Cheniere Energy, Inc.
2017 Annual Report

Corpus Christi Liquefaction Project, March 2018

NOTE REGARDING FORWARD-LOOKING STATEMENTS

The CEO's Letter contains forward-looking statements relating to, among other things, business strategy, performance and expectations for project development. The reader is cautioned not to rely on these statements and should review the section "Cautionary Statement Regarding Forward-Looking Statements" in this Annual Report for important information about these statements, including the risks, uncertainties and other factors that could cause actual results to vary materially from the assumptions, expectations, and projections expressed in any forward-looking statements. These forward-looking statements speak only as of the date made, and other than as required by law, we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or developments or otherwise.

FELLOW SHAREHOLDERS,

2017 was a breakthrough year for Cheniere, one in which we achieved significant operational, financial, and commercial milestones. We demonstrated our commitment to execution, operational excellence, and financial discipline, and we delivered on our promises to customers, employees, and stakeholders. The year was also marked by encouraging developments in the global LNG market, and by the admirable dedication and resilience of our employees.

These are productive and exciting times at Cheniere, and I am confident that our capabilities place us in a strong position to continue our success and capitalize on the significant opportunities present in the market today.

DELIVERING ON OUR PROMISES

In 2017, we, with our engineering, procurement, and construction ("EPC") partner Bechtel, placed Trains 3 and 4 at the Sabine Pass liquefaction project (the "SPL Project") into operation ahead of schedule and on budget. Trains 1 through 4 at the SPL Project were all brought online ahead of schedule and on budget in a period of only 17 months, an unprecedented achievement in our industry.

Building on our operating experience since startup in 2016, we safely and reliably produced over 14 million tonnes of LNG in 2017, and we exported more than 200 LNG cargoes from the SPL Project during the year. Our exports alone made the United States the sixth-largest LNG exporting country worldwide last year. As of December 31, 2017, more than 260 cargoes totaling approximately 930 TBtu of LNG had been exported from the SPL Project, with deliveries to 25 countries and regions, including 11 new destinations during the year.

We executed consistently across all elements of our full-service LNG model, from our gas supply team which efficiently sourced almost 800 TBtu of natural gas feedstock to the SPL Project in 2017, to our commercial team which ensured we fulfilled our obligations to our foundation customers, and our marketing team which successfully sold and delivered portfolio LNG volumes and captured profit optimization opportunities.

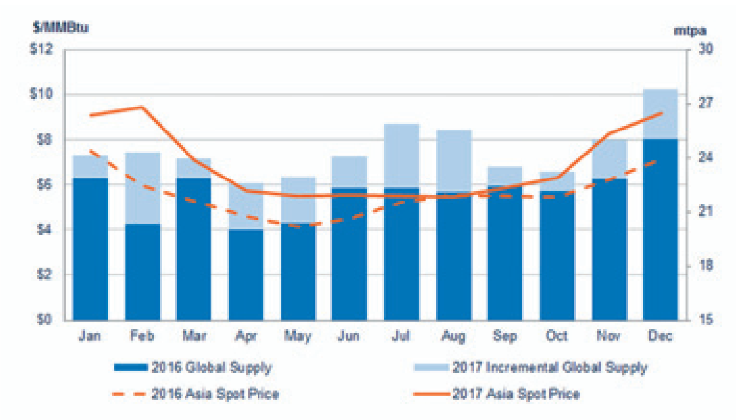
We also continued to progress the construction of Train 5 at the SPL Project and Trains 1 and 2 at our Corpus Christi liquefaction project ("CCL Project"), and those projects were more than 80% complete as of year-end 2017. We have applied lessons learned during the construction of SPL to deliver new efficiencies and improvements in design, engineering, and construction, and we anticipate placing the remaining three Trains into operation in 2019, on schedule and on budget.

FINANCIAL DISCIPLINE

Our record 2017 financial results reflect our dedication to excellence and execution. We reported consolidated revenue of $5.6 billion, and $1.4 billion of operating income for the year. We reported Consolidated Adjusted EBITDA[1] of over $1.8 billion and Distributable Cash Flow[1] of more than $600 million, both metrics within the revised guidance range we provided in November.

We achieved the date of first commercial delivery under our 20-year LNG Sale and Purchase Agreement ("SPA") with Korea Gas Corporation related to Train 3 of the SPL Project in June 2017, and under the respective 20-year SPAs with Gas Natural Fenosa LNG GOM, Limited and BG Gulf Coast, LLC relating to Train 2 of the SPL Project in August 2017. Since achieving the date of first commercial delivery under our 20-year SPA with GAIL (India) Limited related to Train 4 of the SPL Project in March 2018, we now have four long-term SPAs in effect, which, in aggregate, are expected to provide more than $2 billion of fixed fees annually.

We also strengthened the balance sheets across our structure in 2017, raising approximately $5.9 billion of capital across the enterprise during the year as part of our long term balance sheet strategy. We issued more than $5 billion of bonds to refinance credit facilities throughout our corporate structure, completing the refinancing of the Sabine Pass credit facilities and making significant progress on refinancing the credit facilities at Cheniere Corpus Christi Holdings, LLC and Cheniere Energy Partners, L.P. Additionally, we entered into a $750 million revolving credit facility which provides us with access to flexible, cost-effective liquidity to invest in current projects or support our growth initiatives. With more than $700 million of unrestricted cash, and an additional $1.9 billion of restricted cash on the balance sheet as of year-end, we are in a strong liquidity position to fulfill our equity funding requirements for the three Trains under construction and to invest in growth projects.



COMMITMENT TO GROWTH

Operational excellence, reliability, and financial discipline form the foundation from which to execute our growth strategy of marketing incremental liquefaction capacity on a long-term basis. Our reputation as a prudent operator has become a distinct competitive advantage as we look to finance and sanction new projects, and our growth prospects were aided in 2017 by a fundamentally strong global LNG market.

Global LNG supply grew by approximately 28 million tonnes per annum in 2017 – including an incremental 10 million tonnes during the year from the SPL Project – all of which were efficiently absorbed into the market, bolstered particularly by increased demand in Asia. Strong demand for LNG resulted in spot prices during the fourth quarter of 2017 at levels higher than the past three years, despite the increase in global supply. We believe that a significant portion of demand growth has been the result of structural shifts toward cleaner energy across the globe, with the implementation of environmental policies which favor natural gas over coal, nuclear, and liquid fuels, and we anticipate these changes will have positive long-term implications for Cheniere.

