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.

CHENIERE ENERGY, INC.
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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

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|---|---|
| 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 (CH4) 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.

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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.

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<br>19.75 mtpa | Completed<br>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 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.

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.

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.

Construction

SPL entered into lump sum turnkey contracts with 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 (SPL 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.

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.

Capital Resources

We currently expect that SPL's capital resources requirements with respect to Trains 1 through 5 of the SPL Project will be financed through one or more of the following: borrowings, equity contributions from Cheniere Partners and cash flows under the SPAs. We believe that with the net proceeds of borrowings, available commitments under the 2015 SPL Credit Facilities, available commitments under the SPL Working Capital Facility and cash flows from operations, we will have adequate financial resources available to complete Trains 1 through 5 of the SPL Project and to meet our currently anticipated capital, operating and debt service requirements. We currently project that SPL will generate cash flow from the SPL Project by early 2016.

Senior Secured Notes

As of December 31, 2015, Cheniere Partners' subsidiaries had seven series of senior secured notes outstanding (collectively, the "Senior Notes"):

- $1.7 billion of the 2016 SPLNG Senior Notes;
- $0.4 billion of the 2020 SPLNG Senior Notes;
- $2.0 billion of 5.625% Senior Secured Notes due 2021 issued by SPL (the "2021 SPL Senior Notes");
- $1.0 billion of 6.25% Senior Secured Notes due 2022 issued by SPL (the "2022 SPL Senior Notes");
- $1.5 billion of 5.625% Senior Secured Notes due 2023 issued by SPL (the "2023 SPL Senior Notes");
- $2.0 billion of 5.75% Senior Secured Notes due 2024 issued by SPL (the "2024 SPL Senior Notes" and collectively with the 2021 SPL Senior Notes, the 2022 SPL Senior Notes, the 2023 SPL Senior Notes and the 2025 SPL Senior Notes, the "SPL Senior Notes"); and

- $2.0 billion of the 2025 SPL Senior Notes.

Interest on the SPL Senior Notes is payable semi-annually in arrears. Subject to permitted liens, the SPLNG Senior Notes are secured on a pari passu first-priority basis by a security interest in all of SPLNG’s equity interests and substantially all of

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

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

- 1.0% of the principal amount of the 2016 SPLNG Senior Notes; or
- the excess of: (1) the present value at such redemption date of (a) the redemption price of the 2016 SPLNG Senior Notes plus (b) all required interest payments due on the 2016 SPLNG Senior Notes (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the treasury rate as of such redemption date plus 50 basis points; over (2) the principal amount of the 2016 SPLNG Senior Notes, if greater.

SPLNG may redeem all or part of the 2020 SPLNG Senior Notes at any time on or after November 1, 2016 at fixed redemption prices specified in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPLNG may also, at its option, redeem all or part of the 2020 SPLNG Senior Notes at any time prior to November 1, 2016, at a "make-whole" price set forth in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes, SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the "make-whole" price set forth in the common indenture governing the SPL Senior Notes (the "SPL Indenture"), plus accrued and unpaid interest, if any, to the date of redemption. SPL may also, at any time within three months of the respective maturity dates for each series of the SPL Senior Notes, redeem all or part of such series of the SPL Senior Notes at a redemption price equal to 100% of the principal amount of such series of the SPL Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

Under the indentures governing the SPLNG Senior Notes (the "SPLNG Indentures"), except for permitted tax distributions, SPLNG may not make distributions until, among other requirements, deposits are made into debt service reserve accounts and a fixed charge coverage ratio test of 2:1 is satisfied. Under the SPL Indenture, SPL may not make any distributions 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 as required and a debt service coverage ratio test of 1.25:1.00 is satisfied. During the years ended December 31, 2015, 2014 and 2013, SPLNG made distributions of $337.3 million, $346.9 million and $348.9 million, respectively, after satisfying all the applicable conditions in the SPLNG Indentures.

The SPL Indenture includes restrictive covenants. SPL may incur additional indebtedness in the future, including by issuing additional notes, and such indebtedness could be at higher interest rates and have different maturity dates and more restrictive covenants than the current outstanding indebtedness of SPL, including the SPL Senior Notes, the 2015 SPL Credit Facilities and the SPL Working Capital Facility.

2015 SPL Credit Facilities

In June 2015, SPL entered into the 2015 SPL Credit Facilities with commitments aggregating $4.6 billion. The 2015 SPL Credit Facilities are being used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the SPL Project. Borrowings under the 2015 SPL Credit Facilities may be refinanced, in whole or in part, at any time without premium or penalty; however, interest rate hedging and interest rate breakage costs may be incurred. As of December 31, 2015, SPL had $3.8 billion of available commitments and outstanding borrowings of $845.0 million under the 2015 SPL Credit Facilities.

Loans under the 2015 SPL Credit Facilities accrue interest at a variable rate per annum equal to, at SPL's election, LIBOR or the base rate plus the applicable margin. The applicable margin for LIBOR loans ranges from 1.30% to

1.75%, depending on the applicable 2015 SPL Credit Facility, and the applicable margin for base rate loans is 1.75%. Interest on LIBOR loans is due and payable at the end of each LIBOR period and interest on base rate loans is due and payable at the end of each quarter. In addition, SPL is required to pay insurance/guarantee premiums of 0.45% per annum on any drawn amounts under the covered tranches of the 2015 SPL Credit Facilities. The 2015 SPL Credit Facilities also require SPL to pay a quarterly commitment fee calculated at a rate per annum equal to either: (1) 40% of the applicable margin, multiplied by the average daily amount of the undrawn commitment, or (2) 0.70% of the undrawn commitment, depending on the applicable 2015 SPL Credit Facility. The principal of the loans made under the 2015 SPL Credit Facilities must be repaid in quarterly installments, commencing with the earlier of June 30, 2020 and the last day of the first full calendar quarter after the completion date of Trains 1 through 5 of the SPL

Project. Scheduled repayments are based upon an 18-year amortization profile, with the remaining balance due upon the maturity of the 2015 SPL Credit Facilities.

The 2015 SPL Credit Facilities contain conditions precedent for borrowings, as well as customary affirmative and negative covenants. The obligations of SPL under the 2015 SPL Credit Facilities are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a pari passu basis with the SPL Senior Notes and SPL Working Capital Facility.

Under the terms of the 2015 SPL Credit Facilities, SPL is required to hedge not less than 65% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal. Additionally, SPL may not make any distributions until 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 test of 1.25:1.00 is satisfied.

2013 SPL Credit Facilities

In May 2013, SPL entered into four credit facilities aggregating $5.9 billion (collectively, the “2013 SPL Credit Facilities”) to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 4 of the SPL Project, which amended and restated the existing credit facility that was entered into in 2012 (the “2012 SPL Credit Facility”). In June 2015, the 2013 SPL Credit Facilities were replaced with the 2015 SPL Credit Facilities.

In March 2015, in conjunction with SPL’s issuance of the 2025 SPL Senior Notes, SPL terminated approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities. This termination and the replacement of the 2013 SPL Credit Facilities with the 2015 SPL Credit Facilities in June 2015 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2013 SPL Credit Facilities of $96.3 million for the year ended December 31, 2015. The amendment and restatement of the 2012 SPL Credit Facility with the 2013 SPL Credit Facilities in May 2013 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2012 SPL Credit Facility of $88.3 million during the year ended December 31, 2013.

CTPL Term Loan

CTPL has the $400.0 million CTPL Term Loan, which was used to fund modifications to the Creole Trail Pipeline and for general business purposes. The CTPL Term Loan matures in 2017 when the full amount of the outstanding principal obligations must be repaid. CTPL’s loan may be repaid, in whole or in part, at any time without premium or penalty. As of December 31, 2015, CTPL had borrowed the full amount of $400.0 million available under the CTPL Term Loan. Borrowings under the CTPL Term Loan accrue interest at a variable rate per annum equal to, at CTPL’s election, LIBOR or the base rate, plus the applicable margin. The applicable margin for LIBOR loans is 3.25%. Interest on LIBOR loans is due and payable at the end of each LIBOR period.

SPL Working Capital Facility

In September 2015, SPL entered into the $1.2 billion SPL Working Capital Facility, which replaced the $325.0 million SPL LC Agreement. The SPL Working Capital Facility is intended to be used for loans to SPL (“Working Capital Loans”), the issuance of letters of credit on behalf of SPL (“Letters of Credit”), as well as for swing line loans to SPL (“Swing Line Loans”), primarily for certain working capital requirements related to developing and placing into operation the SPL Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and, upon the completion of the debt financing of Train 6 of the SPL Project, request an incremental increase in commitments of up to an additional $390 million. As of December 31, 2015, SPL had $1.1 billion of available commitments, $135.2 million aggregate amount of issued Letters of Credit, $15.0 million in Working Capital Loans and no Swing Line Loans or loans deemed made in connection with a draw upon a Letter of

Credit (“LC Loans” and collectively with Working Capital Loans and Swing Line Loans, the “SPL Working Capital Facility Loans”) outstanding under the SPL Working Capital Facility. As of December 31, 2014, SPL had issued letters of credit in an aggregate amount of $9.5 million, and no draws had been made upon any letters of credit issued under the SPL LC Agreement.

SPL Working Capital Facility Loans accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of the senior facility agent’s published prime rate, the federal funds effective rate, as published by the Federal Reserve Bank of New York, plus 0.50% and one month LIBOR plus 0.50%), plus the applicable margin. The applicable margin for LIBOR SPL Working Capital Facility Loans is 1.75% per annum, and the applicable margin for base rate SPL Working Capital Facility

Loans is 0.75% per annum. Interest on Swing Line Loans and LC Loans is due and payable on the date the loan becomes due. Interest on LIBOR Working Capital Loans is due and payable at the end of each applicable LIBOR period, and interest on base rate Working Capital Loans is due and payable at the end of each fiscal quarter. However, if such base rate Working Capital Loan is converted into a LIBOR Working Capital Loan, interest is due and payable on that date. Additionally, if the loans become due prior to such periods, the interest also becomes due on that date.

SPL incurred $27.5 million of debt issuance costs in connection with the SPL Working Capital Facility. SPL pays (1) a commitment fee equal to an annual rate of 0.70% on the average daily amount of the excess of the total commitment amount over the principal amount outstanding without giving effect to any outstanding Swing Line Loans and (2) a Letter of Credit fee equal to an annual rate of 1.75% of the undrawn portion of all Letters of Credit issued under the SPL Working Capital Facility. If draws are made upon a Letter of Credit issued under the SPL Working Capital Facility and SPL does not elect for such draw (an “LC Draw”) to be deemed an LC Loan, SPL is required to pay the full amount of the LC Draw on or prior to the business day following the notice of the LC Draw. An LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2015, no LC Draws had been made upon any Letters of Credit issued under the SPL Working Capital Facility.

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

The SPL Working Capital Facility contains conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. The obligations of SPL under the SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a pari passu basis with the SPL Senior Notes and the 2015 SPL Credit Facilities.

Arrangement to Refinance Project Debt

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, to redeem or repay $1,665.5 million of the 2016 SPLNG Senior Notes and $420.0 million of the 2020 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.

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.

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.

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.

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.

Capital Resources

We expect to finance the construction costs of the CCL Project from one or more of the following: project financing, existing unrestricted cash, debt and equity offerings by us or our subsidiaries and operating cash flow.

2025 CCH HoldCo II Convertible Senior Notes

In May 2015, CCH HoldCo II issued $1.0 billion aggregate principal amount of the 2025 CCH HoldCo II Convertible Senior Notes on a private placement basis. The $1.0 billion principal of the 2025 CCH HoldCo II Convertible Senior Notes will be used to partially fund costs associated with Stage 1 of the CCL Project and the Corpus Christi Pipeline. The 2025 CCH HoldCo II Convertible Senior Notes bear interest at a rate of 11.0% per annum, which is payable quarterly in arrears. Prior to the substantial completion of Train 2 of the CCL Project, interest on the 2025 CCH HoldCo II Convertible Senior Notes will be paid entirely in kind. Following this date, the interest generally must be paid in cash; however, a portion of the interest may be paid in kind under certain specified circumstances. The 2025 CCH HoldCo II Convertible Senior Notes are secured by a pledge by us of 100% of the equity interests in CCH HoldCo II, and a pledge by CCH HoldCo II of 100% of the equity interests in CCH HoldCo I.

At CCH HoldCo II's option, the outstanding 2025 CCH HoldCo II Convertible Senior Notes are convertible into our common stock 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 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. Conversions are also subject to various limitations and conditions.

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.

2015 CCH Credit Facility

In May 2015, CCH entered into the $8.4 billion 2015 CCH Credit Facility, which is being used to fund a portion of the costs associated with the development, construction, operation and maintenance of Stage 1 of the CCL Project and the Corpus Christi Pipeline. Borrowings under the 2015 CCH Credit Facility may be refinanced, in whole or in part, at any time without premium or penalty; however, interest rate hedging and interest rate breakage costs may be incurred. As of December 31, 2015, CCH had $5.7 billion of available commitments and $2.7 billion of outstanding borrowings under the 2015 CCH Credit Facility.

CCH incurred $289.3 million of debt issuance costs in connection with the 2015 CCH Credit Facility, of which $16.5 million was written off in December 2015 when a portion of the original commitments was terminated by CCH. In addition to interest, CCH will incur a commitment fee at a rate per annum equal to 40% of the margin for LIBOR loans, multiplied by the outstanding undrawn debt commitments. The principal of the loans made under the 2015 CCH Credit Facility must be repaid in quarterly installments, commencing on the earlier of (1) the first quarterly payment date occurring more than three calendar months following project completion and (2) a set date determined by reference to the date under which a certain LNG buyer linked to Train 2 of the CCL Project is entitled to terminate its SPA for failure to achieve the date of first commercial delivery for that agreement. Scheduled repayments will be based upon a 19-year tailored amortization, commencing the first full quarter after the project completion and designed to achieve a minimum projected fixed debt service coverage ratio of 1.55:1.

Loans under the 2015 CCH Credit Facility accrue interest at a variable rate per annum equal to, at CCH's election, LIBOR or the base rate, plus the applicable margin. The applicable margins for LIBOR loans are 2.25% prior to completion and 2.50% on completion and thereafter. The applicable margins for base rate loans are 1.25% prior to completion and 1.50% on completion and thereafter. Interest on LIBOR loans is due and payable at the end of each applicable interest period and interest on base rate loans is due and payable at the end of each quarter. The 2015 CCH Credit Facility also requires CCH to pay a commitment fee at a rate per annum equal to 40% of the margin for LIBOR loans, multiplied by the outstanding undrawn debt commitments.

The obligations of CCH under the 2015 CCH Credit Facility are secured by a first priority lien on substantially all of the assets of CCH and its subsidiaries and by a pledge by CCH HoldCo I of its limited liability company interests in CCH.

Under the terms of the 2015 CCH Credit Facility, CCH is required to hedge not less than 65% of the variable interest rate exposure of its senior secured debt. 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.

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.

Corporate and Other Activities

We are required to maintain corporate and general and administrative functions to serve our business activities described above. We are also in various stages of developing other projects which, among other things, will require acceptable commercial and financing arrangements before we make an FID.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash and cash equivalents (in thousands) for the years ended December 31, 2015, 2014 and 2013. The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals, which are referred to elsewhere in this report. Additional discussion of these items follows the table.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Sources of cash and cash equivalents | | | |
| Proceeds from issuances of debt | $7,073,000 | $3,584,500 | $4,504,478 |
| Use of restricted cash for the acquisition of property, plant and equipment | 6,324,288 | 2,684,433 | 3,129,709 |
| Proceeds from exercise of stock options | 2,279 | 10,805 | 3,698 |
| Proceeds from sale of common shares by Cheniere Holdings | — | 228,781 | 665,001 |
| Proceeds from sale of common units by Cheniere Partners | — | — | 364,775 |
| Other | 1,524 | 3,605 | 3,382 |
| Total sources of cash and cash equivalents | 13,401,091 | 6,512,124 | 8,671,043 |
| | | | |
| Uses of cash and cash equivalents | | | |
| Investment in restricted cash | (6,043,757) | (2,224,196) | (4,083,707) |
| Property, plant and equipment, net | (6,852,583) | (2,829,558) | (3,114,343) |
| Debt issuance and deferred financing costs | (513,062) | (111,807) | (311,050) |
| Repayments of debt | — | (177,000) | (100,000) |
| Distributions and dividends to non-controlling interest | (80,235) | (79,517) | (69,220) |
| Payments related to tax withholdings for share-based compensation | (61,175) | (112,324) | (136,367) |
| Operating cash flow | (265,622) | (124,119) | (52,436) |
| Investment in Cheniere Partners | — | — | (11,122) |
| Other | (131,128) | (66,862) | (33,667) |
| Total uses of cash and cash equivalents | (13,947,562) | (5,725,383) | (7,911,912) |
| | | | |
| Net increase (decrease) in cash and cash equivalents | (546,471) | 786,741 | 759,131 |
| Cash and cash equivalents—beginning of period | 1,747,583 | 960,842 | 201,711 |
| Cash and cash equivalents—end of period | $1,201,112 | $1,747,583 | $960,842 |

Proceeds from Issuances of Debt, Debt Issuance and Deferred Financing Costs and Repayments of Debt

In March 2015, SPL issued an aggregate principal amount of $2.0 billion of the 2025 SPL Senior Notes. Also in March 2015, we issued an aggregate principal amount of $625.0 million of the 2045 Cheniere Convertible Senior Notes, with an original issue discount of 20%, for net proceeds of $495.7 million. In May 2015, CCH HoldCo II issued an aggregate principal amount of $1.0 billion of the 2025 CCH HoldCo II Convertible Senior Notes. Also in May 2015, CCH entered into the 2015 CCH Credit Facility and borrowed $2.7 billion under this facility during the year ended December 31, 2015. In June 2015, SPL entered into the 2015 SPL Credit Facilities aggregating $4.6 billion, which terminated and replaced the 2013 SPL Credit Facilities, and borrowed $845.0 million under this facility during the year ended December 31, 2015. In September 2015, SPL entered into the $1.2 billion SPL Working Capital Facility which replaced the SPL LC Agreement, and borrowed $15.0 million in Working Capital Loans during the year ended December 31, 2015. Debt issuance and deferred financing costs in the year ended December 31, 2015 primarily relate to up-front fees paid upon the closing of these transactions.

In May 2014, SPL issued an aggregate principal amount of $2.0 billion of the 2024 SPL Senior Notes and an additional $0.5 billion principal amount of the 2023 SPL Senior Notes for total net proceeds of approximately $2.5 billion. Additionally, in November 2014, we issued $1.0 billion of the 2021 Cheniere Convertible Unsecured Notes.

Debt issuance and deferred financing costs in the year ended December 31, 2014 primarily relate to up-front fees paid upon the closing of these offerings.

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

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

During the years ended December 31, 2015, 2014 and 2013, we used $6,324.3 million, $2,684.4 million and $3,129.7 million, respectively, of restricted cash for investing activities to partially fund $6,852.6 million, $2,829.6 million and $3,114.3 million used for the acquisition of property, plant and equipment during the years ended December 31, 2015, 2014 and 2013, respectively. These costs primarily related to the construction costs for Trains 1 through 5 of the SPL Project and Trains 1 and 2 of the CCL Project and are capitalized as construction-in-process.

Proceeds from Sale of Common Shares by Cheniere Holdings

The proceeds from the sale of Cheniere Holdings' common shares in the year ended December 31, 2014 related to the public offering of 10.1 million of Cheniere Holdings' common shares for net proceeds of approximately $229 million, after deducting offering expenses. The net proceeds were used to redeem from us the same number of Cheniere Holdings' common shares, which reduced our ownership of Cheniere Holdings' common shares from 84.5% to 80.1%.

In December 2013, Cheniere Holdings completed its initial public offering of 36.0 million common shares at $20.00 per common share. Cheniere Holdings was formed by us to hold our Cheniere Partners limited partner interests. We ultimately received all of the $665.0 million of net proceeds from the Cheniere Holdings initial public offering from the repayment of Cheniere Holdings' intercompany indebtedness and payables owed to us and through a distribution by Cheniere Holdings to us.

Proceeds from Sale of Common Units by Cheniere Partners

The proceeds from the sale of common units of Cheniere Partners in the year ended December 31, 2013 primarily related to a February 2013 common unit purchase agreement with institutional investors to sell 17.6 million common units for net proceeds, after deducting expenses, of approximately $365 million. Cheniere Partners used the proceeds from this offering to purchase 100% of the equity interests in Cheniere Pipeline GP Interests, LLC held by Cheniere Pipeline Company, and the limited partner interest in CTPL held by Grand Cheniere Pipeline, LLC.

Investment in Restricted Cash

In the year ended December 31, 2015, we invested $6,043.8 million in restricted cash primarily related to the net proceeds from the 2025 SPL Senior Notes, 2025 CCH HoldCo II Convertible Senior Notes and the borrowings under the 2015 SPL Credit Facilities, 2015 CCH Credit Facility and SPL Working Capital Facility, net of deferred financing costs. These proceeds were partially offset by the payment of distributions to non-controlling interest. In the year ended December 31, 2014, we invested $2,224.2 million in restricted cash primarily related to the net proceeds from the notes issued by SPL during the year. In the year ended December 31, 2013, we invested $4,083.7 million in restricted cash related to the net proceeds from the CTPL Term Loan, 2013 SPL Credit Facilities and the notes issued by SPL during the year.

Distributions and Dividends to Non-controlling Interest

During the years ended December 31, 2015, 2014 and 2013, Cheniere Partners and Cheniere Holdings, collectively, made distributions and paid dividends of $80.2 million, $79.5 million and $69.2 million, respectively, to common unitholders and common shareholders.

Payments Related to Tax Withholdings for Share-based Compensation

During the years ended December 31, 2015, 2014 and 2013, we used $61.2 million, $112.3 million and $136.4 million respectively, of cash and cash equivalents to purchase restricted stock that was returned to us by employees to cover taxes related to their restricted stock that vested during such periods. The decrease in 2015 primarily resulted from the vesting of awards under the long-term commercial bonus pool related to Trains 3 and 4 of the SPL Project in 2014 and 2013 that did not occur in 2015.

Operating Cash Flow

During the years ended December 31, 2015, 2014 and 2013, we used $265.6 million, $124.1 million and $52.4 million, respectively, of cash in operating activities. The increase in operating cash outflows in 2015 compared to 2014 primarily related to amounts paid upon meeting the contingency related to the interest rate swaps we entered into to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 CCH Credit Facility ("CCH Interest Rate Derivatives") and settlement of other derivative instruments, the timing of amounts paid to third parties for operating costs and increased payments made for general and administrative costs, including payments made for phantom stock vestings. The increase in operating cash outflows in 2014 compared to 2013 primarily related to increased cash outflows related to the settlement of interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2013 SPL Credit Facilities and increased general and administrative costs resulting from an increased number of employees and professional fees.

Other

During the years ended December 31, 2015, 2014 and 2013, we used $131.1 million, $66.9 million and $33.7 million, respectively, of cash in other activities primarily as a result of payments made to a municipal water district for water system enhancements that will increase potable water supply to our Sabine Pass LNG terminal and investments made in unconsolidated entities.

Issuance of Common Stock

During the years ended December 31, 2015, 2014 and 2013, we issued 19,000, 0.5 million and 18.9 million shares, respectively, of restricted stock to new and existing employees.

Contractual Obligations

We are committed to make cash payments in the future pursuant to certain of our contracts. The following table summarizes certain contractual obligations (in thousands) in place as of December 31, 2015:

| | Payments Due By Period (1) | | | | |
|---|---|---|---|---|---|
| | Total | 2016 | 2017 - 2018 | 2019 - 2020 | Thereafter |
| Construction obligations (2) | $6,597,313 | $3,461,085 | $2,712,409 | $423,819 | $— |
| Purchase obligations (3) | 1,629,967 | 472,141 | 526,444 | 372,110 | 259,272 |
| Debt (4) | 18,087,378 | 1,680,500 | 400,000 | 1,265,000 | 14,741,878 |
| Interest payments (4) | 6,584,897 | 850,184 | 1,442,829 | 1,686,007 | 2,605,877 |
| Capital lease obligations (5) | 796,808 | — | 19,920 | 79,680 | 697,208 |
| Operating lease obligations (6) | 561,608 | 99,973 | 202,560 | 184,998 | 74,077 |
| Other obligations | 18,288 | 10,318 | 7,970 | — | — |
| Total | $34,276,259 | $6,574,201 | $5,312,132 | $4,011,614 | $18,378,312 |

(1) Agreements in force as of December 31, 2015 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2015.

