147,797
Total assets	8,516,783	4,265,787	2,267,990	2,289,162	2,422,988
Long-term debt, net of discount	6,576,273	2,167,113	2,192,418	2,187,724	2,110,101
Long-term debt—related party, net of discount	—	—	—	—	72,928
Total equity (deficit)	1,639,744	1,879,978	(14,411)	9,475	82,809

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

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 Bcfe, two docks that can accommodate vessels with capacity of up to 265,000 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 nominal production capacity of approximately 4.5 mtpa. 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. 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.

Overview of Significant Events

In 2013, and through the filing date of this Form 10-K, we continue to develop, construct and operate assets supported by long-term fixed fee contracts. Our significant accomplishments since January 1, 2013 and through the filing date of this Form 10-K include the following:

Sabine Pass Liquefaction issued an aggregate principal amount of \$2.0 billion 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" and collectively with the 2021 Sabine Pass Liquefaction Senior Notes and the 2022 Sabine Pass Liquefaction Senior Notes, the "Sabine Pass Liquefaction Senior Notes"). Net proceeds from these offerings are intended to be used to pay a portion of the capital costs incurred in connection with the construction of

Trains 1 through 4 of the Liquefaction Project;

Sabine Pass Liquefaction entered into four credit facilities (the "2013 Liquefaction Credit Facilities") totaling \$5.9 billion (which were subsequently reduced to \$5.0 billion in connection with the issuance of the 2022 Sabine Pass Liquefaction Senior Notes) to be used for costs associated with the construction of Trains 1 through 4 of the Liquefaction Project;

Sabine Pass Liquefaction issued a notice to proceed to Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") under the lump sum turnkey contract for the engineering, procurement and construction of Trains 3 and 4 of the Liquefaction Project (the "EPC Contract (Trains 3 and 4)");

Sabine Pass Liquefaction entered into an LNG sale and purchase agreement ("SPA") with Centrica plc ("Centrica") that commences upon the date of first commercial delivery for Train 5 and includes an annual contract quantity of 91.25 million 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;

We issued 17.6 million common units to institutional investors for net proceeds, after deducting expenses, of \$372.4 million, which includes the general partner's proportionate capital contribution of \$7.4 million. We used the proceeds from this offering to purchase the Creole Trail Pipeline Business described below;

We completed the acquisition of 100% of the equity interests in Cheniere Pipeline GP Interests, LLC held by Cheniere Pipeline Company, and the limited partner interest in CTPL held by Grand Cheniere Pipeline, LLC (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. As a result of the two transactions, we paid Cheniere net cash of \$313.9 million;

CTPL entered into a \$400.0 million term loan credit facility (the "CTPL Credit Facility") to fund capital expenditures on the Creole Trail Pipeline and for general business purposes; and

We entered into an equity distribution agreement with Mizuho Securities USA Inc., under which we may sell up to \$500.0 million of common units through an at-the-market program.

Liquidity and Capital Resources

Cash and Cash Equivalents

As of December 31, 2013, we had \$351.0 million of cash and cash equivalents and \$1,252.7 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: \$1,059.7 million for the Liquefaction Project, \$101.9 million for CTPL, \$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, which may occur as early as late 2015.

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 at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. 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. We are developing Trains 5 and 6 and commenced the regulatory approval process for these Trains in February 2013.

We have received authorization from the Federal Energy Regulatory Commission (the "FERC") to site, construct and operate Trains 1 through 4. We have also filed an application with the FERC for the approval to construct Trains 5 and 6. The Department of Energy (the "DOE") has granted Sabine Pass Liquefaction an order authorizing the export of up to the equivalent of 16 mtpa (approximately 803 Bcf/yr) of LNG to all nations with which trade is permitted for a 20-year term beginning on the earlier of the date of first export from Train 1 or August 7, 2017. The DOE further issued orders authorizing the export of an additional 503.3 Bcf/yr in total of domestically produced LNG from the Sabine Pass LNG terminal to free trade agreement ("FTA") countries providing for national treatment for trade in natural gas for a 20-year term.

As of December 31, 2013, the overall project completion for Trains 1 and 2 and Trains 3 and 4 of the Liquefaction Project were approximately 54% and 20%, 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 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, which has not yet received regulatory approval for construction. 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 SPA with Sabine Pass Liquefaction to purchase, at Cheniere Marketing's option, up to 104,000,000 MMBtu/yr of LNG. Sabine Pass Liquefaction has the right each year during the term of the SPA to reduce the annual contract quantity based on its assessment of how much LNG it can produce in excess of that required for other customers. Cheniere Marketing may purchase incremental LNG volumes at a price of 115% of Henry Hub plus up to \$3.00 per MMBtu for the most profitable 36,000,000 MMBtu of cargoes sold each year by Cheniere Marketing; and then 20% of net profits of the remaining 68,000,000 MMBtu sold each year by Cheniere Marketing.

Natural Gas Transportation and Supply

For Sabine Pass Liquefaction's feed gas transportation requirements, Sabine Pass Liquefaction has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CTPL and other third party pipeline companies. Sabine Pass Liquefaction has entered into enabling agreements with third parties, and will continue to enter into such agreements in order to secure feed gas for the Liquefaction Project.

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, 2013. 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. Cheniere Partners estimates that the capital costs to modify the Creole Trail Pipeline will be approximately \$100 million. The modifications are expected to be in service in time for the commissioning and testing of Trains 1 and 2.

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, 2013, our subsidiaries had five series of senior secured notes outstanding (collectively, the "Senior Notes"):

\$1,665.5 million of 7.50% Senior Secured Notes due 2016 issued by Sabine Pass LNG (the "2016 Notes");

\$420.0 million of 6.50% Senior Secured Notes due 2020 issued by Sabine Pass LNG (the "2020 Notes" and collectively with the 2016 Notes, the "Sabine Pass LNG Senior Notes");

\$2,000.0 million of the 2021 Sabine Pass Liquefaction Senior Notes;

\$1,000.0 million of the 2022 Sabine Pass Liquefaction Senior Notes; and

\$1,000.0 million of the 2023 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, and 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 some or all of its 2016 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:

• 1.0% of the principal amount of the 2016 Notes; or

• the excess of: a) the present value at such redemption date of (i) the redemption price of the 2016 Notes plus (ii) all required interest payments due on the 2016 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 Notes, if greater.

Sabine Pass LNG may redeem some or all of the 2020 Notes at any time on or after November 1, 2016 at fixed redemption prices specified in the indenture governing the 2020 Notes, plus accrued and unpaid interest, if any, to the date of redemption. Sabine Pass LNG may also redeem some or all of the 2020 Notes at any time prior to November 1, 2016 at a "make-whole" price set forth in the indenture, 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 Notes at a redemption price of 106.5% of the principal amount of the 2020 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 Notes within 180 days of the closing date for such equity offering and at least 65% of the aggregate principal amount of the 2020 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, or December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes, or January 15, 2023, with respect to the 2023 Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction may redeem all or a part 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 also may at any time on or after November 1, 2020, with respect to the 2021 Sabine Pass Liquefaction Senior Notes, or December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes, or January 15, 2023, with respect to the 2023 Sabine Pass Liquefaction Senior Notes, redeem the Sabine Pass Liquefaction Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount 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, 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 indentures 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 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.

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 and the 2013 Liquefaction Credit Facilities described below.

2013 Liquefaction Credit Facilities

Sabine Pass Liquefaction has four credit facilities aggregating \$5.0 billion, 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, and 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") 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.

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 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 Cheniere Partners' 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.

CTPL Credit Facility

CTPL has the CTPL Credit Facility, which will be used to fund modifications to the Creole Trail Pipeline and for general business purposes. Loans under the CTPL Credit Facility 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 under the CTPL Credit Facility is 3.25%. The CTPL Credit Facility matures in 2017 when the full amount of the outstanding principal obligations must be repaid.

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, 2013, 2012 and 2011. The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals, that are referred to elsewhere in this report. Additional discussion of these items follows the table.

	Year Ended December 31,		
	2013	2012	2011
Sources of cash and cash equivalents			
Proceeds from debt issuances and credit facilities	\$4,504,478	\$520,000	\$—
Proceeds from sales of Class B units	—	1,887,342	—
Proceeds from sale of partnership common and general partner units	375,897	250,022	70,157
Contributions to Creole Trail Pipeline Business from Cheniere, net	20,896	11,857	7,666
Operating cash flow	35,664	—	6,840
Total sources of cash and cash equivalents	4,936,935	2,669,221	84,663
Uses of cash and cash equivalents			
LNG terminal costs, net	(3,120,643)	(1,118,787)	(7,394)
Investment in restricted cash and cash equivalents, net of uses of restricted cash and cash equivalents	(1,054,327)	(343,877)	—
Repayments of debt	(100,000)	(550,000)	—
Debt issuance and deferred financing costs	(311,050)	(222,378)	—
Purchase of Creole Trail Pipeline Business, net	(313,892)	—	—
Distributions to unitholders	(91,386)	(57,821)	(48,149)
Operating cash flow	—	(37,741)	—
Other	(13,897)	(740)	(1,054)
Total uses of cash and cash equivalents	(5,005,195)	(2,331,344)	(56,597)
Net increase (decrease) in cash and cash equivalents	(68,260)	337,877	28,066
Cash and cash equivalents—beginning of period	419,292	81,415	53,349
Cash and cash equivalents—end of period	\$351,032	\$419,292	\$81,415

Proceeds from Debt Issuances and Credit Facilities and Debt Issuance and Deferred Financing Costs

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 are intended to be used to pay a portion of the capital costs incurred in connection with the construction of the Liquefaction Project. In May 2013, Sabine Pass Liquefaction closed the 2013 Liquefaction Credit Facilities aggregating \$5.9 billion (which were subsequently reduced to \$5.0 billion in connection with the issuance of the 2022 Sabine Pass Liquefaction Senior Notes). Sabine Pass Liquefaction borrowed \$100.0 million under the 2013 Liquefaction Credit Facilities in June 2013 after meeting the required conditions precedent. Also in May 2013, CTPL entered into the CTPL Credit Facility, which will be used to fund modifications to the Creole Trail Pipeline and for general business purposes. Debt issuance costs primarily relate to up-front fees paid by Sabine Pass Liquefaction upon the closing of the 2013 Liquefaction Credit Facilities and the Sabine Pass Liquefaction Senior Notes.

In October 2012, Sabine Pass LNG issued 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.

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 February 2013, we sold 17.6 million common units to institutional investors for net proceeds, after deducting expenses, of \$365.0 million. We used the proceeds from this offering to purchase the Creole Trail Pipeline Business.

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.

In September 2011, we sold 3.0 million common units in an underwritten public offering and 1.1 million common units to Cheniere Common Units Holding, LLC at a price of \$15.25 per common unit. We received net cash proceeds of \$70.2 million from the offering (including proceeds from our general partner in connection with the exercise of its right to maintain its 2% ownership interest in us), which were used for general business purposes, including development costs for the Liquefaction Project.

In January 2011, we initiated an at-the-market program to sell up to 1.0 million common units, the proceeds from which have primarily been used to fund development costs associated with the Liquefaction Project. During the year ended December 31, 2011, we sold 0.5 million common units for net cash proceeds of \$9.0 million. During the year ended December 31, 2012, we sold 0.5 million common units for net cash proceeds of \$11.1 million. We paid \$0.3 million in commissions to Miller Tabak + Co., Inc., as sales agent, in connection with the at-the-market program during each of the years ended December 31, 2012 and 2011.

Operating Cash Flow

Operating cash flow increased \$73.4 million from 2012 to 2013. The increase in operating cash flow primarily resulted from decreased interest expense in the year ended December 31, 2013 as a result of the reduction of our indebtedness outstanding in 2012.

