CHENIERE ENERGY INC
Form 10-K
February 19, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
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. 001-16383
CHENIERE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	95-4352386
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
700 Milam Street, Suite 1900	
Houston, Texas	77002
(Address of principal executive offices)	(Zip code)

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

Common Stock, $ 0.003 par value	NYSE MKT
(Title of Class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
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 ¨
Non-accelerated filer ¨	Smaller reporting company ¨

(Do not check if a smaller reporting company)
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

The aggregate market value of the registrant’s Common Stock held by non-affiliates of the registrant was approximately $15.8 billion as of June 30, 2015.

235,615,085 shares of the registrant’s Common Stock, $0.003 par value, were outstanding as of February 12, 2016.

Documents incorporated by reference: The definitive proxy statement for the registrant’s Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant’s fiscal year) is incorporated by reference into Part III.

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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 terms listed below have the following meanings:

Common Industry and Other Terms

Bcf/d	billion cubic feet per day
Bcf/yr	billion cubic feet per year
Bcfe	billion cubic feet equivalent
DOE	U.S. Department of Energy
EPC	engineering, procurement and construction
FERC	Federal Energy Regulatory Commission
FTA countries	countries with which the United States has a free trade agreement providing for national treatment for trade in natural gas
GAAP	generally accepted accounting principles in the United States
Henry Hub	the final settlement price (in USD per MMBtu) for the New York Mercantile Exchange's Henry Hub natural gas futures contract for the month in which a relevant cargo's delivery window is scheduled to begin
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas, a product of natural gas consisting primarily of methane (CH_4) that is in liquid form at near atmospheric pressure
MMBtu	million British thermal units, an energy unit
mtpa	million tonnes per annum
non-FTA countries	countries without a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
SEC	Securities and Exchange Commission
SPA	LNG sale and purchase agreement
Train	An industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
TUA	terminal use agreement

Abbreviated Organizational Structure

The following diagram depicts our abbreviated organizational structure as of December 31, 2015, including our ownership of certain subsidiaries, and the references to these entities used in this annual report:

Unless the context requires otherwise, references to “Cheniere,” the “Company,” “we,” “us” and “our” refer to Cheniere Energ Inc. (NYSE MKT: LNG) and its consolidated subsidiaries, including our publicly traded subsidiaries, Cheniere Partners (NYSE MKT: CQP) and Cheniere Holdings (NYSE MKT: CQH).

Unless the context requires otherwise, references to the “CCH Group” refer to CCH HoldCo II, CCH HoldCo I, CCH, CCL and CCP, collectively. References to the “CCL Stage III entities” refer to Corpus Christi Liquefaction Stage III, LLC and Cheniere Corpus Christi Pipeline Stage III, LLC.

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 that we expect to commence or complete construction of our proposed LNG terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions thereof, by certain dates, or at all;
- statements regarding future levels of domestic and international natural gas production, supply or consumption or future levels of LNG imports into or exports from North America and other countries worldwide or purchases of natural gas, regardless of the source of such information, or the transportation or other infrastructure or demand for and prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements relating to the construction of our Trains, including statements concerning the engagement of any EPC contractor or other contractor and the anticipated terms and provisions of any agreement with any EPC or other contractor, and anticipated costs related thereto;
- statements regarding any SPA or other agreement to be entered into or performed substantially in the future, including any revenues anticipated to be received and the anticipated timing thereof, and statements regarding the amounts of total LNG regasification, liquefaction or storage capacities that are, or may become, subject to contracts;
- statements regarding counterparties to our commercial contracts, construction contracts and other contracts;
- statements regarding our planned development and construction of additional Trains, including the financing of such Trains;
- statements that our Trains, when completed, will have certain characteristics, including amounts of liquefaction capacities;
- statements regarding our business strategy, our strengths, our business and operation plans or any other plans, forecasts, projections, or objectives, including anticipated revenues 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 su 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 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.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

Cheniere, a Delaware corporation, was organized in 1983 and is a Houston-based energy company primarily engaged in LNG-related businesses. We own and operate the Sabine Pass LNG terminal in Louisiana through our ownership interest in and management agreements with Cheniere Partners, which is a publicly traded limited partnership that we created in 2007. We own 100% of the general partner interest in Cheniere Partners and 80.1% of Cheniere Holdings, which is a publicly traded limited liability company formed in 2013 that owns a 55.9% limited partner interest in Cheniere Partners. We are currently developing and constructing two natural gas liquefaction and export facilities.

The Sabine Pass LNG terminal is located on the Sabine-Neches Waterway less than four miles from the Gulf Coast. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' wholly owned subsidiary, SPLNG, that include existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. Cheniere Partners is developing and constructing natural gas liquefaction facilities (the "SPL Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through a wholly owned subsidiary, SPL. Cheniere Partners is constructing five Trains and developing a sixth Train, each of which is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. Cheniere Partners also owns a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through a wholly owned subsidiary, CTPL.

We are developing and constructing a second natural gas liquefaction and export facility at the Corpus Christi LNG terminal, which is on nearly 2,000 acres of land that we own or control near Corpus Christi, Texas, and a pipeline facility (the "CCL Project") through wholly owned subsidiaries CCL and CCP, respectively. The CCL Project is being developed for up to three Trains, with expected aggregate nominal production capacity of approximately 13.5 mtpa of LNG, three LNG storage tanks with capacity of approximately 10.1 Bcfe and two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters. The CCL Project is being developed in stages. The first stage ("Stage 1") includes Trains 1 and 2, two LNG storage tanks, one complete marine berth and a second partial berth and all of the CCL Project's necessary infrastructure facilities. The second stage ("Stage 2") includes Train 3, one LNG storage tank and the completion of the second partial berth. The CCL Project also includes a 23-mile, 48-inch natural gas supply pipeline that will interconnect the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline").

The CCL Stage III entities, wholly owned subsidiaries of Cheniere separate from the CCH Group, are also developing two additional Trains and one LNG storage tank at the Corpus Christi LNG terminal adjacent to the CCL Project, along with a second natural gas pipeline.

Cheniere Marketing is engaged in the LNG and natural gas marketing business and is developing a portfolio of long-term, short-term and spot SPAs. Cheniere Marketing has entered into SPAs with SPL and CCL to purchase LNG produced by the SPL Project and the CCL Project.
We are also in various stages of developing other projects which, among other things, will require acceptable commercial and financing arrangements before we make a final investment decision ("FID").

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.

Although results are consolidated for financial reporting, Cheniere, Cheniere Holdings, Cheniere Partners, SPL, SPLNG, CTPL and the CCH Group operate with independent capital structures. The following diagram depicts our abbreviated capital structure as of December 31, 2015:

Our Business Strategy

Our primary business strategy is to develop energy and infrastructure assets with a focus on integrating the U.S. energy market, where supplies are abundant and inexpensive to produce, with international markets, where existing energy supplies are either uncompetitive or insufficient to satisfy growing demand. We plan to implement our strategy by:

- completing construction and commencing operation of the first five Trains of the SPL Project and the first two Trains of the CCL Project;
- obtaining the requisite long-term commercial contracts and financing to reach an FID regarding Train 3 of the CCL Project and Train 6 of the SPL Project;
- safely, efficiently and reliably maintaining and operating our assets;
- developing business relationships for the marketing of additional long-term and short-term agreements for Cheniere Marketing's LNG volumes or additional LNG liquefaction projects or expansions;
- expanding our existing asset base through acquisitions or development of complementary businesses or assets across the LNG value chain; and
- maintaining a flexible capital structure to finance the acquisition, development, construction and operation of the energy assets needed to supply our customers.

Business Segments

Our business activities are conducted by two operating segments for which we provide information in our Consolidated Financial Statements for the years ended December 31, 2015, 2014 and 2013. These two segments are:

- LNG terminal business; and
- LNG and natural gas marketing business.

For information about our segments' revenues, profits and losses and total assets, see Note 17—Business Segment Information of our Notes to Consolidated Financial Statements.

LNG Terminal Business

We began developing our LNG terminal business in 1999 and were among the first companies to secure sites and commence development of new LNG terminals in North America. We are currently focusing our development efforts on two LNG terminal projects currently under construction: the Sabine Pass LNG terminal in western Cameron Parish, Louisiana, less than four miles from the Gulf Coast on the Sabine-Neches Waterway; and the Corpus Christi LNG terminal near Corpus Christi, Texas. Through Cheniere Partners, we have constructed and are operating regasification facilities at the Sabine Pass LNG terminal and are developing and constructing the SPL Project. We own 100% of the general partner interest in Cheniere Partners and 80.1% of Cheniere Holdings, which owns a 55.9% limited partner interest in Cheniere Partners. We currently own a 100% interest in the CCL Project.

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 SPLNG's customers are required to pay fixed monthly fees, whether or not they use the LNG terminal. Each of Total Gas & Power North America, Inc. ("Total") and Chevron U.S.A. Inc. ("Chevron") has reserved approximately 1.0 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009. Total S.A. has guaranteed Total's obligations under its TUA up to $2.5 billion, subject to certain exceptions, and Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

The remaining approximately 2.0 Bcf/d of capacity has been reserved under a TUA by SPL. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, continuing until at least 20 years after SPL delivers its first commercial cargo at the SPL Project. SPL entered into a partial TUA assignment agreement with Total, whereby SPL will progressively gain access to Total's capacity and other services provided under Total's TUA with SPLNG. This agreement will provide SPL 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 SPL to more flexibly manage its LNG storage capacity with the commencement of Train 1. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA.

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

Liquefaction Facilities

The SPL Project is being developed and constructed at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. We 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. In June 2015, we commenced construction of Train 5 and the related facilities.

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term and to non-FTA countries for a 20-year term. The DOE further issued an order authorizing SPL to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. SPL's application for authorization to export that same 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries is currently pending at the DOE. Additionally, the DOE issued orders authorizing SPL to export up to a combined total of 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries and non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order pertaining to the 503.3 Bcf/yr, and the DOE has not yet issued a final ruling on the rehearing request. In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 5 to 10 years from the date the order was issued. Furthermore, the DOE issued an order authorizing SPL to export up to 600 Bcf in total of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing on January 15, 2016.

As of December 31, 2015, the overall project completion percentages for Trains 1 and 2 and Trains 3 and 4 of the SPL Project were approximately 97.4% and 79.5%, respectively. As of December 31, 2015, the overall project completion percentage for Train 5 of the SPL Project was approximately 14.9% with engineering, procurement and construction approximately 41.9%, 20.5% and 0.1% complete, respectively. As of December 31, 2015, the overall project completion of each of our Trains was ahead of the contractual schedule. We produced our first LNG from Train 1 of the SPL Project in February 2016. Based on our current construction schedule, we anticipate that Train 2 will produce LNG as early as mid-2016 and Trains 3 through 5 are expected to commence operations on a staggered basis thereafter.

Customers

SPL has entered into six fixed price, 20-year SPAs with third parties that in the aggregate equate to approximately 19.75 mtpa of LNG, which is approximately 88% of the expected aggregate nominal production capacity of Trains 1 through 5, that commence with the date of first commercial delivery for Trains 1 through 5. Under these SPAs, the customers will purchase LNG from SPL 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 the contracted volumes 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 a specified Train. As of December 31, 2015, SPL 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, SPL 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 Aprovisionamientos 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, SPL has agreed to make up to 285,000 MMBtu/d of LNG available to Gas Natural Fenosa to the extent that Train 2 becomes commercially operable prior to the beginning of the first delivery window with a fixed fee of $2.49 per MMBtu, if produced. The obligations of Gas Natural Fenosa are guaranteed by Gas Natural SDG S.A., a company organized under the laws of Spain.

- Korea Gas Corporation ("KOGAS") has entered into an SPA that commences upon the date of first commercial delivery for Train 3 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of $3.00 per MMBtu, equating to expected annual contracted cash flow from fixed fees of approximately $548 million. KOGAS is organized under the laws of the Republic of Korea.
- GAIL (India) Limited ("GAIL") has entered into an SPA that commences upon the date of first commercial delivery for Train 4 and includes an annual contract quantity of 182,500,000 MMBtu of LNG with a fixed fee of $3.00 per MMBtu,

equating to expected annual contracted cash flow from fixed fees of approximately $548 million. GAIL is organized under the laws of India.

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

In aggregate, the fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion annually for Trains 1 through 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 SPL to purchase, at Cheniere Marketing’s option, any LNG produced by SPL in excess of that required for other customers.