To capitalize on our capabilities and advantageous market conditions, we have made several strategic steps to advance development and commercialization of Train 3 at the CCL Project. In late 2017, we finalized a lump-sum turnkey EPC contract with Bechtel related to Train 3 and issued limited notice to proceed, leveraging personnel and equipment already at the CCL Project site to commence early site work. We also made significant progress in our commercialization efforts during 2017, which ultimately led to the execution of a long-term SPA with Trafigura Pte Ltd in January 2018 and two long-term SPAs with a subsidiary of China National Petroleum Corporation in February 2018. We believe these recent transactions are a result of Cheniere's competitive advantages of strategic positioning, execution and operating credibility, and a value proposition that is difficult for many to match. With sufficient commercialization achieved, we expect to make a Final Investment Decision with respect to Train 3 of the CCL Project in the first half of 2018.

To support our continued access to ample, reliable, and economic natural gas feedstock for LNG production, we launched an open season for the MIDSHIP Pipeline in March 2017 and secured sufficient commercial support to move forward with the project. Later in the year, we filed a 7(c) application with the Federal Energy Regulatory Commission ("FERC") and entered into an equity financing agreement for the MIDSHIP Pipeline, and we anticipate construction will begin in 2018.

We also completed a front-end engineering and design study into midscale liquefaction technology during 2017 and began the process of amending our regulatory filings with FERC to incorporate midscale liquefaction technology on our site at Corpus Christi, adjacent to the CCL Project. We can now approach the global LNG market with multiple technology competencies and the flexibility to deploy the most-cost effective solutions tailored to the demands of the market and our particular sites.

RESILIENT AND DEDICATED WORKFORCE

While we achieved significant milestones across the company in 2017, we also faced formidable challenges from Hurricane Harvey, a thousand-year storm that impacted the CCL Project, the SPL Project, and our headquarters in Houston, and caused significant hardship for the communities where we live and work. Yet, through the storm and in the aftermath, we saw the best of Cheniere and our employees, who repeatedly went above and beyond to help the company, friends, family, and strangers alike. Our dedicated employees at Sabine Pass stayed at the facility overnight to keep our plant running safely during the storm, and others used their own boats to help rescue neighbors, coworkers, and even livestock. After the storm, we held a day of service, knowing that for many the recovery and rebuilding phase will be the most challenging. Additionally, Cheniere was one of the first companies to announce a large donation to the American Red Cross, committing $1 million to their efforts to provide support during and after Hurricane Harvey. I am immensely proud of the Cheniere workforce for their resilience and dedication throughout Hurricane Harvey, and for their continued commitment to our communities as they rebuild.

With the incredible people we have working for Cheniere, and the support that you and other stakeholders provide to our company, I believe we will achieve great success in 2018 and beyond.

Sincerely,

Jack A. Fusco
President and CEO

(1) Consolidated Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures. A reconciliation to Net loss attributable to common stockholders, the most comparable U.S. GAAP measure, is included in the appendix.

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

FORM 10-K

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

For the fiscal year ended December 31, 2017

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 American**
(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 ☒ No ☐

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $11.5 billion as of June 30, 2017.

237,656,695 shares of the registrant's Common Stock, $0.003 par value, were outstanding as of February 15, 2018.

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

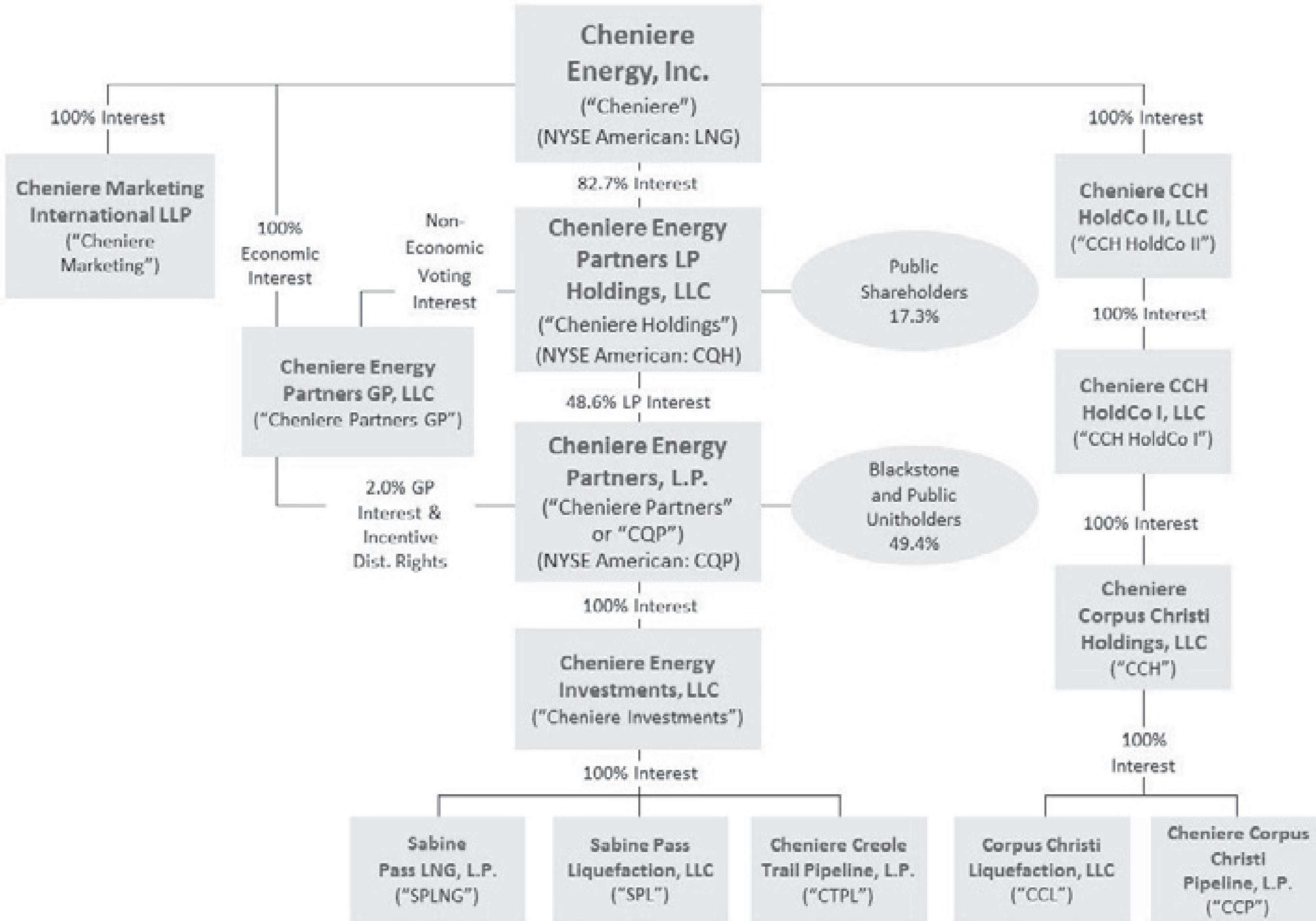
As used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

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

Abbreviated Legal Entity Structure

The following diagram depicts our abbreviated legal entity structure as of December 31, 2017, 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 Energy, Inc. and its consolidated subsidiaries, including our publicly traded subsidiaries, Cheniere Partners and Cheniere Holdings.