Operating cash flow decreased \$44.6 million from 2011 to 2012. The decrease in operating cash flow primarily resulted from increased costs incurred to develop and manage the construction of Trains 1 and 2 of the Liquefaction Project, and decreased LNG cargo export loading fee revenue.

LNG Terminal Costs, net

Capital expenditures for the Sabine Pass LNG terminal were \$3,120.6 million, \$1,118.8 million and \$7.4 million in the years ended December 31, 2013, 2012 and 2011, respectively. We began capitalizing costs associated with the construction of Trains 1 and 2 of the Liquefaction Project as construction-in-process during the second quarter of 2012.

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

During 2013, we invested \$1,054.3 million in restricted cash and cash equivalents, net of uses of restricted cash and cash equivalents. This investment in restricted cash and cash equivalents was primarily a result of the \$4,174.0 million investment in restricted cash and cash equivalents primarily related to the net proceeds from the Sabine Pass Liquefaction Senior Notes, the CTPL Credit Facility and the 2013 Liquefaction Credit Facilities. This investment in restricted cash and cash equivalents was partially offset by the use of \$3,119.6 million of restricted cash and cash equivalents primarily related to the construction of the Liquefaction Project.

During 2012, we invested \$343.9 million in restricted cash and cash equivalents. This investment was a result of the \$1,458.6 million of restricted cash and cash equivalents from the proceeds of Class B unit sales that was partially offset by the use of \$1,114.7 million of restricted cash for the construction of Trains 1 and 2 of the Liquefaction Project.

Repayments of Debt

In the year ended December 31, 2013, the 2012 Liquefaction Credit Facility was amended and restated with the 2013 Liquefaction Credit Facilities described above and \$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.

Distributions to Unitholders

We made \$91.4 million, \$57.8 million and \$48.1 million of distributions to our common and subordinated unitholders and to our general partner in the years ended December 31, 2013, 2012 and 2011, respectively.

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, 2013:

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, 2013	October 1, 2012 - December 31, 2012	\$ 0.425	\$ 16,783	\$ —	\$—	\$ 342
May 15, 2013	January 1, 2013 - March 31, 2013	\$ 0.425	\$ 24,259	\$ —	\$—	\$ 495
August 15, 2013	April 1, 2013 - June 30, 2013	\$ 0.425	\$ 24,259	\$ —	\$—	\$ 495
November 14, 2013	July 1, 2013 - September 30, 2013	\$ 0.425	\$ 24,259	\$ —	\$—	\$ 495

On January 22, 2014, 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 1, 2014 for the fourth quarter of 2013.

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 a liquidation (or merger, combination or sale of 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 1.23 and 1.21, respectively, as of December 31, 2013. 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, 2013 (in thousands).

	Payments Due for Years Ended December 31,				
	Total	2014	2015 - 2016	2017 - 2018	Thereafter
Construction and purchase obligations (1)	\$4,332,551	\$2,281,852	\$1,840,670	\$210,029	\$—
Long-term debt (2)	6,585,500	—	1,665,500	400,000	4,520,000
Interest payments (2)	2,817,267	457,495	904,984	643,436	811,352
Operating lease obligations (3)	299,022	10,167	20,601	13,389	254,865
Service contracts (4)	790,300	99,426	115,613	109,170	466,091
Cooperative endeavor agreements (4)	7,360	2,453	4,907		
Total	\$14,832,000	\$2,851,393	\$4,552,275	\$1,376,024	\$6,052,308

Construction and purchase obligations primarily relate to the EPC Contract (Trains 1 and 2) and the EPC Contract (1)(Trains 3 and 4). A discussion of these obligations can be found at Note 14—"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, 2013. See Note 11—"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 \$112.5 million due in the future under non-cancelable tug boat subleases. A discussion of these obligations can be found in Note 13—"Leases" of our Notes to Consolidated Financial Statements.

(4) A discussion of these obligations can be found in Note 12—"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

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 the 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 commitments pursuant to 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 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.

2012 vs. 2011

Our consolidated net loss was \$175.4 million in 2012 compared to a net loss of \$53.6 million in 2011. The increase in net loss primarily resulted from loss on early extinguishment of the 2013 Notes, increased costs incurred to manage the construction of Trains 1 and 2 of the Liquefaction Project, decreased revenues, increased operating and maintenance expense and increased development expense. Loss on early extinguishment of debt increased \$42.6 million in 2012 as compared to 2011 primarily as a result of make-whole payments associated with the early repayments in full of the 2013 Notes. Our general and administrative expense (including affiliate expense) increased \$42.3 million in 2012 as compared to 2011 primarily as a result of increased costs incurred to manage the construction of Trains 1 and 2 of the Liquefaction Project. Total revenues decreased \$19.4 million in 2012 as compared to 2011 primarily as a result of decreased LNG cargo export loading fee revenue, decreased revenues earned under the amended and restated VCRA, and a provision for loss on a firm purchase commitment for LNG inventory that will be used to restore the heating value of vaporized LNG to conform to natural gas pipeline specifications. Operating and maintenance expense (including affiliate expense) increased \$18.5 million in 2012 as compared to 2011 primarily as a result of the loss incurred to purchase LNG to maintain the cryogenic readiness of the Sabine Pass LNG terminal and increased dredging services in 2012. Development expense increased \$3.8 million in 2012 as compared to 2011 primarily as a result of costs incurred to develop the Liquefaction Project.

Off-Balance Sheet Arrangements

As of December 31, 2013, 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. Actual results could differ from the estimates and assumptions used.

Estimates used in the assessment of impairment of our long-lived assets are the most significant of our estimates. There are numerous uncertainties inherent in estimating future cash flows of assets or business segments. The accuracy of any cash flow estimate is a function of judgment used in determining the amount of cash flows generated. As a result, cash flows may be different from the cash flows that we use to assess impairment of our assets. 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. Significant negative industry or economic trends, including a significant decline in the market price of our common units, reduced estimates of future cash flows of our business or disruptions to our business could lead to an impairment charge of our long-lived assets and other intangible 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 of 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.

Other items subject to estimates and assumptions include asset retirement obligations, valuations of derivative instruments and collectability of accounts receivable and other assets.

As future events and their effects cannot be determined accurately, actual results could differ significantly from our estimates.

Derivatives

We use derivative instruments from time to time to hedge the exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory, 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, and to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 Liquefaction Credit Facilities. We have disclosed certain information regarding these derivative positions, including the fair value of our derivative positions, in Note 8—"Financial Instruments" of our Notes to Consolidated Financial Statements.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments be recorded at fair value and included in the consolidated balance sheet as assets or liabilities unless they satisfy the normal purchases normal sales exception criteria. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. 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. To date, all of our derivative positions fair value determinations have been made by management using quoted prices in active markets for similar assets or liabilities. The ultimate fair value of our derivative instruments is uncertain, and we believe that it is possible that a change in the estimated fair value will occur in the near future as commodity prices and interest rates change.

Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are recognized currently in earnings. Gains and losses in positions to hedge the cash flows attributable to the future sale of LNG inventory are classified as revenues on our Consolidated Statements of Operations. Gains or losses in the positions to mitigate the price risk from future purchases of natural gas to be utilized as fuel to operate the Sabine Pass LNG terminal are classified as derivative gain (loss) on our Consolidated Statements of Operations.

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, we begin to apply mark-to-market accounting at that time. 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.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, restricted cash and cash equivalents, restricted certificates of deposit, accounts receivable, and accounts payable approximate fair value because of the short maturity of those instruments. We use available market data and valuation methodologies to estimate the fair value of debt.

Asset Retirement Obligations

We recognize asset retirement obligations ("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.

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.

Recent Accounting Standards

In February 2013, the Financial Accounting Standards Board ("FASB") issued guidance that requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under GAAP that provide additional detail on these amounts. This guidance is effective prospectively for reporting periods beginning after December 15, 2012. We adopted this standard effective January 1, 2013. The adoption of this guidance did not have an impact on our consolidated financial position, results of operations or cash flows, as it only expanded disclosures.

In December 2011 and February 2013, the FASB issued guidance that requires entities to disclose both gross and net information about both derivatives and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting agreement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of GAAP and those entities that prepare their financial statements on the basis of International Financial Reporting Standards. Retrospective presentation for all comparative periods presented is required. We adopted this guidance effective January 1, 2013. The adoption of this guidance did not have an impact on our consolidated financial position, results of operations or cash flows, as it only expanded disclosures.

There are currently no new accounting standards that have been issued that will have a significant impact on our consolidated financial position, results of operations or cash flows upon adoption.

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 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") and 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"). 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 and Fuel Derivatives. The VaR

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is calculated using the Monte Carlo simulation method. The table below provides information about our LNG Inventory Derivatives and Fuel Derivatives that are sensitive to changes in natural gas prices and interest rates as of December 31, 2013 (in thousands, except for volume and price range data):

Hedge Description	Hedge Instrument	Contract Volume (MMBtu)	Price Range (\$/MMBtu)	Final Hedge Maturity Date	Fair Value (in thousands)	VaR (in thousands)
LNG Inventory Derivatives	Fixed price natural gas swaps	878,610	\$3.732 - \$4.475	April 2014	\$ (161)	\$ —
Fuel Derivatives	Fixed price natural gas swaps	360,000	\$4.222 - \$4.427	May 2014	27	11

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 resulted in a change in the fair value of the Interest Rate Derivatives of \$31.2 million. The table below provides information about our Interest Rate Derivatives that are sensitive to changes in the forward 1-month LIBOR curve as of December 31, 2013:

Hedge Description	Hedge Instrument	Initial Notional Amount	Maximum Notional Amount	Fixed Interest Rate Range (%)	Final Hedge Maturity Date	Fair Value (in thousands)	10% Change in LIBOR (in thousands)
Interest Rate Derivatives	Interest rate swaps	\$20.0 million	\$3.6 billion	1.99	May 2020	\$84,639	\$31,161

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY PARTNERS, L.P.

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

Management's Report on Internal Control Over Financial Reporting

As management, we are responsible for establishing and maintaining adequate internal control over financial reporting for Cheniere Energy Partners, L.P. ("Cheniere Partners") and its subsidiaries. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, we have conducted an assessment, including testing using the criteria in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Cheniere Partners' system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and, even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation.

Based on our assessment, we have concluded that Cheniere Partners' maintained effective internal control over financial reporting as of December 31, 2013, based on criteria in Internal Control—Integrated Framework (1992) issued by the COSO.

Cheniere Partners' independent registered public accounting firm, Ernst & Young LLP, have issued an audit report on Cheniere Partners' internal control over financial reporting as of December 31, 2013, which is contained in this Form 10-K.

Management's Certifications

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

Cheniere Energy Partners, L.P.

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

By: /s/ Charif Souki
Charif Souki
Chief Executive Officer
(Principal Executive Officer)

By: /s/ Michael J. Wortley
Michael J. Wortley
Chief Financial Officer
(Principal Financial Officer)

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 sheets of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive loss, partners' equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule 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 2012, and the consolidated results of their operations and their cash flows for each of the three 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.