Natural Gas Transportation and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has also entered into enabling agreements and natural gas purchase agreements with third parties in order to secure natural gas feedstock for the SPL Project. As of December 31, 2015, SPL has secured up to approximately 2,154.2 million MMBtu of natural gas feedstock through natural gas purchase agreements.

Natural Gas Storage Services

For SPL’s natural gas storage requirements, SPL has entered into firm storage services agreements with third parties. The storage services agreements will assist SPL in managing volatility in natural gas needs for the SPL Project.

Construction

SPL entered into lump sum turnkey contracts with Bechtel Oil, Gas and Chemicals, Inc. (“Bechtel”) for the engineering, procurement and construction of Trains 1 through 5, under which Bechtel charges a lump sum for all work performed and generally bears project cost risk unless certain specified events occur, in which case Bechtel may cause SPL to enter into a change order, or SPL agrees with Bechtel to a change order.

The total contract prices of the EPC contract for Trains 1 and 2, the EPC contract for Trains 3 and 4 and the EPC contract for Train 5 of the SPL Project are approximately $4.1 billion, $3.8 billion and $3.0 billion, respectively, reflecting amounts incurred under change orders through December 31, 2015. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.0 billion and $18.0 billion after financing costs including, in each case, estimated owner’s costs and contingencies.

Pipeline Facilities

During the third quarter of 2015, CTPL completed construction of certain modifications to allow the Creole Trail Pipeline to be able to transport natural gas to the Sabine Pass LNG terminal.

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Final Investment Decision on Train 6

We will contemplate making an FID to commence construction of Train 6 of the SPL Project based upon, among other things, entering into an EPC contract, entering into acceptable commercial arrangements and obtaining adequate financing to construct the Train.

Corpus Christi LNG Terminal

Liquefaction Facilities

The CCL Project is being developed and constructed at the Corpus Christi LNG terminal, on nearly 2,000 acres of land that we own or control near Corpus Christi, Texas. In December 2014, we received authorization from the FERC to site, construct and operate Stages 1 and 2 of the CCL Project. In May 2015, we commenced construction of Stage 1 of the CCL Project.

Through the CCL Stage III entities, which are separate from the CCH Group, we are developing two additional Trains and one LNG storage tank at the Corpus Christi LNG terminal adjacent to the CCL Project, along with a second natural gas pipeline, and we commenced the regulatory approval process in June 2015.

The DOE has authorized the export of up to a combined total of the equivalent of 15 mtpa (approximately 767 Bcf/yr) of domestically produced LNG by vessel from the CCL Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order, and the DOE has not yet issued a final ruling on the rehearing request. Additionally, the DOE has authorized the export of up to a combined total of the equivalent of 514 Bcf/yr of domestically produced LNG by vessel from the two additional Trains being developed adjacent to the CCL Project to FTA countries for a 20-year term. The application for authorization to export that same 514 Bcf/yr of domestically produced LNG by vessel to non-FTA countries is currently pending at the DOE. In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 7 to 10 years from the date the order was issued.

As of December 31, 2015, the overall project completion percentage for Stage 1 of the CCL Project was approximately 29.2% with engineering, procurement and construction approximately 93.6%, 41.9% and 2.2% complete, respectively. The construction of the Corpus Christi Pipeline is planned to commence in 2016. Based on our current construction schedule, we anticipate that Train 1 of the CCL Project will produce LNG as early as late 2018, and Train 2 is expected to commence operations several months thereafter.

Customers

CCL has entered into seven fixed price, 20-year SPAs with six third parties that in the aggregate equate to approximately 7.7 mtpa of LNG, which is approximately 86% of the expected aggregate nominal production capacity of Trains 1 and 2, that commence with the date of first commercial delivery for Trains 1 and 2. In addition, CCL has entered into one fixed price, 20-year SPA with a third party for another 0.8 mtpa of LNG that commences with the date of first commercial delivery for Train 3. Under these eight SPAs, the customers will purchase LNG from CCL for a price consisting of a fixed fee of $3.50 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 the contracted volumes 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 a specified Train. As of December 31, 2015, CCL had the following third-party SPAs:

- Endesa Generación, S.A. (which subsequently assigned its SPA to Endesa S.A.) and Endesa S.A. (together, “Endesa”) have each entered into SPAs that commence upon the date of first commercial delivery for Train 1 and include an aggregate annual contract quantity of 117,322,500 MMBtu of LNG, equating to expected annual contracted cash flow from fixed fees of approximately $411 million. Endesa is organized under the laws of Spain.
- Iberdrola S.A. (“Iberdrola”) has entered into an SPA that commences upon the date of first commercial delivery for Train 2 and includes an annual contract quantity of 39,670,000 MMBtu of LNG, equating to expected annual contracted cash flow from fixed fees of approximately $139 million. In addition, CCL will provide Iberdrola with bridging volumes of 19,840,000 MMBtu per contract year, starting on the date on which Train 1 of the CCL Project becomes commercially

operable and ending on the date of the first commercial delivery of LNG from Train 2 of the CCL Project. Iberdrola is organized under the laws of Spain.

- Gas Natural Fenosa LNG SL ("Gas Natural Fenosa LNG") has entered into an SPA that commences upon the date of first commercial delivery for Train 2 and includes an annual contract quantity of 78,215,000 MMBtu of LNG, equating to expected annual contracted cash flow from fixed fees of approximately $274 million. The obligations of Gas Natural Fenosa LNG are guaranteed by Gas Natural SDG, S.A., a company organized under the laws of Spain.
- Woodside Energy Trading Singapore Pte Ltd ("Woodside") has entered into an SPA that commences upon the date of first commercial delivery for Train 2 and includes an annual contract quantity of 44,120,000 MMBtu of LNG, equating to expected annual contracted cash flow from fixed fees of approximately $154 million. The obligations of Woodside are guaranteed by Woodside Petroleum, LTD, a company organized under the laws of Australia.
- PT Pertamina (Persero) ("Pertamina") has entered into an SPA that commences upon the date of first commercial delivery for Train 1 and includes an annual contract quantity of 39,680,000 MMBtu of LNG (plus, for the contract year in which Train 2 becomes commercially operable and each subsequent year, an additional 39,680,000 MMBtu of LNG), equating to expected aggregate annual contracted cash flow from fixed fees of approximately $278 million once Train 2 becomes commercially operable. Pertamina is organized under the laws of Indonesia.
- Électricité de France, S.A. ("EDF") has entered into an SPA that commences upon the date of first commercial delivery for Train 2 and includes an annual contract quantity of 40,000,000 MMBtu of LNG, equating to expected annual contracted cash flow from fixed fees of approximately $140 million. EDF is organized under the laws of France.
- EDP Energias de Portugal S.A. ("EDP") has entered into an SPA that commences upon the date of first commercial delivery for Train 3 and includes an annual contract quantity of 40,000,000 MMBtu of LNG, equating to expected annual contracted cash flow from fixed fees of approximately $140 million. EDP is organized under the laws of Portugal.

In aggregate, the fixed fee portion to be paid by the third-party SPA customers is approximately $1.4 billion annually for Trains 1 and 2, and $1.5 billion if we make a positive FID with respect to Stage 2 of the CCL Project, with the applicable fixed fees starting from the commencement of commercial operations of the applicable Train. These fixed fees equal approximately $550 million, $846 million and $140 million for each of Trains 1 through 3, respectively.

Natural Gas Transportation and Supply

To ensure CCL is able to transport adequate natural gas feedstock to the Corpus Christi LNG Terminal, CCL has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CCP and third-party pipeline companies. CCL has also entered into enabling agreements with third parties and will continue to enter into such agreements in order to secure natural gas feedstock for the CCL Project.

Construction

CCL entered into separate lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Stages 1 and 2 of the CCL Project under which Bechtel charges a lump sum for all work performed and generally bears project cost risk unless certain specified events occur, in which case Bechtel may cause CCL to enter into a change order, or CCL agrees with Bechtel to a change order.

The total contract prices of the EPC contracts for Stages 1 and 2, which do not include the Corpus Christi Pipeline, are approximately $7.5 billion and $2.4 billion, respectively, reflecting amounts incurred under change orders through December 31, 2015. Total expected capital costs for Stages 1 and 2 are estimated to be between $12.0 billion and $13.0 billion before financing costs, and between $15.0 billion and $16.0 billion after financing costs including, in each case, estimated owner's costs and contingencies. Total expected capital costs for Stage 1 only are estimated to be between $9.0 billion and $10.0 billion before financing costs, and between $11.0 billion and $12.0 billion after financing costs including, in each case, estimated owner's costs and contingencies.

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Pipeline Facilities

In December 2014, the FERC issued a certificate of public convenience and necessity under Section 7(c) of the Natural Gas Act of 1938, as amended (the “NGA”), authorizing CCP to construct and operate the Corpus Christi Pipeline. The Corpus Christi Pipeline is designed to transport 2.25 Bcf/d of natural gas feedstock required by the CCL Project from the existing regional natural gas pipeline grid.

Final Investment Decision on Stage 2

We will contemplate making an FID to commence construction of Stage 2 of the CCL Project based upon, among other things, entering into acceptable commercial arrangements and obtaining adequate financing to construct the facility.

Liquefaction Project Milestones

The following table summarizes significant milestones and anticipated completion dates in the development of our liquefaction projects at the Sabine Pass LNG terminal and the Corpus Christi LNG terminal:

	Target Date	
	Sabine Pass LNG terminal	Corpus Christi LNG terminal
Milestone	Trains 1 - 5	Trains 1 - 2
DOE export authorization	Received	Received
Definitive commercial agreements	Completed 19.75 mtpa	Completed 7.7 mtpa
BG	5.5 mtpa	
Gas Natural Fenosa	3.5 mtpa	
KOGAS	3.5 mtpa	
GAIL	3.5 mtpa	
Total	2.0 mtpa	
Centrica	1.75 mtpa	
Pertamina		1.52 mtpa
Endesa		2.25 mtpa
Iberdrola		0.76 mtpa
Gas Natural Fenosa LNG		1.50 mtpa
Woodside		0.85 mtpa
EDF		0.77 mtpa
EPC contracts	Completed	Completed
Financing	Completed	Completed
FERC authorization	Completed	Completed
Issue Notice to Proceed	Completed	Completed
Commence operations	2016 - 2019	2018/2019

Competition

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

The SPL Project currently does not experience competition with respect to Trains 1 through 5. SPL has entered into six fixed price, 20-year SPAs with third parties that will utilize substantially all of the liquefaction capacity available from these Trains. The CCL Project currently does not experience competition with respect to Trains 1 and 2. CCL has entered into seven fixed price, 20-year SPAs with six third parties that will utilize a substantial majority 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 SPL or CCL need to replace any existing SPA or enter into new SPAs, they will compete on the basis of price per contracted volume of LNG with each other and other natural gas liquefaction projects throughout the world. Revenues associated with any incremental volumes, including those under the SPAs with Cheniere Marketing discussed above, will also be subject to market-based price competition. Many of the companies with which we compete are major energy corporations with longer operating histories, more development experience, greater name recognition, greater financial, technical and marketing resources and greater access to markets than us.

Governmental Regulation

Our LNG terminals are subject to extensive regulation under federal, state and local statutes, rules, regulations and laws. These laws require that we engage in consultations with appropriate federal and state agencies and that we obtain and maintain applicable permits and other authorizations. This regulatory requirement increases our cost of operations and construction, and failure to comply with such laws could result in substantial penalties.

Federal Energy Regulatory Commission

The design, construction and operation of our liquefaction facilities and the export of LNG and the transportation of natural gas through the Creole Trail Pipeline and the Corpus Christi Pipeline are highly regulated activities. In order to site and construct our LNG terminals, we received and are required to maintain authorizations from the FERC under Section 3 of the NGA. The FERC’s approval under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, are required in order to site, construct and operate our liquefaction facilities.