Unless the context requires otherwise, references to the "CCH Group" refer to CCH HoldCo II, CCH HoldCo I, CCH, CCL and CCP, collectively.

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 or present facts or conditions, included herein or incorporated herein by reference are "forward-looking statements." Included among "forward-looking statements" are, among other things:

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

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

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

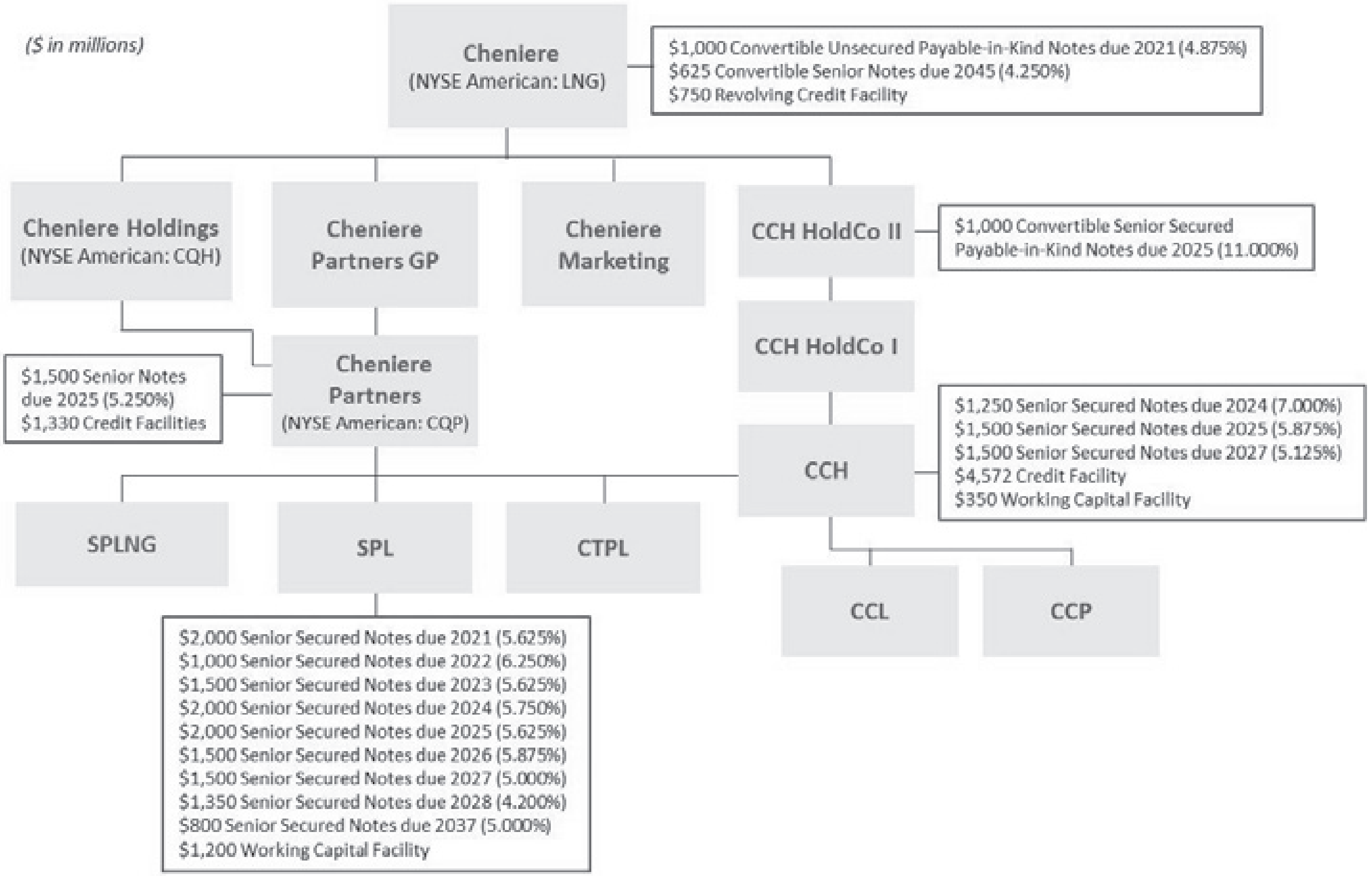
Cheniere, a Delaware corporation, was organized in 1983 and is a Houston-based energy company primarily engaged in LNG-related businesses. Our vision is to provide clean, secure and affordable energy to the world, while responsibly delivering a reliable, competitive and integrated source of LNG, in a safe and rewarding work environment. 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 82.7% of Cheniere Holdings, which is a publicly traded limited liability company formed in 2013 that owns a 48.6% limited partner interest in Cheniere Partners. We are currently developing and constructing two natural gas liquefaction and export facilities. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to economically justify the use of LNG.

The Sabine Pass LNG terminal is located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. Cheniere Partners is developing, constructing and operating natural gas liquefaction facilities (the "SPL Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities (described below) through a wholly owned subsidiary, SPL. Cheniere Partners plans to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is under construction and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 4.5 mtpa of LNG and an adjusted nominal production capacity of approximately 4.3 to 4.6 mtpa of LNG. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' wholly owned subsidiary, SPLNG, that include pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. 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 (collectively, the "CCL Project") through wholly owned subsidiaries CCL and CCP, respectively. The CCL Project is being developed in stages for up to three Trains, with expected aggregate nominal production capacity, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 13.5 mtpa of LNG, three LNG storage tanks with aggregate capacity of approximately 10.1 Bcfe and two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters. 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 natural gas supply pipeline that will interconnect the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline"). Stage 1 and the Corpus Christi Pipeline are currently under construction, and Train 3 is being commercialized and has all necessary regulatory approvals in place. The construction of the Corpus Christi Pipeline is nearing completion.