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, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 21, 2014 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

Houston, Texas
February 21, 2014

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. and subsidiaries' internal control over financial reporting as of December 31, 2013 based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Cheniere Energy Partners, L.P. and subsidiaries' 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 company'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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013 based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cheniere Energy Partners, L.P. and subsidiaries as of December 31, 2013 and 2012 and the related consolidated statements of operations, comprehensive loss, partners' equity and cash flows for each of the three years in the period ended December 31, 2013, and our report dated February 21, 2014 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

Houston, Texas
February 21, 2014

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

	December 31,	
	2013	2012 (1)
ASSETS		
Current assets		
Cash and cash equivalents	\$ 351,032	\$ 419,292
Restricted cash and cash equivalents	227,652	92,519
Advances to affiliate	14,737	4,987
LNG inventory	10,430	2,625
Other—affiliate	3,280	6,572
Prepaid expenses and other	5,997	7,128
Total current assets	613,128	533,123
Non-current restricted cash and cash equivalents		
Property, plant and equipment, net	1,025,056	272,425
Debt issuance costs, net	6,383,939	3,219,592
Non-current derivative assets	313,944	220,949
Advances under long-term contracts	98,123	—
Other	6,561	—
Total assets	76,032	19,698
	\$ 8,516,783	\$ 4,265,787
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities		
Accounts payable	\$ 10,146	\$ 73,760
Accrued liabilities	170,052	47,848
Due to affiliates	45,547	7,562
Deferred revenue	26,593	26,540
Other	13,549	126
Total current liabilities	265,887	155,836
Long-term debt, net of discount		
Deferred revenue	6,576,273	2,167,113
Non-current derivative liabilities	17,500	21,500
Other non-current liabilities	—	26,424
Other non-current liabilities—affiliate	193	216
Commitments and contingencies	17,186	14,720
Partners' equity		
Creole Trail Pipeline Business equity	—	517,170
Common unitholders' interest (57.1 million units and 39.5 million units issued and outstanding at December 31, 2013 and 2012, respectively)	711,771	448,412
Class B unitholders' interest (145.3 million units and 133.3 million units issued and outstanding at December 31, 2013 and 2012, respectively)	(38,216)	(37,342)
Subordinated unitholder' interest (135.4 million units issued and outstanding at December 31, 2013 and 2012)	931,074	949,482
General partner's interest (2% interest with 6.9 million units and 6.3 million units issued and outstanding at December 31, 2013 and 2012, respectively)	35,115	29,496
Accumulated other comprehensive loss	—	(27,240)
Total partners' equity	1,639,744	1,879,978
Total liabilities and partners' equity	\$ 8,516,783	\$ 4,265,787

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

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

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

	Year Ended December 31,		
	2013	2012 (1)	2011 (1)
Revenues			
Revenues	\$265,251	\$256,361	\$269,233
Revenues—affiliate	2,940	8,137	14,655
Total revenues	268,191	264,498	283,888
Expenses			
Operating and maintenance expense	59,957	36,292	22,652
Operating and maintenance expense—affiliate	29,304	18,540	13,719
Depreciation expense	57,486	57,788	57,883
Development expense	11,322	37,559	32,448
Development expense—affiliate	1,402	2,677	4,025
General and administrative expense	11,570	12,316	7,754
General and administrative expense—affiliate	129,836	61,081	23,322
Total expenses	300,877	226,253	161,803
Income (loss) from operations	(32,686)	38,245	122,085
Other income (expense)			
Interest expense, net	(178,400)	(171,646)	(173,590)
Loss on early extinguishment of debt	(131,576)	(42,587)	—
Derivative gain (loss), net	83,448	58	(2,251)
Other	1,097	499	196
Total other expense	(225,431)	(213,676)	(175,645)
Net loss	\$(258,117)	\$(175,431)	\$(53,560)
Net loss attributable to Creole Trail Pipeline Business	\$(18,150)	\$(25,295)	\$(22,541)
Net loss attributable to partners	(239,967)	(150,136)	(31,019)
Basic and diluted net income (loss) per common unit (2)	\$(0.03)	\$0.27	\$1.23
Weighted average number of common units outstanding used for basic and diluted net income (loss) per common unit calculation	54,235	33,470	27,910

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

(2) See Note 16—"Net Income (Loss) per Common Unit" in our Notes to Consolidated Financial Statements for an adjusted net income (loss) per common unit that includes pre-acquisition date net losses of the Creole Trail Pipeline Business.

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

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

	Year Ended December 31,		
	2013	2012 (1)	2011 (1)
Net loss	\$(258,117)	\$(175,431)	\$(53,560)
Other comprehensive income (loss)			
Interest rate cash flow hedges			
Loss on settlements 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 a discontinuance of cash flow hedge accounting	5,973	—	—
Total other comprehensive income (loss)	27,240	(27,240)	—
Comprehensive loss	\$(230,877)	\$(202,671)	\$(53,560)

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

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 Unitholders' 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, December 31, 2010 (1)	26,416	\$(69,191)	—	\$—	135,384	\$(453,896)	3,302	\$(12,921)	\$—	\$545,483	\$9,475
Net loss	—	(5,098)	—	—	—	(25,301)	—	(620)	—	(22,541)	(53,560)
Contributions to predecessor from Cheniere, net Sale of common and general partner units	4,587	68,701	—	—	—	—	94	1,456	—	—	70,157
Distributions	—	(47,186)	—	—	—	—	—	(963)	—	—	(48,149)
Balance, December 31, 2011 (1)	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 predecessor from Cheniere, net 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 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	—	—	—	—	—
	—	(5,149)	—	25,319	—	(20,170)	—	—	—	—	—

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Amortization of beneficial conversion feature of Class B units												
Balance, December 31, 2012 (1)	39,488	\$448,412	133,333	\$(37,342)	135,384	\$949,482	6,290	\$29,496	\$(27,240)	\$517,170	\$1,879,9	
Net loss	—	(67,263)	—	—	—	(167,905)	—	(4,799)	—	(18,150)	(258,117	
Contributions to Creole Trail Pipeline Business from Cheniere, net Acquisition of the Creole Trail Pipeline Business	—	—	—	—	—	—	—	—	—	20,896	20,896	
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 hedges	—	—	—	—	—	—	—	—	27,240	—	27,240	
Beneficial conversion feature of Class B units	—	53,383	—	(180,000)	—	126,617	—	—	—	—	—	
Balance, December 31, 2013	57,078	\$711,771	145,333	\$(38,216)	\$135,384	\$931,074	6,894	\$35,115	\$—	\$—	\$1,639,7	

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

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

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

	Year Ended December 31,		
	2013	2012 (1)	2011 (1)
Cash flows from operating activities			
Net loss	\$(258,117)	\$(175,431)	\$(53,560)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation	57,486	57,498	57,883
Use of restricted cash and cash equivalents for certain operating activities	213,893	78,714	—
Release of (investment in) restricted cash and cash equivalents	(42,548)	(3,654)	—
Non-cash LNG inventory write-downs	26,900	9,393	392
Non-cash LNG inventory—affiliate write-downs	—	11,025	10,600
Amortization of debt discount	7,620	4,695	4,695
Amortization of debt issuance costs	7,328	4,362	4,382
Non-cash derivative gain, net	(83,717)	(619)	(195)
Loss on early extinguishment of debt	131,576	1,470	—
Other	—	3,496	—
Changes in operating assets and liabilities:			
Accounts receivable—affiliate	(1,083)	(1,690)	337
Accounts payable and accrued liabilities	(2,384)	2,214	(1,148)
Due to affiliates	26,091	2,425	(1,789)
Deferred revenue	(3,947)	(4,089)	(3,964)
Advances to affiliate	(9,281)	(4,764)	2,851
LNG inventory	(30,863)	(11,545)	347
LNG inventory—affiliate	—	(11,076)	(14,969)
Other	(7,668)	(165)	978
Other—affiliate	4,378	—	—
Net cash provided by (used in) operating activities	35,664	(37,741)	6,840
Cash flows from investing activities			
LNG terminal costs, net	(3,120,643)	(1,118,787)	(7,394)
Use of restricted cash and cash equivalents for the acquisition of property, plant and equipment	3,119,632	1,114,742	—
Purchase of Creole Trail Pipeline Business, net	(313,892)	—	—
Advances under long-term contracts	(13,897)	(740)	(1,054)
Net cash used in investing activities	(328,800)	(4,785)	(8,448)
Cash flows from financing activities			
Proceeds from issuances of long-term debt, net of debt issuance costs	4,504,478	520,000	—
Repurchases and prepayments of long-term debt	(100,000)	(550,000)	—
Proceeds from sale of partnership common and general partner units, net	375,897	250,022	70,157
Proceeds from sale of Class B units, net	—	1,887,342	—
Contributions to Creole Trail Pipeline Business from Cheniere, net	20,896	11,857	7,666

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Investment in restricted cash and cash equivalents	(4,173,959)	(1,458,619)	—
Debt issuance and deferred financing costs	(311,050)	(222,378)	—
Distributions to owners	(91,386)	(57,821)	(48,149)
Net cash provided by financing activities	224,876	380,403	29,674
Net increase (decrease) in cash and cash equivalents	(68,260)	337,877	28,066
Cash and cash equivalents—beginning of period	419,292	81,415	53,349
Cash and cash equivalents—end of period	\$351,032	\$419,292	\$81,415

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

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 capacity of up to 265,000 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 nominal production capacity of approximately 4.5 mtpa. 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. 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.

As of December 31, 2013, Cheniere owned 100% of our general partner interest and 84.5% 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.

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 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 Cheniere Partners' acquisition of the Creole Trail Pipeline Business described in Note 3—"Summary of Significant Accounting Policies". 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 a liquidation (or merger, combination or sale of 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 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 1.23 and 1.21, respectively, as of December 31, 2013. The Class B units will mandatorily convert into common

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

units on the first business day following the record date with respect to our 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. We currently expect 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.

NOTE 3—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States of America ("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 have been retrospectively adjusted to 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 16—"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.

Cash and Cash Equivalents

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

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

Restricted Cash 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.

Certain amounts that are designated as restricted cash and cash equivalents are contractually restricted as to usage or withdrawal for a certain amount of time. Prior to being restricted and after the restriction is lifted such amounts flow through cash and cash equivalents. For these amounts, we have presented increases and decreases as "Investments in (releases of) restricted cash and cash equivalents" in our Consolidated Statements of Cash Flows.

Certain other 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. This presentation does not impact the total amount of operating, investing or financing cash flows related to these items, however, they 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.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of 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 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 operations.

Management reviews property, plant and equipment for impairment periodically and whenever events or changes in circumstances have indicated that the carrying amount of property, plant and equipment might not be recoverable. We have recorded no significant impairments related to property, plant and equipment for 2013, 2012 or 2011.

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

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

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

Items that may influence our assessment are:

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

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

Revenue Recognition

LNG regasification capacity reservation fees are recognized as revenue over the term of the respective terminal use agreements ("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. The retained 2% of LNG delivered for each customer's account at the Sabine Pass LNG terminal is recognized as revenues as Sabine Pass LNG performs the services set forth in each customer's TUA.

Derivatives

We use derivative instruments from time to time to hedge the exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory, 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, and to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 Liquefaction Credit Facilities. We have disclosed certain information regarding these derivative positions, including the fair value of our derivative positions, in [Note 8—"Financial Instruments"](#) of our Notes to Consolidated Financial Statements.

Accounting guidance for derivative instruments and hedging activities establishes accounting and reporting standards requiring that derivative instruments be recorded at fair value and included in the consolidated balance sheet as assets or liabilities unless they satisfy the normal purchases normal sales exception criteria. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation,

which is established at the inception of a derivative. 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. To date, all of our derivative positions fair value determinations have been made by management using quoted prices in active markets for similar assets or liabilities. The ultimate fair value of our derivative instruments is uncertain, and we believe that it is possible that a change in the estimated fair value will occur in the near future as commodity prices and interest rates change.

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

Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are recognized currently in earnings. Gains and losses in positions to hedge the cash flows attributable to the future sale of LNG inventory are classified as revenues on our Consolidated Statements of Operations. Gains or losses in the positions to mitigate the price risk from future purchases of natural gas to be utilized as fuel to operate the Sabine Pass LNG terminal are classified as derivative gain (loss) on our Consolidated Statements of Operations.

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, we begin to apply mark-to-market accounting at that time. 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.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, restricted cash and cash equivalents, restricted certificates of deposit, accounts receivable, and accounts payable approximate fair value because of the short maturity of those instruments. We use available market data and valuation methodologies to estimate the fair value of debt.