(2) Construction obligations primarily relate to the EPC contracts for the SPL Project and the CCL Project. The estimated remaining costs pursuant to our EPC contracts as of December 31, 2015 is included for Trains with respect to which we have made an FID to commence construction; the EPC contract termination amount is included for Trains with respect to which we have not made an FID. A discussion of these obligations can be found at Note 16—Commitments and Contingencies of our Notes to Consolidated Financial Statements.

(3) Purchase obligations consists of contracts for which conditions precedent have been met, and primarily relate to natural gas supply, transportation and storage services for the SPL Project, maintenance contracts for the SPL Project, purchases of materials for the Corpus Christi Pipeline and LNG cargo transactions by Cheniere Marketing.

As project milestones and other conditions precedent are achieved, our obligations are expected to increase accordingly.

(4) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2015. See Note 11—Debt of our Notes to Consolidated Financial Statements.

(5) Capital lease obligations relate to tug leases related to the CCL Project, as further discussed in Note 15—Leases of our Notes to Consolidated Financial Statements.

(6) Operating lease obligations primarily relate to LNG vessel time charters and land sites related to the SPL Project and the CCL Project and corporate office leases. A discussion of these obligations can be found in Note 15—Leases of our Notes to Consolidated Financial Statements.

In addition, in the ordinary course of business, we maintain letters of credit and have certain cash restricted in support of certain performance obligations of our subsidiaries. As of December 31, 2015, we had $135.2 million aggregate amount of issued Letters of Credit under the SPL Working Capital Facility and $535.1 million of current and non-current restricted cash. For more information, see Note 3—Restricted Cash of our Notes to Consolidated Financial Statements.

Results of Operations

2015 vs. 2014

Our consolidated net loss attributable to common stockholders was $975.1 million, or $4.30 per share (basic and diluted), in the year ended December 31, 2015 compared to a net loss attributable to common stockholders of $547.9 million, or $2.44 per share (basic and diluted), in the year ended December 31, 2014. This $427.2 million increase in net loss was primarily a result of increased interest expense, net of amounts capitalized, increased general and administrative expense (“G&A Expense”), increased impairment expense, net, increased derivative loss, net and increased loss on early extinguishment of debt.

Interest expense, net increased $140.9 million in the year ended December 31, 2015, as compared to the year ended December 31, 2014, primarily as a result of an increase in our indebtedness outstanding as of December 31, 2015 compared to December 31, 2014. For the years ended December 31, 2015 and 2014, we incurred $997.5 million and $587.0 million of total interest cost, respectively, of which we capitalized and deferred $675.3 million and $405.8 million, respectively, which were directly related to the construction of the SPL Project and the CCL Project. G&A Expense increased $100.2 million, from $323.7 million in the year ended December 31, 2014 to $423.9 million in the year ended December 31, 2015, primarily due to increased compensation expense as a result of increased headcount and $62.1 million of accelerated share-based compensation expense resulting from employee terminations.

Impairment expense, net increased to $91.3 million in the year ended December 31, 2015 from zero in the year ended December 31, 2014. The impairment expense recognized during the year ended December 31, 2015 was a result of our strategic focus to complete construction and commence operation of the SPL Project and the CCL Project and primarily attributable to impairments of business development projects totaling $55.1 million primarily associated with a liquid hydrocarbon export project in Texas along the Gulf Coast, as well as $36.2 million resulting primarily from a reserve against funds loaned to Parallax Enterprises, LLC to develop its two mid-scale natural gas liquefaction projects in Louisiana along the Gulf Coast.

Derivative loss, net increased $84.2 million, from $119.4 million in the year ended December 31, 2014, to $203.6 million in the year ended December 31, 2015. The derivative loss recognized during the year ended December 31, 2015 was primarily attributable to the loss recognized upon meeting the contingency related to the CCH Interest Rate Derivatives, as well as the loss recognized in March 2015 upon the termination of interest rate swaps associated with approximately $1.8 billion of commitments that were terminated under the 2013 SPL Credit Facilities. Additionally, both the increase to the notional amount of interest rate derivatives outstanding and the decrease in long-term LIBOR during the year ended December 31, 2015 that was more significant than the decrease in long-term LIBOR during the year ended December 31, 2014 contributed to the increase in derivative loss, net.

Loss on early extinguishment of debt increased $9.9 million, from $114.3 million in the year ended December 31, 2014, to $124.2 million in the year ended December 31, 2015. The loss on early extinguishment of debt during the year ended December 31, 2015 was attributable to the write-off of debt issuance costs and deferred commitment fees totaling $96.3 million associated with the termination of approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities in March 2015 and the replacement of the 2013 SPL Credit Facilities with the 2015 SPL Credit Facilities in June 2015, $16.5 million associated with the termination of a portion of the original commitments under the 2015 CCH Credit Facility and $11.4 million associated with the termination of additional commitments made available under the 2025 CCH HoldCo II Convertible Senior Notes. Loss on early extinguishment of debt during the year ended December 31, 2014 was attributable to the $114.3 million write-off of debt issuance costs and deferred commitment fees in connection with the early extinguishment of $2.1 billion of commitments under the 2013 SPL Credit Facilities in 2014.

2014 vs. 2013

Our consolidated net loss attributable to common stockholders was $547.9 million, or $2.44 per share (basic and diluted), in the year ended December 31, 2014 compared to a net loss attributable to common stockholders of $507.9 million, or $2.32 per share (basic and diluted), in the year ended December 31, 2013. This $40.0 million increase in net loss was primarily a result of decreased derivative gain, net, which was partially offset by increased net loss attributable to non-controlling interest, decreased G&A Expense and decreased loss on early extinguishment of debt.

Derivative gain (loss), net decreased $202.2 million, from $82.8 million gain in the year ended December 31, 2013 to $119.4 million loss in the year ended December 31, 2014, primarily as a result of a decrease in long-term LIBOR during the year ended December 31, 2014, as compared to an increase in long-term LIBOR during the year ended December 31, 2013, and the early settlement of interest rate swaps in connection with the early extinguishment of a portion of the 2013 SPL Credit Facilities in May 2014.

Net loss attributable to non-controlling interest increased $93.1 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of increased net loss recorded by Cheniere Partners and the increased portion of equity ownership in Cheniere Partners not attributable to us resulting from the Cheniere Partners' common unit offering in the first quarter of 2013 and Cheniere Holdings' initial public offering of 36.0 million common shares completed in December 2013. G&A Expense decreased $60.8 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of accelerated expense recognition in the year ended December 31, 2013 for bonus plan awards relating to the SPL Project. Loss on early extinguishment of debt decreased $17.2 million in the year ended December 31, 2014, as compared to the year ended December 31, 2013, due to the write-off of debt issuance costs in connection with the early extinguishment of $2.1 billion of commitments under the 2013 SPL Credit Facilities in May 2014, as compared to the write-off of debt issuance costs and deferred commitment fees in connection with the early extinguishment of a portion of the commitments under the 2012 SPL Credit Facility in April 2013 and under the 2013 SPL Credit Facilities in November 2013.

There was no significant change to interest expense, net of amounts capitalized in the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of our capitalization of interest costs incurred which were directly related to the construction of the first four Trains of the SPL Project. For the years ended December 31, 2014 and 2013, we incurred $587.0 million and $414.0 million of total interest cost, respectively, of which we capitalized and deferred $405.8 million and $235.6 million, respectively.

Off-Balance Sheet Arrangements

As of December 31, 2015, we had no transactions that met the definition of off-balance sheet arrangements that may have a current or future material effect on our consolidated financial position or operating results.

Summary of Critical Accounting Estimates

The preparation of Consolidated Financial Statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and the accompanying notes. Management evaluates its estimates and related assumptions regularly, including those related to the value of properties, plant and equipment, goodwill, asset retirement obligations ("AROs"), income taxes, share-based compensation and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve significant judgment.

Fair Value

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

Derivative Instruments

All derivative instruments, other than those that satisfy specific exceptions, are recorded at fair value. We record changes in the fair value of our derivative positions based on the value for which the derivative instrument could be exchanged between willing parties. If market quotes are not available to estimate fair value, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or determined through industry-standard valuation techniques.

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

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

Goodwill

At December 31, 2015, we had $76.8 million of goodwill associated with our LNG terminal reporting unit. Goodwill represents the excess of cost over fair value of the assets of businesses acquired.

We test goodwill for impairment annually during the fourth quarter, or more frequently as circumstances dictate. The first step in assessing whether an impairment of goodwill is necessary is an optional qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is greater than its carrying amount. If we conclude that it is more likely than not that the fair value of the reporting unit exceeds the related carrying amount, further testing is not necessary. If the qualitative assessment is not performed or indicates that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we compare the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill. If the carrying value of the reporting unit exceeds its fair value, we perform the second step of the goodwill impairment test to measure the amount of goodwill impairment loss to be recorded, as necessary. The second step compares the implied fair value of the reporting unit's goodwill to the carrying value, if any, of that goodwill. We determine the implied fair value of the goodwill in the same manner as determining the amount of goodwill to be recognized in a business combination.

Because quoted market prices for our reporting units are not available, we must apply judgment in determining the estimated fair value of our reporting units for purposes of performing goodwill impairment tests, when such tests are necessary. Management uses all available information to make these fair value estimates, including the present values of expected future cash flows using discount rates commensurate with the risks associated with the assets, future LNG liquefaction, operating costs and depreciation. These estimates are based on current conditions and historical experience and we rely on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. Management reviews its estimates of cash flows on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment.

A lower fair value estimate in the future for our LNG terminal reporting unit could result in impairment of goodwill. Factors that could trigger a lower fair value estimate include significant negative industry or economic trends, cost increases, disruptions to our business and regulatory or political environment changes or other unanticipated events.

Impairment of Long-Lived Assets

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

Share-Based Compensation

The assumptions used in calculating the fair value of share-based payment awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management's judgment. As a result, if factors change and we use different assumptions, our share-based compensation expense could be materially different in the future.

We recognize the cost for our share-based payment awards based on market conditions using Monte Carlo simulations. To calculate the Monte Carlo simulation, we must consider certain variables including volatility factors and dividend yield. Volatility factors are based on the historical and implied volatilities of Cheniere's common stock over the expected lives as estimated on the grant date. The dividend yield is the expected annual dividend yield over the expected life, expressed as a percentage of the stock price on the grant date.

In addition, we are required to estimate the expected forfeiture rate for all of our share-based payment awards and only recognize expense for those shares expected to vest. We consider many factors when estimating expected forfeitures, including types of awards, employee class and historical experience. If our actual forfeiture rate is materially different from our estimate, future share-based compensation expense could be significantly different from what we have recorded in the current period.

See Note 2—Summary of Significant Accounting Policies and Note 13—Share-Based Compensation of our Notes to Consolidated Financial Statements for additional information regarding our share-based compensation.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the tax basis of assets and liabilities and their reported amounts in the Consolidated Financial Statements. Deferred tax assets and liabilities are included in the Consolidated Financial Statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the current period's provision for income taxes. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. This assessment requires significant judgment and is based upon our assessment of our ability to generate future taxable income among other factors.

Recent Accounting Standards

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

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Cash Investments

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

Marketing and Trading Commodity Price Risk

We have entered into commodity derivatives consisting of natural gas purchase agreements to secure natural gas feedstock for the SPL Project (“Liquefaction Supply Derivatives”). In order to test the sensitivity of the fair value of the Liquefaction Supply Derivatives to changes in underlying commodity prices, management modeled a 10% change in the basis price for natural gas for each delivery location. As of December 31, 2015, we estimated the fair value of the Liquefaction Supply Derivatives to be $32.5 million. Based on actual derivative contractual volumes, a 10% increase or decrease in the underlying basis price would have resulted in a change in the fair value of the Liquefaction Supply Derivatives of $0.9 million as of December 31, 2015, compared to $0.4 million as of December 31, 2014. The increase in the effect of change in the underlying basis price was due to a $32.2 million increase in fair value for our natural gas purchase agreements recorded during the third quarter of 2015, which we recognized following the completion and placement into service of certain modifications to the Creole Trail Pipeline and the resulting development of a market for physical gas delivery at locations specified in a portion of our natural gas purchase agreements. See Note 6—Derivative Instruments for additional details about our derivative instruments.

Interest Rate Risk

SPL has entered into interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 SPL Credit Facilities (“SPL Interest Rate Derivatives”). In order to test the sensitivity of the fair value of the SPL Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward 1-month LIBOR curve across the full 7-year term of the SPL Interest Rate Derivatives. This 10% change in interest rates would have resulted in a change in the fair value of the SPL Interest Rate Derivatives of $3.1 million as of December 31, 2015, compared to $16.5 million as of December 31, 2014. The decrease in the effect of change in interest rates was due to lower notional amounts of SPL Interest Rate Derivatives outstanding and a decrease in the forward 1-month LIBOR curve during the year ended December 31, 2015.

CCH has entered into interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 CCH Credit Facility (“CCH Interest Rate Derivatives”). In order to test the sensitivity of the fair value of the CCH Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward 1-month LIBOR curve across the full 7-year term of the CCH Interest Rate Derivatives. This 10% change in interest rates would have resulted in a change in the fair value of the CCH Interest Rate Derivatives of $55.6 million as of December 31, 2015. We did not have any CCH Interest Rate Derivatives as of December 31, 2014.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CHENIERE ENERGY, INC. AND SUBSIDIARIES

MANAGEMENT'S REPORT TO THE STOCKHOLDERS OF CHENIERE ENERGY, INC.

Management's Report on Internal Control Over Financial Reporting

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

Based on our assessment, we have concluded that Cheniere maintained effective internal control over financial reporting as of December 31, 2015, based on criteria in Internal Control—Integrated Framework (2013) issued by the COSO.

Cheniere's independent registered public accounting firm, KPMG LLP, has issued an audit report on Cheniere's internal control over financial reporting as of December 31, 2015, which is contained in this Form 10-K.

Management's Certifications

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

CHENIERE ENERGY, INC.

By: /s/ Neal A. Shear
Neal A. Shear
Interim Chief Executive Officer and President
(Principal Executive Officer)

By: /s/ Michael J. Wortley
Michael J. Wortley
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries (the Company) as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive loss, stockholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2015. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule I for each of the years in the two-year period ended December 31, 2015. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cheniere Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule for each of the years in the two-year period ended December 31, 2015, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cheniere Energy, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 18, 2016, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Houston, Texas
February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.:

We have audited Cheniere Energy, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cheniere Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Cheniere Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive loss, stockholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2015, and our report dated February 18, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Houston, Texas
February 18, 2016

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Cheniere Energy, Inc.

We have audited the accompanying consolidated statements of operations, comprehensive loss, stockholders' equity, and cash flows of Cheniere Energy, Inc. and subsidiaries for the year ended December 31, 2013. Our audit also included the financial statement schedule for the year ended December 31, 2013 listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit.

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

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

/s/ ERNST & YOUNG LLP
Ernst & Young LLP

Houston, Texas
February 21, 2014

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

| | December 31, 2015 | 2014 |
|---|---|---|
| ASSETS | | |
| Current assets | | |
| Cash and cash equivalents | $1,201,112 | $1,747,583 |
| Restricted cash | 503,397 | 481,737 |
| Accounts and interest receivable | 5,749 | 4,419 |
| Inventory | 18,125 | 7,786 |
| Other current assets | 54,203 | 17,352 |
| Total current assets | 1,782,586 | 2,258,877 |
| | | |
| Non-current restricted cash | 31,722 | 550,811 |
| Property, plant and equipment, net | 16,193,907 | 9,246,753 |
| Debt issuance costs, net | 589,213 | 242,323 |
| Non-current derivative assets | 30,887 | 11,744 |
| Goodwill | 76,819 | 76,819 |
| Other non-current assets | 314,455 | 186,356 |
| Total assets | $19,019,589 | $12,573,683 |
| | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities | | |
| Accounts payable | $22,820 | $13,426 |
| Accrued liabilities | 427,199 | 169,129 |
| Current debt, net | 1,676,197 | — |
| Deferred revenue | 26,669 | 26,655 |
| Derivative liabilities | 35,201 | 23,247 |
| Other current liabilities | — | 18 |
| Total current liabilities | 2,188,086 | 232,475 |
| | | |
| Long-term debt, net | 15,128,145 | 9,806,084 |
| Non-current deferred revenue | 9,500 | 13,500 |
| Non-current derivative liabilities | 79,387 | 267 |
| Other non-current liabilities | 53,068 | 19,840 |
| | | |
| Commitments and contingencies (see Note 16) | | |
| | | |
| Stockholders' equity | | |
| Preferred stock, $0.0001 par value, 5.0 million shares authorized, none issued | — | — |
| Common stock, $0.003 par value | | |
| Authorized: 480.0 million shares at December 31, 2015 and 2014 | | |
| Issued and outstanding: 235.6 million shares and 236.7 million shares at December 31, 2015 and 2014, respectively | 708 | 712 |
| Treasury stock: 11.6 million shares and 10.6 million shares at December 31, 2015 and 2014, respectively, at cost | (353,927) | (292,752) |
| Additional paid-in-capital | 3,075,317 | 2,776,702 |

| | | |
|---|---|---|
| Accumulated deficit | (3,623,948) | (2,648,839) |
| Total stockholders' deficit | (901,850) | (164,177) |
| Non-controlling interest | 2,463,253 | 2,665,694 |
| Total equity | 1,561,403 | 2,501,517 |
| Total liabilities and equity | $19,019,589 | $12,573,683 |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Revenues | | | |
| LNG terminal revenues | $269,281 | $267,606 | $265,406 |
| Marketing and trading revenues (losses) | 66 | (1,286) | 242 |
| Other | 1,538 | 1,634 | 1,565 |
| Total revenues | 270,885 | 267,954 | 267,213 |
| Operating costs and expenses | | | |
| Operating and maintenance expense | 79,767 | 84,403 | 88,511 |
| Depreciation and amortization expense | 82,680 | 64,258 | 61,209 |
| Development expense | 42,141 | 54,376 | 60,934 |
| General and administrative expense | 423,862 | 323,709 | 384,512 |
| Impairment expense | 91,317 | — | — |
| Other | 431 | 13,387 | 375 |
| Total operating costs and expenses | 720,198 | 540,133 | 595,541 |
| Loss from operations | (449,313) | (272,179) | (328,328) |
| Other income (expense) | | | |
| Interest expense, net of capitalized interest | (322,083) | (181,236) | (178,400) |
| Loss on early extinguishment of debt | (124,180) | (114,335) | (131,576) |
| Derivative gain (loss), net | (203,639) | (119,401) | 82,790 |
| Other income (expense) | 1,804 | (583) | 1,091 |
| Total other expense | (648,098) | (415,555) | (226,095) |
| Loss before income taxes and non-controlling interest | (1,097,411) | (687,734) | (554,423) |
| Income tax benefit (provision) | 96 | (4,143) | (4,340) |
| Net loss | (1,097,315) | (691,877) | (558,763) |
| Less: net loss attributable to non-controlling interest | (122,206) | (143,945) | (50,841) |
| Net loss attributable to common stockholders | $(975,109) | $(547,932) | $(507,922) |
| Net loss per share attributable to common stockholders—basic and diluted | $(4.30) | $(2.44) | $(2.32) |
| Weighted average number of common shares outstanding—basic and diluted | 226,903 | 224,338 | 218,869 |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS
(in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Net loss | $(1,097,315) | $(691,877) | $(558,763) |
| Other comprehensive income (loss) | | | |
| Loss on settlements of interest rate cash flow hedges retained in other comprehensive income | — | — | (30) |
| Change in fair value of interest rate cash flow hedges | — | — | 21,297 |
| Losses reclassified into earnings as a result of discontinuance of cash flow hedge accounting | — | — | 5,973 |
| Foreign currency translation | — | — | 111 |
| Total other comprehensive income | — | — | 27,351 |
| Comprehensive loss | (1,097,315) | (691,877) | (531,412) |
| Less: comprehensive loss attributable to non-controlling interest | (122,206) | (143,945) | (48,809) |
| Comprehensive loss attributable to common stockholders | $(975,109) | $(547,932) | $(482,603) |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

| | Total Stockholders' Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Common Stock | | Treasury Stock | | | | | | |
| | Shares | Par Value Amount | Shares | Amount | Additional Paid-in Capital | Accumulated Deficit | Accumulated Other Comprehensive Loss | Non-controlling Interest | Total Equity |
| Balance at December 31, 2012 | 223,397 | $671 | 4,727 | $(39,115) | $2,168,781 | $(1,592,985) | $(27,351) | $1,751,604 | $2,261,605 |
| Issuances of stock | 155 | — | — | — | 3,697 | — | — | — | 3,697 |
| Issuances of restricted stock | 18,860 | 57 | — | — | (57) | — | — | — | — |
| Forfeitures of restricted stock | (159) | — | 81 | — | — | — | — | — | — |
| Share-based compensation | — | — | — | — | 283,881 | — | — | — | 283,881 |
| Shares repurchased related to share-based compensation | (4,162) | (12) | 4,162 | (140,711) | 12 | — | — | — | (140,711) |
| Excess tax benefit from share-based compensation | — | — | — | — | 3,385 | — | — | — | 3,385 |
| Foreign currency translation | — | — | — | — | — | — | 111 | — | 111 |
| Interest rate cash flow hedges | — | — | — | — | — | — | 25,207 | 2,032 | 27,239 |
| Loss attributable to non-controlling interest | — | — | — | — | — | — | — | (50,841) | (50,841) |
| Sale of Cheniere Holdings' common shares to non-controlling interest | — | — | — | — | — | — | — | 664,931 | 664,931 |
| Sale of common units to non-controlling interest | — | — | — | — | — | — | 2,033 | 361,869 | 363,902 |
| Distribution to non-controlling interest | — | — | — | — | — | — | — | (69,220) | (69,220) |
| Net loss | — | — | — | — | — | (507,922) | — | — | (507,922) |
| Balance at December 31, 2013 | 238,091 | 716 | 8,970 | (179,826) | 2,459,699 | (2,100,907) | — | 2,660,375 | 2,840,057 |
| | 387 | 1 | — | — | 11,408 | — | — | — | 11,409 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Exercise of stock options | | | | | | | | | |
| Issuances of restricted stock | 550 | 2 | — | — | (2) | — | — | — | — |
| Forfeitures of restricted stock | (726) | (2) | 69 | — | 2 | — | — | — | — |
| Share-based compensation | — | — | — | — | 110,039 | — | — | — | 110,039 |
| Shares repurchased related to share-based compensation | (1,557) | (5) | 1,557 | (112,926) | 5 | — | — | — | (112,926) |
| Excess tax benefit from share-based compensation | — | — | — | — | 3,605 | — | — | — | 3,605 |
| Loss attributable to non-controlling interest | — | — | — | — | — | — | — | (143,945) | (143,945) |
| Issuance of convertible notes, net | — | — | — | — | 191,946 | — | — | — | 191,946 |
| Sale of Cheniere Holdings’ common shares to non-controlling interest | — | — | — | — | — | — | — | 228,781 | 228,781 |
| Distributions to non-controlling interest | — | — | — | — | — | — | — | (79,517) | (79,517) |
| Net loss | — | — | — | — | — | (547,932) | — | — | (547,932) |
| Balance at December 31, 2014 | 236,745 | 712 | 10,596 | (292,752) | 2,776,702 | (2,648,839) | — | 2,665,694 | 2,501,517 |
| Exercise of stock options | 67 | — | — | — | 2,279 | — | — | — | 2,279 |
| Issuances of restricted stock | 19 | — | — | — | — | — | — | — | — |
| Forfeitures of restricted stock | (156) | (1) | 17 | — | 1 | — | — | — | — |
| Share-based compensation | — | — | — | — | 89,636 | — | — | — | 89,636 |
| Shares repurchased related to share-based compensation | (1,036) | (3) | 1,036 | (61,175) | 3 | — | — | — | (61,175) |
| Excess tax benefit from share-based compensation | — | — | — | — | 1,524 | — | — | — | 1,524 |
| Loss attributable to non-controlling interest | — | — | — | — | — | — | — | (122,206) | (122,206) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Equity portion of convertible notes, net | — | — | — | — | 205,172 | — | — | — | 205,172 |
| Distributions to non-controlling interest | — | — | — | — | — | — | — | (80,235) | (80,235) |
| Net loss | — | — | — | — | — | (975,109) | — | — | (975,109) |
| Balance at December 31, 2015 | 235,639 | $708 | 11,649 | $(353,927) | $3,075,317 | $(3,623,948) | $— | $2,463,253 | $1,561,403 |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Cash flows from operating activities | | | |
| Net loss | $(1,097,315) | $(691,877) | $(558,763) |
| Adjustments to reconcile net loss to net cash used in operating activities: | | | |
| Non-cash LNG inventory write-downs | 17,537 | 24,461 | 26,900 |
| Depreciation and amortization expense | 82,680 | 64,258 | 61,209 |
| Share-based compensation | 168,157 | 102,003 | 271,367 |
| Amortization of debt issuance costs and discount | 47,733 | 16,593 | 14,948 |
| Loss on early extinguishment of debt | 124,180 | 114,335 | 131,576 |
| Total (gains) losses on derivatives, net | 168,426 | 118,968 | (84,281) |
| Net cash used for settlement of derivative instruments | (99,616) | (22,758) | 609 |
| Impairment expense | 91,317 | — | — |
| Other | 959 | 15,914 | (2,631) |
| Changes in restricted cash for certain operating activities | 216,898 | 138,679 | 120,593 |
| Changes in operating assets and liabilities: | | | |
| Accounts and interest receivable | (662) | 67 | (31) |
| Inventory | (27,876) | (18,874) | (26,460) |
| Accounts payable and accrued liabilities | 5,966 | 16,073 | 6,687 |
| Deferred revenue | (3,986) | (3,938) | (3,947) |
| Other, net | 39,980 | 1,977 | (10,212) |
| Net cash used in operating activities | (265,622) | (124,119) | (52,436) |
| | | | |
| Cash flows from investing activities | | | |
| Property, plant and equipment, net | (6,852,583) | (2,829,558) | (3,114,343) |
| Use of restricted cash for the acquisition of property, plant and equipment | 6,324,288 | 2,684,433 | 3,129,709 |
| Investment in Cheniere Partners | — | — | (11,122) |
| Other | (131,128) | (66,862) | (33,667) |
| Net cash used in investing activities | (659,423) | (211,987) | (29,423) |
| | | | |
| Cash flows from financing activities | | | |
| Proceeds from issuances of debt | 7,073,000 | 3,584,500 | 4,504,478 |
| Repayments of debt | — | (177,000) | (100,000) |
| Debt issuance and deferred financing costs | (513,062) | (111,807) | (311,050) |
| Investment in restricted cash | (6,043,757) | (2,224,196) | (4,083,707) |
| Distributions and dividends to non-controlling interest | (80,235) | (79,517) | (69,220) |
| Proceeds from sale of common shares by Cheniere Holdings | — | 228,781 | 665,001 |
| Proceeds from sale of common units by Cheniere Partners | — | — | 364,775 |
| Proceeds from exercise of stock options | 2,279 | 10,805 | 3,698 |
| Payments related to tax withholdings for share-based compensation | (61,175) | (112,324) | (136,367) |
| Other | 1,524 | 3,605 | 3,382 |
| Net cash provided by financing activities | 378,574 | 1,122,847 | 840,990 |
| | | | |
| Net increase (decrease) in cash and cash equivalents | (546,471) | 786,741 | 759,131 |
| Cash and cash equivalents—beginning of period | 1,747,583 | 960,842 | 201,711 |

| | | | |
|---|---|---|---|
| Cash and cash equivalents—end of period | $1,201,112 | $1,747,583 | $960,842 |

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

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 includes existing infrastructure of five LNG storage tanks with capacity of approximately 16.9 Bcfe, two docks that can accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. 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 Corpus Christi LNG terminal 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, 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.

## NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements were prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of Cheniere, its majority owned subsidiaries and entities in which it holds a controlling interest, including the accounts of Cheniere Holdings and Cheniere Partners and its wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Investments in non-controlled entities, over which Cheniere has the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for the Company's proportionate share of earnings, losses and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are reported as a component of other assets.

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

Use of Estimates

The preparation of Consolidated Financial Statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and the accompanying notes. Management evaluates its estimates and related assumptions regularly, including those related to the value of property, plant and equipment, goodwill, collectability of accounts and notes receivable, derivative instruments, asset retirement obligations ("AROs"), income taxes including valuation allowances for net deferred tax assets, share-based compensation and fair value measurements. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value

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

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

Recurring fair-value measurements are performed for commodity derivatives and interest rate derivatives as disclosed in Note 6—Derivative Instruments. The carrying amount of cash and cash equivalents, restricted cash, accounts receivable and accounts payable reported on the Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount we would have to pay to repurchase our debt in the open market, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in Note 11—Debt, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments. Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination, intangible assets, goodwill and AROs.

Revenue Recognition

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

LNG and Natural Gas Marketing

We have determined that a portion of our LNG and natural gas marketing business activities is comprised of energy trading and risk management activities for trading purposes and have elected to present these activities on a net basis on our Consolidated Statements of Operations. For our LNG and natural gas marketing transactions that are not energy trading and risk management activities for trading purposes, we determine whether revenue should be reported on a gross or net basis based on an assessment of whether we are acting as the principal or the agent in the transaction. Marketing and trading revenues represent the margin earned on the purchase and transportation of LNG purchases and subsequent sales of LNG and natural gas to third parties. These energy trading and risk management activities include, but are not limited to, the purchase of LNG and natural gas, transportation contracts and LNG inventory derivatives. Below is a brief description of our accounting treatment for each type of energy trading and risk management activity:

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Purchase of LNG and natural gas

The purchase value of LNG or natural gas inventory is recorded as an asset on our Consolidated Balance Sheets at the cost to acquire the product. Our inventory is subject to lower of cost or market adjustment each quarter. Recoveries of losses resulting from interim period lower of cost or market adjustments are made due to market price recoveries on the same inventory in the same fiscal year and are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. Any adjustment to our inventory is recorded on a net basis as LNG and natural gas marketing revenue on our Consolidated Statements of Operations.

Transportation contracts

We enter into transportation contracts with respect to the transport of LNG or natural gas to a specific location for storage, consumption or sale. Transportation costs that are incurred during the purchase of LNG or natural gas are capitalized as part of the acquisition costs of the product. Transportation costs incurred to sell LNG or natural gas are recorded on a net basis as LNG and natural gas marketing revenue on our Consolidated Statements of Operations.

LNG Inventory Derivatives

We use derivative instruments to hedge cash flows attributable to the future sale of LNG inventory. Gains and losses in positions to hedge the cash flows attributable to the future sale of LNG inventory are classified as marketing and trading revenues on our Consolidated Statements of Operations.

Cash and Cash Equivalents

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

Restricted Cash

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

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

Accounts and Notes Receivable

Accounts and notes receivable are reported net of allowances for doubtful accounts. Notes receivable that are not classified as trade receivables are recorded within other current assets in our Consolidated Balance Sheets. Impaired receivables are specifically identified and evaluated for expected losses. The expected loss on impaired receivables is primarily determined based on the debtor’s ability to pay and the estimated value of any collateral. During the year ended December 31, 2015, we recognized bad debt expense of $36.2 million which is primarily attributable to a reserve against funds loaned to Parallax Enterprises, LLC as part of its development of two mid-scale natural gas liquefaction projects in Louisiana along the Gulf Coast. This charge is recorded as impairment expense on our Consolidated Statements of Operations.

Inventory

Inventory is recorded at weighted average cost and is subject to lower of cost or market ("LCM") adjustments at the end of each period. Our LCM adjustments primarily related to LNG inventory purchased to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal that are recorded in operating and maintenance expense on our Consolidated Statements of Operations. Recoveries of losses resulting from interim period LCM adjustments are recorded when market price recoveries occur on the same inventory in the same fiscal year. These recoveries are recognized as gains in later interim periods with such gains not exceeding previously recognized losses. During the years ended December 31, 2015, 2014 and 2013, we recognized $17.5 million, $24.5 million and $26.9 million, respectively, as operating and maintenance expense as a result of LCM adjustments primarily related to LNG inventory purchased to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal.

Accounting for LNG Activities

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

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

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

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction activities, major renewals and betterments that extend the useful life of an asset are capitalized, while expenditures for maintenance and repairs and general and administrative activities are charged to expense as incurred. Interest costs incurred on debt obtained for the construction of property, plant and equipment are capitalized as construction-in-process over the construction period or related debt term, whichever is shorter. We depreciate our property, plant and equipment using the straight-line depreciation method. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed from the account, and the resulting gains or losses are recorded in other operating costs and expenses.

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

During the year ended December 31, 2015, we recorded, primarily in relation to a liquid hydrocarbon export project in Texas along the Gulf Coast, approximately $55.1 million of impairment expense as a result of our strategic focus to complete construction and commence operation of the first five Trains of the SPL Project and the first two Trains of the CCL Project. This amount is included in impairment expense on our Consolidated Statements of Operations and relates to corporate and other within our segment disclosures. We did not record any impairment expense related to property, plant and equipment during the years ended December 31, 2014 or 2013.

Regulated Natural Gas Pipelines

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

Items that may influence our assessment are:

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

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

Derivative Instruments

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

Changes in the fair value of our derivative instruments are recorded in current earnings, unless we elect to apply hedge accounting and meet specified criteria, including completing contemporaneous hedge documentation. We did not have any derivative instruments designated as cash flow hedges as of December 31, 2015 and 2014.

In the past, we elected cash flow hedge accounting for derivatives that we used to hedge the exposure to volatility in floating-rate interest payments. Changes in fair value of derivative instruments designated as cash flow hedges, to the extent the hedge was effective, were recognized in accumulated other comprehensive loss on our Consolidated Balance Sheets. We reclassified gains and losses on the hedges from accumulated other comprehensive loss into interest expense in our Consolidated Statements of Operations as the hedged item was recognized. Any change in the fair value resulting from ineffectiveness was recognized immediately as derivative gain (loss) on our Consolidated Statements of Operations. We used regression analysis to determine whether we expected a derivative to be highly effective as a cash flow hedge, prior to electing hedge accounting and also to determine whether all derivatives designated as cash flow hedges had been effective. We performed these effectiveness tests prior to designation for all new hedges and on a quarterly basis for all existing hedges. We calculated the actual amount of ineffectiveness on our cash flow hedges using the "dollar offset" method, which compared changes in the expected cash flows of the hedged transaction to changes in the value of expected cash flows from the hedge. We discontinued hedge accounting when our effectiveness tests indicated that a derivative was no longer highly effective as a hedge; when the derivative expired or was sold, terminated or exercised; when the hedged item matured, was sold or repaid; or when we determined that the occurrence of the hedged forecasted transaction was not probable. When we discontinued hedge accounting but continued to hold the derivative, prospective changes in fair value of the derivative instrument were recorded in income. Once we concluded that the hedged forecasted transaction became probable of not occurring, the amount remaining in accumulated other comprehensive loss pertaining to the previously designated derivatives was reclassified out of accumulated other comprehensive loss and into income.

See Note 6—Derivative Instruments for additional details about our derivative instruments.

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Concentration of Credit Risk

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

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

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

SPL has entered into six fixed price 20-year SPAs with six unaffiliated third parties. CCL has entered into eight fixed price 20-year SPAs with seven unaffiliated third parties. SPL and CCL are dependent on the respective counterparties' creditworthiness and their willingness to perform under their respective SPAs.

Goodwill

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. The goodwill on our Consolidated Balance Sheets as of December 31, 2015 and 2014 is associated with our LNG terminal reporting unit. We determine our reporting units by identifying each unit that engaged in business activities from which it may earn revenues and incur expenses, had operating results regularly reviewed by the chief operating decision maker for purposes of resource allocation and performance assessment, and had discrete financial information.

Goodwill is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. During the fourth quarters of 2015 and 2014, we performed a qualitative assessment of goodwill in accordance with guidance from the Financial Accounting Standards Board (the "FASB"), which permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If we fail the qualitative test, then we must compare our estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, we perform the second step of the goodwill impairment test to measure the amount of goodwill impairment loss to be recorded, as necessary. The second step compares the implied fair value of the reporting unit's goodwill to the carrying value, if any, of that goodwill. We determine the implied fair value of the goodwill in the same manner as determining the amount of goodwill to be recognized in a business combination.

We completed our annual assessment of goodwill impairment during the fourth quarters of 2015 and 2014, and the tests indicated no impairment. As discussed above regarding our use of estimates, our judgments and assumptions are inherent in our estimate of future cash flows used to determine the estimate of the reporting unit’s fair value. The use of alternate judgments and/or assumptions could result in the recognition of impairment charges in the Consolidated Financial Statements. A lower fair value estimate in the future for our LNG terminal reporting unit could result in an impairment of goodwill. Factors that could trigger a lower fair value estimate include significant negative industry or economic trends, cost increases, disruptions to our business, regulatory or political environment changes or other unanticipated events.

Debt

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

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

Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees and printing costs. These costs are recorded as debt issuance costs on our Consolidated Balance Sheets and are being amortized to interest expense or property, plant and equipment over the term of the related debt facility. Upon early retirement of debt or amendment to a debt agreement, certain fees are written off to loss on early extinguishment of debt.

Asset Retirement Obligations

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

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

Currently, the Creole Trail Pipeline is our only constructed and operating natural gas pipeline. We believe that it is not feasible to predict when the natural gas transportation services provided by the Creole Trail Pipeline will no longer be utilized. In addition, our right-of-way agreements associated with the Creole Trail Pipeline have no stipulated termination dates. Therefore, we have concluded that due to advanced technology associated with current natural gas pipelines and our intent to operate the Creole Trail Pipeline as long as supply and demand for natural gas exists in the United States, we have not recorded an ARO associated with the Creole Trail Pipeline.

Share-based Compensation

We have awarded share-based compensation in the form of stock, restricted stock, stock options and phantom units that are more fully described in Note 13—Share-Based Compensation. We recognize share-based compensation at fair value on the date of grant. The fair value is recognized as expense (net of any capitalization) over the requisite service period. For equity-classified share-based compensation awards (which include stock, restricted stock to employees and non-employee directors and stock options), compensation cost is recognized based on the grant-date fair value using the quoted market price of Cheniere's common stock and not subsequently remeasured. The fair value is recognized as expense (net of any capitalization) using the straight-line basis for awards that vest based on service and market conditions and using the accelerated recognition method for awards that vest based on performance conditions. We estimate the service periods for performance awards utilizing a probability assessment based on when we expect to achieve the performance conditions. For liability-classified share-based compensation awards (which include restricted stock to non-employees and phantom units), compensation cost is initially recognized on the grant date using estimated payout levels. Compensation cost is subsequently adjusted quarterly to reflect the updated estimated payout levels based on the changes in the Company's stock price.

Non-controlling Interests

When we consolidate a subsidiary, we include 100% of the assets, liabilities, revenues and expenses of the subsidiary in our Consolidated Financial Statements, even if we own less than 100% of the subsidiary. Non-controlling interests represent third-party ownership in the net assets of our consolidated subsidiaries and are presented as a component of equity. Changes in our ownership interests in subsidiaries that do not result in deconsolidation are recognized within equity. See Note 9—Non-controlling Interest for additional details about our non-controlling interest.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the tax basis of assets and liabilities and their reported amounts in the Consolidated Financial Statements. Deferred tax assets and liabilities are included in the Consolidated Financial Statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the current period's provision for income taxes. A valuation allowance is recorded to reduce the carrying value of our deferred tax assets when it is more likely than not that a portion or all of the deferred tax assets will expire before realization of the benefit or future deductibility is not probable. A valuation allowance equal to our federal and state net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our federal and state net deferred tax assets.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the tax position.

Net Loss Per Share

Net loss per share ("EPS") is computed in accordance with GAAP. Basic EPS excludes dilution and is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted EPS reflects potential dilution and is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued and were dilutive. Basic and diluted EPS for all periods presented are the same since the effect of our options and unvested stock is anti-dilutive to our net loss per share. Stock options and unvested stock representing securities that could potentially dilute basic EPS in the future that were not included in the diluted computation because they would have been anti-dilutive for the years 2015, 2014 and 2013, were 7.6 million shares, 10.4 million shares and 14.1 million shares, respectively. In addition, 73.9 million shares and 14.3 million shares in aggregate, for the years ended December 31, 2015 and 2014, respectively, that were issuable upon conversion of our convertible notes, as described in Note 11—Debt, were not included in the computation of diluted net loss per share because the computation of diluted net loss per share utilizing the "if-converted" method would be anti-dilutive.

NOTE 3—RESTRICTED CASH

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

SPLNG Senior Notes Debt Service Reserve

SPLNG has consummated private offerings of an aggregate principal amount of $1.7 billion, before discount, of 7.50% Senior Secured Notes due 2016 (the “2016 SPLNG Senior Notes”) and $0.4 billion of 6.50% Senior Secured Notes due 2020 (the “2020 SPLNG Senior Notes” and collectively with the 2016 SPLNG Senior Notes, the “SPLNG Senior Notes”). Under the indentures governing the SPLNG Senior Notes (the “SPLNG Indentures”), except for permitted tax distributions, SPLNG may not make distributions until certain conditions are satisfied, including: (1) there must be on deposit in an interest payment account an amount equal to one-sixth of the semi-annual interest payment multiplied by the number of elapsed months since the last semi-annual interest payment, and (2) there must be on deposit in a permanent debt service reserve fund an amount equal to one semi-annual interest payment. Distributions are permitted only after satisfying the foregoing funding requirements, a fixed charge coverage ratio test of 2:1 and other conditions specified in the SPLNG Indentures.

As of December 31, 2015 and 2014, we classified $77.4 million and $15.0 million, respectively, as current restricted cash for the payment of current interest due. As of December 31, 2015 and 2014, we classified the permanent debt service reserve fund of $13.7 million and $76.1 million, respectively, as non-current restricted cash. These cash accounts are controlled by a collateral trustee; therefore, these amounts are shown as restricted cash on our Consolidated Balance Sheets.

SPL Reserve

During 2013, SPL entered into four credit facilities aggregating $5.9 billion (collectively, the "2013 SPL Credit Facilities"). In June 2015, SPL entered into four credit facilities aggregating $4.6 billion (collectively, the "2015 SPL Credit Facilities"), which replaced the 2013 SPL Credit Facilities. Under the terms and conditions of the 2015 SPL Credit Facilities (and previously the 2013 SPL Credit Facilities), SPL is required to deposit all cash received into reserve accounts controlled by a collateral trustee. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the SPL Project; therefore, these amounts are shown as restricted cash on our Consolidated Balance Sheets.

During 2013, SPL issued an aggregate principal amount of $2.0 billion, before premium, of 5.625% Senior Secured Notes due 2021 (the "2021 SPL Senior Notes"), $1.0 billion of 6.25% Senior Secured Notes due 2022 (the "2022 SPL Senior Notes") and $1.0 billion of 5.625% Senior Secured Notes due 2023 (the "Initial 2023 SPL Senior Notes"). During 2014, SPL issued an aggregate principal amount of $2.0 billion of 5.75% Senior Secured Notes due 2024 (the "2024 SPL Senior Notes") and additional 5.625% Senior Secured Notes due 2023 in an aggregate principal amount of $0.5 billion, before premium (collectively with the Initial 2023 SPL Senior Notes, the "2023 SPL Senior Notes"). In March 2015, SPL issued an aggregate principal amount of $2.0 billion of 5.625% Senior Secured Notes due 2025 (the "2025 SPL Senior Notes" and collectively with the 2021 SPL Senior Notes, the 2022 SPL Senior Notes, the 2023 SPL Senior Notes and the 2024 SPL Senior Notes, the "SPL Senior Notes"). The use of cash proceeds from the SPL Senior Notes is restricted to the payment of liabilities related to the SPL Project; therefore, these amounts are shown as restricted cash on our Consolidated Balance Sheets. See Note 11—Debt for additional details about our debt.

As of December 31, 2015 and 2014, we classified $189.3 million and $155.8 million, respectively, as current restricted cash held by SPL for the payment of current liabilities, including interest payments, related to the SPL Project and zero and $457.1 million, respectively, as non-current restricted cash held by SPL for future SPL Project construction costs.

CTPL Reserve
In May 2013, CTPL entered into a $400.0 million term loan facility (the "CTPL Term Loan"). As of December 31, 2015 and 2014, we classified $7.9 million and $24.9 million, respectively, as current restricted cash held by CTPL for the payment of current liabilities and zero and $11.3 million, respectively, as non-current restricted cash held by CTPL, because the usage and withdrawal of such funds is primarily restricted to the payment of liabilities related to modifications of the Creole Trail Pipeline in order to enable bi-directional natural gas flow, and for the payment of interest during construction of such modifications. The restricted cash reserved to pay interest during construction is controlled by a collateral agent, and can only be released by the collateral agent upon satisfaction of certain terms and conditions. CTPL is required to pay annual fees to the administrative and collateral agents.

CCH Reserve

In May 2015, CCH entered into a credit facility agreement for approximately $8.4 billion (the “2015 CCH Credit Facility”) linked to Stage 1 of the CCL Project and the Corpus Christi Pipeline. Under the terms and conditions of the 2015 CCH Credit Facility, all cash reserved to pay interest during construction is controlled by a collateral agent. These funds can only be released by the collateral agent upon satisfaction of certain terms and conditions and are classified as restricted on our Consolidated Balance Sheets. CCH is required to pay annual fees to the administrative and collateral agents. As of December 31, 2015, we classified $46.8 million as current restricted cash held by CCH.

Other Restricted Cash

As of December 31, 2015 and 2014, $147.1 million and $250.1 million, respectively, of cash was held by our subsidiaries that was restricted to Cheniere.  In addition, as of December 31, 2015 and 2014, $34.9 million and $35.9 million, respectively, had been classified as current restricted cash, and $18.0 million and $6.3 million, respectively, had been classified as non-current restricted cash on our Consolidated Balance Sheets due to various other contractual restrictions.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 4—INVENTORY

As of December 31, 2015 and 2014, inventory consisted of the following (in thousands):

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Natural gas | $5,724 | $— |
| LNG | 5,148 | 4,293 |
| Materials and other | 7,253 | 3,493 |
| Total inventory | $18,125 | $7,786 |

NOTE 5—PROPERTY, PLANT AND EQUIPMENT

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

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| LNG terminal costs | | |
| LNG terminal | $2,509,646 | $2,269,429 |
| LNG terminal construction-in-process | 13,877,209 | 7,155,046 |
| LNG site and related costs, net | 33,512 | 9,395 |
| Accumulated depreciation | (414,731) | (350,497) |
| Total LNG terminal costs, net | 16,005,636 | 9,083,373 |
| Fixed assets and other | | |
| Computer and office equipment | 12,153 | 7,464 |
| Furniture and fixtures | 17,101 | 10,733 |
| Computer software | 69,569 | 46,882 |
| Leasehold improvements | 40,136 | 36,067 |
| Land | 60,984 | 55,522 |
| Other | 79,642 | 36,881 |
| Accumulated depreciation | (91,314) | (30,169) |
| Total fixed assets and other, net | 188,271 | 163,380 |
| Property, plant and equipment, net | $16,193,907 | $9,246,753 |

LNG Terminal Costs

The Sabine Pass LNG terminal is depreciated using the straight-line depreciation method applied to groups of LNG terminal assets with varying useful lives. The identifiable components of the Sabine Pass LNG terminal with similar estimated useful lives have a depreciable range between 15 and 50 years, as follows:

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

Fixed Assets and Other

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 6—DERIVATIVE INSTRUMENTS

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

- commodity derivatives to hedge the exposure to price risk attributable to future: (1) sales of our LNG inventory and (2) purchases of natural gas to operate the Sabine Pass LNG terminal ("Natural Gas Derivatives");
- commodity derivatives consisting of natural gas purchase agreements and associated economic hedges to secure natural gas feedstock for the SPL Project ("Liquefaction Supply Derivatives");
- financial derivatives to hedge the exposure to the commodity markets in which we have contractual arrangements to purchase or sell physical LNG ("LNG Trading Derivatives");
- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 SPL Credit Facilities (and previously the 2013 SPL Credit Facilities) ("SPL Interest Rate Derivatives"); and
- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the 2015 CCH Credit Facility ("CCH Interest Rate Derivatives" and, collectively with the SPL Interest Rate Derivatives, the "Interest Rate Derivatives").

None of our derivative instruments are designated as cash flow hedging instruments, and changes in fair value are recorded within our Consolidated Statements of Operations.