Additionally, we are developing an expansion of the Corpus Christi LNG terminal adjacent to the CCL Project (the "Corpus Christi Expansion Project") and recently began the process of amending our regulatory filings with FERC to incorporate a project design change, from two Trains with an expected aggregate nominal production capacity of approximately 9.0 mtpa to up to seven midscale Trains with an expected aggregate nominal production capacity of approximately 9.5 mtpa. We remain focused on leveraging infrastructure through the expansion of our existing sites. We are also in various stages of developing other projects, including infrastructure projects in support of natural gas supply and LNG demand, which, among other things, will require acceptable commercial and financing arrangements before we make a final investment decision ("FID"). We have made an equity investment of $55 million in Midship Pipeline Company, LLC, which is developing a pipeline with expected capacity of up to 1.44 million Dekatherms per day that will connect new gas production in the Anadarko Basin to Gulf Coast markets, including markets serving the SPL Project and the CCL Project.

Although results are consolidated for financial reporting, Cheniere, Cheniere Holdings, Cheniere Partners, SPL and the CCH Group operate with independent capital structures. The following diagram depicts our abbreviated capital structure as of December 31, 2017:



Our Business Strategy

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

- achieving the date of first commercial delivery for our SPA customers;
- safely, efficiently and reliably maintaining and operating our assets;
- completing construction and commencing operation of Train 5 of the SPL Project and the first three Trains of the CCL Project;
- making LNG available to our SPA customers to generate steady and reliable revenues and operating cash flows;
- obtaining financing to reach FID regarding Train 3 of the CCL Project, and the requisite long-term commercial contracts and financing for Train 6 of the SPL Project;
- further expanding and optimizing the SPL Project and the CCL Project by leveraging existing infrastructure;
- developing business relationships for the marketing of LNG volumes expected to be made available to our integrated marketing function and 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

During the first quarter of 2017, we finalized organizational changes to simplify our corporate structure, improve our operational efficiencies and implement a strategy for sustainable, long-term stockholder value creation through financially disciplined development, construction, operation and investment. As a result of these efforts, we revised the way we manage our business, which resulted in a change to our reportable segments. We previously had two reportable segments: LNG terminal segment and LNG and natural gas marketing segment. We have now determined that we operate as a single operating and reportable segment. Our chief operating decision maker makes resource allocation decisions and assesses performance based on financial information presented on a consolidated basis in the delivery of an integrated source of LNG to our customers.

LNG Terminals

We began developing our first LNG terminal 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 and the Corpus Christi LNG terminal. Through Cheniere Partners, we are developing, constructing and operating the SPL Project and have constructed and are operating regasification facilities at the Sabine Pass LNG terminal. We own 100% of the general partner interest in Cheniere Partners and 82.7% of Cheniere Holdings, which owns a 48.6% limited partner interest in Cheniere Partners. We currently own a 100% interest in the CCL Project.

Sabine Pass LNG Terminal

Liquefaction Facilities

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

	SPL Train 5
Overall project completion percentage	83.1%
Completion percentage of:	
Engineering	100%
Procurement	100%
Subcontract work	63.4%
Construction	62.1%
Date of expected substantial completion	1H 2019

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

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

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

In January 2018, the DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2018, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,511 Bcf/yr).

Customers

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

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $1.6 billion for Trains 1 through 3, increasing to $2.3 billion upon the date of first commercial delivery of Train 4 and to $2.9 billion upon the date of first commercial delivery of Train 5, with the applicable fixed fees starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

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

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

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

During the year ended December 31, 2017, revenues from external customers that were derived from domestic customers was $1.6 billion and from customers outside of the United States was $4.0 billion, of which $1.2 billion, $787 million and $762 million were derived from customers in Japan, Ireland and South Korea, respectively. During the year ended December 31, 2016, revenues from external customers that were derived from domestic customers was $769 million and from customers outside of the United States was $514 million, of which $162 million was derived from a customer in Japan. Substantially all of our revenues from external customers for the year ended December 31, 2015 were attributed to the United States. We attribute revenues from external customers to the country in which the party to the applicable agreement has its principal place of business. Substantially all of our long-lived assets are located in the United States.

During the year ended December 31, 2017, four customers, BG and its affiliates, Gas Natural Fenosa, KOGAS and JERA Co., Inc., individually accounted for more than 10% of our total revenues from external customers at 24%, 14%, 14% and 17%, respectively. During the year ended December 31, 2016, one customer, BG and its affiliates, individually accounted for more than 10% of our total revenues from external customers at 17%.

Natural Gas Transportation, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing volatility in natural gas needs for the SPL Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the SPL Project. As of December 31, 2017, SPL has secured up to approximately 2,214 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts.

Construction

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

The total contract price of the EPC contract for Train 5 of the SPL Project is approximately $3.1 billion reflecting amounts incurred under change orders through December 31, 2017. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.5 billion and $18.5 billion after financing costs including, in each case, estimated owner's costs and contingencies.

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 Train 6.

Regasification Facilities

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

The remaining approximately 2.0 Bcf/d of capacity has been reserved under a TUA by SPL. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, continuing until at least 20 years after SPL delivers its first commercial cargo at the SPL Project. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 3, SPL gained access to a portion of Total's capacity and other services provided under Total's TUA with SPLNG. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the year ended December 31, 2017, SPL recorded $23 million as operating and maintenance expense under this partial TUA assignment agreement.

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

Corpus Christi LNG Terminal

Liquefaction Facilities

The CCL Project is being developed and constructed at the Corpus Christi LNG terminal. In December 2014, we received authorization from the FERC to site, construct and operate Stages 1 and 2 of the CCL Project. The following table summarizes the overall project status of Stage 1 of the CCL Project as of December 31, 2017:

		CCL Stage 1
Overall project completion percentage		81.8%
Completion percentage of:		
Engineering		100%
Procurement		100%
Subcontract work		62.2%
Construction		59.2%
Expected date of substantial completion	Train 1	1H 2019
	Train 2	2H 2019

Train 3 is being commercialized and has all necessary regulatory approvals in place. Separate from the CCH Group, we are also developing the Corpus Christi Expansion Project, adjacent to the CCL Project. We commenced the regulatory approval process in June 2015 and recently began the process of amending our regulatory filings with FERC to incorporate a project design change, from two Trains with an expected aggregate nominal production capacity of approximately 9.0 mtpa to up to seven midscale Trains with an expected aggregate nominal production capacity of approximately 9.5 mtpa.

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

- CCL Project—FTA countries for a 25-year term and to non-FTA countries for a 20-year term up to a combined total of the equivalent of 767 Bcf/yr (approximately 15 mtpa) of natural gas.
- Corpus Christi Expansion Project—FTA countries for a 20-year term in an amount equivalent to 514 Bcf/yr (approximately 10 mtpa) of natural gas. The application for authorization to export that same 514 Bcf/yr of domestically produced LNG by vessel to non-FTA countries is currently pending before the DOE. We intend to amend our DOE applications consistent with the design change in our amended FERC filings.