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 our 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 our 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 LNG sale and purchase agreements ("SPAs") with unaffiliated third parties. We are dependent on the respective counterparties' creditworthiness and their willingness to perform under their respective SPAs.

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

Income Taxes

We are not subject to either federal or state income taxes, as the partners are taxed individually on their allocable share of taxable income. At December 31, 2013, the tax basis of our assets and liabilities was \$454.3 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.

Debt Issuance Costs

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 expense.

Asset Retirement Obligations

We recognize asset retirement obligations ("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.

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 capacity of up to 265,000 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.

The Sabine Pass LNG terminal is supervised by one manager who reports to the chief operating decision maker in deciding how to allocate resources. Sabine Pass Liquefaction obtained approximately 2.0 Bcf/d of regasification capacity under a TUA with Sabine Pass LNG as described in Note 12—"Related Party Transactions". In addition, Sabine Pass Liquefaction entered into an agreement with Total Gas & Power North America, Inc. ("Total") that will provide Sabine Pass Liquefaction with additional berthing and storage capacity reserved by Total under its TUA with Sabine Pass LNG as described in Note 10—"Deferred Revenue".

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. Actual results could differ from the estimates and assumptions used.

Estimates used in the assessment of impairment of our long-lived assets are the most significant of our estimates. There are numerous uncertainties inherent in estimating future cash flows of assets or business segments. The accuracy of any cash flow estimate is a function of judgment used in determining the amount of cash flows generated. As a result, cash flows may be different from the cash flows that we use to assess impairment of our assets. 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. Significant negative industry or economic trends, including a significant decline in the market price of our common units, reduced estimates of future cash flows of our business or disruptions to our business could lead to an impairment charge of our long-lived assets and other intangible 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 of 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.

Other items subject to estimates and assumptions include asset retirement obligations, valuations of derivative instruments and collectability of accounts receivable and other assets.

As future events and their effects cannot be determined accurately, actual results could differ significantly from our estimates.

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:

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

Sabine Pass LNG Senior Notes Debt Service Reserve

Sabine Pass LNG has consummated private debt offerings of an aggregate principal amount of \$1,665.5 million, before discount, of 7.50% Senior Secured Notes due 2016 (the "2016 Notes") and \$420.0 million of 6.50% Senior Secured Notes due 2020 (the "2020 Notes"). See Note 11—"Long-Term Debt". Collectively, the 2016 Notes and the 2020 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 that 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 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 December 31, 2013 and 2012, we classified \$15.0 million and \$17.4 million, respectively, as current restricted cash and cash equivalents for the payment of interest due within twelve months. As of both December 31, 2013 and 2012, 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 closed on 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" and collectively with the 2021 Sabine Pass Liquefaction Senior Notes and the 2022 Sabine Pass Liquefaction Senior Notes, the "Sabine Pass Liquefaction Senior Notes"). Also during 2013, Sabine Pass Liquefaction closed four credit facilities aggregating \$5.9 billion (collectively the "2013 Liquefaction Credit Facilities"), which amended and restated the 2012 Liquefaction Credit Facility. See Note 11—"Long-Term Debt". Under the terms and conditions of the 2012 Liquefaction Credit Facility and 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.

As of December 31, 2013 and 2012, we classified \$192.1 million and \$75.1 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 \$867.6 million and \$196.3 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 credit facility (the "CTPL Credit Facility"). As of December 31, 2013, we classified \$20.5 million and \$81.4 million as current and non-current restricted cash and cash equivalents, respectively, held by CTPL because such funds may only be used for modifications of Creole Trail Pipeline in order to enable bi-directional natural gas flow and for the payment of interest during construction of such

modifications.

NOTE 5—LNG INVENTORY AND LNG INVENTORY—AFFILIATE

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 12—"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.

As of December 31, 2013 and 2012, we had \$10.4 million and \$2.6 million, respectively, of LNG inventory on our Consolidated Balance Sheets. During the years ended December 31, 2013, 2012 and 2011, we recognized \$26.9 million, \$9.4 million, and \$0.4 million, respectively, 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 that is recorded in operating and maintenance expense on our Consolidated Statements of Operations.

As of December 31, 2013 and 2012, we had \$0.1 million and \$4.4 million, respectively, of LNG inventory—affiliate presented as Other—affiliate on our Consolidated Balance Sheets. During the years ended December 31, 2013, 2012 and 2011, we recognized zero, \$11.0 million, and \$10.6 million, respectively, as a result of LCM adjustments to our LNG inventory—affiliate.

NOTE 6—PROPERTY, PLANT AND EQUIPMENT

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

	December 31,	
	2013	2012
LNG terminal costs		
LNG terminal	\$2,225,412	\$2,224,230
LNG terminal construction-in-process	4,448,541	1,228,647
LNG site and related costs, net	149	156
Accumulated depreciation	(291,265) (234,349
Total LNG terminal costs, net	6,382,837	3,218,684
Fixed assets		
Computer and office equipment	612	368
Vehicles	907	704
Machinery and equipment	1,490	1,473
Other	963	760
Accumulated depreciation	(2,870) (2,397
Total fixed assets, net	1,102	908
Property, plant and equipment, net	\$6,383,939	\$3,219,592

Depreciation expense related to the Sabine Pass LNG terminal totaled \$57.3 million, \$57.3 million, and \$57.8 million for the years ended December 31, 2013, 2012 and 2011, respectively.

In June 2012, we began capitalizing costs associated with Trains 1 and 2 of the Liquefaction Project, and in May 2013, we began capitalizing costs associated with Trains 3 and 4 of the Liquefaction Project. For the years ended December 31, 2013 and 2012, we capitalized \$188.7 million and \$35.1 million, respectively, of interest expense related to the construction of Trains 1 through 4 of the Liquefaction Project.

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

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 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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 7—DEBT ISSUANCE COSTS

We have incurred debt issuance costs in connection with our long-term debt. These costs are deferred and are being amortized over the term of the related debt. Upon early retirement or amendment to a debt agreement, certain fees are written off to expense. For the years ended December 31, 2013, 2012, and 2011, we amortized \$43.6 million, \$15.7 million and \$4.4 million, respectively, of debt issuance costs. In addition, for the years ended December 31, 2013, 2012, and 2011, we wrote off \$118.3 million, \$1.5 million and zero, respectively, of debt issuance costs related to early extinguishments of debt.

As of December 31, 2013, we had recorded \$313.9 million of debt issuance costs directly associated with the arrangement of debt financing, net of accumulated amortization, as follows (in thousands):

Long-Term Debt	Debt Issuance Costs	Amortization Period	Accumulated Amortization	Net Costs
2013 Liquefaction Credit Facilities	\$257,924	7.0 years	\$(46,400)) \$211,524
2016 Notes	30,057	10.1 years	(21,100)) 8,957
2020 Notes	9,290	8.1 years	(1,377)) 7,913
2021 Sabine Pass Liquefaction Senior Notes	45,325	8.0 years	(3,910)) 41,415
2022 Sabine Pass Liquefaction Senior Notes	22,226	8.3 years	(195)) 22,031
2023 Sabine Pass Liquefaction Senior Notes	22,230	10.0 years	(1,159)) 21,071
CTPL Credit Facility	1,448	2.0 years	(415)) 1,033
Total	\$388,500		\$(74,556)) \$313,944

NOTE 8—FINANCIAL INSTRUMENTS

Derivative Instruments

We have entered into certain instruments to hedge the exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory ("LNG Inventory Derivatives") and 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"), and 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, 2013 and 2012, which are classified as other current assets, other current liabilities and other non-current liabilities in our Consolidated Balance Sheets.

Fair Value Measurements as of December 31, 2013				December 31, 2012			
Quoted Prices in Active Markets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total

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	(Level 1)			(Level 1)			
LNG Inventory							
Derivatives asset\$—	\$ (161)	\$ —	\$ (161)	\$ —	\$ 232	\$ —	\$ 232
(liability)							
Fuel Derivatives	—	27	—	27	—	(98)	—
asset (liability)							(98)
Interest Rate							
Derivatives asset—	84,639	—	84,639	—	(26,424)	—	(26,424)
(liability)							

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 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The estimated fair values of our LNG Inventory Derivatives and Fuel Derivatives are the amount 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. 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 derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. For transactions in which we have elected the normal purchase normal sale exemption, 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 and certain of our Fuel Derivatives, changes in fair value are reported in earnings.

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. Collateral of \$0.9 million deposited for such contracts, which has not been reflected in the derivative fair value tables, is included in the other current assets balance as of December 31, 2013 and 2012.

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

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

	Balance Sheet Location	Fair Value Measurements as of	
		December 31, 2013	December 31, 2012
LNG Inventory Derivatives asset (liability)	Prepaid expenses and other	\$(161)	\$232
Fuel Derivatives asset	Prepaid expenses and other	27	—
Fuel Derivatives liability	Other current liabilities	—	98

The following table (in thousands) shows the changes in the fair value and settlements of our LNG Inventory Derivatives recorded in revenues (losses) on our Consolidated Statements of Operations during the years ended December 31, 2013, 2012 and 2011:

Year Ended December 31,

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	2013	2012	2011
LNG Inventory Derivatives gain (loss)	\$(463) \$1,036	\$2,300

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 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The following table (in thousands) shows the changes in the fair value and settlements of our Fuel Derivatives and LNG Inventory Derivatives recorded in derivative gain (loss) on our Consolidated Statements of Operations during the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
LNG Inventory Derivatives gain	\$476	\$—	\$—
Fuel Derivatives gain (loss)(1)	181	(622) (2,251)

Excludes settlements of hedges of the exposure to price risk attributable to future purchases of natural gas to be (1)utilized as fuel to operate the Sabine Pass LNG terminal for which Sabine Pass LNG has elected the normal purchase normal sale exemption from derivative accounting.

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.

Based on the continued development of our financing strategy for the Liquefaction Project, during the fourth quarter of 2012 we determined it was no longer probable that a portion of the forecasted variable interest payments on the Liquefaction Credit Facility would occur in the time period originally specified. As a result, a portion of the Interest Rate Derivatives were no longer effective hedges and the hedge relationships for this portion were de-designated as of October 1, 2012. Fair value adjustments on this de-designated portion of the Interest Rate Derivatives subsequent to October 1, 2012 are recorded within our Consolidated Statements of Operations. As of December 31, 2012 we continued to maintain the Interest Rate Derivatives (both designated and de-designated) in anticipation of our upcoming financing needs, particularly for the financing of the construction of Trains 3 and 4 of the Liquefaction Project, and concluded that the likelihood of occurrence of our variable interest payments had not changed to probable not to occur. As a result, the amount recorded in other comprehensive income as of December 31, 2012 related to our designated and de-designated Interest Rate Derivatives remained in other comprehensive income.

During the first quarter of 2013, we 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 11—"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 are recorded as other comprehensive income (loss) within our Consolidated Balance Sheets, and changes in fair value subsequent to their de-designation date are recorded as derivative gain (loss) within our Consolidated Statements of Operations.

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

In June 2013, we 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 our intention to continue to issue fixed rate debt to refinance drawn portions of the 2013 Liquefaction Credit Facilities. As a result, the amount remaining in accumulated other comprehensive income ("AOCI") pertaining to the previously designated Interest Rate Derivatives was reclassified out of AOCI and into income. We have presented the reclassification of unrealized losses from AOCI into income and 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.