The Energy Policy Act of 2005 (the “EPAct”) amended Section 3 of the NGA to establish or clarify the FERC’s exclusive authority to approve or deny an application for the siting, construction, expansion or operation of LNG terminals, although except as specifically provided in the EPAct, nothing in the EPAct is intended to affect otherwise applicable law related to any other federal agency’s authorities or responsibilities related to LNG terminals. The FERC issued final orders in April and July 2012 approving our application for an order under Section 3 of the NGA authorizing the siting, construction and operation of Trains 1 through 4 of the SPL Project. Subsequently, the FERC issued written approval to commence site preparation work for Trains 1 through 4. In October 2012, we applied to amend the FERC approval to reflect certain modifications to the SPL Project, and in August 2013, the FERC issued an order approving the modifications. In October 2013, we applied to further amend the FERC approval, requesting authorization to increase the total 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. In February 2014, the FERC issued an order approving the October 2013 application (the “February 2014 Order”). A party to the proceeding requested a rehearing of the February 2014 Order, and in September 2014, the FERC denied rehearing. The party petitioned the U.S. Court of Appeals for the District of Columbia Circuit to review the February 2014 Order and the FERC Order Denying Rehearing, and that appeal is still pending. In September 2013, we filed an application with the FERC for authorization to add Trains 5 and 6 to the SPL Project, which was granted by the FERC in April 2015.

In order to construct, own, operate and maintain the Creole Trail Pipeline, CTPL received a certificate of public convenience and necessity from the FERC under Section 7 of the NGA. The FERC’s approval under Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, may be required prior to making any modifications to the Creole Trail Pipeline as it is a regulated, interstate natural gas pipeline. The FERC also approved CTPL’s application for authorization to construct, own, operate and maintain certain new facilities in order to enable bi-directional natural gas flow on the Creole Trail Pipeline system to allow for the delivery of up to

1,530,000 Dthd of feed gas to the SPL Project. In November 2013, CTPL received approval from the Louisiana Department of Environmental Quality (“LDEQ”) for the proposed modifications and, with subsequent final FERC clearance, construction was completed in 2015.

In December 2014, the FERC issued an order granting CCL authorization under Section 3 of the NGA to site, construct and operate Stages 1 and 2 of the CCL Project and granting CCP a certificate of public convenience and necessity under Section 7(c) of the NGA to construct and operate the Corpus Christi Pipeline (the “December 2014 Order”). A party to the proceeding requested a rehearing of the December 2014 Order, and in May 2015, the FERC denied rehearing. The party petitioned the U.S. Court of Appeals for the District of Columbia Circuit to review the December 2014 Order and the FERC Order Denying Rehearing, and that appeal is still pending.

Several other material governmental and regulatory approvals and permits will be required prior to construction and operation of our liquefaction projects. In addition, the FERC authorization requires us to obtain certain additional FERC approvals as construction progresses. To date, we have been able to obtain these approvals as needed and the need for these approvals has not materially affected our construction progress. Throughout the life of our LNG terminals, we will be subject to regular reporting requirements to the FERC, the U.S. Department of Transportation and applicable state regulatory agencies regarding the operation and maintenance of our facilities.

In addition to the siting and construction authority with respect to the LNG terminals under the NGA, the FERC has authority to approve, and if necessary, set "just and reasonable rates" for the transportation or sale of natural gas in interstate commerce. In addition, under the NGA, our pipelines are not permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service. The FERC has the authority to grant certificates allowing construction and operation of facilities used in interstate gas transportation and authorizing the provision of services. Under the NGA, the FERC's jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial or any other use and to natural gas companies engaged in such transportation or sale. However, the FERC's jurisdiction does not extend to the production, gathering or local distribution of natural gas.

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

- rates and charges for natural gas transportation and related services;
- the certification and construction of new facilities;
- the extension and abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

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

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

DOE Export License

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term and to non-FTA countries for a 20-year term. The DOE further issued an order authorizing SPL to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. SPL's application for authorization to export that same 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries is currently pending at the DOE. Additionally, the DOE issued orders authorizing SPL to export up to a combined total of 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries and non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order pertaining to the 503.3 Bcf/yr, and the DOE has not yet issued a final ruling on the rehearing request. Furthermore, the DOE issued an order authorizing SPL to export up to 600 Bcf in total of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing on January 15, 2016.

The DOE has authorized the export of up to a combined total of the equivalent of 15 mtpa (approximately 767 Bcf/yr) of domestically produced LNG by vessel from the CCL Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order, and the DOE has not yet issued a final ruling on the rehearing request. Additionally, the DOE has authorized the export of up to a combined total of the equivalent of 514 Bcf/yr of domestically produced LNG by vessel from the two additional Trains being developed adjacent to the CCL Project to FTA countries for a 20-year term. The application for authorization to export that same 514 Bcf/yr of domestically produced LNG by vessel to non-FTA countries is currently pending at the DOE.

In each case, other than as otherwise specified, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 5 to 10 years from the date the order was issued.

Exports of natural gas to FTA countries are “deemed to be consistent with the public interest” and authorization to export LNG to FTA countries shall be granted by the DOE without “modification or delay.” FTA countries which import LNG now or will do so by 2016 include Chile, Mexico, Singapore, South Korea and the Dominican Republic. Exports of natural gas to non-FTA countries are considered by the DOE in the context of a comment period whereby interveners are provided the opportunity to assert that such authorization would not be consistent with the public interest.

Pipelines

The Creole Trail Pipeline and the Corpus Christi Pipeline are also subject to regulation by the U.S. Department of Transportation (“DOT”), under the Pipeline and Hazardous Material Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities.

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

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

In March 2015, the PHMSA issued a final rule amending the pipeline safety regulations to update and clarify certain regulatory requirements, including who can perform post-construction inspections on transmission pipelines. In May 2015, the PHMSA issued a notice of proposed rulemaking proposing to amend gas pipeline safety regulations regarding plastic piping systems used in gas services, including the installation of plastic pipe used for gas transmission lines. In July 2015, the PHMSA issued a notice of proposed rulemaking proposing to add a specific timeframe for operators' notification of accidents or incidents, as well as amending the safety regulations regarding operator qualification requirements by expanding the requirements to include new construction and certain previously excluded operation and maintenance tasks, requiring a program effectiveness review and adding new recordkeeping requirements. These notices of proposed rulemaking are still pending at the PHMSA.

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

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

Pipeline Safety, Regulatory Certainty and Jobs Creation Act of 2011

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

Other Governmental Permits, Approvals and Authorizations

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

Three significant permits are the USACE Section 404 of the Clean Water Act/Section 10 of the Rivers and Harbors Act Permit (the “Section 10/404 Permit”), the Clean Air Act Title V (“Title V”) Operating Permit and the Prevention of Significant Deterioration (“PSD”) Permit, the latter two permits being issued by the LDEQ for the Sabine Pass LNG terminal and by the Texas Commission on Environmental Quality (“TCEQ”) for the CCL Project.

The application for revision of the Sabine Pass LNG terminal’s Section 10/404 Permit to authorize construction of Train 1 through Train 4 was submitted in January 2011. The process included a public comment period which commenced in March 2011 and closed in April 2011. The revised Section 10/404 Permit was received from the USACE in March 2012. An application for a further revision to the Section 10/404 Permit, to address wetlands impacted by the construction of Trains 5 and 6, was received from the USACE in June 2015. The USACE acted in the capacity as a cooperating agency in the FERC’s NEPA review process. In addition, a Section 10/404 permit application is pending with respect to the expansion of the Creole Trail Pipeline. These permits will require us to provide mitigation to compensate for the wetlands impacted by the respective projects. The application to amend the Sabine Pass LNG terminal’s existing Title V and PSD permits to authorize construction of Train 1 through Train 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, Cheniere Partners applied to the LDEQ for a further amendment to the Title V and PSD permits to reflect proposed modifications to the SPL 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, Cheniere Partners 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. The LDEQ issued the amended PSD and Title V permits in June 2015. These permits are final.

An application for an amendment to CCL's Section 10/404 Permit to authorize construction of the CCL Project was submitted in August 2012. The process included a public comment period which commenced in May 2013 and closed in June 2013. The permit was issued by the USACE in July 2014 and subsequently modified in October 2014. CCL applied for new PSD and Title V permits with the TCEQ in August 2012. The TCEQ issued the PSD permit for criteria pollutants in September 2014, the PSD permit for greenhouse gases ("GHG") in February 2015, and the Title V permit in July 2015.

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

In August 2012, Cheniere Corpus Christi Pipeline applied to the TCEQ for new PSD and Title V permits for the proposed compressor station at Sinton, Texas (the “Sinton Compressor Station”). The PSD permit for criteria pollutants at the Sinton Compressor Station was issued by the TCEQ in December 2013; and in November 2014, the TCEQ approved an alteration to the permit to reflect that the Sinton Compressor Station is now considered a minor source, and voided the PSD permit number. The Title V permit was received in May 2015.

In August 2014, the Sabine Pass LNG terminal’s existing wastewater discharge permit was modified by LDEQ to authorize the discharge of wastewaters from the liquefaction facilities, including wastewaters generated with respect to the anticipated operations of Trains 5 and 6. CCL was issued a waste water discharge permit in January 2014 authorizing discharges from the liquefaction facilities. The permit was issued in January 2014.

The Sabine Pass LNG terminal and the Corpus Christi LNG terminal are 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.

Environmental Regulation

Our LNG terminals are subject to various federal, state and local laws and regulations relating to the protection of the environment and natural resources. These environmental laws and regulations may impose substantial penalties for noncompliance and substantial liabilities for pollution. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial civil and criminal fines and penalties for non-compliance.

Clean Air Act (“CAA”)

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

In 2009, the EPA promulgated and finalized the Mandatory Greenhouse Gas Reporting Rule for multiple sections of the economy. This rule requires mandatory reporting of GHG emissions from stationary fuel combustion sources as well as all fugitive emissions throughout LNG terminals. From time to time, Congress has considered proposed legislation directed at reducing GHG emissions, and the EPA has defined GHG emissions thresholds for requiring certain permits for new and existing industrial sources. In addition, many states have already taken regulatory action to monitor and/or reduce emissions of GHGs, primarily through the development of GHG emission inventories or regional GHG cap and trade programs. It is not possible at this time to predict how future regulations or legislation may address GHG emissions and impact our business. However, future regulations and laws could result in increased compliance costs or additional operating restrictions and could have a material adverse effect on our business, financial position, operating results and cash flows.

Coastal Zone Management Act (“CZMA”)

Our LNG terminals are 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")

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

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

Our LNG terminals 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.

LNG and Natural Gas Marketing Business

Cheniere Marketing is engaged in the LNG and natural gas marketing business and is developing a portfolio of long-term, short-term and spot LNG SPAs. Cheniere Marketing has purchased, transported and unloaded commercial LNG cargoes into the Sabine Pass LNG terminal and other LNG terminals worldwide and has used trading strategies intended to maximize margins on these cargoes. Cheniere Marketing has secured the following rights and obligations to support its business:

- pursuant to an SPA with SPL, the right to purchase, at Cheniere Marketing’s option, any LNG produced by SPL in excess of that required for other customers;
- pursuant to SPAs with CCL, the right to purchase, at Cheniere Marketing’s option, any LNG produced by CCL not required for other customers; and
- a portfolio of LNG vessel time charters.

In addition, as of December 31, 2015, Cheniere Marketing has sold approximately 560 million MMBtu of LNG to be delivered to multiple investment grade counterparties between 2016 and 2023, with delivery obligations conditioned on the performance of the SPL Project and the CCL Project. The cargoes have been sold with a portfolio of delivery points, either on a Free on Board basis, delivered to the counterparty at the Sabine Pass LNG terminal, or a Delivered at Terminal (“DAT”) basis, delivered to the counterparty’s LNG receiving terminal. Cheniere Marketing has chartered LNG vessels to be utilized in DAT transactions. In addition, Cheniere Marketing has entered into a long-term agreement to sell LNG cargoes on a DAT basis. The agreement is conditioned upon the buyer achieving certain milestones, including reaching an FID related to certain projects and obtaining related financing.

LNG and Natural Gas Marketing Competition

In purchasing LNG, we compete for supplies of LNG with:

- large, multinational and national companies with longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources;
- oil and gas producers who sell or control LNG derived from their international oil and gas properties; and
- purchasers located in other countries where prevailing market prices can be substantially different from those in the United States.

In marketing LNG and natural gas, we compete for sales of LNG and natural gas with a variety of competitors, including:

- major integrated marketers who have large amounts of capital to support their marketing operations and offer a full-range of services and market numerous products other than natural gas;
- producer marketers who sell their own natural gas production or the production of their affiliated natural gas production company;
- small geographically focused marketers who focus on marketing natural gas for the geographic area in which their affiliated distributor operates; and
-

aggregators who gather small volumes of natural gas from various sources, combine them and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately.