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.

Customers

CCL entered into eight fixed-price SPAs with terms of at least 20 years (plus extension rights) with seven third parties to make available an aggregate amount of LNG that is between approximately 85% to 95% of the expected aggregate adjusted nominal production capacity of Trains 1 and 2. Under these eight SPAs, the customers will purchase LNG from CCL for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. In certain circumstances, the customers may elect to cancel or suspend deliveries of LNG cargoes, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered as a result of such cancellation or suspension. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under our SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under our SPAs. The variable fee under CCL's SPAs entered into in connection with the development of Stage 1 of the CCL Project was sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation related to, and operating and maintenance costs to produce, the LNG to be sold under each such SPA. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery for Train 1 or Train 2, as specified in each SPA.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $550 million for Train 1, increasing to $1.4 billion upon the date of first commercial delivery of Train 2 of the CCL Project, with the applicable fixed fees generally starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

The annual contracted cash flows from fixed fees of each buyer of LNG under CCL's third-party SPAs that constitute more than 10% of CCL's aggregate fixed fees under all its SPAs for Trains 1 and 2 of the CCL Project are:

- approximately $410 million from Endesa S.A.;
- approximately $280 million from PT Pertamina (Persero); and
- approximately $270 million from Gas Natural Fenosa, which is guaranteed by Gas Natural SDG, S.A.

The average annual contracted cash flow from fixed fees from buyers under all of our other third-party SPAs for Trains 1 and 2 of the CCL Project is approximately $460 million.

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

Natural Gas Transportation, Storage and Supply

To ensure CCL is able to transport adequate natural gas feedstock to the Corpus Christi LNG terminal, it has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CCP and certain third-party pipeline companies. CCL has entered into a firm storage services agreement with a third party to assist in managing volatility in natural gas needs for the CCL Project. CCL has also entered into enabling agreements and long-term natural gas supply contracts with third parties, and will continue to enter into such agreements, in order to secure natural gas feedstock for the CCL Project. As of December 31, 2017, CCL has secured up to approximately 2,024 TBtu of natural gas feedstock through long-term natural gas supply contracts, a portion of which is subject to the achievement of certain project milestones and other conditions precedent.

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 price of the EPC contract for Stage 1, which does not include the Corpus Christi Pipeline, is approximately $7.8 billion, reflecting amounts incurred under change orders through December 31, 2017. Total expected capital costs for Stage 1 and the Corpus Christi Pipeline 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 and total expected capital costs for the Corpus Christi Pipeline of between $350 million and $400 million. The total contract price of the EPC contract for Stage 2, which was amended and restated in December 2017, is approximately $2.4 billion.

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. The construction of the Corpus Christi Pipeline commenced in January 2017 and is nearing completion.

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.

Competition

The SPL Project currently does not experience competition with respect to Trains 1 through 5. SPL has entered into six fixed price SPAs with terms of at least 20 years (plus extension rights) 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 eight fixed price SPAs with terms of at least 20 years (plus extension rights) with seven third parties that will utilize substantially all of the liquefaction capacity available from these Trains. Each customer will be required to pay an escalating fixed fee for its annual contract quantity even if it elects not to purchase any LNG from us.

If and when 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 sold by our integrated marketing function discussed above, will also be subject to market-based price competition. Many of the companies with which we compete are major energy corporations with longer operating histories, more development experience, greater name recognition, greater financial, technical and marketing resources and greater access to markets than us.

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

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 the cost of construction and operation, and failure to comply with such laws could result in substantial penalties and/or loss of necessary authorizations.

Federal Energy Regulatory Commission

The design, construction and operation of our liquefaction facilities, the export of LNG and the transportation of natural gas through the Creole Trail Pipeline and the Corpus Christi Pipeline are highly regulated activities. Under the NGA, the FERC's jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial or any other use and to natural gas companies engaged in such transportation or sale. However, the FERC's jurisdiction does not extend to the production, gathering, local distribution or export of natural gas.

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

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

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

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

In December 2014, the FERC issued an order granting CCL authorization under Section 3 of the NGA to site, construct and operate Stage 1 and Stage 2 of the CCL Project and issued a certificate of public convenience and necessity under Section 7(c) of the NGA authorizing CCP 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 "Order Denying Rehearing"). The party petitioned the U.S. Court of Appeals for the District of Columbia Circuit (the "Court of Appeals") to review the December 2014 Order and the Order Denying Rehearing, and that petition was denied on November 4, 2016.

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

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

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

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

The FERC's jurisdiction under the NGA allows it to impose civil and criminal penalties for any violations of the NGA and any rules, regulations or orders of the FERC up to $1.3 million per day per violation, including any conduct that violates the NGA's prohibition against market manipulation. In accordance with the EPAct, the FERC issued a final rule under the NGA making it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to the FERC's jurisdiction, to defraud, make an untrue statement of material fact or omit a material fact or engage in any practice, act or course of business that operates or would operate as a fraud or deceit upon any entity. Finally, 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.

DOE Export License

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

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

Pipelines

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

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

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

In March 2015, PHMSA issued a final rule amending the pipeline safety regulations to update and clarify certain regulatory requirements, including who can perform post-construction inspections on transmission pipelines. In September 2015, PHMSA issued a rule indefinitely delaying the effective date for the amendment to the regulation regarding post-construction inspections.

In May 2015, PHMSA issued a notice of proposed rulemaking proposing to amend gas pipeline safety regulations regarding plastic piping systems used in gas services, including the installation of plastic pipe used for gas transmission lines. The PHMSA has not finalized any of the regulations proposed in this notice.

In July 2015, PHMSA issued a notice of proposed rulemaking proposing to add a specific timeframe for operators' notification of accidents or incidents, as well as amending the safety regulations regarding operator qualification requirements by expanding the requirements to include new construction and certain previously excluded operation and maintenance tasks, requiring a program effectiveness review and adding new recordkeeping requirements. In January 2017, PHMSA issued a final rule (effective as of March 24, 2017) adding a specific time frame for operators' notification of accidents or incidents but delayed final action on the proposed operator qualification requirements until a later date.

In April 2016, the PHMSA issued a notice of proposed rulemaking addressing changes to the regulations governing the safety of gas transmission pipelines. Specifically, PHMSA is considering certain integrity management requirements for "moderate consequence areas," requiring an integrity verification process for specific categories of pipelines, and mandating more explicit requirements for the integration of data from integrity assessments to an operator's compliance procedures. The PHMSA is also considering whether to revise requirements for corrosion control and expanding the definition of regulated gathering lines. These notices of proposed rulemaking are still pending at the PHMSA. The PHMSA has not finalized any of the regulations proposed in this notice.