At December 31, 2013, 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	\$2.9 billion	August 14, 2012	July 31, 2019	1.98%	One-month LIBOR
Interest Rate Derivatives - Not Designated	—	\$671.0 million	June 5, 2013	May 28, 2020	2.05%	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, 2013	December 31, 2012
Interest Rate Derivatives - Not Designated	Non-current derivative assets	\$98,123	\$—
Interest Rate Derivatives - Not Designated	Other current liabilities	13,484	—
Interest Rate Derivatives - Designated	Non-current derivative liabilities	—	21,290
Interest Rate Derivatives - Not Designated	Non-current derivative liabilities	—	5,134

The following table (in thousands) details the effect of our Interest Rate Derivatives included in Other Comprehensive Income ("OCI") and AOCI during the year ended December 31, 2013:

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

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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, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Interest Rate Derivatives - Not Designated	\$88,596	\$679	\$—

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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 our Consolidated Balance Sheets	Net Amounts Presented in our Consolidated Balance Sheets	Gross Amounts not Offset in our Consolidated Balance Sheets		Net Amount
				Derivative Instrument	Cash Collateral Received (Paid)	
As of December 31, 2013:						
Fuel Derivatives	\$27	\$—	\$27	\$—	\$—	\$27
LNG Inventory Derivatives	(161)	(161)	—	—	—	—
Interest Rate Derivatives - Not Designated	98,123	—	98,123	—	—	98,123
Interest Rate Derivatives - Not Designated	(13,484)	—	(13,484)	—	—	(13,484)
As of December 31, 2012:						
Fuel Derivatives	(98)	(98)	—	—	—	—
LNG Inventory Derivatives	232	—	232	—	—	232
Interest Rate Derivatives - Designated	(21,290)	—	(21,290)	—	—	(21,290)
Interest Rate Derivatives - Not Designated	(5,134)	—	(5,134)	—	—	(5,134)

Other Financial Instruments

The estimated fair value of our other financial instruments, including those financial instruments for which the fair value option was not elected are set forth in the table below. The carrying amounts reported on our Consolidated Balance Sheets for cash and cash equivalents, restricted cash and cash equivalents, accounts receivable, interest receivable and accounts payable approximate fair value due to their short-term nature.

Other Financial Instruments (in thousands):

	December 31, 2013		December 31, 2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
2016 Notes, net of discount (1)	\$1,651,807	\$1,868,607	\$1,647,113	\$1,824,177
2020 Notes (1)	420,000	432,600	420,000	437,850
2021 Sabine Pass Liquefaction Senior Notes (1)	2,011,562	1,961,273	—	—
2022 Sabine Pass Liquefaction Senior Notes (1)	1,000,000	982,500	—	—
2023 Sabine Pass Liquefaction Senior Notes (1)	1,000,000	935,000	—	—
2012 Liquefaction Credit Facility (2)	—	—	100,000	100,000
2013 Liquefaction Credit Facilities (2)	100,000	100,000	—	—
CTPL Credit Facility (3)	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, 2013 and 2012, 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 has the ability to call this debt at anytime 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 anytime without penalty.

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NOTE 9—ACCRUED LIABILITIES

As of December 31, 2013 and 2012, accrued liabilities (including amounts due to affiliates) consisted of the following (in thousands):

	December 31,	
	2013	2012
Interest and related debt fees	\$80,151	\$16,327
Affiliate	44,384	5,744
Liquefaction Project costs	83,127	26,131
LNG terminal costs	1,612	977
Other	5,162	4,413
Total accrued liabilities (including affiliate)	\$214,436	\$53,592

NOTE 10—DEFERRED REVENUE

Advance Capacity Reservation Fee

In November 2004, Total paid Sabine Pass LNG a nonrefundable advance capacity reservation fee of \$10.0 million in connection with the reservation of approximately 1.0 Bcf/d of LNG regasification capacity at the Sabine Pass LNG terminal. An additional advance capacity reservation fee payment of \$10.0 million was paid by Total to Sabine Pass LNG in April 2005. The advance capacity reservation fee payments are being amortized as a reduction of Total's regasification capacity reservation fee under its TUA over a 10-year period beginning with the commencement of its TUA on April 1, 2009. As a result, we recorded the advance capacity reservation fee payments that Sabine Pass LNG received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

In November 2004, Sabine Pass LNG also entered into a TUA to provide Chevron U.S.A. Inc. ("Chevron") with approximately 0.7 Bcf/d of LNG regasification capacity at the Sabine Pass LNG terminal. In December 2005, Chevron exercised its option to increase its reserved capacity by approximately 0.3 Bcf/d to approximately 1.0 Bcf/d, making advance capacity reservation fee payments to Sabine Pass LNG totaling \$20.0 million. The advance capacity reservation fee payments are being amortized as a reduction of Chevron's regasification capacity reservation fee under its TUA over a 10-year period beginning with the commencement of its TUA on July 1, 2009. As a result, we recorded the advance capacity reservation fee payments that Sabine Pass LNG received, although non-refundable, as deferred revenue to be amortized to income over the corresponding 10-year period.

As of December 31, 2013, we had recorded \$4.0 million and \$17.5 million as current and non-current deferred revenue on our Consolidated Balance Sheets, respectively, related to the Total and Chevron advance capacity reservation fees. As of December 31, 2012, we had recorded \$4.0 million and \$21.5 million as current and non-current deferred revenue on our Consolidated Balance Sheets, respectively, related to the Total and Chevron advance capacity reservation fees.

TUA Payments

Following the achievement of commercial operability of the Sabine Pass LNG terminal in September 2008, Sabine Pass LNG began receiving capacity reservation fee payments from Cheniere Marketing under its TUA. Effective July 1, 2010, Cheniere Marketing assigned its existing TUA with Sabine Pass LNG to Cheniere Energy Investments, LLC ("Cheniere Investments"), including all of its rights, titles, interests, obligations and liabilities in and under the

TUA. Sabine Pass Liquefaction obtained this reserved capacity as a result of an assignment in July 2012 by Cheniere Investments of its rights, title and interest under its TUA. In connection with the assignment, Sabine Pass LNG, Sabine Pass Liquefaction and Cheniere Investments entered into a 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. Cheniere Investments' right to use capacity at the Sabine Pass LNG terminal will be reduced as each of Trains 1 through 4 reaches commercial operation. The percentage of the monthly capacity payments payable by Cheniere Investments will be reduced from 100% to zero (unless Cheniere Investments utilizes terminal use capacity after Train 4 reaches commercial operations), and the percentage of the monthly capacity payments payable by us will increase by the amount that Cheniere Investments' percentage decreases. We have guaranteed Sabine Pass Liquefaction's obligations under its TUA and the obligations of Cheniere Investments under its TURA. However, the revenue earned by Sabine Pass LNG from capacity payments

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by Cheniere Investments under its TUA was eliminated and under its TURA is eliminated upon consolidation of our financial statements. As a result, we have zero current deferred revenue—affiliate related to Cheniere Investments' monthly advance capacity reservation fee payment as of December 31, 2013 and 2012.

Total and Chevron are obligated to make monthly TUA payments to Sabine Pass LNG in advance of the month of service. These monthly payments are recorded to current deferred revenue in the period cash is received and are then recorded as revenue in the next month when the TUA service is performed. As of December 31, 2013 and 2012, we had recorded \$21.2 million and \$21.1 million, respectively, as current deferred revenue on our Consolidated Balance Sheets related to Total's and Chevron's monthly TUA payments.

NOTE 11—LONG-TERM DEBT

As of December 31, 2013 and 2012, our long-term debt consisted of the following (in thousands):

	December 31,	
	2013	2012
Long-term debt		
2016 Notes	\$1,665,500	\$1,665,500
2020 Notes	420,000	420,000
2021 Sabine Pass Liquefaction Senior Notes	2,000,000	—
2022 Sabine Pass Liquefaction Senior Notes	1,000,000	—
2023 Sabine Pass Liquefaction Senior Notes	1,000,000	—
2012 Liquefaction Credit Facility	—	100,000
2013 Liquefaction Credit Facilities	100,000	—
CTPL Credit Facility	400,000	—
Total long-term debt	6,585,500	2,185,500
Long-term debt premium (discount)		
2016 Notes	(13,693) (18,387
2021 Sabine Pass Liquefaction Senior Notes	11,562	—
CTPL Credit Facility	(7,096) —
Total long-term debt, net of discount	\$6,576,273	\$2,167,113

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2013 (in thousands):

	Payments Due for the Years Ended December 31,				
	Total	2014	2015 to 2016	2017 to 2018	Thereafter
Debt:					
2016 Notes	\$1,665,500	\$—	\$1,665,500	\$—	\$—
2020 Notes	420,000	—	—	—	420,000
	2,000,000	—	—	—	2,000,000

2021 Sabine Pass Liquefaction Senior Notes					
2022 Sabine Pass Liquefaction Senior Notes	1,000,000	—	—	—	1,000,000
2023 Sabine Pass Liquefaction Senior Notes	1,000,000	—	—	—	1,000,000
2013 Liquefaction Credit Facilities	100,000	—	—	—	100,000
CTPL Credit Facility	400,000	—	—	400,000	—
Total Debt	\$6,585,500	\$—	\$1,665,500	\$400,000	\$4,520,000

Sabine Pass LNG Senior Notes

As of December 31, 2013 and 2012, Sabine Pass LNG had an aggregate principal amount of \$1,665.5 million, before discount, of the 2016 Notes and \$420.0 million of the 2020 Notes outstanding. Borrowings under the 2016 Notes and 2020 Notes bear interest at a fixed rate of 7.50% and 6.50%, respectively. The terms of the 2016 Notes and the 2020 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.

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Sabine Pass LNG may redeem some or all of its 2016 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:

• 1% of the principal amount of the 2016 Notes; or

the excess of: a) the present value at such redemption date of (i) the redemption price of the 2016 Notes plus (ii) all required interest payments due on the 2016 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 Notes, if greater.

Sabine Pass LNG may redeem all or part of the 2020 Notes at any time on or after November 1, 2016, at fixed redemption prices specified in the indenture governing the 2020 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 Notes at any time prior to November 1, 2016, at a "make-whole" price set forth in the indenture governing the 2020 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 Notes at a redemption price of 106.5% of the principal amount of the 2020 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 Notes within 180 days of the closing date for such equity offering and at least 65% of the aggregate principal amount of the 2020 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: 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 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. During the years ended December 31, 2013, 2012 and 2011, Sabine Pass LNG made distributions of \$348.9 million, \$333.5 million and \$313.6 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, Sabine Pass Liquefaction also issued \$1.0 billion 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%. 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 and the 2023 Sabine Pass Liquefaction Senior Notes are governed by a common indenture (the "indenture"). The 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, or December 15, 2021, with respect to the 2022 Sabine Pass Liquefaction Senior Notes, or January 15, 2023, with respect to the 2023 Sabine Pass

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

In connection with the issuance of the 2022 Sabine Pass Liquefaction Senior Notes, Sabine Pass Liquefaction also entered into a registration rights agreement (the "2022 Liquefaction Registration Rights Agreement"). Under the 2022 Liquefaction Registration Rights Agreement, Sabine Pass Liquefaction has agreed to use commercially reasonable efforts to file with the SEC and cause to become effective a registration statement relating to an offer to exchange the 2022 Sabine Pass Liquefaction Senior Notes for a like aggregate principal amount of SEC-registered notes with terms identical in all material respects to the 2022 Sabine Pass Liquefaction Senior Notes (other than with respect to restrictions on transfer or to any increase in annual interest rate) within 360 days after November 25, 2013. Under specified circumstances, Sabine Pass Liquefaction may be required to file a shelf registration statement to cover resales of the Sabine Pass Liquefaction Senior Notes. If Sabine Pass Liquefaction fails to satisfy this obligation, Sabine Pass Liquefaction may be required to pay additional interest to holders of the 2022 Sabine Pass Liquefaction Senior Notes under certain circumstances.

2013 Liquefaction Credit Facilities

In May 2013, Sabine Pass Liquefaction closed 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 a \$100.0 million borrowing under the 2013 Liquefaction Credit Facilities in June 2013 after meeting the required conditions precedent.