LNG and Natural Gas Marketing Governmental Regulation

In 1992 and 1993, the FERC concluded that sellers of short-term or long-term natural gas supplies would not have market power over the sale for resale of natural gas. The FERC established light-handed regulation over sales for resale of natural gas and adopted regulations granting blanket certificates to allow entities selling natural gas to make interstate sales for resale at negotiated rates. In 2003, the FERC amended the blanket marketing certificates to require that all sellers adhere to a code of conduct with respect to natural gas sales. The code of conduct addresses such matters as natural gas withholding, manipulation of market prices, communication of accurate information and record retention.

The FERC's Standards of Conduct apply to interstate pipelines that conduct transmission transactions with an affiliate that engages in marketing functions. Interstate pipelines must treat all transmission customers on a not unduly discriminatory basis. The general principles of the Standards of Conduct are: (1) independent functioning, which requires transmission function employees to function independently of marketing function employees; (2) no-conduit rule, which prohibits passing transmission function information to marketing function employees; and (3) transparency, which imposes posting requirements to detect undue preference.

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

The prices at which we sell natural gas are not regulated, insofar as the interstate market is concerned and, for the most part, are not subject to state regulation. We are permitted to make sales of natural gas for resale in interstate commerce pursuant to a blanket marketing certificate automatically granted by the FERC. Our sales of natural gas will be affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation.

Commodity Futures Trading Commission ("CFTC")

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The regulatory regime created by the Dodd-Frank Act is designed primarily to (1) regulate certain participants in the swaps markets, including entities falling within the categories of "Swap Dealer" and "Major Swap Participant," (2) require clearing and exchange trading of certain classes of swaps as designated by the CFTC, (3) increase swap market transparency through robust reporting and recordkeeping requirements, (4) reduce financial risks in the derivatives market by imposing margin or collateral requirements on both cleared and, in certain cases, uncleared swaps, (5) establish position limits on certain swaps and futures products, and (6) otherwise enhance the rulemaking and enforcement authority of the CFTC and the SEC regarding the derivatives markets. As required by the Dodd-Frank Act, the CFTC, the SEC and other regulators have been promulgating rules and regulations implementing the regulatory provisions of the Dodd-Frank Act, although neither the CFTC nor the SEC has yet adopted or implemented all of the rules required by the Dodd-Frank Act. In addition, the CFTC and its staff regularly issue rule amendments and guidance, policy statements and letters interpreting or taking no-action positions, including time-limited no action positions, regarding the derivatives provisions of the Dodd-Frank Act and the rules of the CFTC under these provisions.

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

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

As required by provisions of the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require Swap Dealers and Major Swap Participants, including those that are regulated financial institutions, to collect initial and variation margin with respect to uncleared swaps from their counterparties that are financial end users, registered swap dealers or major swap participants. These rules do not require collection of margin from commercial end users who qualify for the end user exception from the mandatory clearing requirement or certain other counterparties. We expect to qualify as such a commercial end user with respect to the swaps that we enter into to hedge our commercial risks. The Dodd-Frank Act’s swaps regulatory provisions and the related rules may also adversely affect our existing derivative contracts and restrict our ability to monetize such contracts, cause us to restructure certain contracts, reduce the availability of derivatives to protect against risks or to optimize assets, adversely affect our ability to execute our hedging strategies and impact the liquidity of certain swaps products, all of which could increase our business costs.

Under the Commodity Exchange Act as amended by the Dodd-Frank Act, the CFTC is directed generally to prevent manipulation, including by fraudulent or deceptive practices, in two markets: (1) physical commodities traded in interstate commerce, including physical energy and other commodities, as well as (2) financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-manipulation and anti-disruptive trading practices regulations that prohibit, among other things, manipulative or deceptive schemes in the physical commodities, futures, options and swaps markets. Should we violate these laws and regulations, we could be subject to a CFTC enforcement action and material penalties, possibly resulting in changes in the rates we can charge.

European Market Infrastructure Regulation (“EMIR”)

EMIR is a European Union (“EU”) regulation designed to increase the stability of the OTC derivative markets throughout the EU member states. EMIR regulates OTC derivatives, central counterparties and trade repositories and imposes requirements for certain market participants with respect to derivatives reporting, clearing and risk mitigation. In addition, certain market participants are subject to a central counterparty clearing obligation and collateral requirements. All non-cleared derivatives require risk management, including timely confirmations of transactions, portfolio reconciliation, portfolio compression (when there exist 500 or more OTC derivatives outstanding with a counterparty) and dispute resolution. In addition, standards for the imposition of margin requirements under EMIR were proposed in June 2015, under which the exchange of initial and variation margin in respect of certain non-cleared derivatives would be required, including from non-financial counterparties that are above the EMIR clearing threshold for the class of derivatives involved. Further, for non-cleared derivatives, outstanding contracts must be marked to market value daily or marked to model where conditions necessitate. Other EMIR risk management requirements for non-cleared derivatives are being considered, but those requirements have yet to be finalized.

Under EMIR, covered entities must report all derivatives concluded and any modification or termination of a derivative to a registered or recognized trade repository within one business day of the transaction. Records related to derivatives must be retained for at least five years following termination.

Our subsidiaries and affiliates operating in the EU are subject to EMIR and its increased regulatory requirements for record keeping, marking to market, timely confirmation, derivative contract reporting, portfolio reconciliation, the posting of margin and dispute resolution. Regulation under EMIR could significantly increase the cost of derivative contracts, materially alter the terms of derivatives contracts and reduce the availability of derivatives to protect against risks that we encounter.

Regulation on Wholesale Energy Market Integrity and Transparency (“REMIT”)

REMIT is an EU regulation that prohibits market manipulation and insider trading in European wholesale energy markets and imposes various obligations on participants in these markets. REMIT requires persons who enter into transactions, including the placing of orders to trade, in one or more wholesale energy markets in the EU to notify the applicable national regulatory authority (“NRA”) of suspected breaches and implement procedures to identify breaches. All market participants, such as us, must disclose inside information and cannot use inside information to buy or sell wholesale energy products for their own account or on behalf of a third party, directly or indirectly, induce others to buy or sell wholesale energy products based on inside information, or disclose such inside information to any other person except in the normal course of employment. Market participants must also register with the relevant NRA (the Office of Gas and Electricity Markets ("Ofgem") is the NRA in the United Kingdom) and provide a record of wholesale energy market transactions to the European Agency for the Cooperation of Energy Regulators ("ACER") and information on capacity and utilization for production, storage, consumption or transmission. An affiliate of Cheniere Marketing is registered with Ofgem as a market participant under REMIT. Should we violate these laws and regulations, we could be subject to investigation and penalties.

Market participants and third parties acting on their behalf are required to report transactions in wholesale energy contracts admitted to trading at organized market places and fundamental data from the European Network of Transmission System Operators for Electricity (ENTSO) central information transparency platforms to ACER. Additional records of transactions and fundamental data with respect to the remaining wholesale energy contracts (OTC standard and non-standard supply contracts and transportation contracts) and reportable fundamental data from transmission system operators (TSOs), storage system operators (SSOs) and LNG system operators (LSOs) will have to be provided to ACER beginning April 7, 2016.

Markets in Financial Instruments Directive and Regulation ("MiFID II")

MiFID II is an EU directive that is due to apply starting January 3, 2017. Under the current regulatory regime, Markets in Financial Instruments Directive ("MiFID"), we are exempt from needing to have our trading activities authorized. MiFID II will narrow the scope of exemptions currently available and broadens the directive's application to include commodity derivatives that can be physically settled and are traded on an organized trading facility in addition to other regulated markets or multilateral trading facilities.

We expect to be eligible to trade on our own account in commodity derivatives without requiring authorization from the Financial Conduct Authority ("FCA") in the United Kingdom by relying on the "ancillary activity" exemption under MiFID II provided that (1) such activity is ancillary to our main business, when considered on a group basis, and that main business is not the provision of investment services or market making in relation to commodity derivatives; (2) we do not apply a high-frequency algorithmic trading technique; and (3) we notify the relevant competent authority on an annual basis that we are relying on this exemption and, upon request, report the basis upon which we fall within the exemption. If we are unable to meet the ancillary activity exemption, and no other exemption is available to us, then we will need to become authorized by the FCA in order to trade on our own account in commodity derivatives. FCA authorization would require additional regulatory obligations such as capital requirements, conduct of business rules, systems and control issues and approval by the FCA of significant controllers, i.e. our shareholders and certain persons involved in our management. A temporary exemption precludes commodity trading firms from the capital requirements of other investment firms until the end of 2017. This exemption is due for review prior to December 31, 2017.

Further, if we were to become authorized, we will be counted as a financial counterparty (instead of a non-financial counterparty) for the purpose of EMIR. This may require additional reporting obligations and risk mitigation requirements under EMIR, including collateral exchange and marking transactions either to market or to an approved model.

Market Abuse Regulation ("MAR")

MAR, which applies beginning on July 3, 2016, is intended to update and strengthen the existing EU market abuse framework by extending its scope to new markets and by introducing new requirements. MAR prohibits market abuse on EU regulated markets, which encompasses trading in financial instruments on the basis of inside information, the improper disclosure of inside information and the manipulation of market prices through practices such as the dissemination of rumors or the conducting of certain trades in financial instruments. This will apply to financial instruments (as defined under MiFID II) which are traded on an EU regulated market, a multilateral trading facility, or an organized trading facility as well as other financial instruments the price or value of which depends on or has an effect on the price or value of financial instruments.

Market Factors

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

We expect that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to oil and coal. Global demand for natural gas is projected by the International Energy Agency to grow by approximately 23 Tcf between 2013 and 2025, with LNG increasing its current share of approximately ten percent of the global market. Wood Mackenzie forecasts that global demand for LNG will increase by 72%, from approximately 245 mtpa, or 11.9 Tcf, in 2015, to 421 mtpa, or 20.5 Tcf, in 2025 and that LNG production from existing facilities and new facilities already under construction will be able to supply the market with 365 mtpa in 2025, resulting in a market need for construction of additional facilities capable of producing an incremental 56 mtpa of LNG. We believe our new projects that do not already have capacity sold under long-term contracts are competitive and well-positioned to capture a portion of this incremental market need.

We have limited exposure, particularly in the LNG terminal business for our seven Trains under construction, to the decline in oil prices, even if it persists for more than 12 months, as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements. These agreements contain fixed fees that are required to be paid even if the customers elect to cancel or suspend delivery of LNG cargoes. To date, we have contracted approximately 19.75 mtpa of aggregate production capacity for Trains 1 through 5 of the SPL Project with third-party customers. Train 6 has not been contracted to date. We have contracted approximately 7.7 mtpa for Trains 1 and 2 of the CCL Project, and approximately 0.8 mtpa for Train 3 of the CCL Project, with third-party customers. As of January 31, 2016, oil and gas futures prices indicate that LNG exported from the U.S. continues to be competitively priced, supporting the opportunity for U.S. LNG to fill uncontracted future demand through the execution of long-term, medium-term and short-term contracting of LNG from our terminals.

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 and the development and operation of our LNG and natural gas marketing business.

Employees

We had 888 full-time employees at January 31, 2016.

Available Information

Our common stock has been publicly traded since March 24, 2003 and is traded on the NYSE MKT under the symbol “LNG.” Our principal executive offices are located at 700 Milam Street, Suite 1900, Houston, Texas 77002, and our telephone number is (713) 375-5000. Our internet address is www.cheniere.com. We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC under the Exchange Act. These reports may be accessed free of charge through our internet website. We make our website content available for informational purposes only. The website should not be relied upon for investment purposes and is not incorporated by reference into this Form 10-K.

We will also make available to any stockholder, 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, Inc., Investor Relations Department, 700 Milam Street Suite 1900, Houston, Texas 77002 or call (713) 375-5000. In addition, the public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers, like us, that file electronically with the SEC.

ITEM 1A. RISK FACTORS

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 LNG Terminal Business;
- Risks Relating to Our LNG and Natural Gas Marketing Business;
- Risks Relating to Our LNG Businesses in General; and
- Risks Relating to Our Business in General.