Natural Gas Pipeline Safety Act of 1968 ("NGPSA")

Louisiana 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 sanctions.

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 approximately $200,000 per day per violation (increased from the prior $100,000), with a maximum of approximately $2 million in civil penalties for any related series of violations (increased from the prior $1 million).

Other Governmental Permits, Approvals and Authorizations

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

Three significant permits are the USACE Section 404 of the Clean Water Act/Section 10 of the Rivers and Harbors Act Permit (the "Section 10/404 Permit"), the Clean Air Act Title V Operating Permit (the "Title V Permit") and the Prevention of Significant Deterioration Permit (the "PSD Permit"), of which the latter two permits are issued by the LDEQ 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 Trains 1 through 4 was submitted in January 2011. The process included a public comment period, which commenced in March 2011 and closed in April 2011. The revised Section 10/404 Permit was received from the USACE in March 2012. A modification to the Section 10/404 Permit, to address wetlands impacted by the construction of Trains 5 and 6, was issued by the USACE in June 2015. The USACE acted in the capacity as a cooperating agency in the review process under the National Environmental Policy Act of 1969. 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 Trains 1 through 4 was initially submitted in December 2010 and revised in March 2011. The process included a public comment period from June 2011 to August 2011 and a public hearing in August 2011. The final revised Title V and PSD Permits were issued by the LDEQ in December 2011. Although these permits are final, a petition with the EPA has been filed pursuant to the Clean Air Act requesting that the EPA object to the Title V Permit. The EPA has not ruled on this petition. In June 2012, SPL 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, SPL applied to the LDEQ for an 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 Permit in June 2015. These permits are final. In October 2016, SPL applied to the LDEQ for another amendment to its PSD and Title V Permits to reflect certain facility modifications, updated emissions and as-built capacity factors. The LDEQ issued the amended PSD and Title V Permits in September 2017. 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 amended 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. The PSD Permit issued in September 2014 was altered in February 2015 to reflect CCL's decision to change the emissions control technology on the refrigeration turbines from water-injected to dry low emission turbines. CCL has submitted an application to amend the PSD permit for criteria pollutants. The planned amendment would reflect updates related to refined operational direction and changes that were made during the design and procurement process. The amendment process is expected to include a public comment period.

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. 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 for the Sinton Compressor Station was issued by the TCEQ in May 2015, however TCEQ voided the Title V Permit in October 2017 as the facility was no longer a major source.

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. In December 2017, further modification of this permit was granted to include 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 Sabine Pass LNG terminal and the Corpus Christi LNG terminal are subject to PHMSA safety regulations and standards for the transportation and storage of LNG and regulations of the U.S. Coast Guard relating to maritime safety and facility security.

Commodity Futures Trading Commission ("CFTC")

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

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

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

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

Under the Commodity Exchange Act as amended by the Dodd-Frank Act, the CFTC is directed generally to prevent manipulation of or fraud involving financial instruments, such as futures, options and swaps, on any commodity, including contracts for sale of physical commodities such as physical energy. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-manipulation and anti-disruptive trading practices regulations that prohibit, among other things, manipulative, deceptive or fraudulent schemes or material misrepresentation in the futures, options, swaps and cash markets. In addition, separate from the Dodd-Frank Act, our use of futures and options on commodities is subject to the Commodity Exchange Act and CFTC regulations, as well as the rules of futures exchanges on which any of these instruments are executed. Should we violate any of these laws and regulations, we could be subject to a CFTC or an exchange enforcement action and material penalties, possibly resulting in changes in the rates we can charge. The Dodd-Frank Act's swaps regulatory provisions and the related rules may 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, increase the costs of entering into and maintaining swaps, 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.

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 have been adopted and, as to the collection of initial margin, are being phased in, under which the exchange of initial and variation margin in respect of certain non-cleared derivatives is required, including from non-financial counterparties that have positions in any derivatives of any class that, in the aggregate, 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 publicly 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.

REMIT transaction and fundamental data reporting obligations have been fully implemented since April 2016. With regard to REMIT transaction reporting, transactions carried out on an organized market place must be reported by the market operator, all other contracts for the delivery of natural gas to the EU are reported by market participants. Fundamental data reporting obligations are largely managed by transmission system operators (TSOs), storage system operators (SSOs) and LNG system operators (LSOs). LNG fundamental data may be reported by either LSOs or terminal capacity holders. In addition, under REMIT, market participants have obligations to publicly disclose inside information pertaining to their business or facilities.

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

MiFID II is an EU directive that came into effect on January 3, 2018. This new directive has replaced the original Markets in Financial Instruments Directive ("MiFID"), and, like its predecessor, applies across the EU and EEA member states. MiFID II has narrowed the scope of exemptions currently available for commodity derivatives dealers. In addition, MiFID II has expanded the scope of the directive's application to include commodity derivatives that can be physically settled and which are traded on an organized trading facility in addition to other regulated markets or multilateral trading facilities. Notably, physically settled power and gas contracts have been excluded from the scope of MiFID II and are regulated under REMIT.

We are eligible to trade on our own account in commodity derivatives as a result of 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, we would be subject to the regulatory capital requirements under the EU's Capital Requirements Directive IV ("CRD IV"). A temporary exemption applies to CRD IV, which precludes commodity trading firms from these capital requirements. This exemption is slated to end in 2020 when a new prudential framework for MiFID investment firms is expected to come into effect.

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 came into effect 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 trading venues, 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.

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 require significant expenditures for compliance, can affect the cost and output of operations and may impose substantial penalties for non-compliance and substantial liabilities for pollution. Many of these laws and regulations, such as those noted below, restrict or prohibit impacts to the environment or the types, quantities and concentration of substances that can be released into the environment and can lead to substantial 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 sources, including fuel combustion sources. In 2010, the EPA expanded the rule to include reporting obligations for LNG terminals. In addition, the EPA has defined GHG emissions thresholds that would subject GHG emissions from new and modified industrial sources to regulation if the source is subject to PSD Permit requirements due to its emissions of non-GHG criteria pollutants. The Obama Administration took several actions intended to limit GHG emissions, including regulating emissions from new and existing Electricity Generating Units ("EGUs") and from new and modified oil and gas operations. The timing, extent and impact of these rules and other Obama Administration initiatives remain uncertain as the Trump Administration has undertaken steps to delay their implementation, and to review, repeal and potentially replace them. On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan after concluding the October 2015 final rule exceeds EPA's statutory authority under the CAA. The October 2017 proposal does not include regulations to replace the Clean Power Plan and EPA stated in the October 2017 proposal that it has not determined whether it will issue replacement regulations to regulate GHG emissions from existing EGUs. Many of the Trump Administration's efforts to rollback Obama Administration actions have been challenged in court.