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, and 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 the second borrowing and 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 8—"Financial Instruments".

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In November 2013, Sabine Pass Liquefaction issued the 2022 Sabine Pass Liquefaction Senior Notes, and a portion of the available commitments pursuant to the 2013 Liquefaction Credit Facilities was terminated. Net proceeds from the offering of approximately \$978 million are intended to be used to pay a portion of the capital costs in connection with the construction of the Liquefaction Project in lieu of the terminated portion of the commitments under the 2013 Liquefaction Credit Facilities. The 2022 Sabine Pass Liquefaction Notes are pari passu in right of payment with all existing and future senior debt of Sabine Pass Liquefaction. As a result of Sabine Pass Liquefaction's issuance of the 2022 Sabine Pass Liquefaction Senior Notes in November 2013, Sabine Pass Liquefaction has terminated \$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.

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. 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.

The 2012 Liquefaction Credit Facility had a maturity date of the earlier of July 31, 2019 or the second anniversary of the completion date of Trains 1 and 2 of the Liquefaction Project. Borrowings under the 2012 Liquefaction Credit Facility could have been 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 a \$100.0 million borrowing under the 2012 Liquefaction Credit Facility in August 2012 after meeting the required conditions precedent.

Borrowings under the 2012 Liquefaction Credit Facility bore interest at a variable rate equal to, at Sabine Pass Liquefaction's election, LIBOR or the base rate, plus the applicable margin. The applicable margin for LIBOR loans was 3.50% during construction and 3.75% during operations. Interest on LIBOR loans was due and payable at the end of each LIBOR period. The 2012 Liquefaction Credit Facility required Sabine Pass Liquefaction to pay certain up-front fees to the agents and lenders in the aggregate amount of approximately \$178 million and provided 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. Annual administrative fees were also required to be paid to the agent and the trustee. The principal of loans made under the 2012 Liquefaction Credit Facility had to be repaid in quarterly installments, commencing with the last day of the first calendar quarter ending at least three months following the completion of Trains 1 and 2 of the Liquefaction Project. Scheduled repayments were based upon an 18-year amortization profile, with the remaining balance due upon the maturity of the 2012 Liquefaction Credit Facility.

Under the terms and conditions of the 2012 Liquefaction Credit Facility, all cash held by Sabine Pass Liquefaction was controlled by the collateral agent. These funds could only be released by the collateral agent upon satisfaction of certain terms and conditions related to the use of proceeds, and the cash balance of \$100.0 million held in these accounts as of December 31, 2012 was classified as restricted on our Consolidated Balance Sheets.

The 2012 Liquefaction Credit Facility contained conditions precedent for the second borrowing and any subsequent borrowings, as well as customary affirmative and negative covenants. The obligations of Sabine Pass Liquefaction under the 2012 Liquefaction Credit Facility were secured by substantially all of the assets of Sabine Pass Liquefaction

as well as all of the membership interests in Sabine Pass Liquefaction, and a security interest in Cheniere Partners' rights under its Unit Purchase Agreement with Blackstone dated May 14, 2012, on a pari passu basis with the Sabine Pass Liquefaction Senior Notes.

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 8—"Financial Instruments".

In February 2013, Sabine Pass Liquefaction issued the 2021 Sabine Pass Liquefaction Senior Notes to refinance a portion of the 2012 Liquefaction Credit Facility, and a portion of available commitments pursuant to the 2012 Liquefaction Credit Facility was suspended. In April 2013, Sabine Pass Liquefaction issued an aggregate principal amount of \$500.0 million of additional 2021 Sabine Pass Liquefaction Senior Notes and \$1.0 billion of 2023 Sabine Pass Liquefaction Senior Notes, and as a result,

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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 in the year ended December 31, 2013.

CTPL Credit Facility

In May 2013, CTPL entered into the CTPL Credit Facility, which will be 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 CTPL Credit Facility 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, 2013, CTPL had borrowed the full amount of \$400.0 million available under the CTPL Credit Facility.

Borrowings under the CTPL Credit Facility 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 CTPL Credit Facility, 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 CTPL Credit Facility contains customary affirmative and negative covenants. The obligations of CTPL under the CTPL Credit Facility 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 CTPL Credit Facility 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 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.

NOTE 12—RELATED PARTY TRANSACTIONS

As of December 31, 2013 and 2012, we had \$14.7 million and \$5.0 million of advances to affiliates, respectively. In addition, we have entered into the following 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 Sabine Pass Liquefaction's TUA, Sabine Pass Liquefaction is required to pay for a portion of the cost to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal. During years ended December 31, 2013, 2012 and 2011, we recorded \$26.6 million, \$10.1 million and zero, respectively, as operating and maintenance expense related to this obligation.

Cheniere Investments, Sabine Pass Liquefaction and Sabine Pass LNG entered into the 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 ("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, \$4.9 million and \$11.2 million during the years ended December 31, 2013, 2012 and 2011, respectively, related to the amended and restated VCRA.

LNG Sale and Purchase Agreement ("SPA")

Cheniere Marketing has entered into an SPA with Sabine Pass Liquefaction to purchase, at Cheniere Marketing's option, up to 104,000,000 MMBtu/yr of LNG. Sabine Pass Liquefaction has the right each year during the term to reduce the annual contract quantity based on its assessment of how much LNG it can produce in excess of that required for other customers. Cheniere Marketing may purchase incremental LNG volumes at a price of 115% of Henry Hub plus up to \$3.00 per MMBtu for the most profitable 36,000,000 MMBtu of cargoes sold each year by Cheniere Marketing and then 20% of net profits of the remaining 68,000,000 MMBtu sold each year by Cheniere Marketing.

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 on our Consolidated Balance Sheets, and 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, 2013, we had 41,000 MMBtu of LNG inventory—affiliate recorded at \$0.1 million on our Consolidated Balance Sheets, and as of December 31, 2012, we had 1,369,000 MMBtu of LNG inventory—affiliate recorded at \$4.4 million on our Consolidated Balance Sheets. During the years ended December 31, 2013 and 2012, we recognized a loss of zero and \$1.4 million, respectively, as a result of LCM adjustments to our LNG inventory—affiliate.

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, 2013 and 2012 was \$0.2 million and was classified as other current liabilities and other current assets, 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 \$0.5 million and revenues of \$1.0 million related to LNG inventory—affiliate derivatives in the years ended

December 31, 2013 and 2012, respectively.

Service Agreements

During the years ended December 31, 2013, 2012 and 2011, we recorded general and administrative expense—affiliate of \$113.0 million, \$53.5 million, and \$19.0 million, respectively, under the following service agreements.

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,

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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 we receive 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 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 we receive 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 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 we receive 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 Energy

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Investments, LLC. 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.

Agreement to Fund Sabine Pass LNG's Cooperative Endeavor Agreements

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 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 modified its TUA 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 VCRA, allowing Cheniere Marketing to utilize Cheniere Investments' capacity under the TUA after the assignment. In July 2012, Cheniere Investments entered into an 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. The amended and restated VCRA provides that Cheniere Marketing will continue to fund the CEAs during the term of the amended and restated VCRA and, in exchange, Cheniere Marketing will receive any future credits.

On a consolidated basis, these advance tax payments were recorded to other 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, 2013 and 2012, we had \$17.2 million and \$14.7 million of other non-current assets and non-current liabilities—affiliate resulting from Sabine Pass LNG's ad valorem tax payments and the advance tax payments received from Cheniere Marketing, respectively.

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 the natural gas or LNG to the Sabine Pass LNG terminal.

Sabine Pass LNG recorded \$3.3 million, \$2.8 million and \$4.2 million of natural gas and LNG purchased from Cheniere Marketing under this agreement in the years ended December 31, 2013, 2012 and 2011, respectively.

Sabine Pass LNG recorded revenues—affiliate of \$14.7 million, \$2.8 million and zero for natural gas sold to Cheniere Marketing under this agreement in the year ended December 31, 2013, 2012 and 2011, 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, \$0.3 million, and \$0.3 million pursuant to this agreement in the years ended December 31, 2013, 2012 and 2011, 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 Cheniere Marketing to provide its LNG cargo vessels with tug boat and marine services at the Sabine Pass LNG terminal. Tug Services recorded revenues—affiliate from Cheniere Marketing of \$2.8 million, \$2.8 million, and \$2.7 million pursuant to this agreement in the years ended December 31, 2013, 2012 and 2011, respectively.

NOTE 13—LEASES

During the years ended December 31, 2013, 2012 and 2011, we recognized rental expense for all operating leases of \$10.0 million, \$10.0 million, and \$9.2 million, respectively.

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

Year ending December 31,	Lease Payments
	(2)
2014	\$10,167
2015	10,261
2016	10,340
2017	10,401
2018	2,988
Thereafter (1)	254,865
Total	\$299,022

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

Lease payments for Sabine Pass LNG's tug boat lease represent its lease payment obligation and do not take into (2) account the \$112.5 million of sublease payments Sabine Pass LNG will receive from its three TUA customers that effectively offset these lease payment obligations, as discussed below.

Land Leases

We recognized \$2.2 million, \$2.3 million, and \$1.8 million of site lease expense on our Consolidated Statements of Operations in 2013, 2012 and 2011, 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 and increasing the annual lease payments to \$1.5 million. 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 annual lease payment is \$138,000. The lease has an initial term of five years, with options to renew for five 1-year extensions with similar terms as the initial term. 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 annual lease payment is \$257,800. 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 five 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 at the Sabine Pass LNG terminal as a result of its purchase of Tug Services. 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 five years each. We have

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

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 Chevron, Total and Cheniere Marketing 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 14—COMMITMENTS AND CONTINGENCIES

Commitments and Contingencies

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 contracts for the engineering, procurement and construction ("EPC") of 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.

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 at the Sabine Pass LNG terminal 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 at the Sabine Pass LNG terminal.

Services Agreements

We have entered into certain services agreements with affiliates. See Note 12—"Related Party Transactions" for information regarding such agreements.

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

Restricted Net Assets

At December 31, 2013, our restricted net assets of consolidated subsidiaries were approximately \$1,318 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 ("CEAs")

In July 2007, Sabine Pass LNG executed CEAs with various Cameron Parish, Louisiana taxing authorities. See Note 12—"Related Party Transactions" for information regarding such agreements.

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, 2013, 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.

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

NOTE 15—SUPPLEMENTAL CASH FLOW INFORMATION AND DISCLOSURES OF NON-CASH
 TRANSACTIONS

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

	Year Ended December 31,		
	2013	2012	2011
Cash paid during the year for interest, net of amounts capitalized	\$ 120,908	\$ 160,273	\$ 164,513
LNG terminal costs funded with accounts payable and accrued liabilities (including affiliate)	166,252	99,680	—
Class B units issued in connection with the Creole Trail Pipeline Business acquisition	180,000	—	—

NOTE 16—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 21, 2014, 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 1, 2014 for the fourth quarter of 2013.

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's 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's and Blackstone's Class B units, respectively. The impact of the beneficial conversion feature is also included in earnings per unit for the year ended December 31, 2013.

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The following is a schedule by years, based on the capital structure as of December 31, 2013, of the anticipated impact to the capital accounts in connection with the amortization of the beneficial conversion feature (in thousands):

	Common Units	Class B Units	Subordinated Units
2014	(2)	6	(4)
2015	(232)	781	(549)
2016	(29,564)	99,685	(70,121)
2017	(505,937)	1,705,956	(1,200,019)

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 General Partner had participated in the pre-acquisition date net losses of the Creole Trail Pipeline Business.