Risks Relating to Our Financial Matters

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

As of December 31, 2015, we had $17.3 billion of total debt outstanding on a consolidated basis (before debt discounts and debt premiums), excluding $135.2 million of outstanding letters of credit. We incur, and will incur, significant interest expense relating to the assets at the Sabine Pass and Corpus Christi LNG terminals, and we anticipate needing to incur substantial additional debt and issue equity to finance the construction of Train 6 of the SPL Project and Train 3 of the CCL Project. Our ability to fund our capital expenditures and refinance our indebtedness will depend on our ability to access additional project financing as well as the debt and equity capital markets. A variety of factors beyond our control could impact the availability or cost of capital, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets. Our financing costs could increase or future borrowings or equity offerings may be unavailable to us or unsuccessful, which could cause us to be unable to pay or refinance our indebtedness or to fund our other liquidity needs. We also rely on borrowings under our credit facilities to fund our capital expenditures. If any of the lenders in the syndicates backing these facilities were unable to perform on its commitments, we may need to seek replacement financing, which may not be available as needed, or may be available in more limited amounts or on more expensive or otherwise unfavorable terms.

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

We had net losses of $975.1 million, $547.9 million and $507.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. In addition, our net cash flow used in operating activities was $265.6 million, $124.1 and $52.4 million for the years ended December 31, 2015, 2014 and 2013, respectively. We will continue to incur significant capital and operating expenditures while we develop and construct the SPL Project and the CCL Project. We currently expect that we will not begin to receive cash flows from operations under any SPA until early 2016, at the earliest. Any delays beyond the expected development period for Train 1 of the SPL Project would prolong, and could increase the level of, operating losses and negative operating cash flows. Our future liquidity may also be affected by the timing of construction financing availability in relation to the incurrence of construction costs and other outflows and by the timing of receipt of cash flows under SPAs in relation to the incurrence of project and operating expenses. Moreover, many factors (including factors beyond our control) could result in a disparity between liquidity sources and cash needs, including factors such as construction delays and breaches of agreements. Our ability to generate any significant positive operating cash flow and achieve profitability in the future is dependent on our ability to successfully and timely complete the applicable Train.

We may sell equity or equity-related securities or assets, including equity interests in Cheniere Partners or Cheniere Holdings. Such sales could dilute our stockholders' proportionate indirect interests in our assets, business operations and proposed liquefaction and other projects of Cheniere Partners or other subsidiaries, and could adversely affect the market price of our common stock.

We have pursued and are pursuing a number of alternatives in order to finance the construction of Train 6 of the SPL Project and Train 3 of the CCL Project, including potential issuances and sales of additional equity or equity-related securities by us, Cheniere Partners, or Cheniere Holdings. Such sales, in one or more transactions, could dilute our stockholders' proportionate indirect interests in our assets, business operations and proposed projects of Cheniere Partners, including the SPL Project, or in other subsidiaries or projects, including the CCL Project. In addition, such sales, or the anticipation of such sales, could adversely affect the market price of our common stock.

Our stockholders may experience dilution upon the conversion of our convertible notes.

In November 2014, we issued an aggregate principal amount of $1.0 billion Convertible Unsecured Notes due 2021 (the "2021 Cheniere Convertible Unsecured Notes") to RRJ Capital II Ltd, Baytree Investments (Mauritius) Pte Ltd and Seatown Lionfish Pte. Ltd. In March 2015, we issued $625.0 million aggregate principal amount of 4.25% Convertible Senior Notes due 2045 (the "2045 Cheniere Convertible Senior Notes") to certain investors through a registered direct offering. In May 2015, CCH HoldCo II issued $1.0 billion aggregate principal amount of 11% Convertible Senior Secured Notes due 2025 (the "2025 CCH HoldCo II Convertible Senior Notes" and together with the 2021 Cheniere Convertible Unsecured Notes and the 2045 Cheniere Convertible Senior Notes, the "Convertible Notes") to EIG Management Company, LLC. We have the option to satisfy the 2021 Cheniere Convertible Unsecured Notes and the 2045 Cheniere Convertible Senior Notes conversion obligations with cash, common stock or a combination thereof. The 2025 CCH HoldCo II Convertible Senior Notes conversion obligations must be satisfied with common stock. The 2021 Cheniere Convertible Unsecured Notes are convertible at an initial conversion price of $93.64. Prior to December 15, 2044, the 2045 Cheniere Convertible Senior Notes will be convertible upon the occurrence of certain conditions, and on and after such date they will become freely convertible. The 2045 Cheniere Convertible Senior Notes will become convertible into the common stock of Cheniere at an initial conversion price of $138.38 per share. Provided the total market capitalization of Cheniere at that time is not less than $10.0 billion, the 2025 CCH HoldCo II Convertible Senior Notes will be convertible at CCH HoldCo II's option on or after the later of (1) 58 months from May 1, 2015, and (2) the substantial completion of Train 2 of the CCL Project (the "Eligible Conversion Date"). The conversion price for 2025 CCH HoldCo II Convertible Senior Notes converted at CCH HoldCo II's option is the lower of (1) a 10% discount to the average of the daily volume-weighted average price ("VWAP") of our common stock for the 90 trading day period prior to the date on which notice of conversion is provided, and (2) a 10% discount to the closing price of our common stock on the trading day preceding the date on which notice of conversion is provided. At the option of the holders, the 2025 CCH HoldCo II Convertible Senior Notes are convertible on or after the six-month anniversary of the Eligible Conversion Date, provided the total market capitalization of Cheniere at that time is not less than $10.0 billion, at a conversion price equal to the average of the daily VWAP of our common stock for the 90 trading day period prior to the date on which notice of conversion is provided. The conversion of some or all of the Convertible Notes into shares of our common stock will dilute the ownership percentages and voting power of our existing stockholders. Based on the initial conversion price, if we elect to satisfy the entire conversion obligations of the 2021 Cheniere Convertible Unsecured Notes and the 2045 Cheniere Convertible Senior Notes with common stock, an aggregate of approximately 22.3 million shares of our common stock would be issued upon the conversion, assuming the notes are converted at maturity and all interest on the notes is paid in kind for the 2021 Cheniere Convertible Unsecured Notes. Because the conversion rate for the 2025 CCH HoldCo II Convertible Senior Notes will depend on the price of our common stock at the time of conversion, we cannot meaningfully estimate the number of shares of our common stock, if any, that would be issued upon the conversion of such notes; however, under these convertible notes, a maximum of 47,108,466 shares of our common stock (subject to adjustment in the event of a stock split) may be issued in the aggregate upon the conversion of all of the 2025 CCH HoldCo II Convertible Senior Notes. Any sales in the public market of the shares issuable upon conversion of the Convertible

Notes could adversely affect the prevailing market prices of our common stock. In addition, the existence of the Convertible Notes may encourage short selling by market participants because the conversion of the Convertible Notes could be used to satisfy short positions, or the anticipated conversion of the Convertible Notes into shares of our common stock could depress the price of our common stock.

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 SPLNG and agreed to pay SPLNG approximately $125 million annually, and upon satisfaction of the conditions precedent to payment thereunder, by six third-party customers that have entered into SPAs with SPL and agreed to pay SPL an aggregate of $2.9 billion annually in fixed fees; and upon satisfaction of the conditions precedent to payment thereunder, by six third-party customers that have entered into SPAs with CCL for Trains 1 and 2 and agreed to pay an aggregate of $1.4 billion annually in fixed fees. We are dependent on each customer’s continued willingness and ability to perform its obligations under its SPA. We are also exposed to the credit risk of any guarantor of these customers’ obligations under their respective TUA or SPA in the event that we must seek recourse under a guaranty. If any customer fails to perform its obligations under its TUA or SPA, our business, contracts, financial condition, operating results, cash flow, liquidity and prospects could be materially and adversely affected, even if we were ultimately successful in seeking damages from that customer or its guarantor for a breach of the TUA or SPA.

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

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

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

Our subsidiaries may be restricted under the terms of their indebtedness from making distributions under certain circumstances, which may limit Cheniere Partners’ ability to pay or increase distributions to us or inhibit our access to cash flows from the CCL Project and could materially and adversely affect us.

The agreements governing our subsidiaries’ indebtedness restrict payments that our subsidiaries can make to Cheniere Partners or us in certain events and limit the indebtedness that our subsidiaries can incur. For example, SPLNG may not make distributions 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. SPLNG 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 indentures governing the $1.7 billion of 7.50% Senior Secured Notes due 2016 and $0.4 billion of 6.50% Senior Secured Notes due 2020, both issued by SPLNG (the “SPLNG Indentures”). In order to satisfy this fixed charge coverage ratio test, we estimate that SPLNG’s consolidated cash flow, as defined in such indentures, must be greater than approximately $340 million. Thus, TUA payments from SPL and either Chevron or Total are needed to satisfy the test. If the fixed charge coverage ratio test is not satisfied, SPLNG will not be permitted by the SPLNG Indentures to make distributions to Cheniere Partners, which may prevent Cheniere Partners from making distributions to us and its other unitholders, which could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

SPL is likewise restricted from making distributions under agreements governing its indebtedness generally until, among other requirements, substantial completion of Trains 1 and 2 of the SPL Project has occurred, deposits are made into debt service reserve accounts and a debt service coverage ratio of 1.25:1.00 is satisfied.

CCH is restricted from making distributions under agreements governing its indebtedness generally until, among other requirements, the completion of the construction of Trains 1 and 2 of the CCL Project, funding of a debt service reserve account equal to six months of debt service and achieving a historical debt service coverage ratio and fixed projected debt service coverage ratio of at least 1.25:1.00.

CCH HoldCo II is restricted from making distributions to Cheniere under agreements governing its indebtedness generally until, among other requirements, Trains 1 and 2 of the CCL Project are in commercial operation and a historical debt service coverage ratio and a projected fixed debt services coverage ratio of 1.20:1.00 are achieved.

Our subsidiaries' inability to pay distributions to Cheniere Partners or us to incur additional indebtedness as a result of the foregoing restrictions in the agreements governing their indebtedness may inhibit Cheniere Partners' ability to pay or increase distributions to us and its other unitholders or inhibit our access to cash flows from the CCL Project, which could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

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 SPLNG, SPL, CCH and CCH HoldCo II 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.

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

To reduce our exposure to fluctuations in the price, volume and timing risk associated with the purchase of natural gas, we use futures, swaps and option contracts traded or cleared on the Intercontinental Exchange and the New York Mercantile Exchange or over-the-counter options and swaps with other natural gas merchants and financial institutions. Hedging arrangements 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 and other provisions of the Dodd-Frank Act and the rules adopted thereunder and other regulations, including EMIR and REMIT, could adversely affect our ability to hedge risks associated with our business and our operating results and cash flows.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal regulation of the over-the-counter ("OTC") derivatives market and made other amendments to the Commodity Exchange Act that are relevant to our business. The provisions of Title VII of the Dodd-Frank Act and the rules adopted thereunder by the Commodity Futures Trading Commission ("CFTC"), the SEC and other federal regulators may adversely affect our ability to manage certain of our risks on a cost effective basis. Such laws and regulations may also adversely affect our ability to execute our strategies with respect to hedging our exposure to variability in expected future cash flows attributable to the future sale of our LNG inventory and to price risk attributable to future purchases of natural gas to be utilized as fuel to operate our LNG terminals and to secure natural gas feedstock for our liquefaction facilities.

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The CFTC has proposed new rules setting limits on the positions in certain core futures contracts, economically equivalent futures contracts, options contracts and swaps for or linked to certain physical commodities, including Henry Hub natural gas, held by market participants, with limited exemptions for certain bona fide hedging and other types of transactions. Under the CFTC's proposed rules regarding aggregation of positions, a party that controls the trading of, or owns 10% or more of the equity interests in, another party will have to aggregate the positions of the controlled party with its own positions for purposes of determining compliance with position limits unless an exemption applies. Upon the adoption and effectiveness of final CFTC position limits and aggregation rules, our ability to execute our hedging strategies described above could be limited. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits and aggregation rules may become final and effective.

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

As required by the Dodd-Frank Act, the CFTC and the federal banking regulators have adopted rules requiring certain market participants to collect margin with respect to uncleared swaps from their counterparties that are financial end users and certain registered swap dealers and major swap participants. The requirements of those rules are to be phased in commencing on September 1, 2016. Although we believe we will qualify as a non-financial end user for purposes of these rules, were we not to do so and have to post margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would be increased. Our counterparties that are subject to the regulations imposing the Basel III capital requirements on them may increase the cost to us of entering into swaps with them or, although not required to collect margin from us under the margin rules, require us to post collateral with them in connection with such swaps in order to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets.