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

Coastal Zone Management Act ("CZMA")

The siting and construction of our LNG terminals within the coastal zone may be subject to the requirements of the CZMA. 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 generation, handling and disposal of solid and hazardous wastes and require corrective action for releases into the environment. In the event such wastes are generated in connection with our facilities, we will be subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes.

Protection of Species, Habitats and Wetlands

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

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. These factors include changes in worldwide supply and demand for natural gas, LNG and substitute products, the relative prices for natural gas, crude oil and substitute products in North America and international markets, the rate of fuel switching for power generation from coal, nuclear or oil to natural gas and economic growth in developing countries. In addition, our ability to obtain additional funding to execute our business strategy is subject to the investment community's appetite for investment in LNG and natural gas infrastructure and our ability to access capital markets.

We expect that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to oil and coal. Global demand for natural gas is projected by the International Energy Agency to grow by approximately 19 trillion cubic feet ("Tcf") between 2016 and 2025, with LNG's share growing from about 10% currently to about 15% of the global gas market. Wood Mackenzie forecasts that global demand for LNG will increase by 65%, from approximately 255 mtpa, or 12.2 Tcf, in 2016, to approximately 422 mtpa, or 20.3 Tcf, in 2025, and that LNG production from existing facilities and new facilities already under construction will be able to supply the market with approximately 386 mtpa in 2025, resulting in a market need for construction of additional facilities capable of producing an incremental 36.4 mtpa of LNG. We believe the capital and operating costs of the uncommitted capacity of our SPL Project, CCL Project and Corpus Christi Expansion Project are competitive with new proposed projects globally and we are 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 as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements. These agreements contain fixed fees that are required to be paid even if the customers elect to cancel or suspend delivery of LNG cargoes. We have contracted an aggregate amount of LNG that is between approximately 80% to 95% of the expected aggregate adjusted nominal production capacity for Trains 1 through 5 of the SPL Project with third-party customers. We have contracted an aggregate amount of LNG that is between approximately 85% to 95% of the expected aggregate adjusted nominal production capacity of Trains 1 and 2 of the CCL Project with third-party customers. As of January 31, 2018, U.S. natural gas prices indicate that LNG exported from the U.S. continues to be competitively priced, supporting the opportunity for U.S. LNG to fill uncontracted future demand through the execution of long-term, medium-term and short-term contracting of LNG from our 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 1,230 full-time employees at January 31, 2018.

Available Information

Our common stock has been publicly traded since March 24, 2003 and is traded on the NYSE American 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 Operations and Commercialization;
- Risks Relating to Our LNG Business in General; and
- Risks Relating to Our Business in General.

Risks Relating to Our Financial Matters

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

As of December 31, 2017, we had $722 million of cash and cash equivalents, $1.9 billion of current restricted cash, $11 million of non-current restricted cash and $26.1 billion of total debt outstanding on a consolidated basis (before debt discounts, debt premiums and unamortized debt issuance costs), excluding $914 million aggregate 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 additional debt 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 and the repricing of market risks and volatility in capital and financial markets. Our financing costs could increase or future borrowings or equity offerings may be unavailable to us or unsuccessful, which could cause us to be unable to pay or refinance our indebtedness or to fund our other liquidity needs. We also rely on borrowings under our credit facilities to fund our capital expenditures. If any of the lenders in the syndicates backing these facilities was 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. We may not achieve profitability or generate positive operating cash flow in the future.

We had net losses attributable to common stockholders of $393 million, $610 million and $975 million for the years ended December 31, 2017, 2016 and 2015, respectively. In the future, we may incur operating losses and experience negative operating cash flow. We may not be able to reduce costs, increase revenues or reduce our debt service obligations sufficiently to maintain our cash resources, which could cause us to have inadequate liquidity to continue our business.

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

We may sell equity or equity-related securities 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 19.1 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; on the performance, 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 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 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.

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

Our 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, SPL is restricted from making distributions under agreements governing its indebtedness generally until, among other requirements, deposits are made into debt service reserve accounts and a debt service coverage ratio of 1.25:1.00 is satisfied.

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, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

In addition to restrictions on the ability of us, Cheniere Partners, SPL, CCH and CCH HoldCo II to make distributions or incur additional indebtedness, the agreements governing our indebtedness also contain various other covenants that may prevent us from engaging in beneficial transactions, including limitations on our 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 our 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.

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

The CFTC has re-proposed position limits rules that would modify and expand the applicability of position limits on the amounts of certain speculative futures contracts, as well as economically equivalent options, futures and swaps for or linked to certain physical commodities, including Henry Hub natural gas, that market participants may hold, subject to limited exemptions for certain bona fide hedging positions and other types of transactions. The CFTC also has adopted final rules regarding aggregation of positions that apply to futures on agricultural commodities, under which a party that controls the trading for the account of, or owns 10% or more of the equity interests in, another party will have to aggregate the positions in all such controlled accounts and of all such controlled or owned parties with their own positions for purposes of determining compliance with position limits rules unless an exemption applies. To the extent the revised CFTC position limits proposal becomes final, our ability to execute our hedging strategies described above could be limited. It is uncertain at this time whether, when and in what form the CFTC's proposed new position limits rules may become final and effective.

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

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

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

The Federal Reserve Board also has proposed rules that would limit certain physical commodity activities of financial holding companies. Such rules, if adopted, may adversely affect our ability to execute our strategies by restricting our available counterparties for certain types of transactions, limiting our ability to obtain certain services, and reducing liquidity in physical and financial markets. It is uncertain at this time whether, when and in what form the Federal Reserve's proposed rules regarding financial holding companies may become final and effective.

EMIR may result in increased costs for OTC derivative counterparties entering into swaps subject to EMIR. We, and our non-EU subsidiaries and affiliates, are each categorized as an entity that would be a non-financial counterparty below EMIR's clearing threshold (a "TCE NFC-") when transacting OTC derivatives with EU counterparties as our derivatives business is used for hedging alone. Our entities which are TCE NFC-s are not directly subject to EMIR when transacting with EU counterparties. However, an EU counterparty requires a TCE NFC- to undertake certain obligations required by EMIR in order to ensure the EU counterparty's compliance with EMIR. Further, our EU subsidiaries and affiliates are each categorized as a non-financial counterparty below EMIR's clearing threshold (a "NFC-") when transacting OTC derivatives and accordingly are directly subject to EMIR. Regulation under EMIR as a NFC-, or complying with the obligations imposed upon a TCE NFC- by an EU counterparty as a consequence of 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 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.