The following table (in thousands) shows the fair value of the derivative instruments that are required to be measured at fair value on a recurring basis as of December 31, 2015 and 2014, which are classified as other current assets, non-current derivative assets, derivative liabilities or non-current derivative liabilities in our Consolidated Balance Sheets.

| | Fair Value Measurements as of December 31, 2015 | | | | December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total | Quoted Prices in Active Markets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Natural Gas Derivatives asset (liability) | $— | $ (66 ) | $ — | $(66 ) | $— | $ 219 | $ — | $219 |
| Liquefaction Supply Derivatives asset (liability) | — | (25 ) | 32,492 | 32,467 | — | — | 342 | 342 |
| LNG Trading Derivatives asset | — | 1,053 | — | 1,053 | — | — | — | — |
| SPL Interest Rate Derivatives liability | — | (8,740 ) | — | (8,740 ) | — | (12,036 ) | — | (12,036 ) |
| CCH Interest Rate Derivatives liability | — | (104,999 ) | — | (104,999) | — | — | — | — |

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

The fair value of substantially all of the Liquefaction Supply Derivatives is developed through the use of internal models which are impacted by inputs that are unobservable in the marketplace. As a result, the fair value of the Liquefaction Supply Derivatives is designated as Level 3 within the valuation hierarchy. The curves used to generate the fair value of the Liquefaction Supply Derivatives are based on basis adjustments applied to forward curves for a liquid trading point. In addition, there may be observable liquid market basis information in the near term, but terms of a particular Liquefaction Supply Derivatives contract may exceed the period for which such information is available, resulting in a Level 3 classification. In these instances, the fair value of the contract incorporates extrapolation assumptions made in the determination of the market basis price for future delivery periods in which applicable commodity basis prices were either not observable or lacked corroborative market data. Internal fair value models that include contractual pricing with a fixed basis include fixed basis amounts for delivery at locations for which no market currently exists. Internal fair value models also include conditions precedent to the respective long-term natural gas purchase agreements. As of December 31, 2015 and 2014, some of the Liquefaction Supply Derivatives existed within markets for which the pipeline infrastructure has not been developed to accommodate marketable physical gas flow. In the absence of infrastructure to accommodate marketable physical gas flow, our internal fair value models are based on a market price that equates to our own contractual pricing due to: (1) the inactive and unobservable market and (2) conditions precedent and their impact on the uncertainty in the timing of our actual receipt of the physical volumes associated with each forward. The fair value of the Liquefaction Supply Derivatives is predominantly driven by market commodity basis prices and our assessment of the associated conditions precedent, including evaluating whether the respective market is available as pipeline infrastructure is developed. Upon the completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow, we recognize a gain or loss based on the fair value of the respective natural gas purchase agreements as of the reporting date.

There were no transfers into or out of Level 3 Liquefaction Supply Derivatives for the years ended December 31, 2015, 2014 and 2013. As all of the Liquefaction Supply Derivatives are either purely index-priced or index-priced with a fixed basis, we do not believe that a significant change in market commodity prices would have a material impact on our Level 3 fair value measurements. The following table includes quantitative information for the unobservable inputs for the Level 3 Liquefaction Supply Derivatives as of December 31, 2015:

| | Net Fair Value Asset (in thousands) | Valuation Technique | Significant Unobservable Input | Significant Unobservable Inputs Range |
|---|---|---|---|---|
| Liquefaction Supply Derivatives | $32,492 | Income Approach | Basis Spread | $ (0.350) - $0.050 |

Derivative assets and liabilities arising from our derivative contracts with the same counterparty are reported on a net basis, as all counterparty derivative contracts provide for net settlement. The use of derivative instruments exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments in instances when our derivative instruments are in an asset position.

Commodity Derivatives

We recognize all commodity derivative instruments, including the Natural Gas Derivatives, Liquefaction Supply Derivatives and LNG Trading Derivatives (collectively, “Commodity Derivatives”), as either assets or liabilities and measure those instruments at fair value. Changes in the fair value of our Commodity Derivatives are reported in earnings.

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

| | December 31, 2015 | | | | December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| | Natural Gas Derivatives (1) | Liquefaction Supply Derivatives | LNG Trading Derivatives | Total | Natural Gas Derivatives (1) | Liquefaction Supply Derivatives | LNG Trading Derivatives | Total |
| Balance Sheet Location | | | | | | | | |
| Other current assets | $— | $ 2,737 | $ 640 | $3,377 | $219 | $ 76 | $ — | $295 |
| | — | 30,304 | 583 | 30,887 | — | 586 | — | 586 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Non-current derivative assets | | | | | | | | |
| Total derivative assets | — | 33,041 | 1,223 | 34,264 | 219 | 662 | — | 881 |
| Derivative liabilities | (66 ) | (490 ) | (107 ) | (663 ) | — | (53 ) | — | (53 ) |
| Non-current derivative liabilities | — | (84 ) | (63 ) | (147 ) | — | (267 ) | — | (267 ) |
| Total derivative liabilities | (66 ) | (574 ) | (170 ) | (810 ) | — | (320 ) | — | (320 ) |
| Derivative asset (liability), net | $(66 ) | $ 32,467 | $ 1,053 | $33,454 | $219 | $ 342 | $ — | $561 |

(1) Does not include collateral of $5.5 million deposited for such contracts, which is included in other current assets in our Consolidated Balance Sheets as of both December 31, 2015 and 2014.

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CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The following table (in thousands) shows the changes in the fair value and settlements and location of our Commodity Derivatives recorded on our Consolidated Statements of Operations during the years ended December 31, 2015, 2014 and 2013:

| | | Year Ended December 31, | | |
|---|---|---|---|---|
| | Statement of Operations Location | 2015 | 2014 | 2013 |
| Natural Gas Derivatives loss | Marketing and trading revenues (losses) | $(407) | $(1,298) | $(350) |
| Natural Gas Derivatives gain | Operating and maintenance expense | 2,065 | 1,389 | 658 |
| Liquefaction Supply Derivatives gain (1) | Operating and maintenance expense | 32,503 | 342 | — |
| LNG Trading Derivatives gain | Marketing and trading revenues (losses) | 1,053 | — | — |

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery.

The use of Commodity Derivatives exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments in instances when our Commodity Derivatives are in an asset position.

Natural Gas Derivatives

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

Liquefaction Supply Derivatives

SPL has entered into index-based physical natural gas supply contracts and associated economic hedges to secure natural gas feedstock for the SPL Project. The terms of the physical contracts primarily range from approximately one to seven years and commence upon the occurrence of conditions precedent, including the date of first commercial operation of specified Trains of the SPL Project. We recognize the Liquefaction Supply Derivatives as either assets or liabilities and measure those instruments at fair value. Changes in the fair value of the Liquefaction Supply Derivatives are reported in earnings. 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. The notional natural gas position of the Liquefaction Supply Derivatives was approximately 1,240.5 million MMBtu.

LNG Trading Derivatives

As of December 31, 2015, we have entered into certain LNG Trading Derivatives representing a net position of zero MMBtu, and we may from time to time enter into certain financial derivatives in the form of swaps, forwards, options or futures to economically hedge exposure to the commodity markets in which we have contractual arrangements to purchase or sell physical LNG. We have entered into LNG Trading Derivatives to secure a fixed price position to minimize future cash flow variability associated with such LNG transactions.

Interest Rate Derivatives

SPL Interest Rate Derivatives

SPL has entered into SPL Interest Rate Derivatives to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2015 SPL Credit Facilities. The SPL Interest Rate Derivatives hedge a portion of the expected outstanding borrowings over the term of the 2015 SPL Credit Facilities.

In March 2015, SPL settled a portion of the SPL Interest Rate Derivatives and recognized a derivative loss of $34.7 million within our Consolidated Statements of Operations in conjunction with the termination of approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities as discussed in Note 11—Debt. In May 2014, SPL settled a portion of the SPL Interest Rate Derivatives and recognized a derivative loss of $9.3 million within our Consolidated Statements of Operations in conjunction with the early termination of approximately $2.1 billion of commitments under the 2013 SPL Credit Facilities.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

CCH Interest Rate Derivatives

In February 2015, CCH entered into CCH Interest Rate Derivatives to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2015 CCH Credit Facility. The CCH Interest Rate Derivatives hedge a portion of the expected outstanding borrowings over the term of the 2015 CCH Credit Facility. The CCH Interest Rate Derivatives have a seven-year term and were contingent upon reaching a final investment decision with respect to the CCL Project, which was reached in May 2015. Upon meeting the contingency related to the CCH Interest Rate Derivatives in May 2015, we paid $50.1 million related to contingency and syndication premiums, which is included in derivative gain (loss), net on our Consolidated Statements of Operations.

As of December 31, 2015, we had the following Interest Rate Derivatives outstanding:

| | Initial Notional Amount | Maximum Notional Amount | Effective Date | Maturity Date | Weighted Average Fixed Interest Rate Paid | Variable Interest Rate Received |
|---|---|---|---|---|---|---|
| SPL Interest Rate Derivatives | $20.0 million | $628.8 million | August 14, 2012 | July 31, 2019 | 1.98% | One-month LIBOR |
| CCH Interest Rate Derivatives | $28.8 million | $5.5 billion | May 20, 2015 | May 31, 2022 | 2.29% | One-month LIBOR |

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

| | December 31, 2015 | | | December 31, 2014 | | |
|---|---|---|---|---|---|---|
| | SPL Interest Rate Derivatives | CCH Interest Rate Derivatives | Total | SPL Interest Rate Derivatives | CCH Interest Rate Derivatives | Total |
| Balance Sheet Location | | | | | | |
| Other current assets | $— | $— | $— | $— | $— | $— |
| Non-current derivative assets | — | — | — | 11,158 | — | 11,158 |
| Total derivative assets | — | — | — | 11,158 | — | 11,158 |
| | | | | | | |
| Derivative liabilities | (5,940) | (28,559) | (34,499) | (23,194) | — | (23,194) |
| Non-current derivative liabilities | (2,800) | (76,440) | (79,240) | — | — | — |
| Total derivative liabilities | (8,740) | (104,999) | (113,739) | (23,194) | — | (23,194) |
| | | | | | | |
| Derivative liability, net | $(8,740) | $(104,999) | $(113,739) | $(12,036) | $— | $(12,036) |

The following table (in thousands) details the effect of our SPL Interest Rate Derivatives included in Other Comprehensive Income (“OCI”) and accumulated other comprehensive income (“AOCI”) during the year ended December 31, 2013. The SPL Interest Rate Derivatives had no effect on OCI during the years ended December 31, 2015 and 2014.

| | Gain (Loss) in OCI | Gain (Loss) Reclassified from AOCI into | Losses Reclassified into Earnings as a |
|---|---|---|---|

| | | Interest Expense (Effective Portion) | Result of Discontinuance of Cash Flow Hedge Accounting |
|---|---|---|---|
| Year Ended December 31, 2013 | | | |
| SPL Interest Rate Derivatives - Designated | $21,297 | $— | $5,807 |
| SPL Interest Rate Derivatives - Settlements | (30) | — | 166 |

The following table (in thousands) shows the changes in the fair value and settlements of the Interest Rate Derivatives, including contingency and syndication premiums related to the CCH Interest Rate Derivatives, recorded in derivative gain (loss), net on our Consolidated Statements of Operations during the years ended December 31, 2015, 2014 and 2013:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| SPL Interest Rate Derivatives gain (loss) | $(41,722) | $(119,401) | $88,596 |
| CCH Interest Rate Derivatives loss | (161,917) | — | — |

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Balance Sheet Presentation

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

| Offsetting Derivative Assets (Liabilities) | Gross Amounts Recognized | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts Presented in the Consolidated Balance Sheets |
|---|---|---|---|
| As of December 31, 2015 | | | |
| Natural Gas Derivatives | $188 | $(254) | $(66) |
| Liquefaction Supply Derivatives | 33,636 | (595) | 33,041 |
| Liquefaction Supply Derivatives | (574) | — | (574) |
| LNG Trading Derivatives | 1,922 | (699) | 1,223 |
| LNG Trading Derivatives | (2,826) | 2,656 | (170) |
| SPL Interest Rate Derivatives | (8,740) | — | (8,740) |
| CCH Interest Rate Derivatives | (104,999) | — | (104,999) |
| As of December 31, 2014 | | | |
| Natural Gas Derivatives | 223 | (4) | 219 |
| Liquefaction Supply Derivatives | 662 | — | 662 |
| Liquefaction Supply Derivatives | (320) | — | (320) |
| SPL Interest Rate Derivatives | 11,158 | — | 11,158 |
| SPL Interest Rate Derivatives | (23,194) | — | (23,194) |

## NOTE 7—OTHER NON-CURRENT ASSETS

As of December 31, 2015 and 2014, other non-current assets consisted of the following (in thousands):

| | December 31, 2015 | December 31, 2014 |
|---|---|---|
| Advances made under EPC and non-EPC contracts | $83,579 | $10,683 |
| Advances made to municipalities for water system enhancements | 89,953 | 36,441 |
| Tax-related payments and receivables | 31,712 | 26,279 |
| Conveyed assets to non-affiliates | — | 14,751 |
| Equity method investments | 20,295 | 19,064 |
| Other | 88,916 | 79,138 |
| Total other non-current assets | $314,455 | $186,356 |

## NOTE 8—VARIABLE INTEREST ENTITY

Cheniere Partners

Cheniere Partners is a master limited partnership formed by us in 2006 to own and operate the Sabine Pass LNG terminal and related assets. Cheniere Holdings is a limited liability company formed by us in 2013 to hold our Cheniere Partners limited partner interests. As of December 31, 2015, we owned 80.1% of Cheniere Holdings, which owns a 55.9% limited partner interest in Cheniere Partners in the form of 12.0 million common units, 45.3 million Class B units and 135.4 million subordinated units. We also own 100% of the general partner interest and the incentive distribution rights in Cheniere Partners.

Cheniere Partners GP, our wholly owned subsidiary, is the general partner of Cheniere Partners. In May 2012, Cheniere Partners, Cheniere and Blackstone CQP Holdco LP (“Blackstone CQP Holdco”) entered into a unit purchase agreement (the “Blackstone Unit Purchase Agreement”) whereby Cheniere Partners agreed to sell to Blackstone CQP Holdco in a private placement 100.0 million Class B units of Cheniere Partners (“Class B units”) at a price of $15.00 per Class B unit. In August 2012, all conditions to funding were met and Blackstone CQP Holdco purchased its initial 33.3 million Class B units, and as of December 31, 2012, Blackstone CQP Holdco had purchased the remaining 66.7 million Class B units. At initial funding, the board of directors of Cheniere Partners GP was modified to include three directors appointed by Blackstone CQP Holdco, four directors appointed by us and four independent directors mutually agreed upon by Blackstone CQP Holdco and us and appointed by us. In addition, we provided Blackstone CQP Holdco with a right to maintain one board seat on our Board of Directors (our “Board”). A quorum of Cheniere Partners GP directors consists of a majority of all directors, including at least two directors appointed by Blackstone CQP Holdco, two directors appointed by us and two independent directors. Blackstone CQP Holdco will no longer be entitled to appoint Cheniere Partners GP directors in the event that Blackstone CQP Holdco's ownership in Cheniere Partners is less than: (1) 20% of outstanding common units, subordinated units and Class B units, and (2) 50.0 million Class B units.

As a result of contractual changes in the governance of Cheniere Partners GP in connection with the Blackstone Unit Purchase Agreement, we have determined that Cheniere Partners GP is a variable interest entity and that we, as the holder of the equity at risk, do not have a controlling financial interest due to the rights held by Blackstone CQP Holdco. However, we continue to consolidate Cheniere Partners as a result of Blackstone CQP Holdco's right to maintain one board seat on our Board which creates a de facto agency relationship between Blackstone CQP Holdco and us. GAAP requires that when a de facto agency relationship exists, one of the members of the de facto agency relationship must consolidate the variable interest entity based on certain criteria. As a result, we consolidate Cheniere Partners in our Consolidated Financial Statements.

## NOTE 9—NON-CONTROLLING INTEREST

Cheniere Holdings was formed by us to hold our limited partner interest in Cheniere Partners and in December 2013, completed its initial public offering. Additionally, in November 2014, Cheniere Holdings sold 10.1 million common shares at $22.76 per common share to redeem from us the same number of common shares. As of both December 31, 2015 and 2014, our ownership interest in Cheniere Holdings was 80.1%, with the remaining non-controlling interest held by the public. Our ownership of Cheniere Partners interests is further discussed in Note 8—Variable Interest Entity.

## NOTE 10—ACCRUED LIABILITIES

As of December 31, 2015 and 2014, accrued liabilities consisted of the following (in thousands):

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Interest expense and related debt fees | $159,968 | $112,858 |
| Compensation and benefits | 99,511 | 6,425 |
| Liquefaction projects costs | 145,105 | 22,014 |
| LNG terminal costs | 3,918 | 1,077 |
| Other accrued liabilities | 18,697 | 26,755 |
| Total accrued liabilities | $427,199 | $169,129 |

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

NOTE 11—DEBT

As of December 31, 2015 and 2014, our debt consisted of the following (in thousands):

| | Interest Rate | December 31, 2015 | 2014 |
|---|---|---|---|
| Long-term debt | | | |
| 2016 SPLNG Senior Notes | 7.500% | $— | $1,665,500 |
| 2020 SPLNG Senior Notes | 6.500% | 420,000 | 420,000 |
| 2021 SPL Senior Notes | 5.625% | 2,000,000 | 2,000,000 |
| 2022 SPL Senior Notes | 6.250% | 1,000,000 | 1,000,000 |
| 2023 SPL Senior Notes | 5.625% | 1,500,000 | 1,500,000 |
| 2024 SPL Senior Notes | 5.750% | 2,000,000 | 2,000,000 |
| 2025 SPL Senior Notes | 5.625% | 2,000,000 | — |
| 2015 SPL Credit Facilities (1) | (2) | 845,000 | — |
| 2021 Cheniere Convertible Unsecured Notes | 4.875% | 1,054,033 | 1,004,469 |
| 2025 CCH HoldCo II Convertible Senior Notes | 11.000% | 1,050,588 | — |
| 2045 Cheniere Convertible Senior Notes | 4.250% | 625,000 | — |
| CTPL Term Loan (3) | (4) | 400,000 | 400,000 |
| 2015 CCH Credit Facility (5) | (6) | 2,713,000 | — |
| Total long-term debt | | 15,607,621 | 9,989,969 |
| Long-term debt premium (discount) | | | |
| 2016 SPLNG Senior Notes | | — | (8,998) |
| 2021 SPL Senior Notes | | 8,718 | 10,177 |
| 2023 SPL Senior Notes | | 6,392 | 7,088 |
| 2021 Cheniere Convertible Unsecured Notes | | (174,095) | (189,717) |
| 2045 Cheniere Convertible Senior Notes | | (319,062) | — |
| CTPL Term Loan | | (1,429) | (2,435) |
| Total long-term debt, net | | 15,128,145 | 9,806,084 |
| | | | |
| Current debt | | | |
| 2016 SPLNG Senior Notes | | 1,665,500 | — |
| 2016 SPLNG Senior Notes - discount | | (4,303) | — |
| SPL Working Capital Facility (7) | (8) | 15,000 | — |
| Total current debt, net | | 1,676,197 | — |
| | | | |
| Total debt, net | | $16,804,342 | $9,806,084 |

(1) Matures on the earlier of December 31, 2020 or the second anniversary of the completion date of Trains 1 through 5 of the SPL Project.

(2) Variable interest rate, at SPL’s election, is LIBOR or the base rate plus the applicable margin. The applicable margins for LIBOR loans range from 1.30% to 1.75%, depending on the applicable 2015 SPL Credit Facility, and the applicable margin for base rate loans is 1.75%. Interest on LIBOR loans is due and payable at the end of each LIBOR period, and interest on base rate loans is due and payable at the end of each quarter.

(3) Matures on May 28, 2017, when the full amount of the outstanding principal obligations must be repaid.

(4) Variable interest rate, at CTPL’s election, is LIBOR or the base rate plus the applicable margin. CTPL has historically elected LIBOR loans, for which the applicable margin is 3.25% and is due and payable at the end of

each LIBOR period.

(5) Matures on the earlier of May 13, 2022 or the second anniversary of the completion date of the first two Trains of the CCL Project.

(6) Variable interest rate, at CCH’s election, is LIBOR or the base rate plus the applicable margin. The applicable margins for LIBOR loans are 2.25% prior to completion of the first two Trains of the CCL Project and 2.50% on completion and thereafter. The applicable margins for base rate loans are 1.25% prior to completion of the first two Trains of the CCL Project and 1.50% on completion and thereafter. Interest on LIBOR loans is due and payable at the end of each applicable interest period, and interest on base rate loans is due and payable at the end of each quarter.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

(7) Matures on December 31, 2020, with various terms for underlying loans, as further described below under SPL Working Capital Facility. As of December 31, 2014, no loans were outstanding under the $325.0 million senior letter of credit and reimbursement agreement that was entered into in April 2014 (the "SPL LC Agreement") it replaced.

(8) Variable interest rates, based on LIBOR or the base rate, as further described below under SPL Working Capital Facility.

For the years ended December 31, 2015, 2014 and 2013, we incurred $997.5 million, $587.0 million and $414.0 million of total interest cost, respectively, of which we capitalized and deferred $675.3 million $405.8 million and $233.0 million, respectively, including amortization of debt issuance costs, primarily related to the construction of the SPL Project in all periods and additionally the CCL Project in 2015.

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2015 (in thousands):

| Years Ending December 31, | Principal Payments |
|---|---|
| 2016 | $ 1,680,500 |
| 2017 | 400,000 |
| 2018 | — |
| 2019 | — |
| 2020 | 1,265,000 |
| Thereafter | 13,942,621 |
| Total | $ 17,288,121 |

SPLNG Senior Notes

The terms of the 2016 SPLNG Senior Notes and the 2020 SPLNG Senior Notes are substantially similar. Interest on the SPLNG Senior Notes is payable semi-annually in arrears. Subject to permitted liens, the SPLNG Senior Notes are secured on a first-priority basis by a security interest in all of SPLNG's equity interests and substantially all of its operating assets.

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

- 1.0% of the principal amount of the 2016 SPLNG Senior Notes; or
- the excess of: (1) the present value at such redemption date of (a) the redemption price of the 2016 SPLNG Senior Notes plus (b) all required interest payments due on the 2016 SPLNG Senior Notes (excluding accrued but unpaid interest to the redemption date), computed using a discount rate equal to the treasury rate as of such redemption date plus 50 basis points; over (2) the principal amount of the 2016 SPLNG Senior Notes, if greater.

SPLNG may redeem all or part of the 2020 SPLNG Senior Notes at any time on or after November 1, 2016, at fixed redemption prices specified in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. SPLNG may also, at its option, redeem all or part of the 2020 SPLNG Senior Notes at any time prior to November 1, 2016, at a "make-whole" price set forth in the indenture governing the 2020 SPLNG Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

Under the SPLNG Indentures, except for permitted tax distributions, SPLNG may not make distributions until certain conditions are satisfied as described in Note 3—Restricted Cash. During the years ended December 31, 2015, 2014 and

2013, SPLNG made distributions of $337.3 million, $346.9 million and $348.9 million, respectively, after satisfying all the applicable conditions in the SPLNG Indentures.

SPL Senior Notes

The terms of the SPL Senior Notes are governed by a common indenture (the “SPL Indenture”), and interest on the SPL Senior Notes is payable semi-annually in arrears. The SPL Indenture contains customary terms and events of default and certain covenants that, among other things, limit SPL’s ability and the ability of SPL’s restricted subsidiaries to: incur additional indebtedness; issue preferred stock, make certain investments or pay dividends or distributions on capital stock or subordinated indebtedness; purchase, redeem or retire capital stock; sell or transfer assets, including capital stock of SPL’s restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; incur liens; enter into transactions with affiliates; consolidate, merge, sell or lease all or substantially all of SPL's assets; and enter into certain LNG sales contracts. Subject to permitted liens, the SPL Senior Notes are secured on a pari passu first-priority basis by a security interest in all of the membership interests in SPL and substantially all of SPL's assets. SPL may not make any distributions until, among other requirements, substantial completion of Trains 1 and 2 of the SPL Project has occurred, deposits are made into debt service reserve accounts as required and a debt service coverage ratio for the prior 12-month period and a projected debt service coverage ratio for the upcoming 12-month period of 1.25:1.00 are satisfied.

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes, SPL may redeem all or part of such series of the SPL Senior Notes at a redemption price equal to the "make-whole" price set forth in the SPL Indenture, plus accrued and unpaid interest, if any, to the date of redemption. SPL may also, at any time within three months of the respective maturity dates for each series of the SPL Senior Notes, redeem all or part of such series of the SPL Senior Notes at a redemption price equal to 100% of the principal amount of such series of the SPL Senior Notes to be redeemed, plus accrued and unpaid interest, if any, to the date of redemption.

2015 SPL Credit Facilities

In June 2015, SPL entered into the 2015 SPL Credit Facilities with commitments aggregating $4.6 billion. The 2015 SPL Credit Facilities are being used to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the SPL Project. Borrowings under the 2015 SPL Credit Facilities may be refinanced, in whole or in part, at any time without premium or penalty; however, interest rate hedging and interest rate breakage costs may be incurred. As of December 31, 2015, SPL had $3.8 billion of available commitments and outstanding borrowings of $845.0 million under the 2015 SPL Credit Facilities.