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, 2013						
Net loss	\$(258,117)					
Declared distributions	99,015	97,035	—	—	1,980	
Assumed allocation of undistributed net loss	\$(357,132)	(98,522)	—	(233,680)	(6,780)	(18,150)
Assumed allocation of net income (loss)		\$(1,487)	\$—	\$(233,680)	\$(4,800)	\$(18,150)
Assumed allocation of net income (loss) adjusted for the Creole Trail Pipeline Business		\$(6,762)	\$—	\$(246,192)	\$(5,163)	
Weighted average units outstanding		54,235	140,500	135,384		
Net loss per unit		\$(0.03)	\$—	\$(1.73)		
Net loss per unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business		\$(0.12)	\$—	\$(1.82)		
Year Ended December 31, 2012 (1)						
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	\$(236,932)	(46,061)	—	(157,917)	(7,659)	(25,295)
		\$9,061	\$25,319	\$(178,087)	\$(6,429)	\$(25,295)

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Assumed allocation of net income (loss)						
Assumed allocation of net income (loss) adjusted for the Creole Trail Pipeline Business	3,463	25,319	(197,278)	(6,935)		
Weighted average units outstanding	33,470	43,303	135,384			
Net income (loss) per unit	\$0.27	\$0.58	\$ (1.32)			
Net income (loss) per unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business	\$0.10	\$0.58	\$ (1.46)			
Year Ended December 31, 2011 (1)						
Net loss						\$(53,560)
Declared distributions	50,136	49,134	—	—	1,002	
Assumed allocation of undistributed net loss	\$(103,696)	(14,819)	—	(64,713)	(1,623)	(22,541)
Assumed allocation of net income (loss)	\$34,315	\$—	\$ (64,713)	\$(621)	\$(22,541)	
Assumed allocation of net income (loss) adjusted for the Creole Trail Pipeline Business	\$30,199	\$—	\$ (82,687)	\$(1,072)		
Weighted average units outstanding	27,910	—	135,384			
Net income (loss) per unit	\$1.23	\$—	\$ (0.48)			
Net income (loss) per unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business	\$1.08	\$—	\$ (0.61)			

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

CHENIERE ENERGY PARTNERS, L.P. AND SUBSIDIARIES
SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED 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, 2013 (1):				
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
Net income per common unit—basic and diluted (2)	\$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 (2)	\$0.04	\$0.06	\$(0.20) \$(0.01
Year ended December 31, 2012 (1):				
Revenues	\$69,353	\$61,423	\$66,358	67,364
Income (loss) from operations	19,161	12,750	(8,177) 14,511
Net loss	(25,062) (30,386) (51,371) (68,612
Net income (loss) per common unit—basic and diluted (2)	\$0.23	\$0.17	\$0.04	\$(0.06
Net Income (loss) per common unit, adjusted to include pre-acquisition date net losses of the Creole Trail Pipeline Business—basic and diluted (2)	\$0.20	\$0.14	\$(0.02) \$(0.09

(1) Retrospectively adjusted as discussed in Note 3—"Summary of Significant Accounting Policies" in our Notes to Consolidated Financial Statements.

The sum of the quarterly net income (loss) per common unit may not equal the full year amount as the (2) 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, 2013, 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 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 54 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, 2013, 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, 2013, 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"), 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 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, 2013 disclosures pursuant to ITRA regarding one of its portfolio companies that may be deemed to be an affiliate of Blackstone. Because of the broad definition of "affiliate" in Exchange Act Rule 12b-2, this portfolio company of Blackstone, through Blackstone's ownership of Cheniere Partners, may also be deemed to be an affiliate of ours.

We have received notice from Blackstone 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 during the quarter ended December 31, 2013 have not been reported by Travelport. Blackstone 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 OFAC.

In our Form 10-Q reports for the quarterly periods ended on March 31, 2013, June 30, 2013 and September 30, 2013, 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.

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 31, 2014, 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	61	Director, Chairman of the Board and Chief Executive Officer
R. Keith Teague	49	Director, President and Chief Operating Officer
Michael J. Wortley	37	Director, Senior Vice President and Chief Financial Officer
James R. Ball	63	Director
David I. Foley	46	Director
Meg A. Gentle	39	Director
Sean T. Klimczak	37	Director
Lon McCain	65	Director
Philip Meier	54	Director
Vincent Pagano, Jr.	63	Director
Oliver G. Richard, III	61	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 twenty 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 Senior Vice President-Asset Group of Cheniere since April 2008. 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. He served as Vice President-Pipeline Operations of Cheniere beginning in May 2006 until April 2008. He has also served as President of Cheniere Pipeline Company, a wholly owned subsidiary of Cheniere, since January 2005. 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. 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 and is a member of the Conflicts Committee. Mr. Ball has served as a non-executive director of Gas Strategies Group Ltd, a professional services company providing commercial energy advisory services ("GSG"), since September 2011. 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. and PBF Energy Inc.

Meg A. Gentle is a director of our general partner. In addition, Ms. Gentle has served as Cheniere's Senior Vice President–Marketing since June 2013 and is a director of Cheniere Energy Partners LP Holdings, LLC. She served as Senior Vice President and Chief Financial Officer of 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 and Chief Financial Officer of Cheniere from March 2009 to June 2013. She served as Senior Vice President - Strategic Planning and Finance of 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 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 a Master of Business Administration 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 communications company, and Hovnanian Enterprises, Inc., a publicly traded real estate 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 distributor, 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.cheniereenergypartners.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, we believe that all Section 16(a) filing requirements were met during 2013 in a timely manner.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Our general partner has paid no cash compensation to its executive officers since its inception. All of the executive officers of our general partner are also executive officers of Cheniere. Cheniere compensates these officers for the performance of their duties as executive officers of Cheniere, which includes managing our partnership. Cheniere does not allocate this compensation between services for us and services for Cheniere and its affiliates. Instead, an affiliate of Cheniere provides us various general and administrative services, 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 12—"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 in cash 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 2013.

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. 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, commencing February 1, 2012 and ending May 31, 2012, the Chairman of the Conflicts Committee received a special monthly fee of \$16,777 and each other member of the Conflicts Committee received a special monthly fee of \$13,333 in connection with increased work performed by the Conflicts Committee in connection with the Liquefaction Project during that time. The special monthly fees were paid in arrears. 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 2013 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)	—	—	—	—	—	—	—
H. Davis Thames (2)	—	—	—	—	—	—	—
James R. Ball (3)	50,000	81,450	—	—	—	—	131,450
David I. Foley (4)	—	—	—	—	—	—	—
Meg A. Gentle (2)	—	—	—	—	—	—	—
Sean T. Klimczak (4)	—	—	—	—	—	—	—

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Lon McCain (5)	80,000	89,490	—	—	—	—	169,490
Philip Meier (6)	—	—	—	—	—	—	—
Vincent Pagano, Jr. (7)	65,861	88,260	—	—	—	—	154,121
Oliver G. Richard, III (8)	65,000	81,540	—	—	—	—	146,540

Reflects aggregate grant date fair value. The phantom units are to be settled, at the director's election, in common (1) units, cash, or a combination 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.

Mr. Souki and Mr. Teague served as executive officers of our general partner and as executive officers of Cheniere during fiscal year 2013. Ms. Gentle served as an executive officer of our general partner until June 2013 and an (2) executive officer of Cheniere during fiscal year 2013. Mr. Thames served as an executive officer of our general partner from June 2013 until January 2014 and an executive officer of Cheniere during fiscal year 2013. 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.

Mr. Ball was granted 3,000 phantom units in 2013 with a grant date fair value of \$80,250. Mr. Ball received (3) \$81,540 in cash upon the vesting of 3,000 phantom units in September 2013. As of December 31, 2013, he held 12,000 phantom units.

Messrs. Foley and Klimczak are Senior Managing Directors in the Private Equity Group of The Blackstone Group (4) L.P. and they do not receive additional compensation for service as directors.

Mr. McCain was granted 3,000 phantom units in 2013 with a grant date fair value of \$89,490. Mr. McCain (5) received \$89,490 in cash upon the vesting of 3,000 phantom units in May 2013. As of December 31, 2013, he held 7,500 phantom units.

Mr. Meier is compensated by Blackstone pursuant to the Meier Consulting Letter Agreement and received no (6) 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.

Mr. Pagano was granted 3,000 phantom units in 2013 with a grant date fair value of \$89,760. Mr. Pagano received (7) \$88,260 in cash upon the vesting of 3,000 phantom units in December 2013. As of December 31, 2013, he held 12,000 phantom units.

Mr. Richard was granted 3,000 phantom units in 2013 with a grant date fair value of \$80,250. Mr. Richard received (8) \$81,540 in cash upon the vesting of 3,000 phantom units in September 2013. As of December 31, 2013, he held 12,000 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 31, 2014, the following units were outstanding: 57,078,848 common units, 135,383,831 subordinated units and 145,333,334 Class B units. In addition, as of January 31, 2014, there were 6,893,796 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 800, 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 31, 2014.

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 %
Ong Tiong Sin, RRJ Capital Master Fund I, L.P., Novolink Investments Limited (3)	12,048,192	21 %	—	—	—	—	3 %

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, (1) Inc. owns approximately 84% 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 6,893,796 of our general partner units.

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

Information is based on a Schedule 13D filed with the SEC by Ong Tiong Sin and others on March 11, 2013. The address is RRJ Capital Ltd, c/o RRJ Management (HK) Limited, Room 1201-02, 12/F Man Yee Building, 68 Des Voeux Road, Central, Hong Kong. These holdings consist of: (a) 9,638,554 common units held by Novolink

(3) Investments Limited; (b) 963,855 common units held by Pertin Investment Limited; and (c) 1,445,783 common units held by Bosland Limited. Mr. Ong is the sole shareholder and a director of Pertin Investment Limited, the sole shareholder and a director of Bosland Limited and the sole shareholder of RRJ Capital Ltd. RRJ Capital Ltd is the general partner of RRJ Master Fund I, L.P. RRJ Capital Master Fund I, L.P. is the sole shareholder of Novolink Investments Limited. The persons described in this footnote indicate shared voting and investment power.

Directors and Executive Officers

The following table sets forth information with respect to our common units owned of record and beneficially as of January 31, 2014, 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 31, 2014, the directors and executive officers of Cheniere Partners beneficially owned an aggregate of 409,635 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 31, 2014, 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 31, 2014, Cheniere Energy

Partners LP Holdings, LLC had 231,700,000 common shares outstanding and Cheniere Energy, Inc. had 238,106,267 shares of common stock outstanding.

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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 (1)(2)	400,100	1 %	—	—	6,720,445	3 %
R. Keith Teague	—	*	—	—	1,081,591	*
Meg A. Gentle (3)	8,035	*	—	—	1,502,367	1 %
James R. Ball	—	—	—	—	—	—
David I. Foley (4)	—	—	—	—	—	—
Sean T. Klimczak (4)	—	—	—	—	—	—
Lon McCain	—	—	—	—	—	—
Vincent Pagano, Jr.	—	—	—	—	—	—
Michael J. Wortley (5)	1,000	*	—	—	462,240	*
H. Davis Thames (5)	500	*	—	—	1,361,179	1 %
Philip Meier	—	—	—	—	—	—
Oliver G. Richard, III	—	—	—	—	—	—
All directors and executive officers as a group (11 persons)	409,135	1 %	—	—	9,766,643	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) Includes 80,000 shares issuable upon exercise of currently exercisable stock options held by Ms. Gentle.

(4) 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.

(5) As of January 14, 2014, Mr. Wortley replaced Mr. Thames as Chief Financial Officer and a director of our general partner.

Equity Compensation Plan Information

In 2007, the board of directors of our general partner adopted the Cheniere Energy Partners, L.P. Long-Term Incentive Plan. The following table provides certain information as of December 31, 2013 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)
Equity compensation plans approved by security holders	—	N/A	—
Equity compensation plans not approved by security holders	—	N/A	1,250,000
Total	—	N/A	1,250,000

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

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 12—"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 fiscal years ended December 31, 2013 and 2012.