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

EMIR may result in increased costs for OTC derivative counterparties and also lead to an increase in the costs of, and demand for, the liquid collateral that EMIR requires central counterparties to accept. Although we expect to qualify as a non-financial counterparty under EMIR and thus not be required to post margin under EMIR, our subsidiaries and affiliates operating in the EU may still be subject to increased regulatory requirements, including recordkeeping, marking to market, timely confirmations, derivatives reporting, portfolio reconciliation and dispute resolution procedures. Regulation under EMIR could significantly increase the cost of derivatives contracts, materially alter the terms of derivatives contracts and reduce the availability of derivatives to protect against risks that we encounter. The increased trading costs and collateral costs may have an adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our subsidiaries and affiliates operating in the EU may be subject to REMIT as wholesale energy market participants. This classification imposes increased regulatory obligations on our subsidiaries and affiliates, including a prohibition to use or disclose insider information or to engage in market manipulation in wholesale energy markets, and an obligation to report certain data. These regulatory obligations may increase the cost of compliance for our business and if we violate these laws and regulations, we could be subject to investigation and penalties.

Risks Relating to Our LNG Terminal Business

Operation of the Sabine Pass LNG terminal, the SPL Project and the CCL 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 SPL Project and the CCL 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 or the CCL Project.

It will take several years to construct the SPL Project and the CCL Project, and even if successfully constructed, the SPL Project and the CCL Project would be subject to the operating risks described herein. Accordingly, there are many risks associated with the SPL Project and the CCL 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 or the Corpus Christi Pipeline, 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 or the Corpus Christi Pipeline may be significantly higher than our current estimates as a result of many factors, including change orders under existing or future EPC contracts resulting from the occurrence of certain specified events that may give Bechtel the right to cause us to enter into change orders or resulting from changes with which we otherwise agree. We 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 or the Corpus Christi Pipeline beyond the estimated development periods, as well as change orders to the EPC contracts with Bechtel or any future EPC contract related to additional Trains or the Corpus Christi Pipeline, 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 applicable 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 Train 6 of the SPL Project and Train 3 of the CCL Project, 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, SPLNG may need to purchase and process LNG. SPLNG’s TUA customers, including SPL, 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, SPLNG may need to procure such LNG.

SPLNG needs to maintain the cryogenic readiness of the Sabine Pass LNG terminal. Together with SPL, 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, SPLNG 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 SPLNG 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.

SPLNG 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 operating results.

SPLNG’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 SPLNG will have to purchase additional natural gas from third parties. SPLNG 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 our liquefaction projects, higher construction costs and the deferral of the dates on which payments are due under the SPAs, all of which could adversely affect us.

In August and September of 2005, Hurricanes Katrina and Rita, respectively, damaged coastal and inland areas located in Texas, Louisiana, Mississippi and Alabama, resulting in the temporary suspension of construction of the Sabine Pass LNG terminal. In September 2008, Hurricane Ike struck the Texas and Louisiana 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 SPL Project, the CCL Project or our other facilities. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods and rising sea levels; if any such effects were to occur, they could have an adverse effect on our coastal operations.

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

The design, construction and operation of interstate natural gas pipelines, LNG terminals, including the SPL Project and the CCL Project and other facilities, and the import and export of LNG and the transportation of natural gas, are highly regulated activities. Approvals of the FERC and DOE under Section 3 and Section 7 of the NGA, as well as several other material governmental and regulatory approvals and permits, including several under the CAA and the CWA, are required in order to construct and operate an LNG facility and an interstate natural gas pipeline and export LNG. Although the FERC has issued an order under Section 3 of the NGA authorizing the siting, construction and operation of six Trains of the SPL Project and an order authorizing the siting, construction and operation of three trains of the CCL Project, the FERC orders require us to obtain certain additional approvals in conjunction with ongoing construction and operations of our liquefaction facilities. We also have two pending applications with the DOE for authorization to export LNG to non-FTA countries in addition to the orders previously granted to us by the DOE. Authorizations obtained from other federal and state regulatory agencies also contain ongoing conditions, and additional approval and permit requirements may be imposed. We cannot control the outcome of the review and approval process. We do not know whether or when any such approvals or permits can be obtained, or whether or not any existing or potential interventions or other actions by third parties will interfere with our ability to obtain and maintain such permits or approvals. If we are unable to obtain and maintain the necessary approvals and permits, we may not be able to recover our investment in our projects. There is no assurance that we will obtain and maintain these governmental permits, approvals and authorizations, or that we will be able to obtain them on a timely basis, and failure to obtain and maintain any of these permits, approvals or authorizations could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

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

Timely and cost-effective completion of the SPL Project and the CCL 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. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor. This would likely result in significant project delays and increased costs, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

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

We will depend upon third-party pipelines and other facilities that will provide gas delivery options to our liquefaction facilities and pipelines. 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.

Our interstate natural gas pipelines and their FERC gas tariffs are subject to FERC regulation.

Our interstate natural gas pipelines are 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 our pipelines, the rates and terms of conditions of service and abandonment of facilities. Under the NGA, the rates charged by our interstate natural gas pipelines must be just and reasonable, and we are prohibited from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. If we fail to comply with all applicable statutes, rules, regulations and orders, our interstate pipelines 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 FERC 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 we fail to seek FERC 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, we could be subject to substantial penalties and fines. Under the EPAct, 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 Office of Pipeline Safety's rules and related regulations and orders, we could be subject to significant penalties and fines.

Any reduction in the capacity of, or the allocations to, interconnecting, third-party pipelines could cause a reduction of volumes transported in our pipelines, which would adversely affect our revenues and cash flow.

We will be dependent upon third-party pipelines and other facilities to provide delivery options to and from our pipelines. If any pipeline connection were to become unavailable for volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to continue shipping natural gas to end markets could be restricted, thereby reducing our revenues. Any permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our pipelines could have a material adverse effect on our business, financial condition, operating results, cash flow, liquidity and prospects.

Failure to obtain and maintain approvals and permits from governmental and regulatory agencies with respect to the development and operation of our interstate natural gas pipelines would have a detrimental effect on us and our pipeline projects.

The design, construction and operation of interstate natural gas pipelines and the transportation of natural gas are all highly regulated activities. The FERC's approval under 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 from the USACE and state environmental agencies, are required in order to construct and operate an interstate natural gas pipeline. We have no control over 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 pipeline 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.

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

We do not own the land on which our pipelines are 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 our pipelines, our business could be materially and adversely affected.

Risks Relating to Our LNG and Natural Gas Marketing Business

The limited capital resources and credit available to our LNG and natural gas marketing business may limit our ability to develop that business.

We have limited capital available to our LNG and natural gas marketing business. The business also currently has limited access to third-party sources of financing. Other investment-grade marketing companies have greater financial resources than we do. Our LNG and natural gas marketing business continues to develop and implement its business strategy and may not generate sufficient revenues and cash flows to cover the significant fixed costs of the business.

Our exposure to the performance and credit risks of counterparties under agreements may adversely affect our operating results, liquidity and access to financing.

Our LNG and natural gas marketing business involves our entering into various purchase and sale, hedging and other transactions with numerous third parties (commonly referred to as “counterparties”). In such arrangements, we are exposed to the performance and credit risks of our counterparties, including the risk that one or more counterparties fails to perform its obligation to make deliveries of commodities and/or to make payments. These risks may increase during periods of commodity price volatility. Defaults by suppliers and other counterparties may adversely affect our operating results, liquidity and access to financing.

Cheniere Marketing may not be able to contract with customers to facilitate the export of LNG on its chartered LNG vessels.

Cheniere Marketing has entered into SPAs with SPL and CCL pursuant to which Cheniere Marketing has the option to purchase LNG at the SPL Project and the CCL Project, respectively. Cheniere Marketing has also entered into LNG vessel charters in order to secure shipping capacity for the export of LNG to purchasers. Under the charters, some of which have terms of up to 5 years, Cheniere Marketing is obligated to make payments for these vessels regardless of use. However, Cheniere Marketing may not be able to enter into contracts with purchasers of LNG in quantities equivalent to the vessel capacities for which Cheniere Marketing is required to make payments. Failure to secure buyers for a sufficient amount of LNG could materially and adversely affect Cheniere Marketing’s business, operating results, cash flows and liquidity.

Risks Relating to Our LNG Businesses in General

We may not construct or operate all of our proposed LNG facilities or Trains or any additional LNG facilities or Trains beyond those currently planned, which could limit our growth prospects.

We may not construct some of our proposed LNG facilities or Trains, whether due to lack of commercial interest or inability to obtain financing or otherwise. Our ability to develop additional liquefaction facilities will also depend on the availability and pricing of LNG and natural gas in North America and other places around the world. Competitors may have longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources and access to sources of natural gas and LNG than we do. If we are unable or unwilling to construct and operate additional LNG facilities, our prospects for growth will be limited.

Our cost estimates for Trains are subject to change as a result of cost overruns, change orders under existing or future construction contracts, changes in commodity prices (particularly nickel and steel), escalating labor costs and the potential need for additional funds to be expended to maintain construction schedules. In the event we experience cost overruns, delays or both, the amount of funding needed to complete a Train could exceed our available funds and result in our failure to complete such Train and thereby negatively impact our business and limit our growth prospects.

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

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

- additions to competitive regasification capacity in North America, Europe, Asia and other markets, which could divert LNG from the Sabine Pass LNG terminal;
- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient LNG tanker capacity;
- weather conditions;
- reduced demand and lower prices for natural gas;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- decreased oil and natural gas exploration activities, which may decrease the production of natural gas;
- cost improvements that allow competitors to offer LNG regasification services or provide liquefaction capabilities at reduced prices;

- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;

- political conditions in natural gas producing regions;
- adverse relative demand for LNG compared to other markets, which may decrease LNG imports into or exports from North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

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

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

Current operations at the Sabine Pass LNG terminal are dependent upon the ability of our TUA customers to import LNG supplies into the United States, which is primarily dependent upon LNG being a competitive source of energy in North America. In North America, due mainly to a historically abundant supply of natural gas and 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 the SPL Project and the CCL Project will be dependent upon the ability of our SPA customers to deliver LNG supplies from the United States, which is primarily dependent upon LNG being a competitive source of energy internationally. The success of our business plan is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be supplied from North America and delivered to international markets at a lower cost than the cost of other alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may 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 our 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 may 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 the SPL Project and the CCL Project specifically, could have a material adverse effect on our customers and on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

- increased construction costs;
- economic downturns, increases in interest rates or other events that may affect the availability of sufficient financing for LNG projects on commercially reasonable terms;
- decreases in the price of LNG, which might decrease the expected returns relating to investments in LNG projects;

- the inability of project owners or operators to obtain governmental approvals to construct or operate LNG facilities;
- political unrest or local community resistance to the siting of LNG facilities due to safety, environmental or security concerns; and
- any significant explosion, spill or similar incident involving an LNG facility or LNG vessel.

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

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

- an inadequate number of shipyards constructing LNG vessels and a backlog of orders at these shipyards;
- political or economic disturbances in the countries where the vessels are being constructed;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances at the shipyards;
- bankruptcy or other financial crisis of shipbuilders;
- quality or engineering problems;
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire; and
- shortages of or delays in the receipt of necessary construction materials.

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

We have contracted for firm capacity for our natural gas feedstock transportation requirements for Trains 1 through 5 of the SPL Project and have an option for firm capacity for Train 6, and partially for the CCL Project. We cannot control the regulatory and permitting approvals or third parties' construction times. If and when we need to replace one or more of our agreements with these interconnecting pipelines, we may not be able to do so on commercially reasonable terms or at all, which could impair our ability to fulfill our obligations under certain of our SPAs and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

Our liquefaction projects are 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. 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 our liquefaction projects 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 our liquefaction projects;
- decreases in the cost of competing sources of natural gas or alternate fuels such as coal, heavy fuel oil and diesel;
- decreases in the price of non-U.S. LNG, including decreases in price as a result of contracts indexed to lower oil prices;
- increases in capacity and utilization of nuclear power and related facilities; and
- displacement of LNG by pipeline natural gas or alternate fuels in locations where access to these energy sources is not currently available.

Terrorist attacks, including cyberterrorism, or military campaigns may adversely impact our business.

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

Risks Relating to Our Business in General

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 our LNG terminals and construction of liquefaction facilities are 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.