SPL incurred $88.3 million of debt issuance costs in connection with the 2015 SPL Credit Facilities. In addition to interest, SPL is required to pay insurance/guarantee premiums of 0.45% per annum on any drawn amounts under the covered tranches of the 2015 SPL Credit Facilities. The 2015 SPL Credit Facilities also require SPL to pay a quarterly commitment fee calculated at a rate per annum equal to either: (1) 40% of the applicable margin, multiplied by the average daily amount of the undrawn commitment, or (2) 0.70% of the undrawn commitment, depending on the applicable 2015 SPL Credit Facility. The principal of the loans made under the 2015 SPL Credit Facilities must be repaid in quarterly installments, commencing with the earlier of June 30, 2020 and the last day of the first full calendar quarter after the completion date of Trains 1 through 5 of the SPL Project. Scheduled repayments are based upon an 18-year amortization profile, with the remaining balance due upon the maturity of the 2015 SPL Credit Facilities.

The 2015 SPL Credit Facilities contain conditions precedent for borrowings, as well as customary affirmative and negative covenants. The obligations of SPL under the 2015 SPL Credit Facilities are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a pari passu basis with the SPL Senior Notes and the $1.2 billion Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement (the "SPL Working Capital Facility") described below.

Under the terms of the 2015 SPL Credit Facilities, SPL is required to hedge not less than 65% of the variable interest rate exposure of its projected outstanding borrowings, calculated on a weighted average basis in comparison to its anticipated draw of principal. Additionally, SPL may not make any distributions until 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 test of 1.25:1.00 is satisfied.

2013 SPL Credit Facilities

In May 2013, SPL entered into the 2013 SPL Credit Facilities to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 4 of the SPL Project, which amended and restated the credit facility that was entered into in 2012 (the "2012 SPL Credit Facility"). As of December 31, 2014, SPL had no outstanding borrowings under the 2013 SPL Credit Facilities. In June 2015, the 2013 SPL Credit Facilities were replaced with the 2015 SPL Credit Facilities.

In March 2015, in conjunction with SPL's issuance of the 2025 SPL Senior Notes, SPL terminated approximately $1.8 billion of commitments under the 2013 SPL Credit Facilities. This termination and the replacement of the 2013 SPL Credit Facilities with the 2015 SPL Credit Facilities in June 2015 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2013 SPL Credit Facilities of $96.3 million for the year ended December 31, 2015. The amendment and restatement of the 2012 SPL Credit Facility with the 2013 SPL Credit Facilities in May 2013 resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2012 SPL Credit Facility of $88.3 million during the year ended December 31, 2013.

Convertible Notes

2021 Cheniere Convertible Unsecured 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”) on a private placement basis in reliance on the exemption from registration provided for under section 4(a)(2) of the Securities Act and Regulation S promulgated thereunder. The 2021 Cheniere Convertible Unsecured Notes accrue interest at a rate of 4.875% per annum, which is payable in kind semi-annually in arrears by increasing the principal amount of the 2021 Cheniere Convertible Unsecured Notes outstanding. Beginning one year after the closing date, the 2021 Cheniere Convertible Unsecured Notes will be 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 conversion date. 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.

Under GAAP, certain convertible debt instruments that may be settled in cash upon conversion are required to be separately accounted for as liability (debt) and equity (conversion option) components of the instrument in a manner that reflects the issuer’s non-convertible debt borrowing rate. We determined that the fair value of the debt component was $808.8 million and the residual value of the equity component was $191.2 million as of the issuance date. As of December 31, 2015 and 2014, the carrying value of the equity component was $203.0 million and $191.9 million, respectively. The debt component is accreted to the total principal amount due at maturity by amortizing the debt discount. The effective rate of interest to amortize the debt discount was approximately 9.6% and 9.2% as of December 31, 2015 and 2014, respectively, and the remaining period over which the debt discount will be amortized was 5.4 years as of December 31, 2015. As of December 31, 2015, the if-converted value of the 2021 Cheniere Convertible Unsecured Notes did not exceed the principal balance.

2025 CCH HoldCo II Convertible Senior Notes

In May 2015, CCH HoldCo II issued $1.0 billion aggregate principal amount of 11.0% Convertible Senior Secured Notes due 2025 (the “2025 CCH HoldCo II Convertible Senior Notes”) on a private placement basis in reliance on the exemption from registration provided for under section 4(a)(2) of the Securities Act. The 2025 CCH HoldCo II Convertible Senior Notes were issued pursuant to the amended and restated note purchase agreement entered into among CCH HoldCo II, EIG Management Company, LLC, The Bank of New York Mellon, the Company and the note purchasers. The $1.0 billion principal of the 2025 CCH HoldCo II Convertible Senior Notes will be used to partially fund costs associated with Stage 1 of the CCL Project and the Corpus Christi Pipeline. The 2025 CCH HoldCo II Convertible Senior Notes bear interest at a rate of 11.0% per annum, which is payable quarterly in arrears. Prior to the substantial completion of Train 2 of the CCL Project, interest on the 2025 CCH HoldCo II Convertible Senior Notes will be paid entirely in kind. Following this date, the interest generally must be paid in cash; however, a portion of the interest may be paid in kind under certain specified circumstances. The 2025 CCH HoldCo II Convertible Senior Notes are secured by a pledge by us of 100% of the equity interests in CCH HoldCo II, and a pledge by CCH HoldCo II of 100% of the equity interests in CCH HoldCo I.

At CCH HoldCo II's option, the outstanding 2025 CCH HoldCo II Convertible Senior Notes are convertible into our common stock, provided the total market capitalization of Cheniere at that time is not less than $10.0 billion, 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. Conversions are also subject to various limitations and conditions.

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

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.

In December 2015, CCH HoldCo II terminated the additional commitments that were made by the purchasers at the original issuance date of the 2025 CCH HoldCo II Convertible Senior Notes. This termination of additional commitments resulted in a write-off of debt issuance costs and deferred commitment fees associated with the 2025 CCH HoldCo II Convertible Senior Notes of $11.4 million during the year ended December 31, 2015.

2045 Cheniere Convertible Senior Notes

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. 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. 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 payable in cash 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.

We determined that the fair value of the debt component of the 2045 Cheniere Convertible Senior Notes was $304.3 million and the residual value of the equity component was $195.7 million as of the issuance date, excluding debt issuance costs. As of December 31, 2015, the carrying value of the equity component, net of debt issuance costs, was $194.0 million. The debt component is accreted to the total principal amount due at maturity by amortizing the debt discount. The effective rate of interest to amortize the debt discount was approximately 9.4% as of December 31, 2015, and the remaining period over which the debt discount will be amortized was 29.2 years. As of December 31, 2015, the if-converted value of the 2045 Cheniere Convertible Senior Notes did not exceed the principal balance.

Interest expense, before capitalization, related to the 2021 Cheniere Convertible Unsecured Notes, the 2025 CCH HoldCo II Convertible Senior Notes and the 2045 Cheniere Convertible Senior Notes (together, the “Convertible Notes”) consisted of the following (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Interest per contractual rate | $145,848 | $4,469 | $— |
| Amortization of debt discount | 28,347 | 2,328 | — |
| Amortization of debt issuance costs | 2,989 | 4 | — |
| Total interest expense related to the Convertible Notes | $177,184 | $6,801 | $— |

CTPL Term Loan

In May 2013, CTPL entered into the CTPL Term Loan, which was used to fund modifications to the Creole Trail Pipeline and for general business purposes. CTPL incurred $10.0 million of direct lender fees that were recorded as a debt discount. As of December 31, 2015, CTPL had borrowed the full amount of $400.0 million available under the

CTPL Term Loan. The outstanding balance may be repaid, in whole or in part, at any time without premium or penalty.

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

Cheniere Partners has guaranteed (1) the obligations of CTPL under the CTPL Term Loan if the maturity of the CTPL loans is accelerated following the termination by SPL of a transportation precedent agreement in limited circumstances and (2) the obligations of Cheniere Investments in connection with its obligations under an equity contribution agreement (a) to pay operating expenses of CTPL until CTPL receives revenues under a service agreement with SPL and (b) to fund interest payments on the CTPL loans after the funds in an interest reserve account have been exhausted.

2015 CCH Credit Facility

In May 2015, CCH entered into the $8.4 billion 2015 CCH Credit Facility, which is being used to fund a portion of the costs associated with the development, construction, operation and maintenance of Stage 1 of the CCL Project and the Corpus Christi Pipeline. Borrowings under the 2015 CCH Credit Facility may be refinanced, in whole or in part, at any time without premium or penalty; however, interest rate hedging and interest rate breakage costs may be incurred. As of December 31, 2015, CCH had $5.7 billion of available commitments and $2.7 billion of outstanding borrowings under the 2015 CCH Credit Facility.

CCH incurred $289.3 million of debt issuance costs in connection with the 2015 CCH Credit Facility, of which $16.5 million was written off in December 2015 when a portion of the original commitments was terminated by CCH. In addition to interest, CCH will incur a commitment fee at a rate per annum equal to 40% of the margin for LIBOR loans, multiplied by the outstanding undrawn debt commitments. The principal of the loans made under the 2015 CCH Credit Facility must be repaid in quarterly installments, commencing on the earlier of (1) the first quarterly payment date occurring more than three calendar months following project completion and (2) a set date determined by reference to the date under which a certain LNG buyer linked to Train 2 of the CCL Project is entitled to terminate its SPA for failure to achieve the date of first commercial delivery for that agreement. Scheduled repayments will be based upon a 19-year tailored amortization, commencing the first full quarter after the project completion and designed to achieve a minimum projected fixed debt service coverage ratio of 1.55:1.

The 2015 CCH Credit Facility contains conditions precedent for borrowings, as well as customary affirmative and negative covenants. The obligations of CCH under the 2015 CCH Credit Facility are secured by a first priority lien on substantially all of the assets of CCH and its subsidiaries and by a pledge by CCH HoldCo I of its limited liability company interests in CCH.

Under the terms of the 2015 CCH Credit Facility, CCH is required to hedge not less than 65% of the variable interest rate exposure of its senior secured debt. 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.

SPL Working Capital Facility

In September 2015, SPL entered into the $1.2 billion SPL Working Capital Facility, which replaced the $325.0 million SPL LC Agreement. The SPL Working Capital Facility is intended to be used for loans to SPL ("Working Capital Loans"), the issuance of letters of credit on behalf of SPL ("Letters of Credit"), as well as for swing line loans to SPL ("Swing Line Loans"), primarily for certain working capital requirements related to developing and placing into operation the SPL Project. SPL may, from time to time, request increases in the commitments under the SPL Working Capital Facility of up to $760 million and, upon the completion of the debt financing of Train 6 of the SPL Project, request an incremental increase in commitments of up to an additional $390 million. As of December 31, 2015, SPL had $1.1 billion of available commitments, $135.2 million aggregate amount of issued Letters of Credit, $15.0 million in Working Capital Loans and no Swing Line Loans or loans deemed made in connection with a draw upon a Letter of Credit ("LC Loans" and collectively with Working Capital Loans and Swing Line Loans, the "SPL Working Capital Facility Loans") outstanding under the SPL Working Capital Facility. As of December 31, 2014, SPL had issued letters of credit in an aggregate amount of $9.5 million, and no draws had been made upon any letters of credit issued under the SPL LC Agreement.

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

SPL incurred $27.5 million of debt issuance costs in connection with the SPL Working Capital Facility. SPL pays (1) a commitment fee equal to an annual rate of 0.70% on the average daily amount of the excess of the total commitment amount over the principal amount outstanding without giving effect to any outstanding Swing Line Loans and (2) a Letter of Credit fee equal to an annual rate of 1.75% of the undrawn portion of all Letters of Credit issued under the SPL Working Capital Facility. If draws are made upon a Letter of Credit issued under the SPL Working Capital Facility and SPL does not elect for such draw (an “LC Draw”) to be deemed an LC Loan, SPL is required to pay the full amount of the LC Draw on or prior to the business day following the notice of the LC Draw. An LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2015, no LC Draws had been made upon any Letters of Credit issued under the SPL Working Capital Facility.

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

The SPL Working Capital Facility contains conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. The obligations of SPL under the SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as all of the membership interests in SPL on a pari passu basis with the SPL Senior Notes and the 2015 SPL Credit Facilities.

Fair Value Disclosures

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

| | December 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| 2016 SPLNG Senior Notes, net of discount (1) | $1,661,197 | $1,652,891 | $1,656,502 | $1,718,621 |
| 2020 SPLNG Senior Notes (1) | 420,000 | 403,200 | 420,000 | 428,400 |
| 2021 SPL Senior Notes, net of premium (1) | 2,008,718 | 1,832,955 | 2,010,177 | 1,985,050 |
| 2022 SPL Senior Notes (1) | 1,000,000 | 912,500 | 1,000,000 | 1,020,000 |
| 2023 SPL Senior Notes, net of premium (1) | 1,506,392 | 1,299,263 | 1,507,089 | 1,476,947 |
| 2024 SPL Senior Notes (1) | 2,000,000 | 1,715,000 | 2,000,000 | 1,970,000 |
| 2025 SPL Senior Notes (1) | 2,000,000 | 1,710,000 | — | — |
| 2015 SPL Credit Facilities (2) | 845,000 | 845,000 | — | — |
| 2021 Cheniere Convertible Unsecured Notes, net of discount (3) | 879,938 | 825,413 | 814,751 | 1,025,563 |
| 2025 CCH HoldCo II Convertible Senior Notes (3) | 1,050,588 | 914,363 | — | — |
| 2045 Cheniere Convertible Senior Notes, net of discount (4) | 305,938 | 331,919 | — | — |
| CTPL Term Loan, net of discount (2) | 398,571 | 400,000 | 397,565 | 400,000 |
| 2015 CCH Credit Facility (2) | 2,713,000 | 2,713,000 | — | — |
| SPL Working Capital Facility (2) | 15,000 | 15,000 | — | — |

(1) The Level 2 estimated fair value was based on quotations obtained from broker-dealers who make markets in these and similar instruments based on the closing trading prices on December 31, 2015 and 2014, as applicable.

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

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

(4) The Level 1 estimated fair value was based on unadjusted quoted prices in active markets for identical liabilities that we had the ability to access at the measurement date.

NOTE 12—INCOME TAXES

Income tax benefit (provision) included in our reported net loss consisted of the following (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Current: | | | |
| Federal | $— | $— | $— |
| State | — | — | — |
| Foreign | (1,970) | (4,143) | (4,082) |
| Total current | (1,970) | (4,143) | (4,082) |
| Deferred: | | | |
| Federal | — | — | — |
| State | — | — | — |
| Foreign | 2,066 | — | (258) |
| Total deferred | 2,066 | — | (258) |
| Total income tax benefit (provision) | $96 | $(4,143) | $(4,340) |

The reconciliation of the federal statutory income tax rate to our effective income tax rate is as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| U.S. federal statutory tax rate | 35.0 % | 35.0 % | 35.0 % |
| Non-controlling interest | (2.3)% | (4.8)% | (3.3)% |
| State tax rate | 1.9 % | 4.3 % | 4.5 % |
| Uncertain tax position | — % | (12.5)% | — % |
| Net impact of non-U.S. taxes | (1.3)% | (2.0)% | (0.8)% |
| Valuation allowance | (30.1)% | (19.8)% | (34.3)% |
| Other | (3.1)% | (0.6)% | (1.9)% |
| Effective tax rate as reported | 0.1 % | (0.4)% | (0.8)% |

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Significant components of our deferred tax assets and liabilities at December 31, 2015 and 2014 are as follows (in thousands):

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Deferred tax assets | | |
| Net operating loss carryforwards and credits | | |
| Federal and foreign | $862,218 | $637,919 |
| State | 166,321 | 136,917 |
| Book deferred gain | 77,182 | 77,182 |
| Share-based compensation expense | 71,693 | 28,432 |
| Property, plant and equipment | 12,957 | 29,483 |
| Derivative instruments | 54,052 | 389 |
| Other | 14,366 | 15,075 |
| Total deferred tax assets | 1,258,789 | 925,397 |
| | | |
| Deferred tax liabilities | | |
| Investment in limited partnership | (57,466) | (46,601) |
| Convertible debt | (128,948) | — |
| Total deferred tax liabilities | (186,414) | (46,601) |
| | | |
| Net deferred tax assets | 1,072,375 | 878,796 |
| Less: net deferred tax asset valuation allowance | (1,070,309) | (878,796) |
| Total net deferred tax asset | $2,066 | $— |

The federal deferred tax assets presented above do not include the state tax benefits as our net deferred state tax assets are offset with a full valuation allowance.

At December 31, 2015, we had federal and state net operating loss (“NOL”) carryforwards of approximately $3.2 billion and $2.1 billion, respectively. These NOL carryforwards will expire between 2025 and 2035.

Due to our history of NOLs, current year NOLs and significant risk factors related to our ability to generate taxable income, we have established a valuation allowance to fully offset our federal and state net deferred tax assets as of December 31, 2015 and our total net deferred tax assets as of 2014. We will continue to evaluate our ability to release the valuation allowance in the future. The increase in the net deferred tax asset valuation allowance was $191.5 million for the year ended December 31, 2015. Deferred tax assets and deferred tax liabilities are classified as non-current in our Consolidated Balance Sheets.

Changes in the balance of unrecognized tax benefits are as follows (in thousands):

| | Year Ended December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Balance at beginning of the year | $104,491 | $19,484 |
| Additions based on tax positions related to current year | — | 85,932 |
| Additions for tax positions of prior years | — | — |
| Reductions for tax positions of prior years | (851) | (925) |
| Settlements | — | — |
| Balance at end of the year | $103,640 | $104,491 |

Our effective tax rate will not be affected if the unrecognized federal income tax benefits provided above were recognized. Currently, we do not recognize any accrued liabilities, interest and penalties associated with the unrecognized tax benefits provided above in our Consolidated Statements of Operations or our Consolidated Balance Sheets. We recognize interest and penalties related to income tax matters as part of income tax expense.

We experienced an ownership change within the provisions of Internal Revenue Code ("IRC") Section 382 in 2008, 2010 and 2012. An analysis of the annual limitation on the utilization of our NOLs was performed in accordance with IRC Section 382. It was determined that IRC Section 382 will not limit the use of our NOLs in full over the carryover period. We will continue to monitor trading activity in our shares which may cause an additional ownership change which could ultimately affect our ability to fully utilize our existing tax NOL carryforwards.

We are subject to taxation in the U.S., United Kingdom, Chile, Singapore and various state jurisdictions. The federal tax returns for the years before 2011 remain open to examination for the purpose of determining the amount of remaining tax NOL and other carryforwards. The federal tax returns for the years 2012 through 2015 remain open for all purposes of examination by the IRS and other taxing authorities.

Accounting for share-based compensation provides that when settlement of a share based award contributes to an NOL carryforward, neither the associated excess tax benefit nor the credit to additional paid-in capital ("APIC") should be recorded until the share-based award deduction reduces income tax payable. Upon utilization of the loss in future periods, a benefit of $168.7 million will be reflected in APIC.

## NOTE 13—SHARE-BASED COMPENSATION

We have granted stock, restricted stock, phantom units and options to purchase common stock to employees, outside directors and a consultant under the Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan (the "1997 Plan"), Amended and Restated 2003 Stock Incentive Plan, as amended (the "2003 Plan"), 2011 Incentive Plan, as amended (the "2011 Plan") and the 2015 Long-Term Cash Incentive Plan (the "2015 Plan").

The 1997 Plan provides for the issuance of stock options to purchase up to 5.0 million shares of our common stock, all of which have been granted. Non-qualified stock options were granted to employees, contract service providers and outside directors. The 2003 Plan and 2011 Plan provide for the issuance of 21.0 million shares and 35.0 million shares, respectively, of our common stock that may be in the form of non-qualified stock options, incentive stock options, purchased stock, restricted (non-vested) stock, bonus (unrestricted) stock, stock appreciation rights, phantom units and other share-based performance awards deemed by the Compensation Committee of our Board (the "Compensation Committee") to be consistent with the purposes of the 2003 Plan and 2011 Plan. As of December 31, 2015, all of the shares under the 2003 Plan have been granted and 26.9 million shares, net of cancellations, have been granted under the 2011 Plan. The 2015 Plan generally provides for cash-settled awards in the form of stock appreciation rights, phantom unit awards, performance unit awards, other-stock based awards and cash awards.

In August 2012, the Compensation Committee granted the Long-Term Commercial Bonus Award for Trains 1 and 2 of the SPL Project, which consisted of approximately $60 million in cash awards and 10 million restricted shares of common stock under the 2011 Plan. Upon grant, 35% of the restricted stock award vested when SPL 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 Trains 1 and 2 of the SPL Project. The remainder of the restricted stock awards vest on each of the first four anniversaries of NTP at the rate of 10%, 15%, 15% and 25%. As of December 31, 2015, 75% of the restricted stock awards had vested, and the remaining 25% of the awards will vest in August 2016.

In February 2013, the Compensation Committee granted the Long-Term Commercial Bonus Awards related to Trains 3 and 4 of the SPL Project under the 2003 Plan and 2011 Plan. A portion of each employee's Long-Term Commercial Bonus Award for Trains 3 and 4 of the SPL Project was granted as a stock price award ("Stock Price Award"), with vesting of the Stock Price Award conditional on the achievement of minimum average Company stock price hurdles, and a portion was granted as a milestone award ("Milestone Award"), with vesting of the Milestone Award conditional on certain performance milestones relating to financing and constructing Trains 3 and 4 of the SPL Project. As of December 31, 2015, 100% of the Stock Price Awards had vested and 50% of the Milestone Awards had vested. The remaining 20% and 30% of Milestone Awards will vest upon substantial completion of Train 4 of the SPL Project, as defined in the EPC contract for Trains 3 and 4 of the SPL Project, and on the first anniversary thereof, respectively.

In April 2015, the Compensation Committee recommended and our Board approved the 2014-2018 Long-Term Cash Incentive Program (the “2014-2018 LTIP”) under the Company’s 2015 Plan. The 2014-2018 LTIP consists of phantom units settled in cash with five consecutive annual performance periods commencing on November 1 and ending on October 31 of each year from November 1, 2013 through October 31, 2018. Awards under the 2014-2018 LTIP will be subject to a three-year vesting schedule, with one-third of the phantom units vesting and becoming payable on each of the first, second and third anniversaries of the date of the grant (with the exception of the initial grant for the 2014 performance period, which will vest and become payable on each of February 1, 2016, February 1, 2017 and February 1, 2018). The 2014-2018 LTIP is 100% performance-based and will reward long-term performance measured against growth in the Company’s market capitalization, referred to in the plan documents

CHENIERE ENERGY, INC. AND SUBSIDIARIES
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as total shareholder value ("TSV"), above certain thresholds. Under the 2014-2018 LTIP, the general pool is awarded generally between 2% and 4% of the growth in TSV and the senior executive pool is capped at 2% of the growth in TSV, with the Chief Executive Officer's compensation targeted at 50% of the senior executive pool, subject to adjustment at the discretion of the Compensation Committee. The number of phantom units comprising the senior executive pool has also been capped, and cannot exceed an amount equal to 1.5% of the shares of our common stock outstanding in any one year.

For the years ended December 31, 2015, 2014 and 2013, the total share-based compensation expense, net of capitalization, recognized in our net loss was $172.4 million, $102.0 million and $271.4 million, respectively, and for the same periods we capitalized as part of the cost of capital assets $22.9 million, $8.2 million and $12.5 million, respectively.

The total unrecognized compensation cost at December 31, 2015 relating to non-vested share-based compensation arrangements was $182.7 million, which is expected to be recognized over a weighted average period of 2.2 years.

During the year ended December 31, 2014, we recognized $10.8 million of share-based compensation expense related to the modification of long-term commercial bonus awards resulting from an employee termination. We did not have any modifications during the years ended December 31, 2015 and 2013.

We have disclosed the deferred tax benefit realized from share-based compensation exercised during the annual period in Note 12—Income Taxes. A valuation allowance equal to the deferred tax asset has been established due to the uncertainty of realizing the tax benefits related to this deferred tax asset.

Restricted Stock

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the recipient terminates employment with the Company prior to the lapse of the restrictions. For the years ended December 31, 2015, 2014 and 2013, we issued 19,000 shares, 550,000 shares and 18,860,000 shares, respectively, of restricted stock awards to our employees, executives, directors and a consultant. These awards vest based on service conditions (one, three or four-year service periods), performance conditions and/or market conditions. The amortization of the value of restricted stock grants is accounted for as a charge to compensation expense or capitalized, depending on the employee, with a corresponding increase to additional paid-in-capital over the requisite service period.