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 and \$0.3 million pursuant to this agreement in the years ended December 31, 2013 and 2012.

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 12—"Related Party Transactions" of our Notes to Consolidated Financial Statements. During each of the years ended December 31, 2013, 2012 and 2011, 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, \$0.1 million and \$0.4 million under this agreement in the years ended December 31, 2013, 2012 and 2011, respectively. During the years ended December 31, 2013, 2012 and 2011, Sabine Pass LNG recorded revenues—affiliate from Cheniere Investments of zero, \$0.1 million and \$0.4 million, respectively, 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 2013 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 2013 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

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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

Ernst & Young LLP served as our independent auditor for the fiscal years ended December 31, 2013 and 2012. The following table sets forth the fees paid to Ernst & Young LLP for professional services rendered for 2013 and 2012:

	Ernst & Young LLP	
	Fiscal 2013	Fiscal 2012
Audit Fees	\$2,874,749	\$1,376,834
Audit-Related Fees	—	253,777
Total	\$2,874,749	\$1,630,611

Audit Fees—Audit fees for 2013 and 2012 include attestation services and review of documents filed with the SEC in addition to audit, review and all other services performed to comply with generally accepted auditing standards.

Audit-Related Fees—Audit-related fees for 2012 include services rendered in connection with the offering of securities pursuant to a registration statement.

There were no tax or other fees in 2013 and 2012.

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, 2013 and 2012 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.:

<u>Management's Report to the Unitholders of Cheniere Energy Partners, L.P.</u>	<u>54</u>
<u>Reports of Independent Registered Public Accounting Firm—Ernst & Young LLP</u>	<u>55</u>
<u>Consolidated Balance Sheets</u>	<u>57</u>
<u>Consolidated Statements of Operations</u>	<u>58</u>
<u>Consolidated Statements of Partners' Equity</u>	<u>60</u>
<u>Consolidated Statements of Cash Flows</u>	<u>61</u>
<u>Notes to Consolidated Financial Statements</u>	<u>62</u>
<u>Supplemental Information to Consolidated Financial Statements—Summarized Quarterly Financial Data</u>	<u>89</u>

(2) Financial Statement Schedules:

<u>Schedule I—Condensed Financial Information of Registrant for the years ended December 31, 2013, 2012 and 2011</u>	<u>112</u>
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(3) Exhibits:

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)
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)

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- 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 under the Indenture (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 under the Indenture (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 under the Indenture (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* Form of 5.625% Senior Secured Note due 2021 (Included as Exhibit A-1 to Exhibit 4.6 above)
- 4.11* Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.9 above)
- 4.12* Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.8 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)
- 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* 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)
- 10.5* 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)

- 10.6* Guaranty, dated as of November 9, 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)
- 10.7* 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* 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)
- 10.14* 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)
- 10.15* 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)
- 10.16* 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)
- 10.17* 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)
- 10.18* 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)
- 10.19* 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)
- 10.20* 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)
- 10.21*

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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)

10.22* 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)

10.23* LNG Sale and Purchase Agreement (FOB), dated May 14, 2012, by and between Sabine Pass Liquefaction, LLC and Cheniere Marketing, LLC. (Incorporated by reference to Exhibit 10.7 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012)

10.24* 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)

10.25* 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)

- 10.26* 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)
- 10.27* 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)
- 10.28* 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)
- 10.29* 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)
- 10.30* 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-0010 Fuel Provisional Sum, dated August 8, 2012, (iv) the Change Order CO-0011 Currency Provisional Sum, dated August 8, 2012, (v) the Change Order CO-0012 Delay in NTP, dated August 8, 2012, and (vi) the Change Order CO-0013 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)
- 10.31* 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-0014 Bundle of Changes, dated September 5, 2012, (ii) the Change Order CO-0015 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-0017 Condensate Header, dated December 3, 2012 and (v) the Change Order CO-0018 Increase in Power Requirements, dated

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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)

10.32* 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-0019 Delete Tank 6 Scope of Work, dated February 27, 2013 and (ii) the Change Order CO-0020 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)

10.33* 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-0021 Increase to Insurance Provisional Sum, dated April 17, 2013, (ii) the Change Order CO-0022 Removal of LNG Static Mixer Scope, dated May 8, 2013, (iii) the Change Order CO-0023 Revised LNG Rundown Line, dated May 30, 2013, (iv) the Change Order CO-0024 Reroute Condensate Header, Substation HVAC Stacks, Inlet Metering Station Pile Driving, dated June 11, 2013 and (v) the Change Order CO-0025 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)

10.34* 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)

10.35* 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-0031 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)

10.36* 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)

10.37* 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)

10.38* 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

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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)

- 10.39* 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)
- 10.40* 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)
- 10.41* 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)
- 10.42* 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)

- 10.43* 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)
- 10.44* 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)
- 10.45* 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)
- 10.46* 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)
- 10.47* 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)
- 10.48* Amended and Restated Management Services Agreement, dated as of August 9, 2012, by and between Cheniere LNG Terminals, Inc. 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)
- 10.49* 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)
- 10.50* 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)
- 10.51* Management Services Agreement, dated May 14, 2012, by and between Cheniere LNG Terminals, Inc. 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)

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- 10.52* 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)
- 10.53* 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)
- 10.54* 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)
- 10.55* 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)
- 10.56* 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)

- 10.57* 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)
- 10.58* 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, Inc. 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)
- 10.59* Registration Rights Agreement, dated February 1, 2013, between Sabine Pass Liquefaction, LLC and Morgan Stanley & Co. 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 February 4, 2013)
- 10.60* Registration Rights Agreement, dated April 16, 2013, between Sabine Pass Liquefaction, LLC and Morgan Stanley & Co. LLC (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 1-33366), filed on April 16, 2013)
- 10.61* Registration Rights Agreement, dated as of November 25, 2013, between Sabine Pass Liquefaction, LLC and Morgan Stanley & Co. LLC (Incorporated by reference to Exhibit 10.1 to Cheniere Energy Partners, L.P.'s Current Report on Form 8-K (SEC File No. 1-33366), filed on November 25, 2013)
- 10.62* 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)
- 10.63* 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)
- 10.64* Class B Unit Purchase Agreement, dated as of May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, 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 May 15, 2012)
- 10.65* 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)
- 10.66* 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)

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- 10.67* Subscription Agreement, dated May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, Inc. (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)
- 10.68* 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)
- 10.69* 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)
- 10.70* 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)

- 10.71* 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)
- 10.72* 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)
- 10.73* 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)
- 10.74*† 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)
- 10.75*† 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)
- 10.76*† 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)
- 10.77*† 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)
- 10.78*† 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)
- 10.79*† 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)
- 10.80*† 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) [NTD: Update/Refile?]
- 10.81*† 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)

- 10.82*† 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)
- 10.83*† 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)
- 10.84*† 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)
- 10.85*† 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)
- 10.86*† 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)

10.87*†	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)
21.1	Subsidiaries of Cheniere Energy Partners, L.P.
23.1	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

* Incorporated by reference

† Management contract or compensatory plan or arrangement

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED BALANCE SHEET

(in thousands)

	December 31,	
	2013	2012 (1)
ASSETS		
Current assets		
Cash and cash equivalents	\$314,782	\$392,945
Prepaid expenses and other	112	134
Total current assets	314,894	393,079
Investment in affiliates	1,328,613	1,489,565
Non-current receivable—affiliates	—	940
Other	—	874
Total assets	\$1,643,507	\$1,884,458
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Commitments and contingencies	\$3,763	\$4,480
Unitholders' equity	1,639,744	1,879,978
Total liabilities and unitholders' equity	\$1,643,507	\$1,884,458

(1) Retrospectively adjusted as discussed in Note 1—"Summary of Significant Accounting Policies" in our Notes to Condensed Financial Statements.

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

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SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS

(in thousands)

	Year Ended December 31,		
	2013	2012 (1)	2011 (1)
Operating costs and expenses	\$ 14,417	\$ 18,262	\$ 13,104
Interest expense, net	—	12	—
Interest income	242	235	38
Equity loss of affiliates	(243,942)	(157,416)	(40,494)
Net loss	\$(258,117)	\$(175,431)	\$(53,560)
Other comprehensive income (loss) attributable to affiliates	27,240	(27,240)	—
Comprehensive loss, net	\$(230,877)	\$(202,671)	\$(53,560)

(1) Retrospectively adjusted as discussed in Note 1—"Summary of Significant Accounting Policies" in our Notes to Condensed Financial Statements.

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

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SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT—

CHENIERE ENERGY PARTNERS, L.P.

CONDENSED STATEMENT OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2013	2012 (1)	2011 (1)
Cash flows from operating activities	\$(13,056)	\$(17,508)	\$(13,948)
Cash flows from investing activities			
Investment in subsidiaries	(405,452)	(1,785,866)	(38,333)
Distributions received from affiliates, net	369,726	61,529	59,910
Purchase of Creole Trail Pipeline Business, net	(313,892)	—	—
Other	—	3	—
Net cash used in investing activities	(349,618)	(1,724,334)	21,577
Cash flows from financing activities:			
Proceeds from sale of Class B units	—	1,887,342	—
Distributions to owners	(91,386)	(57,821)	(48,149)
Proceeds from sale of partnership common and general partner units, net	375,897	250,021	70,157
Deferred financing costs	—	(874)	—
Net cash provided by financing activities	284,511	2,078,668	22,008
Net increase in cash and cash equivalents	(78,163)	336,826	29,637
Cash and cash equivalents—beginning of year	392,945	56,119	26,482
Cash and cash equivalents—end of year	\$314,782	\$392,945	\$56,119

(1) Retrospectively adjusted as discussed in Note 1—"Summary of Significant Accounting Policies" in our Notes to Condensed Financial Statements.

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

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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. We also revised the presentation in prior periods of distributions received from affiliates, net within our Condensed Statement of Cash Flows to conform to the presentation adopted in 2013. This reclassification had no effect on our overall consolidated financial position or results of operations.

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

NOTE 2—SUPPLEMENTAL CASH FLOW INFORMATION AND DISCLOSURES OF NON-CASH TRANSACTIONS

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Non-cash capital contributions (1)	\$ (243,942)	\$ (132,121)	\$ (17,953)
Non-cash capital contributions related to the Creole Trail Pipeline Business (1)	(18,150)	(25,295)	(22,541)

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHENIERE ENERGY PARTNERS, L.P.

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

By: /s/ Charif Souki
Charif Souki
Chief Executive Officer and
Chairman of the Board

Date: February 21, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the general partner of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Charif Souki Charif Souki	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 21, 2014
/s/ R. Keith Teague R. Keith Teague	President and Chief Operating Officer, Director (Principal Operating Officer)	February 21, 2014
/s/ Michael J. Wortley Michael J. Wortley	Senior Vice President and Chief Financial Officer, Director (Principal Financial Officer)	February 21, 2014
/s/ Leonard Travis Leonard Travis	Chief Accounting Officer (Principal Accounting Officer)	February 21, 2014
/s/ James R. Ball James R. Ball	Director	February 21, 2014
/s/ David I. Foley David I. Foley	Director	February 21, 2014
/s/ Meg A. Gentle Meg A. Gentle	Director	February 21, 2014
/s/ Sean T. Klimczak Sean T. Klimczak	Director	February 21, 2014
/s/ Lon McCain Lon McCain	Director	February 21, 2014
/s/ Philip Meier Philip Meier	Director	February 21, 2014

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/s/ Vincent Pagano Jr. Vincent Pagano Jr.	Director	February 21, 2014
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/s/ Oliver G. Richard, III Oliver G. Richard, III	Director	February 21, 2014
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