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

Our business is and will be subject to extensive federal, state and local laws and regulations that regulate and restrict, among other things, discharges to air, land and water, with particular respect to the protection of the environment and natural resources; the handling, storage and disposal of hazardous materials, hazardous waste and petroleum products; and remediation associated with the release of hazardous substances. Many of these laws and regulations, such as the CAA, the Oil Pollution Act, the CWA and the RCRA, and analogous state laws and regulations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our facilities, and require us to maintain permits and provide governmental authorities with access to our facilities for inspection and reports related to our compliance. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties or to capital expenditures related to pollution control equipment that could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Federal and state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. As the owner and operator of our facilities, we could be liable for the costs of cleaning up hazardous substances released into the environment at or from our facilities and for resulting damage to natural resources.

The Obama Administration is pursuing a number of regulatory and policy initiatives to reduce GHG emissions in the United States from a variety of sources. For example, in October 2015, the EPA promulgated a final rule to implement the Obama Administration's Clean Power Plan, which is designed to reduce GHG emissions from power plants in the United States. Other federal and state initiatives are being considered or may be considered in the future to address GHG emissions through, for example, United States treaty commitments, direct regulation, a carbon emissions tax, or cap-and-trade programs. Such initiatives could affect the demand for or cost of natural gas, which we consume at the Sabine Pass LNG terminal, or could increase compliance costs for our operations.

Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to or exported from the Sabine Pass LNG terminal through the Sabine-Neches Waterway less than four miles from the Gulf Coast and LNG exported from the Corpus Christi LNG terminal near Corpus Christi, Texas on nearly 2,000 acres of land that we own or control, 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.

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

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

We may experience increased labor costs, and the unavailability of skilled workers or our failure to attract and retain qualified personnel could adversely affect us. In addition, changes in our senior management or other key personnel could affect our business results.

We are dependent upon the available labor pool of skilled employees. We compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct and operate our facilities and pipelines and to provide our customers with the highest quality service. Our affiliates who hire personnel on our behalf are also subject to the Fair Labor Standards Act, which governs such matters as minimum wage, overtime and other working conditions. 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 for us to attract and retain qualified personnel and could require an increase in the wage and benefits packages that we offer, thereby increasing our operating costs. Any increase in our operating costs could materially and adversely affect our business, financial condition, operating results, liquidity and prospects.

We depend on our executive officers for various activities. We are currently in a transition process with respect to our Chief Executive Officer, which could affect our strategic direction or our business results. Further, we do not maintain key person life insurance policies on any of our personnel. Although we have arrangements relating to compensation and benefits with certain of our executive officers, we do 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 seriously harm us.

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 2016 will be dependent upon one facility, the Sabine Pass LNG terminal located in southern Louisiana. Due to our lack of asset and geographic diversification, an adverse development at the Sabine Pass LNG terminal or the Corpus Christi LNG terminal, including the related pipelines, or in the LNG industry, would have a significantly greater impact on our financial condition and operating results than if we maintained more diverse assets and operating areas.

We may incur impairments to goodwill or long-lived assets.

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

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

The market price of our common stock has historically experienced and may continue to experience volatility. For example, between January 1, 2015 and December 31, 2015, the market price of our common stock ranged between $35.09 and $82.32. Such fluctuations may continue as a result of a variety of factors, some of which are beyond our control, including:

- domestic and worldwide supply of and demand for natural gas and corresponding fluctuations in the price of natural gas;
- 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 stockholders;
- sales of a high volume of shares of our common stock by our stockholders;
- operating and stock price performance of companies that investors deem comparable to us;
- events affecting other companies that the market deems comparable to us;
- changes in government regulation or proposals applicable to us;
- actual or potential non-performance by any customer or a counterparty under any agreement;
- announcements made by us or our competitors of significant contracts;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general conditions in the industries in which we operate;
- general economic conditions;
- the failure of securities analysts to cover our common stock 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 stock, regardless of our operating performance. If we were to be the object of securities class litigation as a result of volatility in our common stock 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.

If there is a determination that any of the restructuring transactions entered into prior to and in connection with Cheniere Holdings’ initial public offering are taxable for U.S. federal income tax purposes and Cheniere Holdings ceases to be a member of our consolidated group for U.S. federal income tax purposes, then we could incur significant income tax liabilities.

Prior to and in connection with Cheniere Holdings’ initial public offering, we, Cheniere Holdings and other members of our consolidated group for U.S. federal income tax purposes participated in a series of restructuring transactions intended to qualify as tax-free for U.S. federal income tax purposes. No ruling from the U.S. Internal Revenue Service was requested in connection with such restructuring transactions. Under the Internal Revenue Code, Cheniere Holdings will cease to be a member of our consolidated group for U.S. federal income tax purposes (a deconsolidation) if at any time we own less than 80% of the vote or 80% of the value of Cheniere Holdings’ outstanding shares, whether by issuance of additional shares by Cheniere Holdings or by our sale or other disposition of Cheniere Holdings’ shares. If any of the restructuring transactions is determined to be taxable for U.S. federal income tax purposes for any reason, following a deconsolidation, we could incur significant income tax liabilities.

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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, 2015, there were no pending legal matters that would reasonably be expected to have a material impact on our consolidated operating results, financial position or cash flows.

ITEM 4. MINE SAFETY DISCLOSURE

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER

Market Information, Holders and Dividends

Our common stock has traded on the NYSE MKT under the symbol "LNG" since March 24, 2003. The table below presents the high and low sales prices of our common stock, as reported by the NYSE MKT, for each quarter during 2015 and 2014.

	High	Low
2015		
First Quarter	$82.32	$65.68
Second Quarter	81.12	67.38
Third Quarter	71.11	46.23
Fourth Quarter	54.95	35.09
2014		
First Quarter	$56.30	$40.43
Second Quarter	72.76	50.91
Third Quarter	85.00	67.12
Fourth Quarter	79.80	58.10

As of February 12, 2016, we had 235.6 million shares of common stock outstanding held by approximately 657 record owners.

We have never paid a cash dividend on our common stock. We currently intend to retain earnings to finance the growth and development of our business and do not anticipate paying any cash dividends on the common stock in the foreseeable future. Any future change in our dividend policy will be made at the discretion of our Board of Directors (our "Board") in light of our financial condition, capital requirements, earnings, prospects and any restrictions under any financing agreements, as well as other factors our Board deems relevant.

Purchase of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes stock repurchases for the three months ended December 31, 2015:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share (2)	Total Number of Shares Purchased as a Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
October 1 - 31, 2015	16,451	$49.95	—	—
November 1 - 30, 2015	9,869	$49.52	—	—
December 1 - 31, 2015	375,098	$41.46	—	—

(1) Represents shares surrendered to us by participants in our share-based compensation plans to settle the participants' personal tax liabilities that resulted from the lapsing of restrictions on shares awarded to the participants under these plans.

(2) The price paid per share was based on the closing trading price of our common stock on the dates on which we repurchased shares from the participants under our share-based compensation plans.

For additional information, see Note 13—Share-Based Compensation of our Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Total Stockholder Return

In 2015, we changed our benchmark indexes from the Russell 2000 Index and the S&P Oil & Gas Exploration & Production Index to the S&P 500 Index and a customized peer group to better align with our competitors. The customized peer group of 20 companies includes: (1) Calpine Corp. (CPN), (2) Dynegy Inc. (DYN), (3) Dominion Resources, Inc. (D), (4) PG&E Corporation (PCG), (5) Sempra Energy (SRE), (6) Public Service Enterprise Group Inc. (PEG), (7) DTE Energy Company (DTE), (8) Ameren Corporation (AEE), (9) CMS Energy Company (CMS), (10) Kinder Morgan, Inc. (KMI), (11) Enterprise Product Partners L.P. (EPD), (12) Enbridge (ENB), (13) TransCanada Corporation (TRP), (14) Energy Transfer Equity, L.P. (ETE), (15) Spectra Energy Corp (SE), (16) Magellan Midstream Partners LP (MMP), (17) Plains All American Pipeline, L.P. (PAA), (18) MarkWest Energy Partners, L.P. (MWE), (19) ONEOK Inc. (OKE) and (20) Targa Resources Corp. (TRGP) (collectively, the "Peer Group"). We selected the Peer Group companies because they are publicly traded companies that have: (1) comparable Global Industries Classification Standards, (2) similar market capitalization, (3) similar enterprise values and (4) similar operating characteristics and capital intensity.

The following graph compares the five-year total return on our common stock, the S&P 500 Index and the Peer Group used in 2015 and the Russell 2000 Index and the S&P Oil & Gas Exploration & Production Index used in 2014. The graph was constructed on the assumption that $100 was invested in our common stock, the S&P 500 Index and the Peer Group on December 31, 2010 and that any dividends were fully reinvested.

Company / Index	2010	2011	2012	2013	2014	2015
Cheniere Energy, Inc.	100.00	157.43	340.22	781.16	1,275.36	674.82
S&P 500 Index	100.00	102.11	118.45	156.82	178.29	180.75
Peer Group	100.00	120.72	133.72	164.65	199.04	138.43
Russell 2000 Index (used in 2014)	100.00	95.82	111.49	154.78	162.35	155.18
S&P Oil & Gas Exploration & Production Index (used in 2014)	100.00	93.57	96.98	123.64	110.55	72.80

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data set forth below (in thousands, except per share data) 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,				
	2015	2014	2013	2012	2011
Revenues	$270,885	$267,954	$267,213	$266,220	$290,444
General and administrative expense (1)	423,862	323,709	384,512	152,081	88,427
Income (loss) from operations	(449,313)	(272,179)	(328,328)	(76,454)	55,895
Interest expense, net of capitalized interest	(322,083)	(181,236)	(178,400)	(200,811)	(259,393)
Net loss attributable to common stockholders	(975,109)	(547,932)	(507,922)	(332,780)	(198,756)
Net loss per share attributable to common stockholders—basic and diluted	$(4.30)	$(2.44)	$(2.32)	$(1.83)	$(2.60)
Weighted average number of common shares outstanding—basic and diluted	226,903	224,338	218,869	181,768	76,483

	December 31,				
	2015	2014	2013	2012	2011
Cash and cash equivalents	$1,201,112	$1,747,583	$960,842	$201,711	$459,160
Restricted cash (current)	503,397	481,737	598,064	520,263	102,165
Non-current restricted cash	31,722	550,811	1,031,399	272,924	82,892
Property, plant and equipment, net	16,193,907	9,246,753	6,454,399	3,282,305	2,107,129
Total assets	19,019,589	12,573,683	9,673,237	4,639,085	2,915,325
Current debt, net	1,676,197	—	—	—	492,724
Long-term debt, net	15,128,145	9,806,084	6,576,273	2,167,113	2,465,113
Long-term debt-related parties, net	—	—	—	—	9,598
Total equity (deficit)	1,561,403	2,501,517	2,840,057	2,261,605	(172,992)

(1) General and administrative expense includes $163.9 million, $96.7 million, $252.1 million, $53.2 million and $24.4 million share-based compensation expense recognized in the years ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively.

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

Introduction

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

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

Overview of Business

Cheniere, a Delaware corporation, is a Houston-based energy company primarily engaged in LNG-related businesses. We own and operate the Sabine Pass LNG terminal in Louisiana through our ownership interest in and management agreements with Cheniere Partners, which is a publicly traded limited partnership that we created in 2007. We own 100% of the general partner interest in Cheniere Partners and 80.1% of Cheniere Holdings, which is a publicly traded limited liability company formed in 2013 that owns a 55.9% limited partner interest in Cheniere Partners. We are currently developing and constructing two natural gas liquefaction and export facilities.

The Sabine Pass LNG terminal is located on the Sabine-Neches Waterway less than four miles from the Gulf Coast. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' wholly owned subsidiary, SPLNG, that include existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. Cheniere Partners is developing and constructing natural gas liquefaction facilities (the "SPL Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities through a wholly owned subsidiary, SPL. Cheniere Partners is constructing five Trains and developing a sixth Train, each of which is expected to have a nominal production capacity of approximately 4.5 mtpa of LNG. Cheniere Partners also owns a 94-mile pipeline that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline") through a wholly owned subsidiary, CTPL.

We are developing and constructing a second natural gas liquefaction and export facility at the Corpus Christi LNG terminal, which is on nearly 2,000 acres of land that we own or control near Corpus Christi, Texas, and a pipeline facility (the "CCL Project") through wholly owned subsidiaries CCL and CCP, respectively. The CCL Project is being developed for up to three Trains, with expected aggregate nominal production capacity of approximately 13.5 mtpa of LNG, three LNG storage tanks with capacity of approximately 10.1 Bcfe and two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters. The CCL Project is being developed in stages. The first stage ("Stage 1") includes Trains 1 and 2, two LNG storage tanks, one complete marine berth and a second partial berth and all of the CCL Project's necessary infrastructure facilities. The second stage ("Stage 2") includes Train 3, one LNG storage tank and the completion of the second partial berth. The CCL Project also includes a 23-mile, 48-inch natural gas supply pipeline that will interconnect the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline").