Grants of restricted stock to employees and non-employee directors that vest based on service and/or performance conditions are measured at the closing quoted market price of the Company's common stock on the grant date. For restricted stock awards granted to non-employees that vest based on service and/or performance conditions, the Company records compensation cost equal to the fair value of the award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. In addition, compensation cost for unvested restricted stock awards to non-employees is adjusted quarterly for any changes in the Company's stock price.

Grants of restricted stock to employees and non-employees based on market conditions are measured using valuations based on Monte Carlo simulations. There were no restricted stock awards granted with market conditions in 2015 or 2014. For the awards granted in 2013 with market conditions, we used the following variables in our Monte Carlo simulations:

- Expected Volatility 44% - 62%
- Risk Free Rate 2.80% - 2.83%

| | |
|---|---|
| Cost of Equity | 16.50% - 16.60% |

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

The table below provides a summary of our restricted stock outstanding as of December 31, 2015 and changes during the year ended December 31, 2015 (in thousands, except for per share information):

| | Shares | Weighted Average Grant Date Fair Value Per Share |
|---|---|---|
| Non-vested at January 1, 2015 | 10,477 | $21.56 |
| Granted | 19 | 70.43 |
| Vested | (2,804) | 17.89 |
| Forfeited | (156) | 23.25 |
| Non-vested at December 31, 2015 | 7,536 | $22.80 |

The weighted average grant date fair values per share of restricted stock granted during the years ended December 31, 2015, 2014 and 2013 were $70.43, $60.09 and $21.89, respectively. The total grant date fair value of restricted stock vested during the years ended December 31, 2015, 2014 and 2013 were $50.2 million, $84.0 million and $227.3 million, respectively.

Phantom Units

Phantom units are share-based awards granted to employees over a vesting period that entitle the grantee to receive the cash equivalent to the value of a share of our common stock upon each vesting. Phantom units are not eligible to receive quarterly distributions. We initially measure compensation cost based on our stock price on the grant date, which is included in accrued liabilities on our Consolidated Balance Sheets and is adjusted quarterly for any changes in our stock price and period of service rendered. During the years ended December 31, 2015 and 2014, we granted 5.9 million and approximately 79,000 phantom units, respectively, to employees, including units awarded under the 2015 Plan. We did not grant any phantom units to employees during the year ended December 31, 2013. The value of phantom units vested during the year ended December 31, 2015 was $4.6 million. There were no vestings of phantom units during the year ended December 31, 2014.

Stock Options

Stock options to employees are valued at the date of grant using a Black-Scholes valuation model and the cost is recognized over the option vesting period. We did not issue any options to purchase shares of our common stock and did not declare dividends on our common stock during the years ended December 31, 2015, 2014 and 2013.

The table below provides a summary of our options outstanding as of December 31, 2015 and changes during the year ended December 31, 2015:

| | Options | Weighted Average Exercise Price | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value |
|---|---|---|---|---|
| | (in thousands) | | (in years) | (in thousands) |
| Outstanding at January 1, 2015 | 93 | $35.81 | 0.81 | $3,224 |
| Granted | — | — | | |

| | | | | |
|---|---|---|---|---|
| Exercised | (66 | ) 34.18 | | |
| Forfeited or Expired | — | — | | |
| Outstanding at December 31, 2015 | 27 | $39.88 | 0.27 | $— |
| Exercisable at December 31, 2015 | 27 | $39.88 | 0.27 | $— |

The total intrinsic value of options exercised during the years ended December 31, 2015, 2014 and 2013 was $2.7 million, $11.9 million and $2.0 million, respectively. We received $2.3 million, $10.8 million and $3.7 million during the years ended December 31, 2015, 2014 and 2013, respectively, of proceeds from the exercise of stock options.

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## NOTE 14—EMPLOYEE BENEFIT PLAN

We have a defined contribution plan ("401(k) Plan") which allows eligible employees to contribute up to 100% of their compensation up to the IRS maximum. We match each employee's salary deferrals (contributions) up to six percent of compensation and may make additional contributions at our discretion. Employees are immediately vested in the contributions made by us. Our contributions to the 401(k) Plan were $4.9 million, $3.6 million and $2.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. We have made no discretionary contributions to the 401(k) Plan to date.

## NOTE 15—LEASES

During the years ended December 31, 2015, 2014 and 2013, we recognized rental expense for all operating leases of $24.3 million, $19.1 million and $13.9 million, respectively, related primarily to office space, land sites and LNG vessel time charters. Our land site leases for the Sabine Pass LNG terminal and the Corpus Christi LNG terminal have initial terms varying up to 30 years with multiple options to renew up to an additional 60 years.

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

| Years Ending December 31, | Operating Leases |
|---|---|
| 2016 | $99,973 |
| 2017 | 101,484 |
| 2018 | 101,076 |
| 2019 | 101,039 |
| 2020 | 83,959 |
| Thereafter (1) | 74,077 |
| Total | $561,608 |

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

### Capital Leases

During the year ended December 31, 2015, we entered into a lease agreement for tug services related to our CCL Project that was accounted for as a capital lease. As of December 31, 2015, we did not have any assets recorded under this obligation due to the service term of this lease commencing in 2018. We will record assets acquired under capital leases, net of accumulated amortization, in property, plant and equipment, net, on our Consolidated Balance Sheets upon commencement of the service term, and the related amortization expense on our Consolidated Statements of Operations.

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

| Years Ending December 31, | Capital Leases |
|---|---|
| 2016 | $— |
| 2017 | — |
| 2018 | 19,920 |
| 2019 | 39,840 |
| 2020 | 39,840 |

| | |
|---|---|
| Thereafter | 697,208 |
| Total | $796,808 |

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CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

## NOTE 16—COMMITMENTS AND CONTINGENCIES

Cheniere has various contractual obligations which are recorded as liabilities in our Consolidated Financial Statements. Other items, such as certain purchase commitments and other executed contracts which do not meet the definition of a liability as of December 31, 2015, are not recognized as liabilities but require disclosures in our Consolidated Financial Statements.

### LNG Terminal Commitments and Contingencies

#### Obligations under LNG TUAs

SPLNG has entered into third-party TUAs with Total Gas & Power North America, Inc. (“Total”) and Chevron U.S.A. Inc. (“Chevron”) to provide berthing for LNG vessels and for the unloading, storage and regasification of LNG at the Sabine Pass LNG terminal.

#### Obligations under Bechtel EPC Contracts

SPL has entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Trains 1 and 2 (the “EPC Contract (SPL Trains 1 and 2)”), Trains 3 and 4 (the “EPC Contract (SPL Trains 3 and 4)”) and Train 5 (the “EPC Contract (SPL Train 5)”) of the SPL Project.

The EPC Contract (SPL Trains 1 and 2), the EPC Contract (SPL Trains 3 and 4) and the EPC Contract (SPL Train 5) provide that SPL will pay Bechtel contract prices of $4.1 billion, $3.8 billion and $3.0 billion, respectively, subject to adjustment by change order. SPL has the right to terminate each EPC contract for its convenience, in which case Bechtel will be paid (1) the portion of the contract price for the work performed, (2) costs reasonably incurred by Bechtel on account of such termination and demobilization, and (3) a lump sum of up to $30.0 million depending on the termination date.

CCL has entered into lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Stage 1 (the “EPC Contract (CCL Stage 1)”) and Stage 2 (the “EPC Contract (CCL Stage 2”) of the CCL Project. The contract prices of the EPC Contract (CCL Stage 1) and EPC Contract (CCL Stage 2) are approximately $7.5 billion and $2.4 billion, respectively, reflecting amounts incurred under change orders through December 31, 2015. CCL has the right to terminate each of the EPC contracts for its convenience, in which case Bechtel will be paid the portion of the contract price for the work performed plus costs reasonably incurred by Bechtel on account of such termination and demobilization. If the EPC Contract (CCL Stage 1) is terminated, Bechtel will also be paid a lump sum of up to $30.0 million depending on the termination date. If the EPC Contract (CCL Stage 2) is terminated prior to the issuance of notice to proceed, Bechtel will also be paid a lump sum of up to $5.0 million, and if the EPC Contract (CCL Stage 2) is terminated after issuance of the notice to proceed, Bechtel will be paid a lump sum of up to $30.0 million depending on the termination date.

#### Obligations under SPAs

SPL has entered into third-party SPAs which obligate SPL to purchase and liquefy sufficient quantities of natural gas to deliver 1,030.0 million MMBtu per year of LNG to the customers’ vessels, subject to completion of construction of Trains 1 through 5 of the SPL Project.

CCL has entered into third-party SPAs which obligate CCL to purchase and liquefy sufficient quantities of natural gas to deliver 438.7 million MMBtu per year of LNG to the customers' vessels, subject to completion of construction of Trains 1 through 3 of the CCL Project.

Obligations under Natural Gas Supply, Transportation and Storage Service Agreements

SPL has entered into index-based physical natural gas supply contracts to secure natural gas feedstock for the SPL Project. The terms of these contracts primarily range from approximately one to seven years and commence upon the occurrence of conditions precedent, including SPL's declaration to the respective natural gas supplier that it is ready to commence the term of the supply arrangement in anticipation of the date of first commercial operation of the applicable, specified Trains of 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, of which we determined that we have purchase obligations for the contracts for which conditions precedent were met.

Additionally, SPL has entered into transportation and storage service agreements for the SPL Project. The initial term of the transportation agreements ranges from 10 to 20 years, with renewal options for certain contracts, and commences upon the occurrence of conditions precedent. The term of our storage service agreements is typically three years.

As of December 31, 2015, SPL's purchase obligations under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent were met were as follows (in thousands):

| Years Ending December 31, | Payments Due (1) |
|---|---|
| 2016 | $341,039 |
| 2017 | 284,263 |
| 2018 | 231,550 |
| 2019 | 182,470 |
| 2020 | 189,640 |
| Thereafter | 259,273 |
| Total | $1,488,235 |

(1) Pricing of natural gas supply contracts are variable based on market commodity basis prices adjusted for basis spread. Amounts included are based on prices and basis spreads as of December 31, 2015.

Other Purchase Obligations

As of December 31, 2015, we had approximately $48.9 million in purchase obligations due over the next two years, primarily related to purchases of materials for the Corpus Christi Pipeline.

Restricted Net Assets

At December 31, 2015, our restricted net assets of consolidated subsidiaries were approximately $2.9 billion.

Obligations under Certain Guarantee Contracts

Cheniere and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate transactions with third parties. These arrangements include financial guarantees, letters of credit and debt guarantees. As of December 31, 2015, there were no liabilities recognized under these guarantee arrangements.

Other Commitments

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

Legal Proceedings

We may in the future be involved as a party to various legal proceedings, which are incidental to the ordinary course of business. We regularly analyze current information and, as necessary, provide accruals for probable liabilities on the eventual disposition of these matters. In the opinion of management, as of December 31, 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.

NOTE 17—BUSINESS SEGMENT INFORMATION

We have two reportable segments: LNG terminal segment and LNG and natural gas marketing segment. We determine our reportable segments by identifying each segment that engaged in business activities from which it may earn revenues and incur expenses, had operating results regularly reviewed by the entities' chief operating decision maker for purposes of resource allocation and performance assessment, and had discrete financial information. 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 the United States.

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Our LNG terminal segment consists of the Sabine Pass and Corpus Christi LNG terminals. We own and operate the Sabine Pass LNG terminal located on the Sabine-Neches Waterway less than four miles from the Gulf Coast through our ownership interest in and management agreements with Cheniere Partners. We own 100% of the general partner interest in Cheniere Partners and 80.1% of the common shares of Cheniere Holdings, which owns a 55.9% limited partner interest in Cheniere Partners. We are also developing and constructing a second natural gas liquefaction and export facility at the Corpus Christi LNG terminal near Corpus Christi, Texas.

Our LNG and natural gas marketing segment consists of LNG and natural gas marketing activities by Cheniere Marketing. Cheniere Marketing is developing a platform for LNG sales to international markets with professional staff based in the United States, United Kingdom, Singapore and Chile.

The following table (in thousands) summarizes revenues (losses), loss from operations and total assets for each of our reporting segments:

| | Segments | | | |
|---|---|---|---|---|
| | LNG Terminal | LNG & Natural Gas Marketing | Corporate and Other (1) | Total Consolidation |
| As of or for the Year Ended December 31, 2015 | | | | |
| Revenues from external customers (2) | $269,281 | $66 | $1,538 | $270,885 |
| Intersegment revenues (losses) (3) | 2,225 | 29,373 | (31,598) | — |
| Depreciation and amortization expense | 65,137 | 1,071 | 16,472 | 82,680 |
| Loss from operations | (69,923) | (85,577) | (293,813) | (449,313) |
| Interest expense, net of capitalized interest | (219,831) | — | (102,252) | (322,083) |
| Loss before income taxes and non-controlling interest (4) | (596,432) | (87,133) | (413,846) | (1,097,411) |
| Share-based compensation | 32,948 | 14,401 | 147,959 | 195,308 |
| Goodwill | 76,819 | — | — | 76,819 |
| Total assets | 17,571,442 | 550,896 | 897,251 | 19,019,589 |
| Expenditures for additions to long-lived assets | 6,984,152 | 2,731 | 97,216 | 7,084,099 |
| | | | | |
| As of or for the Year Ended December 31, 2014 | | | | |
| Revenues (losses) from external customers (2) | $267,606 | $(1,285) | $1,633 | $267,954 |
| Intersegment revenues (losses) (3) | (779) | 41,908 | (41,129) | — |
| Depreciation and amortization expense | 58,883 | 271 | 5,104 | 64,258 |
| Loss from operations | (89,790) | (12,993) | (169,396) | (272,179) |
| Interest expense, net of capitalized interest | (177,400) | — | (3,836) | (181,236) |
| Loss before income taxes and non-controlling interest (4) | (480,366) | (14,874) | (192,494) | (687,734) |
| Share-based compensation | 14,129 | 6,027 | 90,073 | 110,229 |
| Goodwill | 76,819 | — | — | 76,819 |
| Total assets | 10,580,612 | 567,460 | 1,425,611 | 12,573,683 |
| Expenditures for additions to long-lived assets | 2,684,045 | 1,888 | 161,882 | 2,847,815 |
| | | | | |
| As of or for the Year Ended December 31, 2013 | | | | |
| Revenues from external customers (2) | $265,409 | $242 | $1,562 | $267,213 |
| Intersegment revenues (losses) (3) | 2,983 | 45,049 | (48,032) | — |
| Depreciation and amortization expense | 58,099 | 941 | 2,169 | 61,209 |

| | | | | |
|---|---|---|---|---|
| Loss from operations | (121,040 ) | (47,966 ) | (159,322 ) | (328,328 ) |
| Interest expense, net of capitalized interest | (182,003 ) | — | 3,603 | (178,400 ) |
| Loss before income taxes and non-controlling interest (4) | (350,734 ) | (48,851 ) | (154,838 ) | (554,423 ) |
| Share-based compensation | 29,805 | 46,293 | 207,783 | 283,881 |
| Goodwill | 76,819 | — | — | 76,819 |
| Total assets | 8,663,795 | 62,327 | 947,115 | 9,673,237 |
| Expenditures for additions to long-lived assets | 3,222,454 | 39 | 9,778 | 3,232,271 |

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(1) Includes corporate activities, business development, oil and gas exploration, development and exploitation, strategic activities and certain intercompany eliminations. These activities have been included in the corporate and other column due to the lack of a material impact that these activities have on our Consolidated Financial Statements.
(2) Substantially all of the LNG terminal revenues relate to regasification capacity reservation fee payments made by Total and Chevron. LNG and natural gas marketing and trading revenue consists primarily of the domestic marketing of natural gas imported into the Sabine Pass LNG terminal.
(3) Intersegment revenues (losses) related to our LNG and natural gas marketing segment are primarily a result of international revenue allocations using a cost plus transfer pricing methodology. These LNG and natural gas marketing segment intersegment revenues (losses) are eliminated with intersegment revenues (losses) in our Consolidated Statements of Operations.
(4) Items to reconcile loss from operations and loss before income taxes and non-controlling interest include consolidated other income (expense) amounts as presented on our Consolidated Statements of Operations primarily related to our LNG terminal segment.

NOTE 18—SUPPLEMENTAL CASH FLOW INFORMATION

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Cash paid during the year for interest, net of amounts capitalized and deferred | $122,860 | $130,578 | $120,908 |
| Balance in property, plant and equipment, net funded with accounts payable and accrued liabilities | 301,375 | 129,842 | 154,517 |
| Non-cash conveyance of assets | 13,169 | — | — |

NOTE 19—RECENT ACCOUNTING STANDARDS

The following table provides a brief description of recent accounting standards that had not yet been adopted by the Company as of December 31, 2015:

| Standard | Description | Expected Date of Adoption | Effect on our Consolidated Financial Statements or Other Significant Matters |
|---|---|---|---|
| ASU 2014-09, Revenue from Contracts with Customers (Topic 606) | The standard amends existing revenue recognition guidance and requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance may be early adopted beginning January 1, 2017, and may be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. | January 1, 2018 | We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures. |

| | | | |
|---|---|---|---|
| ASU 2014-15, Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern | The standard requires an entity’s management to evaluate, for each reporting period, whether there are conditions and events that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the financial statements are issued. Additional disclosures are required if management concludes that conditions or events raise substantial doubt about the entity’s ability to continue as a going concern. Early adoption is permitted. | December 31, 2016 | The adoption of this guidance is not expected to have an impact on our Consolidated Financial Statements or related disclosures. |

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| Standard | Description | Expected Date of Adoption | Effect on our Consolidated Financial Statements or Other Significant Matters |
|---|---|---|---|
| ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis | This amendment primarily affects asset managers and reporting entities involved with limited partnerships or similar entities, but the analysis is relevant in the evaluation of any reporting organization's requirement to consolidate a legal entity. This guidance changes (1) the identification of variable interests, (2) the variable interest entity characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This guidance may be early adopted, and may be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption. | January 1, 2016 | The adoption of this guidance is not expected to have an impact on our Consolidated Financial Statements or related disclosures. |
| ASU 2015-03, Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs and ASU 2015-15, Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements | This standard requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the debt liability rather than as an asset. Debt issuance costs incurred in connection with line of credit arrangements may be presented as an asset and subsequently amortized ratably over the term of the line of credit arrangement. This guidance may be early adopted, and must be adopted retrospectively to each prior reporting period presented. | January 1, 2016 | Upon adoption of this standard, the balance of debt, net will be reduced by the balance of debt issuance costs, net, except for the balance related to line of credit arrangements, on our Consolidated Balance Sheets. Additionally, disclosures will be required for a change in accounting principle. |
| ASU 2015-05, Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement | This standard clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. This guidance may be early adopted, and may be adopted as either retrospectively or prospectively to arrangements entered into, or materially modified, after the effective date. | January 1, 2016 | The adoption of this guidance is not expected to have an impact on our Consolidated Financial Statements or related disclosures. |
| ASU 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory | This standard requires inventory to be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. | January 1, 2017 | We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related |

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| This guidance may be early adopted and must be adopted prospectively. | disclosures. |

CHENIERE ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—CONTINUED

Additionally, the following table provides a brief description of a recent accounting standard that was adopted by the Company during the reporting period:

| Standard | Description | Date of Adoption | Effect on our Consolidated Financial Statements or Other Significant Matters |
|---|---|---|---|
| ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes | This standard requires all deferred tax assets and liabilities to be classified as non-current on the balance sheet instead of separating them between current and non-current. This guidance may be adopted either prospectively or retrospectively. | December 31, 2015 | We early adopted this guidance in the quarterly period ended December 31, 2015 on a prospective basis. There was no impact on our Consolidated Financial Statements or related disclosures upon adoption of this standard. |

NOTE 20—SUBSEQUENT EVENTS

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, to redeem or repay $1,665.5 million of the 2016 SPLNG Senior Notes and $420.0 million of the 2020 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.

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

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

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| Year ended December 31, 2015: | | | | |
| Revenues | $68,369 | $68,025 | $66,059 | $68,432 |
| Loss from operations | (60,244) | (95,874) | (52,074) | (241,121) |
| Net loss | (335,844) | (141,802) | (307,092) | (312,577) |
| Net loss attributable to common stockholders | (267,709) | (118,495) | (297,808) | (291,097) |
| Net loss per share attributable to common stockholders—basic and diluted (1) | (1.18) | (0.52) | (1.31) | (1.28) |
| Year ended December 31, 2014: | | | | |
| Revenues | $67,550 | $67,645 | $66,807 | $65,952 |
| Loss from operations | (47,805) | (62,200) | (61,164) | (101,010) |
| Net loss | (122,345) | (280,710) | (104,800) | (184,022) |
| Net loss attributable to common stockholders | (97,810) | (201,928) | (89,581) | (158,613) |
| Net loss per share attributable to common stockholders—basic and diluted (1) | (0.44) | (0.90) | (0.40) | (0.70) |

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Based on their evaluation as of the end of the fiscal year ended December 31, 2015, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are (1) accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

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

Management's Report on Internal Control Over Financial Reporting

Our Management's Report on Internal Control Over Financial Reporting is included in our Consolidated Financial Statements on page 60 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

Compliance Disclosure

Pursuant to Section 13(r) of the Exchange Act, if during the fiscal year ended December 31, 2015, we or any of our affiliates had engaged in certain transactions with Iran or with persons or entities designated under certain executive orders, we would be required to disclose information regarding such transactions in our annual report on Form 10-K as required under Section 219 of the Iran Threat Reduction and Syria Human Rights Act of 2012 ("ITRA"). During the fiscal year ended December 31, 2015, we did not engage in any transactions with Iran or with persons or entities related to Iran.

Blackstone CQP Holdco LP, an affiliate of The Blackstone Group L.P. ("Blackstone Group"), is a holder of more than 29% of the outstanding equity interests of Cheniere Partners and has three representatives on the Board of Directors of Cheniere Partners GP. Accordingly, Blackstone Group may be deemed an "affiliate" of Cheniere Partners, as that term is defined in Exchange Act Rule 12b-2. During the year ended December 31, 2015, Blackstone Group has included in its quarterly reports on Form 10-Q for the quarterly periods ended March 31, 2015, June 30, 2015 and September 30, 2015 disclosures pursuant to ITRA regarding two of its portfolio companies that may be deemed to be affiliates of Blackstone Group. Because of the broad definition of "affiliate" in Exchange Act Rule 12b-2, these portfolio companies of Blackstone Group, through Blackstone Group's ownership of Cheniere Partners, may also be deemed to be affiliates of ours. We have not independently verified the disclosure described in the following paragraphs.

Blackstone Group has reported that Hilton Worldwide Holdings Inc. (“Hilton”) has engaged in the following activity during the fiscal quarter ended September 30, 2015: an Iranian governmental delegation stayed at the Transcorp Hilton Abuja for one night. The stays were booked and paid for by the government of Nigeria. The hotel received revenues of approximately $5,320 from these dealings, and net profit to Hilton from these dealings was approximately $495, as reported by Blackstone Group. The gross revenues and net profits attributable to such activities by Hilton during the fiscal year ended December 31, 2015 have not been reported by Hilton. Hilton believes that the hotel stays were exempt from the Iranian Transactions and Sanctions Regulations, 31 C.F.R. Part 560, pursuant to the International Emergency Economic Powers Act ("IEEPA") and under 31 C.F.R. Section 560.210 (d). Blackstone Group has reported that the Transcorp Hilton Abuja intends to continue engaging in future similar transactions to the extent they remain permissible under applicable laws and regulations.

Blackstone Group has reported that Travelport Worldwide Limited ("Travelport") has engaged in the following activities: as part of its global business in the travel industry, Travelport provides certain passenger travel related Travel Commerce Platform and Technology Services to Iran Air. Travelport also provides certain airline Technology Services to Iran Air Tours. The gross revenues and net profits attributable to such activities by Travelport during the fiscal year ended December 31, 2015 have not been reported by Travelport; the gross revenues and net profits attributable to such activities by Travelport during the first nine months of 2015 were reported by Travelport to be approximately $435,000 and $307,000, respectively. Blackstone Group has reported that Travelport intends to continue these business activities with Iran Air and Iran Air Tours as such activities are either exempt from applicable sanctions prohibitions or specifically licensed by the Office of Foreign Assets Control.