The CCL Stage III entities, wholly owned subsidiaries of Cheniere separate from the CCH Group, are also developing two additional Trains and one LNG storage tank at the Corpus Christi LNG terminal adjacent to the CCL Project, along with a second natural gas pipeline.

Cheniere Marketing is engaged in the LNG and natural gas marketing business and is developing a portfolio of long-term, short-term and spot SPAs. Cheniere Marketing has entered into SPAs with SPL and CCL to purchase LNG produced by the SPL Project and the CCL Project.

We are also in various stages of developing other projects which, among other things, will require acceptable commercial and financing arrangements before we make a final investment decision ("FID").

Overview of Significant Events

Our significant accomplishments since January 1, 2015 and through the filing date of this Form 10-K include the following:

Cheniere

- We issued an aggregate principal amount of $625.0 million Convertible Senior Notes due 2045 (the "2045 Cheniere Convertible Senior Notes") through a registered direct offering. The 2045 Cheniere Convertible Senior Notes were issued with an original issue discount of 20% and accrue interest at a rate of 4.25% per annum, which is payable semi-annually in arrears. The net proceeds of the 2045 Cheniere Convertible Senior Notes are being used for general corporate purposes.
- Cheniere Marketing and CCL received authorization from the DOE to export up to a combined total of the equivalent of 767 Bcf/yr of domestically produced LNG by vessel from the CCL Project to non-FTA countries for a 20-year term.
- CCH entered into a credit facility (the "2015 CCH Credit Facility") to be used for costs associated with the development, construction, operation and maintenance of the CCL Project, with commitments of $8.4 billion linked to Stage 1 of the CCL Project and the Corpus Christi Pipeline.
- CCH HoldCo II issued $1.0 billion aggregate principal amount of 11% Convertible Senior Secured Notes due 2025 (the "2025 CCH HoldCo II Convertible Senior Notes"), which will be used to pay a portion of the capital costs associated with Stage 1 of the CCL Project and the Corpus Christi Pipeline.
- CCL issued a notice to proceed ("NTP") to Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") under the lump sum turnkey contract for the engineering, procurement and construction of Stage 1 of the CCL Project (the "EPC Contract (CCL Stage 1)").

Cheniere Partners

- SPL issued an aggregate principal amount of $2.0 billion of 5.625% Senior Secured Notes due 2025 (the "2025 SPL Senior Notes"). Net proceeds from the offering will be used to pay a portion of the capital costs associated with the construction of the first four Trains of the SPL Project.
- We received authorization from the FERC to site, construct and operate Trains 5 and 6 of the SPL Project.
- SPL received authorization from the DOE to export up to a combined total of the equivalent of 503.3 Bcf/yr of domestically produced LNG by vessel from Trains 5 and 6 of the SPL Project to non-FTA countries for a 20-year term.
- SPL and Bechtel entered into a lump sum turnkey contract for the engineering, procurement and construction of Train 5 of the SPL Project (the "EPC Contract (SPL Train 5)").
- SPL entered into four credit facilities (collectively, the "2015 SPL Credit Facilities") aggregating $4.6 billion, which terminated and replaced its existing credit facilities. The 2015 SPL Credit Facilities will be used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the SPL Project.
- SPL issued an NTP to Bechtel under the EPC Contract (SPL Train 5).
- SPL entered into a $1.2 billion Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement (the "SPL Working Capital Facility"), which replaced the $325.0 million senior letter of credit and reimbursement agreement that was entered into in April 2014 (the "SPL LC Agreement"). The SPL Working Capital Facility will be used primarily for certain working capital requirements related to developing and placing into operation the SPL Project.

- In January 2016, Cheniere Partners engaged 13 financial institutions to act as Joint Lead Arrangers, Mandated Lead Arrangers and other participants to assist in the structuring and arranging of up to approximately $2.8 billion of senior secured credit facilities. Proceeds from these new credit facilities are intended to be used by Cheniere Partners to prepay

$400.0 million of the CTPL term loan facility (the "CTPL Term Loan"), to redeem or repay $1,665.5 million of the 7.50% Senior Secured Notes due 2016 (the "2016 SPLNG Senior Notes") and $420.0 million of the 6.50% Senior Secured Notes due 2020 (the "2020 SPLNG Senior Notes" and collectively with the 2016 SPLNG Senior Notes, the "SPLNG Senior Notes"), to pay associated transaction fees, expenses and make-whole amounts, if applicable, and for general business purposes of Cheniere Partners and its subsidiaries.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, Cheniere, Cheniere Holdings, Cheniere Partners, SPL, SPLNG, CTPL and the CCH Group operate with independent capital structures. We expect the cash needs for at least the next twelve months will be met for each of these independent capital structures as follows:

- SPLNG through operating cash flows, existing unrestricted cash and debt offerings or equity contributions;
- SPL through project debt and borrowings, equity contributions from Cheniere Partners and operating cash flows;
- Cheniere Partners through operating cash flows from SPLNG, SPL and CTPL, existing unrestricted cash and debt or equity offerings;
- Cheniere Holdings through distributions from Cheniere Partners;
- CCH Group through project financing, operating cash flow from CCL and CCP and equity contributions from Cheniere;

and

- Cheniere through project financing, existing unrestricted cash, debt and equity offerings by us or our subsidiaries, operating cash flows, services fees from Cheniere Holdings, Cheniere Partners and its other subsidiaries and distributions from our investments in Cheniere Holdings and Cheniere Partners.

As of December 31, 2015, we had cash and cash equivalents of $1,201.1 million available to Cheniere. In addition, we had current and non-current restricted cash of $535.1 million (which included current and non-current restricted cash available to us and our subsidiaries) designated for the following purposes: $46.8 million for the CCL Project; $189.3 million for the SPL Project; $7.9 million for CTPL; $91.1 million for interest payments related to the SPLNG Senior Notes described below; and $200.0 million for other restricted purposes.

In November 2014, we issued an aggregate principal amount of $1.0 billion Convertible Unsecured Notes due 2021 (the "2021 Cheniere Convertible Unsecured Notes"). The 2021 Cheniere Convertible Unsecured Notes are convertible at the option of the holder into our common stock at the then applicable conversion rate, provided that the closing price of our common stock is greater than or equal to the conversion price on the date of conversion. The initial conversion price was $93.64 and is subject to adjustment upon the occurrence of certain specified events. We have the option to satisfy the conversion obligation with cash, common stock or a combination thereof.

In March 2015, we issued the 2045 Cheniere Convertible Senior Notes. We have the right, at our option, at any time after March 15, 2020, to redeem all or any part of the 2045 Cheniere Convertible Senior Notes at a redemption price equal to the accreted amount of the 2045 Cheniere Convertible Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to such redemption date. The conversion rate will initially equal 7.2265 shares of our common stock per $1,000 principal amount of the 2045 Cheniere Convertible Senior Notes, which corresponds to an initial conversion price of approximately $138.38 per share of our common stock. The conversion rate is subject to adjustment upon the occurrence of certain specified events. We have the option to satisfy the conversion obligation with cash, common stock or a combination thereof.

Substantially all of our revenues from external customers and long-lived assets for each of the years ended December 31, 2015, 2014 and 2013 are attributed to or located in the United States.

Cheniere Holdings

Cheniere Holdings was formed by us to hold our Cheniere Partners limited partner interests, thereby allowing us to segregate our lower risk, stable, cash flow generating assets from our higher risk, early stage development projects and marketing activities. As of December 31, 2015, we had an 80.1% direct ownership interest in Cheniere Holdings. We receive dividends on our Cheniere Holdings shares from the distributions that Cheniere Holdings receives from Cheniere Partners, and we receive management fees for managing Cheniere Holdings. For the year ended December 31, 2015, we received $14.7 million in dividends on our Cheniere Holdings common shares and $1.0 million of management fees from Cheniere Holdings.

Cheniere Partners

Our ownership interest in the Sabine Pass LNG terminal is held through Cheniere Partners. As of December 31, 2015, we own 80.1% of Cheniere Holdings, which owns a 55.9% limited partner interest in Cheniere Partners in the form of 11,963,488 common units, 45,333,334 Class B units and 135,383,831 subordinated units. We also own 100% of the general partner interest and the incentive distribution rights in Cheniere Partners.

Prior to the initial public offering by Cheniere Holdings, we received quarterly equity distributions from Cheniere Partners related to our limited partner and 2% general partner interests. We will continue to receive quarterly equity distributions from Cheniere Partners related to our 2% general partner interest, and we receive fees for providing services to Cheniere Partners, SPLNG, SPL and CTPL. During the year ended December 31, 2015, we received $2.0 million in distributions on our general partner interest and $92.6 million in total service fees, including reimbursement of operating expenses, from Cheniere Partners, SPLNG, SPL and CTPL.

Cheniere Partners' common unit and general partner distributions are being funded from accumulated operating surplus. We have not received distributions on our subordinated units with respect to the quarters ended on or after June 30, 2010. Cheniere Partners will not make distributions on our subordinated units until it generates additional cash flow from the SPL Project, SPLNG's excess capacity or other new business, which would be used to make quarterly distributions on our subordinated units before any increase in distributions to the common unitholders.

Cheniere Partners' 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 Cheniere Partners Class B units are not entitled to cash distributions except in the event of a liquidation of Cheniere Partners, a merger, consolidation or other combination of Cheniere Partners with another person or the sale of all or substantially all of the assets of Cheniere Partners. On a quarterly basis beginning on the initial purchase 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 Holdings and Blackstone CQP Holdco LP was 1.62 and 1.59, respectively, as of December 31, 2015. We expect the Class B units to mandatorily convert into common units within 90 days of the substantial completion date of Train 3 of the SPL Project, which Cheniere Partners currently expects to occur before April 30, 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.

LNG Terminal Business

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 SPLNG's customers are required to pay fixed monthly fees, whether or not they use the LNG terminal. Each of Total Gas & Power North America, Inc. ("Total") and Chevron U.S.A. Inc. ("Chevron") has reserved approximately 1.0 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009. Total S.A. has guaranteed Total's obligations under its TUA up to $2.5 billion, subject to certain exceptions, and Chevron Corporation has guaranteed Chevron's obligations under its TUA up to 80% of the fees payable by Chevron.

The remaining approximately 2.0 Bcf/d of capacity has been reserved under a TUA by SPL. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, continuing until at least 20 years after SPL delivers its first commercial cargo at the SPL Project. SPL entered into a partial TUA assignment agreement with Total, whereby SPL will progressively gain access to Total's capacity and other services provided under Total's TUA with SPLNG. This agreement will provide SPL 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 SPL to more flexibly manage its LNG storage capacity with the commencement of Train 1. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA.

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

Liquefaction Facilities

The SPL Project is being developed and constructed at the Sabine Pass LNG terminal adjacent to the existing regasification facilities. We have received authorization from the FERC to site, construct and operate Trains 1 through 6. We 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. In June 2015, we commenced construction of Train 5 and the related facilities.

The DOE has authorized the export of up to a combined total of the equivalent of 16 mtpa (approximately 803 Bcf/yr) of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries for a 30-year term and to non-FTA countries for a 20-year term. The DOE further issued an order authorizing SPL to export up to the equivalent of approximately 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries for a 25-year period. SPL's application for authorization to export that same 203 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to non-FTA countries is currently pending at the DOE. Additionally, the DOE issued orders authorizing SPL to export up to a combined total of 503.3 Bcf/yr of domestically produced LNG from the Sabine Pass LNG terminal to FTA countries and non-FTA countries for a 20-year term. A party to the proceeding requested a rehearing of the non-FTA order pertaining to the 503.3 Bcf/yr, and the DOE has not yet issued a final ruling on the rehearing request. In each case, the terms of these authorizations begin on the earlier of the date of first export thereunder or the date specified in the particular order, which ranges from 5 to 10 years from the date the order was issued. Furthermore, the DOE issued an order authorizing SPL to export up to 600 Bcf in total of domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing on January 15, 2016.

As of December 31, 2015, the overall project completion percentages for Trains 1 and 2 and Trains 3 and 4 of the SPL Project were approximately 97.4% and 79.5%, respectively. As of December 31, 2015, the overall project completion percentage for Train 5 of the