In our Form 10-Q reports for the quarterly periods ended on March 31, 2015, June 30, 2015 and September 30, 2015, we disclosed, under "Item 5. Other Information—Compliance Disclosure" in each such report, as amended, activities as required by Section 13(r) of the Exchange Act as transactions or dealings with the government of Iran that have not been specifically authorized by a U.S. federal department or agency. Such disclosures are incorporated herein by reference.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Items 10 through 14 of Part III of this Report is incorporated by reference from Cheniere's definitive proxy statement, which is to be filed pursuant to Regulation 14A within 120 days after the end of Cheniere's fiscal year ended December 31, 2015.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements—Cheniere Energy, Inc. and Subsidiaries:



(2) Financial Statement Schedules:



(3) Exhibits:

Certain of the agreements filed as exhibits to this Form 10-K contain representations, warranties, covenants and conditions by the parties to the agreements that have been made solely for the benefit of the parties to the agreement. These representations, warranties, covenants and conditions:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other parties in connection with the negotiation of the agreements, which disclosures are not necessarily reflected in the agreements;
- may apply standards of materiality that differ from those of a reasonable investor; and
- were made only as of specified dates contained in the agreements and are subject to subsequent developments and changed circumstances.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time. These agreements are included to provide you with information regarding their terms and are not intended to provide any other factual or disclosure information about the Company or the other parties to the agreements. Investors should not rely on them as statements of fact.

| Exhibit No. | Description |
|---|---|
| 2.1 | Amended and Restated Purchase and Sale Agreement, dated as of August 9, 2012, by and among Cheniere Energy Partners, L.P., Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012) |
| 3.1 | Restated Certificate of Incorporation of the Company (Incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2004 (SEC File No. 001-16383), filed on August 10, 2004) |

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| Exhibit No. | Description |
|---|---|
| 3.2 | Certificate of Amendment of Restated Certificate of Incorporation of the Company (Incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on February 8, 2005) |
| 3.3 | Certificate of Amendment of Restated Certificate of Incorporation of the Company (Incorporated by reference to Exhibit 4.3 to the Company’s Registration Statement on Form S-8 (SEC File No. 333-160017), filed on June 16, 2009) |
| 3.4 | Certificate of Amendment of Restated Certificate of Incorporation of the Company (Incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on June 7, 2012) |
| 3.5 | Certificate of Amendment of Restated Certificate of Incorporation of the Company (Incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on February 5, 2013) |
| 3.6 | Bylaws of Cheniere Energy, Inc., as amended and restated December 9, 2015 (Incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on December 15, 2015) |
| 4.1 | Specimen Common Stock Certificate of the Company (Incorporated by reference to Exhibit 4.1 to the Company’s Registration Statement on Form S-1 (SEC File No. 333-10905), filed on August 27, 1996) |
| 4.2 | Indenture, dated as of November 9, 2006, by and among Sabine Pass LNG, L.P., as issuer, the guarantors as defined therein and The Bank of New York, as trustee (Incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006) |
| 4.3 | Form of 7.50% Senior Secured Note due 2016 (Included as Exhibit A1 to Exhibit 4.2 above) |
| 4.4 | Indenture, dated as of October 16, 2012, by and among Sabine Pass LNG, L.P., the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to SPLNG’s Current Report on Form 8-K (SEC File No. 333-138916), filed on October 19, 2012) |
| 4.5 | Form of 6.5% Senior Secured Note due 2020 (Included as Exhibit A1 to Exhibit 4.4 above) |
| 4.6 | Indenture, dated as of February 1, 2013, by and among Sabine Pass Liquefaction, LLC, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on February 4, 2013) |
| 4.7 | Form of 5.625% Senior Secured Note due 2021 (Included as Exhibit A-1 to Exhibit 4.6 above) |
| 4.8 | First Supplemental Indenture, dated as of April 16, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013) |
| 4.9 | Second Supplemental Indenture, dated as of April 16, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013) |
| 4.10 | Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.9 above) |
| 4.11 | Third Supplemental Indenture, dated as of November 25, 2013, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on November 25, 2013) |
| 4.12 | Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.11 above) |
| 4.13 | Fourth Supplemental Indenture, dated as of May 20, 2014, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014) |
| 4.14 | Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.13 above) |
| 4.15 | |

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|---|---|
| | Fifth Supplemental Indenture, dated as of May 20, 2014, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014) |
| 4.16 | Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.15 above) |
| 4.17 | Sixth Supplemental Indenture, dated as of March 3, 2015, between Sabine Pass Liquefaction, LLC and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on March 3, 2015) |
| 4.18 | Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.17 above) |

| Exhibit No. | Description |
|---|---|
| 4.19 | Indenture, dated as of November 28, 2014, by and between Cheniere Energy, Inc., as Issuer, and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 2, 2014) |
| 4.20 | Form of 4.875% Unsecured PIK Convertible Note due 2021 (Included as Exhibit A to Exhibit 4.19 above) |
| 4.21 | Indenture, dated as of March 9, 2015, between the Company, the Guarantors and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 13, 2015) |
| 4.22 | First Supplemental Indenture, dated as of March 9, 2015, between the Company, as Issuer, and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 13, 2015) |
| 4.23 | Form of 4.25% Convertible Senior Note due 2045 (Included as Exhibit A to Exhibit 4.22 above) |
| 4.24 | Note Purchase Agreement, dated as of January 16, 2015, by and among Cheniere CCH HoldCo II, LLC, as Issuer, the Company (solely for purposes of acknowledging and agreeing to Section 9 thereof), EIG Management Company, LLC, as administrative agent, The Bank of New York Mellon, as collateral agent, and the note purchasers named therein (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 16, 2015) |
| 4.25 | Amended and Restated Note Purchase Agreement, dated as of March 1, 2015, by and among Cheniere CCH HoldCo II, LLC, as Issuer, the Company (solely for purposes of acknowledging and agreeing to Section 9 thereof), EIG Management Company, LLC, as administrative agent, The Bank of New York Mellon, as collateral agent, and the note purchasers named therein (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on March 2, 2015) |
| 4.26 | Amendment to Amended and Restated Note Purchase Agreement, dated as of March 16, 2015, by and among Cheniere CCH HoldCo II, LLC, as Issuer, EIG Management Company, LLC, as administrative agent, and the note purchasers named therein (Incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 4.27 | Amendment 2 to Amended and Restated Note Purchase Agreement, dated as of May 8, 2015, with effect as of May 1, 2015, by and among Cheniere CCH Hold Co II, LLC, as Issuer, the Company, EIG Management Company, LLC, as administrative agent, and the required note holders named therein (Incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 4.28 | Form of 11.0% Senior Secured Notes due 2025 (Incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.1 | LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004) |
| 10.2 | Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on March 10, 2005) |
| 10.3 | Amendment of LNG Terminal Use Agreement, dated June 15, 2010, by and between Total Gas & Power North America, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 6, 2010) |
| 10.4 | Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004) |
| 10.5 | Parent Guarantee, dated as of November 5, 2004, by Total S.A. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004) |

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|---|---|
| 10.6 | Letter Agreement, dated September 11, 2012, between Total Gas & Power North America, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 2, 2012) |
| 10.7 | LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004) |
| 10.8 | Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.28 to SPLNG.’s Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006) |

| Exhibit No. | Description |
|---|---|
| 10.9 | Amendment of LNG Terminal Use Agreement, dated June 16, 2010, by and between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 6, 2010) |
| 10.10 | Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 15, 2004) |
| 10.11 | Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.12 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006) |
| 10.12 | Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.1 to SPLNG’s Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012) |
| 10.13 | Letter Agreement, dated May 28, 2013, by and between Sabine Pass LNG, L.P. and Sabine Pass Liquefaction, LLC (Incorporated by reference to Exhibit 10.1 to SPLNG’s Quarterly Report on Form 10-Q (SEC File No. 333-138916), filed on August 2, 2013) |
| 10.14 | Guarantee Agreement, dated as of July 31, 2012, by Cheniere Energy Partners, L.P. in favor of Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.2 to SPLNG.’s Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012) |
| 10.15† | Cheniere Energy, Inc. Amended and Restated 1997 Stock Option Plan (Incorporated by reference to Exhibit 10.14 to the Company’s Quarterly on Form 10-Q (SEC File No. 000-16383), filed on November 4, 2005) |
| 10.16† | Form of Cancellation and Grant of Non-Qualified Stock Options (three-year vesting) under the Cheniere Energy, Inc. 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on August 2, 2005) |
| 10.17† | Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.13 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 4, 2005) |
| 10.18† | Addendum to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.3 to the Company’s Annual Report on Form 10-K for the year ended December 31, 2005 (SEC File No. 001-16383), filed on March 13, 2006) |
| 10.19† | Amendment No. 1 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 4.10 to the Company’s Registration Statement on Form S-8 (SEC File No. 333-134886), filed on June 9, 2006) |
| 10.20† | Amendment No. 2 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.84 to the Company’s Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2007) |
| 10.21† | Amendment No. 3 to Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit A to the Company’s Proxy Statement (SEC File No. 001-16383), filed on April 23, 2008) |
| 10.22† | Amendment No. 4 to the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on June 15, 2009) |
| 10.23† | Form of Non-Qualified Stock Option Grant for Employees and Consultants (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007) |
| 10.24† | Form of Non-Qualified Stock Option Grant for Employees and Consultants (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.3 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), |

| | |
|---|---|
| | filed on January 11, 2007) |
| 10.25† | Form of Amendment to Non-Qualified Stock Option Grant (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on April 3, 2007) |
| 10.26† | Form of Restricted Stock Grant (three-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.5 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007) |
| 10.27† | Form of Restricted Stock Grant (four-year vesting) under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.6 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on January 11, 2007) |

| Exhibit No. | Description |
|---|---|
| 10.28† | Form of Amendment to Non-Qualified Stock Option Grant under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2008) |
| 10.29† | Form of Restricted Stock Grant under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (US - New Hire) (Incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.30† | Form of Restricted Stock Grant under the Cheniere Energy, Inc. Amended and Restated 2003 Stock Incentive Plan (UK - New Hire) (Incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.31† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2003 Stock Incentive Plan (US Executive Form) (Incorporated by reference to Exhibit 10.97 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.32† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2003 Stock Incentive Plan (US Non-Executive Form) (Incorporated by reference to Exhibit 10.99 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.33† | Form of Long-Term Incentive Award - Restricted Stock Grant (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on January 10, 2011) |
| 10.34† | Cheniere Energy, Inc. 2011 Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on June 22, 2011) |
| 10.35† | Amendment No. 1 to the Cheniere Energy, Inc. 2011 Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on February 5, 2013) |
| 10.36† | Cheniere Energy, Inc. 2011 - 2013 Bonus Plan (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed March 8, 2011) |
| 10.37† | Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2011 Incentive Plan (US - New Hire) (Incorporated by reference to Exhibit 10.13 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.38† | Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2011 Incentive Plan (UK - New Hire) (Incorporated by reference to Exhibit 10.14 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.39† | Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2011 Incentive Plan (Director) (Incorporated by reference to Exhibit 10.20 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on July 30, 2015) |
| 10.40† | Form of 2011 - 2013 Bonus Plan Long-Term Commercial Cash Award (US Form) (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.41† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant under the 2011 Incentive Plan (US Form) (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.42† | Form of 2011 - 2013 Bonus Plan Long-Term Commercial Cash Award (UK - Executive Form) (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.43† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant under the 2011 Incentive Plan (UK - Executive) (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.44† | Form of 2011 - 2013 Bonus Plan Long-Term Commercial Cash Award (UK Form) (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |

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| 10.45† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant under the 2011 Incentive Plan (UK Form) (Incorporated by reference to Exhibit 10.8 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.46† | Form of 2011 - 2013 Bonus Plan Long-Term Commercial Cash Award (US - Consultant/Independent Contractor) (Incorporated by reference to Exhibit 10.9 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |

| Exhibit No. | Description |
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| 10.47† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant under the 2011 Incentive Plan (US - Consultant/Independent Contractor) (Incorporated by reference to Exhibit 10.10 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.48† | Form of 2011 - 2013 Bonus Plan Long-Term Commercial Cash Award (US - Executive Form) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.49† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant under the 2011 Incentive Plan (US - Executive Form) (Incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on August 10, 2012) |
| 10.50† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2011 Incentive Plan (US Executive Form) (Incorporated by reference to Exhibit 10.96 to the Company’s Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.51† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2011 Incentive Plan (US Non-Executive Form) (Incorporated by reference to Exhibit 10.98 to the Company’s Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.52† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2011 Incentive Plan (UK Executive Form) (Incorporated by reference to Exhibit 10.100 to the Company’s Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.53† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2011 Incentive Plan (UK Non-Executive Form) (Incorporated by reference to Exhibit 10.101 to the Company’s Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.54† | Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the 2011 Incentive Plan (US Consultant Form) (Incorporated by reference to Exhibit 10.102 to the Company’s Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 22, 2013) |
| 10.55† | Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on April 24, 2015) |
| 10.56† | Cheniere Energy, Inc. 2014-2018 Long-Term Cash Incentive Program (Incorporated by reference to Exhibit 10.9 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.57† | Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (US - Executive) (Incorporated by reference to Exhibit 10.10 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.58† | Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (US - Non-Executive) (Incorporated by reference to Exhibit 10.11 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.59† | Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (UK - Executive) (Incorporated by reference to Exhibit 10.12 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.60† | Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (UK - Non-Executive) (Incorporated by reference to Exhibit 10.13 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.61† | Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (US - Consultant) (Incorporated by reference to Exhibit 10.14 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.62† | Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (UK - Consultant) (Incorporated by reference to Exhibit 10.15 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.63† | |

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| | Cheniere Energy, Inc. 2008 Change of Control Cash Payment Plan (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008) |
| 10.64† | Form of Change of Control Agreement (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 14, 2008) |
| 10.65† | Indefinite Term Employment Agreement, dated February 20, 2006, between Cheniere International, Inc. and Jean Abiteboul; Letter Agreement, dated February 23, 2006, between Cheniere Energy, Inc. and Jean Abiteboul; Amendment to a Contract of Employment, dated March 20, 2007, between Cheniere LNG Services SARL and Jean Abiteboul; and Amendment to Indefinite Term Contract of Employment, effective January 16, 2008, between Cheniere LNG Services and Jean Abiteboul (Incorporated by reference to Exhibit 10.94 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 27, 2009) |

| Exhibit No. | Description |
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| 10.66† | Second Amendment to Contract of Employment, dated effective April 30, 2012, by and between Jean Abiteboul and Cheniere LNG Services, SARL (Incorporated by reference to Exhibit 99.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on April 27, 2012) |
| 10.67† | Meg Gentle’s Assignment Letter, dated July 30, 2013 (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on July 30, 2013) |
| 10.68† | Amendment No. 1 to Meg Gentle's Assignment Letter, dated June 16, 2015 (Incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on June 17, 2015) |
| 10.69† | Terms and Conditions of Employment Agreement between Cheniere Supply & Marketing, Inc. and Jean Abiteboul (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-6383), filed on February 5, 2014) |
| 10.70† | Termination Agreement and Release, dated March 7, 2014, between H. Davis Thames and Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.4 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 1, 2014) |
| 10.71† | Letter Agreement between the Company and Neal Shear, dated December 18, 2015 (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on December 23, 2015) |
| 10.72† | Cheniere Energy, Inc. Retirement Policy, dated effective June 11, 2015 (Incorporated by reference to Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.73*† | Form of Indemnification Agreement for officers of Cheniere Energy, Inc. |
| 10.74*† | Form of Indemnification Agreement for directors of Cheniere Energy, Inc. |
| 10.75† | Cheniere Energy, Inc. 2015 Employee Inducement Incentive Plan (Incorporated by reference to Exhibit 4.8 to the Company’s Registration Statement on Form S-8 (SEC File No. 333-207651), filed on October 29, 2015) |
| 10.76† | Form of Cheniere Energy, Inc. 2015 Employee Inducement Incentive Plan Restricted Stock Grant - US Form (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.77† | Form of Cheniere Energy, Inc. 2015 Employee Inducement Incentive Plan Restricted Stock Grant - UK Form (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.78 | Collateral Trust Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, Sabine Pass LNG-GP, Inc. and Sabine Pass LNG-LP, LLC (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006) |
| 10.79 | Amended and Restated Parity Lien Security Agreement, dated November 9, 2006, by and between Sabine Pass LNG, L.P. and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.2 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006) |
| 10.80 | Third Amended and Restated Multiple Indebtedness Mortgage, Assignment of Rents and Leases and Security Agreement, dated November 9, 2006, by Sabine Pass LNG, L.P. to and for the benefit of The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.3 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006) |
| 10.81 | Amended and Restated Parity Lien Pledge Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., Sabine Pass LNG-GP, Inc., Sabine Pass LNG-LP, LLC and The Bank of New York, as collateral trustee (Incorporated by reference to Exhibit 10.4 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006) |
| 10.82 | Security Deposit Agreement, dated November 9, 2006, by and among Sabine Pass LNG, L.P., The Bank of New York, as collateral trustee, and The Bank of New York, as depositary agent |

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| | (Incorporated by reference to Exhibit 10.5 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on November 16, 2006) |
| 10.83 | Credit Agreement, dated as of May 28, 2013, among Cheniere Creole Trail Pipeline, L.P., as borrower, the lenders party thereto from time to time, Morgan Stanley Senior Funding, Inc., as administrative agent, The Bank of New York Mellon, as collateral agent, and The Bank of New York Mellon, as depositary bank (Incorporated by reference to Exhibit 10.6 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 29, 2013) |
| 10.84 | Second Amended and Restated Credit Agreement (Term Loan A), dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, Société Générale, as the Commercial Banks Facility Agent and the Common Security Trustee, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015) |

| Exhibit No. | Description |
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| 10.85 | Second Amended and Restated Common Terms Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent (Incorporated by reference to Exhibit 10.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015) |
| 10.86 | Amended and Restated KSURE Covered Facility Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, The Korea Development Bank, New York Branch, as the KSURE Covered Facility Agent, Société Générale, as the Common Security Trustee, and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.5 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015) |
| 10.87 | KEXIM Direct Facility Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, Shinhan Bank New York Branch, as the KEXIM Facility Agent, Société Générale, as the Common Security Trustee, and The Export-Import Bank of Korea, a governmental financial institution of the Republic of Korea (“KEXIM”), as the KEXIM Direct Facility Lender, Joint Lead Arranger and Joint Lead Bookrunner (Incorporated by reference to Exhibit 10.3 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015) |
| 10.88 | KEXIM Covered Facility Agreement, dated as of June 30, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, Shinhan Bank New York Branch, as the KEXIM Facility Agent, Société Générale, as the Common Security Trustee, KEXIM and the lenders from time to time party thereto (Incorporated by reference to Exhibit 10.4 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on July 1, 2015) |
| 10.89 | Omnibus Amendment, dated as of September 24, 2015, to the Second Amended and Restated Common Terms Agreement among Sabine Pass Liquefaction, LLC, as Borrower, the representatives and agents from time to time parties thereto, and Société Générale, as the Common Security Trustee and Intercreditor Agent (Incorporated by reference to Exhibit 10.6 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015) |
| 10.90 | Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, among Sabine Pass Liquefaction, LLC, as Borrower, The Bank of Nova Scotia, as Senior Issuing Bank and Senior Facility Agent, ABN Amro Capital USA LLC, HSBC Bank USA, National Association and ING Capital LLC, as Senior Issuing Banks, Société Générale, as Swing Line Lender and Common Security Trustee, and the senior lenders party thereto from time to time (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 11, 2015) |
| 10.91 | Amended and Restated Subscription Agreement, dated as of November 26, 2014, by and among Cheniere Energy, Inc., RRJ Capital II Ltd, Baytree Investments (Mauritius) Pte Ltd and Seatown Lionfish Pte. Ltd. relating to convertible PIK notes of Cheniere Energy, Inc. (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on December 2, 2014) |
| 10.92 | Common Terms Agreement, dated May 13, 2015, among Cheniere Corpus Christi Holdings, LLC, as Borrower, Corpus Christi Liquefaction, LLC, Cheniere Corpus Christi Pipeline, L.P., Corpus Christi Pipeline GP, LLC, as Guarantors, Société Générale, as Term Loan Facility Agent and Intercreditor Agent and any other facility agents party thereto from time to time (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.93 | Common Security and Account Agreement, dated May 13, 2015, among Cheniere Corpus Christi Holdings, LLC, as Company, Corpus Christi Liquefaction, LLC, Cheniere Corpus Christi Pipeline, L.P., and Corpus Christi Pipeline GP, LLC, as Guarantors, the Senior Creditor Group Representatives party thereto from time to time, Société Générale, as Intercreditor Agent and Security Trustee, and Mizuho Bank, Ltd, as Account Bank (Incorporated by reference to Exhibit 10.2 to the Company’s |

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| | Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.94 | Pledge Agreement, dated May 13, 2015, among Cheniere CCH HoldCo I, LLC, as Pledgor, and Société Générale, as Security Trustee (Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.95 | Corpus Christi Liquefied Natural Gas Project Term Loan Facility Agreement, dated May 13, 2015, among Cheniere Corpus Christi Holdings, LLC, as Borrower, Corpus Christi Liquefaction, LLC, Cheniere Corpus Christi Pipeline, L.P., Corpus Christi Pipeline GP, LLC, as Guarantors, Term Lenders party thereto from time to time, and Société Générale, as Term Loan Facility Agent (Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.96 | Equity Contribution Agreement, dated May 13, 2015, among Cheniere Corpus Christi Holdings, LLC, and the Company (Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |

| Exhibit No. | Description |
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| 10.97 | Registration Rights Agreement for 11.0% Senior Secured Notes due 2025, dated May 13, 2015, among the Company, Cheniere CCH HoldCo II, LLC, and EIG Management Company, LLC as Agent on behalf of the Note Holders (Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.98 | Pledge Agreement, dated May 13, 2015, among the Company, EIG Management Company, LLC, as Administrative Agent for the Note Holders, and The Bank of New York Mellon as the Collateral Agent for the Note Holders (Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.99 | Pledge Agreement, dated May 13, 2015, among Cheniere CCH HoldCo II, LLC, EIG Management Company, LLC, as Administrative Agent for the Note Holders, and The Bank of New York Mellon as the Collateral Agent for the Note Holders (Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015) |
| 10.100 | Master Ex-Ship LNG Sales Agreement, dated April 26, 2007, between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S., including Letter Agreement, dated April 26, 2007, and Specific Order No. 1, dated April 26, 2007 (Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2007) |
| 10.101 | LNG Lease Agreement, dated June 24, 2008, between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 11, 2008) |
| 10.102 | LNG Lease Agreement, dated September 30, 2011, by and between Cheniere Marketing, LLC and Cheniere Energy Investments, LLC (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 7, 2011) |
| 10.103 | Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on November 14, 2011) |
| 10.104 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0001 EPC Terms and Conditions, dated May 1, 2012, (ii) the Change Order CO-0002 Heavies Removal Unit, dated May 23, 2012, (iii) the Change Order CO-0003 LNTP, dated June 6, 2012, (iv) the Change Order CO-0004 Addition of Inlet Air Humidification, dated July 10, 2012, (v) the Change Order CO-0005 Replace Natural Gas Generators with Diesel Generators, dated July 10, 2012, (vi) the Change Order CO-0006 Flange Reduction and Valve Positioners, dated June 20, 2012, and (vii) the Change Order CO-0007 Relocation of Temporary Facilities, Power Poles Relocation Reimbursement, and Duck Blind Road Improvement Reimbursement, dated July 13, 2012 (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on August 3, 2012) |
| 10.105 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0008 Delay in Full Placement of Insurance, dated July 27, 2012, (ii) the Change Order CO-0009 HAZOP Action Items, dated July 31, 2012, (iii) the Change Order CO-00010 Fuel Provisional Sum, dated August 8, 2012, (iv) the Change Order CO-00011 Currency Provisional Sum, dated August 8, 2012, (v) the Change Order CO-00012 Delay in NTP, dated August 8, 2012, and (vi) the Change Order CO-00013 Early EPC Work Credit, dated August 29, 2012 (Incorporated by reference to Exhibit 10.2 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed |

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| | on November 2, 2012) |
| 10.106 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00014 Bundle of Changes, dated September 5, 2012, (ii) the Change Order CO-00015 Static Mixer, Air Cooler Walkways, etc., dated November 8, 2012, (iii) the Change Order CO-0016 Delay in Full Placement of Insurance, dated October 29, 2012, (iv) the Change Order CO-00017 Condensate Header, dated December 3, 2012 and (v) the Change Order CO-00018 Increase in Power Requirements, dated January 17, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.26 to Cheniere Partners' Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013) |

| Exhibit No. | Description |
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| 10.107 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00019 Delete Tank 6 Scope of Work, dated February 27, 2013 and (ii) the Change Order CO-00020 Modification to Builder's Risk Insurance Sum Insured Value, dated March 14, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013) |
| 10.108 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00021 Increase to Insurance Provisional Sum, dated April 17, 2013, (ii) the Change Order CO-00022 Removal of LNG Static Mixer Scope, dated May 8, 2013, (iii) the Change Order CO-00023 Revised LNG Rundown Line, dated May 30, 2013, (iv) the Change Order CO-00024 Reroute Condensate Header, Substation HVAC Stacks, Inlet Metering Station Pile Driving, dated June 11, 2013 and (v) the Change Order CO-00025 Feed Gas Connection Modifications, dated June 11, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.45 to Amendment No. 1 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on October 18, 2013) |
| 10.109 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00026 Bundle of Changes, dated June 28, 2013, (ii) the Change Order CO-00027 16" Water Pumps, dated July 12, 2013, (iii) the Change Order CO-00028 HRU Operability, dated July 26, 2013, (iv) the Change Order CO-00029 Belleville Washers, dated August 14, 2013 and (v) the Change Order CO-00030 Soils Preparation Provisional Sum Transfer dated August 29, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on November 8, 2013) |
| 10.110 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00031 LNG Intank Pump Replacement Scope Reduction/OSBL Additional Piling for the Cathodic Protection Rectifier Platform and Drum Storage Shelter dated October 15, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.35 to Amendment No. 2 to SPL's Registration Statement on Form S-4/A (SEC File No. 333-192373), filed on January 28, 2014) |
| 10.111 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00032 Intra-Plant Feed Gas Header and Jefferson Davis Electrical Distribution, dated January 9, 2014, (ii) the Change Order CO-00033 Revised EPC Agreement Attachments S & T, dated March 24, 2014 and (iii) the Change Order CO-00034 Greenfield/Brownfield Demarcation Adjustment, dated February 19, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 1, 2014) |
| 10.112 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between |

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| | Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00035 Resolution of FERC Open Items, Additional FERC Support Hours and Greenfield/Brownfield Milestone Adjustment, dated May 9, 2014 (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 31, 2014) |
| 10.113 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00036 Future Tie-Ins and Jeff Davis Invoices, dated July 9, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.23 to SPL's Registration Statement on Form S-4 (SEC File No. 333-198358), filed on August 26, 2014) |

| Exhibit No. | Description |
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| 10.114 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00037 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated October 31, 2014 and (ii) the Change Order CO-00038 Control Room Modifications and Miscellaneous Items, dated January 6, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.26 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2015) |
| 10.115 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00039 Increase to Existing Facility Labor Provisional Sum and Decrease to Sales and Use Tax Provisional Sum, dated February 12, 2015 and (ii) the Change Order CO-00040 Load Shedding and LNG Tank Tie-In Crane, dated February 24, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on April 30, 2015) |
| 10.116 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00041 Additional Building Utility Tie-in Packages and Fire and Gas Modifications, dated April 9, 2015 (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015) |
| 10.117 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Liquefaction Facility, dated as of November 11, 2011, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00042 Platform Design Modifications, Compressor Oil Fills, Additional Building Modifications, dated October 16, 2015, and (ii) the Change Order CO-00043 Soil Provisional Sum Closure, dated December 2, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.32 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 18, 2016) |
| 10.118 | Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated December 20, 2012, by and between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on December 27, 2012) |
| 10.119 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0001 Electrical Station HVAC Stacks, dated June 4, 2013, (ii) the Change Order CO-0002 Revised LNG Rundown Lines, dated May 30, 2013, (iii) the Change Order CO-0003 Currency Provisional Sum Closure, dated May 29, 2013 and (iv) the Change Order CO-0004 Fuel Provisional Sum Closure, dated May 29, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.48 to Amendment No. 1 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on October 18, 2013) |
| 10.120 | |

Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-0005 Credit to EPC Contract Value for TSA Work, dated June 24, 2013, (ii) the Change Order CO-0006 HRU Operability with Lean Gas & Controls Upgrade and Ultrasonic Meter Configuration and Calibration, dated July 26, 2013, (iii) the Change Order CO-0007 Additional Belleville Washers, dated August 15, 2013, (iv) the Change Order CO-0008 GTG Switchgear Arrangement/Upgrade Fuel Gas Heater System, dated August 26, 2013, and (v) the Change Order CO-0009 Soils Preparation Provisional Sum Transfer and Closure, dated August 26, 2013 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.49 to Amendment No. 1 to Cheniere Holdings' Registration Statement on Form S-1/A (SEC File No. 333-191298), filed on October 18, 2013)

| Exhibit No. | Description |
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| 10.121 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00010 Insurance Provisional Sum Adjustment, dated January 23, 2014, (ii) the Change Order CO-00011 Additional Stage 2 GTGs, dated January 23, 2014, (iii) the Change Order CO-0012 Lien and Claim Waiver Modification, dated March 24, 2014 and (iv) the Change Order CO-00013 Revised Stage 2 EPC Agreement Attachments S&T, dated March 24, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to SPL’s Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 1, 2014) |
| 10.122 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00014 Additional 13.8kv Circuit Breakers and Misc. Items, dated July 14, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.28 to SPL’s Registration Statement on Form S-4 (SEC File No. 333-198358), filed on August 26, 2014) |
| 10.123 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00015 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated October 31, 2014 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.32 to SPL’s Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2015) |
| 10.124 | Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00016 Louisiana Sales and Use Tax Provisional Sum Adjustment, dated February 12, 2015 and (ii) the Change Order CO-00017 Load Shedding Study and Scope Change, dated February 24, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.3 to SPL’s Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on April 30, 2015) |
| 10.125 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00018 Permanent Restroom Trailers and Installation of Tie-In for GTG Fuel Gas Interconnect, dated May 21, 2015 (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015) |
| 10.126 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 2 Liquefaction Facility, dated as of December 20, 2012, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00019 East Meter Piping Tie-ins, dated August 26, 2015 (Incorporated by reference to Exhibit 10.1 to SPL’s Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on October 30, 2015) |
| 10.127 | Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K/A (SEC File No. 001-33366), filed on July 1, 2015) |

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| 10.128 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00001 Currency and Fuel Provisional Sum Adjustment, dated June 25, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015) |
| 10.129 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00002 Credit to EPC Contract Value for TSA Work, dated September 17, 2015 (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on October 30, 2015) |

| Exhibit No. | Description |
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| 10.130 | Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between Sabine Pass Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00003 Perimeter Fencing Scope Removal, East Meter Piping Scope Change, Additional Bathroom Facilities, dated November 18, 2015 (Incorporated by reference to Exhibit 10.45 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 18, 2016) |
| 10.131 | Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 1 Liquefaction Facility, dated December 6, 2013, between Corpus Christi Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 10, 2013) |
| 10.132 | Change orders to the Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 1 Liquefaction Facility, dated as of December 6, 2013, between Corpus Christi Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (1) the Change Order CO-00001 Cost Impacts Associated with Delay in NTP, dated March 9, 2015, (2) the Change Order CO-00002 DLE/IAC Scope Change, dated March 25, 2015, (3) the Change Order CO-00003 Currency and Fuel Provisional Sum Closures, dated May 13, 2015 and (4) the Change Order CO-00004 Bridging Extension Through May 17, 2015, dated May 12, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.22 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on July 30, 2015) |
| 10.133 | Change orders to the Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 1 Liquefaction Facility, dated as of December 6, 2013, between Corpus Christi Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: (1) the Change Order CO-00005 Revised Buildings to Include Jetty and Geo-Tech Impact to Buildings, dated June 4, 2015, (2) the Change Order CO-00006 Marine and Dredging Execution Change, dated June 16, 2015, (3) the Change Order CO-00007 Temporary Laydown Areas, AEP Substation Relocation, Power Monitoring System for Substation, Bollards for Power Line Poles, Multiplex Interface for AEP Hecker Station, dated June 30, 2015, (4) the Change Order CO-00008 West Jetty Shroud and Fencing, Temporary Strainers on Loading Arms, Breasting and Mooring Analysis, Addition of Crossbar from Platform at Ethylene Bullets to Platform for PSV Deck, Reduction of Vapor Fence at Bed 22, Relocation of Gangway Tower, Changes in Dolphin Size, dated July 28, 2015, (5) the Change Order CO-00009 Post FEED Studies, dated July 1, 2015, (6) the Change Order CO-00010 Additional Post FEED Studies, Feed Gas ESD Valve Bypass, Flow Meter on Bog Line, Additional Simulations, FERC #43, dated July 1, 2015, (7) the Change Order CO-00011 Credit to EPC Contract Value for TSA Work, dated July 7, 2015, and (8) the Change Order CO-00012 Reduction of Provisional Sum for Operating Spares, Liquid Condensate Tie-In, Automatic Shut-Off Valve in Condensate Truck Fill Line, Firewater Monitor and Hydrant Coverage Test, dated August 11, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.134* | Change order to the Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 1 Liquefaction Facility, dated as of December 6, 2013, between Corpus Christi Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00013 Change in FEED Gas Tie-In, Utility Water and Potable Water Tie-In Changes, Ditch Design at Permanent Buildings, Koch Pipeline Cover, Monitoring of Raw Water Lake During Piling, Card Readers and Muster Points, Additional Asphalt in the Temporary Facilities Area, FAA Lighting and Marking, FERC Condition 84, dated October 13, 2015 (Portions of this exhibit have |

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| | been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) |
| 10.135 | Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated December 6, 2013, by and between Corpus Christi Liquefaction, LLC and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 10, 2013) |
| 10.136 | GDF Transatlantic Option Agreement, dated April 26, 2007, between Cheniere Marketing, Inc. and Gaz de France International Trading S.A.S. (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 9, 2007) |
| 10.137 | LNG Sale and Purchase Agreement (FOB), dated November 21, 2011, between Sabine Pass Liquefaction, LLC (Seller) and Gas Natural Aprovisionamientos SDG S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on November 21, 2011) |

| Exhibit No. | Description |
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| 10.138 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated April 3, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Gas Natural Aprovisionamientos SDG S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013) |
| 10.139 | LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between Sabine Pass Liquefaction, LLC (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on December 12, 2011) |
| 10.140 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between Sabine Pass Liquefaction, LLC (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.18 to Cheniere Partners' Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013) |
| 10.141 | LNG Sale and Purchase Agreement (FOB), dated December 14, 2012, between Sabine Pass Liquefaction, LLC (Seller) and Total Gas & Power North America, Inc. (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on December 17, 2012) |
| 10.142 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated August 28, 2015, between Sabine Pass Liquefaction, LLC (Seller) and Total Gas & Power North America, Inc. (Buyer) (Incorporated by reference to Exhibit 10.4 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015) |
| 10.143 | Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between Sabine Pass Liquefaction, LLC (Seller) and BG Gulf Coast LNG, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on January 26, 2012) |
| 10.144 | LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between Sabine Pass Liquefaction, LLC (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on January 30, 2012) |
| 10.145 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.19 to Cheniere Partners' Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013) |
| 10.146 | LNG Sale and Purchase Agreement (FOB), dated March 22, 2013, between Sabine Pass Liquefaction, LLC (Seller) and Centrica plc (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on March 25, 2013) |
| 10.147 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated September 11, 2015, between Sabine Pass Liquefaction, LLC (Seller) and Centrica plc (Buyer) (Incorporated by reference to Exhibit 10.5 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on October 30, 2015) |
| 10.148 | Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between Sabine Pass Liquefaction, LLC (Seller) and Cheniere Marketing, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to SPL's Current Report on Form 8-K (SEC File No. 333-192373), filed on August 11, 2014) |
| 10.149 | LNG Sale and Purchase Agreement (FOB), dated April 1, 2014, between Corpus Christi Liquefaction, LLC (Seller) and Endesa Generación, S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on April 2, 2014) |
| 10.150 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated July 23, 2015, between Endesa S.A. (Buyer) and Corpus Christi Liquefaction, LLC (Seller) (Incorporated by reference to |

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| | Exhibit 10.9 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.151 | Amendment No. 2 of LNG Sale and Purchase Agreement (FOB), dated July 23, 2015, between Endesa S.A. (Buyer) and Corpus Christi Liquefaction, LLC (Seller) (Incorporated by reference to Exhibit 10.10 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.152 | LNG Sale and Purchase Agreement (FOB), dated April 7, 2014, between Corpus Christi Liquefaction, LLC (Seller) and Endesa S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on April 8, 2014) |
| 10.153 | Assignment and Amendment Agreement, dated April 7, 2014, among Endesa Generación S.A., Endesa S.A. and Corpus Christi Liquefaction, LLC. (Incorporated by reference to Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 1, 2014) |
| 10.154 | Amended and Restated LNG Sale and Purchase Agreement (FOB), dated March 20, 2015, between Corpus Christi Liquefaction, LLC (Seller) and PT Pertamina (Persero) (Buyer) (Incorporated by reference to Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |

| Exhibit No. | Description |
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| 10.155 | LNG Sale and Purchase Agreement (FOB), dated May 30, 2014, between Corpus Christi Liquefaction, LLC (Seller) and Iberdrola, S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on May 30, 2014) |
| 10.156 | LNG Sale and Purchase Agreement (FOB), dated June 2, 2014, between Corpus Christi Liquefaction, LLC (Seller) and Gas Natural Fenosa LNG SL (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on June 2, 2014) |
| 10.157 | LNG Sale and Purchase Agreement (FOB), dated June 30, 2014, between Corpus Christi Liquefaction, LLC (Seller) and Woodside Energy Trading Singapore Pte Ltd (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on June 30, 2014) |
| 10.158 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated July 24, 2015, between Woodside Energy Trading Singapore PTE Ltd (Buyer) and Corpus Christi Liquefaction, LLC (Seller) (Incorporated by reference to Exhibit 10.11 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.159 | LNG Sale and Purchase Agreement (FOB), dated July 17, 2014, between Corpus Christi Liquefaction, LLC (Seller) and Électricité de France, S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on July 17, 2014) |
| 10.160 | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 24, 2015, between Corpus Christi Liquefaction, LLC (Seller) and Électricité de France, S.A. (Buyer) (Incorporated by reference to Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on April 30, 2015) |
| 10.161 | Amendment No. 2 of LNG Sale and Purchase Agreement, dated July 15, 2015, between Électricité de France, S.A. (Buyer) and Corpus Christi Liquefaction, LLC (Seller) (Incorporated by reference to Exhibit 10.12 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015) |
| 10.162 | LNG Sale and Purchase Agreement (FOB), dated December 18, 2014, between Corpus Christi Liquefaction, LLC (Seller) and EDP Energias de Portugal S.A. (Buyer) (Incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (SEC File No. 001-16383), filed on December 18, 2014) |
| 10.163* | Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated November, 18, 2015, between Corpus Christi Liquefaction, LLC (Seller) and EDP Energias de Portugal S.A. (Buyer) |
| 10.164 | Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement, dated October 23, 2007, by and between Cheniere Marketing, Inc. and Sabine Pass LNG, L.P. (Incorporated by reference to Exhibit 10.7 to the Company’s Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007) |
| 10.165 | Unit Purchase Agreement, dated May 14, 2012, by and among Cheniere Energy Partners, L.P., Cheniere Energy, Inc. and Blackstone CQP Holdco LP (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012) |
| 10.166 | Class B Unit Purchase Agreement, dated as of May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, LLC (Incorporated by reference to Exhibit 10.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012) |
| 10.167 | First Amendment to Class B Unit Purchase Agreement, dated as of August 9, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere Class B Units Holdings, LLC (Incorporated by reference to Exhibit 10.3 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012) |
| 10.168 | Subscription Agreement, dated May 14, 2012, by and between Cheniere Energy Partners, L.P. and Cheniere LNG Terminals, LLC (Incorporated by reference to Exhibit 10.4 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 15, 2012) |

| | |
|---|---|
| 10.169 | Letter Agreement, dated as of August 9, 2012, among Cheniere Energy, Inc., Cheniere Energy Partners, L.P. and Blackstone CQP Holdco LP (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012) |
| 10.170 | Investors’ and Registration Rights Agreement, dated as of July 31, 2012, by and among Cheniere Energy, Inc., Cheniere Energy Partners, L.P., Cheniere Energy Partners GP, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on August 6, 2012) |
| 10.171 | Third Amended and Restated Agreement of Limited Partnership of Cheniere Energy Partners, L.P., dated August 9, 2012 (Incorporated by reference to Exhibit 3.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on August 9, 2012) |
| 10.172 | Amended and Restated Limited Liability Company Agreement of Cheniere Energy Partners LP Holdings, LLC, dated December 13, 2013 (Incorporated by reference to Exhibit 3.1 to Cheniere Holdings’ Current Report on Form 8-K (SEC File No. 001-36234), filed on December 18, 2013) |

| Exhibit No. | Description |
|---|---|
| 10.173 | Amended and Restated Limited Liability Company Agreement of Cheniere GP Holding Company, LLC, dated December 13, 2013 (Incorporated by reference to Exhibit 10.3 to Cheniere Holdings' Current Report on Form 8-K (SEC File No. 001-36234), filed on December 18, 2013) |
| 10.174 | Payment Deferral Agreement (O&M Agreement), dated March 27, 2014, between Cheniere Energy Investments, LLC and Cheniere LNG O&M Services, LLC (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 1, 2014) |
| 10.175 | Nomination and Standstill Agreement, dated August 21, 2015, by and between the Company, Icahn Partners Master Fund LP, Icahn Partners LP, Icahn Onshore LP, Icahn Offshore LP, Icahn Capital LP, IPH GP LLC, Icahn Enterprises Holdings LP, Icahn Enterprises G.P. Inc., Beckton Corp., High River Limited Partnership, Hopper Investments LLC, Barberry Corp., Carl C. Icahn, Jonathan Christodoro and Samuel Merksamer (Incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on August 24, 2015) |
| 21.1* | Subsidiaries of Cheniere Energy, Inc. |
| 23.1* | Consent of KPMG LLP |
| 23.2* | Consent of Ernst & Young LLP |
| 31.1* | Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act |
| 31.2* | Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act |
| 32.1** | Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS* | XBRL Instance Document |
| 101.SCH* | XBRL Taxonomy Extension Schema Document |
| 101.CAL* | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.DEF* | XBRL Taxonomy Extension Definition Linkbase Document |
| 101.LAB* | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE* | XBRL Taxonomy Extension Presentation Linkbase Document |

* Filed herewith.
** Furnished herewith.
† Management contract or compensatory plan or arrangement

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

CONDENSED BALANCE SHEETS
(in thousands)

| | December 31, 2015 | 2014 |
|---|---|---|
| ASSETS | | |
| Current assets | $132 | $— |
| Non-current restricted cash | 6,572 | 5,847 |
| Property, plant and equipment, net | 8,899 | 2,596 |
| Debt receivable—affiliates | 843,629 | 809,416 |
| Investments in affiliates | (426,420) | (25,169) |
| Other non-current assets | 2,845 | 414 |
| Total assets | $435,657 | $793,104 |
| | | |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Accrued liabilities | $8,051 | $8,086 |
| Current debt—affiliate | 143,580 | 134,444 |
| Long-term debt, net | 1,185,876 | 814,751 |
| | | |
| Stockholders' deficit | (901,850) | (164,177) |
| Total liabilities and equity | $435,657 | $793,104 |

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

CONDENSED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
(in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Operating costs and expenses | | | |
| Depreciation expense | 58 | — | — |
| General and administrative expense (recovery) | (356) | 10,597 | 1,171 |
| Total operating costs and expenses | (298) | 10,597 | 1,171 |
| | | | |
| Other income (expense) | | | |
| Interest expense, net | (93,116) | (4,205) | — |
| Interest expense, net—affiliates | (9,137) | (9,137) | (9,137) |
| Interest income | 3 | 3 | — |
| Interest income—affiliates | 34,213 | 34,213 | 34,213 |
| Equity losses of affiliates | (907,370) | (558,209) | (531,827) |
| Total other expense | (975,407) | (537,335) | (506,751) |
| | | | |
| Net loss attributable to common stockholders | $(975,109) | $(547,932) | $(507,922) |
| | | | |
| Other comprehensive income | — | — | 25,319 |
| Comprehensive loss | $(975,109) | $(547,932) | $(482,603) |

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

CONDENSED STATEMENTS OF CASH FLOWS
(in thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Net cash used in operating activities | $(117,915) | $(240) | $(5,796) |
| Cash flows from investing activities | | | |
| Investments in affiliates | (320,584) | (901,329) | 139,494 |
| Net cash provided by (used in) investing activities | (320,584) | (901,329) | 139,494 |
| Cash flows from financing activities | | | |
| Proceeds from issuance of debt | 500,000 | 1,000,000 | — |
| Proceeds from sale of common stock, net | — | — | 3,628 |
| Payments related to tax withholdings for share-based compensation | (61,179) | (112,324) | (140,711) |
| Excess tax benefit from share-based compensation | 1,524 | 3,605 | 3,385 |
| Proceeds from exercise of stock options | 2,283 | 10,806 | — |
| Other | (4,129) | (518) | — |
| Net cash provided by (used in) financing activities | 438,499 | 901,569 | (133,698) |
| Net increase (decrease) in cash and cash equivalents | — | — | — |
| Cash and cash equivalents—beginning of period | — | — | — |
| Cash and cash equivalents—end of period | $— | $— | $— |

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

NOTES TO CONDENSED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The condensed financial statements represent the financial information required by Securities and Exchange Commission Regulation S-X 5-04 for Cheniere.

In the condensed financial statements, Cheniere’s investments in affiliates are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded on the balance sheets. The loss from operations of the affiliates is reported on a net basis as investment in affiliates (investment in and equity in net losses of affiliates).

A substantial amount of Cheniere’s operating, investing and financing activities are conducted by its affiliates. The condensed financial statements should be read in conjunction with Cheniere’s Consolidated Financial Statements.

NOTE 2—DEBT

As of December 31, 2015 and 2014, our debt consisted of the following (in thousands):

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| Note—Affiliate | $143,580 | $134,444 |

Note—Affiliate

We have a $93.7 million long-term note (“Note—Affiliate”) with Cheniere Terminals, a wholly owned subsidiary of Cheniere. Borrowings under the Note—Affiliate bear interest equal to the terms of Cheniere Terminals’ credit agreement at a fixed rate of 9.75% per annum. Interest is calculated on the unpaid principal amount of the Note—Affiliate outstanding and is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year.

NOTE 3—GUARANTEES

Guarantees on Behalf of Cheniere Marketing

Many of Cheniere Marketing’s natural gas purchase, sale, transportation and shipping agreements have been guaranteed by Cheniere. As of December 31, 2015, there was no liability that was recorded related to these guaranteed contracts.

Guarantee on behalf of Sabine Pass Tug Services, LLC

Sabine Pass Tug Services, LLC (“Tug Services”), a wholly owned subsidiary of Cheniere Partners, entered into a Marine Services Agreement (“Tug Agreement”) for four tugs with Alpha Marine Services, LLC. The initial term of the Tug Agreement ends on the tenth anniversary of the service date, with Tug Services having the option for two additional extension terms of five years each. This contract has been guaranteed by Cheniere for up to $5.0 million.

NOTE 4 —SUPPLEMENTAL CASH FLOW INFORMATION

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Non-cash capital contributions (1) | $(907,370) | $(558,209) | $(531,827) |

(1) Amounts represent equity losses of affiliates.

SIGNATURES

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

CHENIERE ENERGY, INC.
(Registrant)

By: /s/ Neal A. Shear
Neal A. Shear
Interim Chief Executive Officer and President
(Principal Executive Officer)
Date: February 18, 2016

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

| Signature | Title | Date |
|---|---|---|
| /s/ Neal A. Shear<br>Neal A. Shear | Interim Chief Executive Officer and President and Director<br>(Principal Executive Officer) | February 18, 2016 |
| /s/ Michael J. Wortley<br>Michael J. Wortley | Senior Vice President and Chief Financial Officer<br>(Principal Financial Officer) | February 18, 2016 |
| /s/ Leonard Travis<br>Leonard Travis | Vice President and Chief Accounting Officer<br>(Principal Accounting Officer) | February 18, 2016 |
| /s/ G. Andrea Botta<br>G. Andrea Botta | Chairman of the Board | February 18, 2016 |
| /s/ Vicky A. Bailey<br>Vicky A. Bailey | Director | February 18, 2016 |
| /s/ Nuno Brandolini<br>Nuno Brandolini | Director | February 18, 2016 |
| /s/ Jonathan Christodoro<br>Jonathan Christodoro | Director | February 18, 2016 |
| /s/ David I. Foley<br>David I. Foley | Director | February 18, 2016 |
| /s/ David B. Kilpatrick<br>David B. Kilpatrick | Director | February 18, 2016 |
| /s/ Samuel Merksamer<br>Samuel Merksamer | Director | February 18, 2016 |
| /s/ Donald F. Robillard, Jr. | Director | February 18, 2016 |

Donald F. Robillard, Jr.

| | | |
|---|---|---|
| /s/ Heather R. Zichal<br>Heather R. Zichal | Director | February 18, 2016 |