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

In making our investment decisions for the SPL Project, we have relied on several economic development programs in Louisiana, including Industrial Tax Exemption ("ITE") contracts. If we were to lose significant tax incentives through the economic development programs or if the ITE contracts were declared void, the loss of such tax incentives and/or exemptions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

SPL has utilized the ITE program, which is available for a "new" manufacturing establishment or an "addition" to an existing manufacturing establishment. SPL has entered into a total of nine ITE contracts, which exempt from ad valorem property taxes all of SPL's assets when placed in service.

On October 12, 2016, a lawsuit was filed by JMCB, LLC ("JMCB") against SPL, the Louisiana Department of Economic Development ("LED") and the Louisiana Board of Commerce and Industry ("BCI") (the "Pending Matter"). In the Pending Matter, JMCB contends that one of SPL's ITE contracts should be declared an improper and unauthorized act of BCI. JMCB asks the court to declare the contract null and void and without legal effect. JMCB's petition is filed as a class action that seeks declaratory relief for all similarly situated taxpayers in Cameron Parish and for the governmental agencies that would have received the ad valorem property taxes, but for the ITE contract. SPL believes that the likelihood that the resolution of the Pending Matter will have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity or prospects is remote. If we do not prevail in the Pending Matter, the loss of such tax exemption could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Risks Relating to Our LNG Terminal Operations and Commercialization

Operation of the Sabine Pass LNG terminal, the SPL Project and the CCL Project, our pipelines 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, our pipelines 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 fully 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 effect 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 have already experienced increased costs due to change orders. We do not have any prior experience in constructing liquefaction facilities, and other than Trains 1 through 4 of the SPL Project, as of January 2018, 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, including change orders to comply with existing or future environmental or other regulations.

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 fully constructed (which could cause further delays). Our ability to obtain financing that may be needed to provide additional funding to cover increased costs will depend, in part, on factors beyond our control. Accordingly, we may not be able to obtain financing on terms that are acceptable to us, or at all. Even if we are able to obtain financing, we may have to accept terms that are disadvantageous to us or that may have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

Our ability to complete development of 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 fully execute our business strategy.

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 future customers in the event of significant delays. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

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 orders under Section 3 of the NGA authorizing the siting, construction and operation of six Trains and related facilities of the SPL Project and three Trains and related facilities of the CCL Project and Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline and the Corpus Christi Pipeline, the FERC orders require us to comply with certain ongoing conditions and obtain certain additional approvals in conjunction with ongoing construction and operations of our liquefaction and pipeline facilities. We will be required to obtain similar approvals and permits with respect to any expansion or modification of our liquefaction and pipeline facilities. We cannot control the outcome of the FERC's or the DOE's review and approval processes. Certain of these governmental permits, approvals and authorizations are or may be subject to rehearing requests, appeals and other challenges.

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

We are 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 SPL Project and the CCL Project, and any liquidated damages that we receive may not be sufficient to cover the damages that we suffer as a result of any such delay or impairment. The obligations of Bechtel and our other contractors to pay liquidated damages under their agreements are subject to caps on liability, as set forth therein.

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

We are relying on third-party engineers to estimate the future capacity ratings and performance capabilities of the 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, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We 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, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

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 the Natural Gas Policy Act of 1978 (the "NGPA"). The FERC regulates the transportation of natural gas in interstate commerce, including the construction and operation of pipelines, the rates, 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.

In addition, as a natural gas market participant, 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 and the NGPA to impose penalties for current violations of up to $1.3 million per day for each violation.

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

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

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

Our integrated marketing function 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.

We may not be able to contract with customers to sell LNG produced in excess of the aggregate annual contract quantities committed to SPL's and CCL's third-party SPAs.

We expect to sell any LNG produced in excess of the aggregate annual contract quantity committed to SPL's and CCL's third-party SPAs through our integrated marketing function. We are developing a portfolio of long-, medium- and short-term SPAs to transport and unload commercial LNG cargoes to locations worldwide, which is primarily sourced by LNG produced by the SPL Project and the CCL Project in excess of the contract quantities committed to SPL's and CCL's third party SPAs, supplemented by volume procured from other locations worldwide, as needed. Failure to secure buyers for a sufficient amount of LNG could materially and adversely affect our 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 natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;
- political conditions in natural gas producing regions;
- adverse relative demand for LNG compared to other markets, which may decrease LNG imports into or exports from North America; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

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

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

Operations of the SPL Project are, and operations at 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 alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside the United States, which could increase the available supply of natural gas outside the United States and could result in natural gas in those markets being available at a lower cost than LNG exported to those markets.

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

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

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

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

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

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

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

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

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

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

We have contracted for firm capacity for our natural gas feedstock transportation requirements for Trains 1 through 5 of the SPL Project and Trains 1 and 2 of 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 a 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 construction and operation of our LNG terminals and our pipelines are, and will be, subject to the inherent risks associated with these types of operations, including explosions, pollution, release of toxic substances, fires, hurricanes and adverse weather conditions and other hazards, each of which could result in significant delays in commencement or interruptions of operations and/or in damage to or destruction of our facilities or damage to persons and property. In addition, our operations and the facilities and vessels of third parties on which our operations are dependent face possible risks associated with acts of aggression or terrorism.

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

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. In addition, certain environmental laws and regulations authorize regulators having jurisdiction over our LNG terminals to issue compliance orders, which may restrict or limit operations or increase compliance or operating costs. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties or to capital expenditures 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.

In October 2015, the EPA promulgated a final rule to implement the Obama Administration’s Clean Power Plan, which is designed to reduce GHG emissions from power plants in the United States. In February 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. In March 2017, President Trump directed EPA via Executive Order to review and determine whether it is appropriate to revise or rescind the Clean Power Plan. On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan after concluding the October 2015 final rule exceeds EPA’s statutory authority under the CAA. The October 2017 proposal does not include regulations to replace the Clean Power Plan and EPA stated in the October 2017 proposal that it has not determined whether it will issue replacement regulations to regulate GHG emissions from existing EGUs. The Trump Administration announced in June 2017 that the United States would withdraw from the Paris Accord, an international agreement within the United Nations Framework Convention on Climate Change under which the Obama Administration committed the United States to reducing its economy-wide GHG emission by 26-28% below 2005 levels by 2025. Other federal and state initiatives may be considered in the future to address GHG emissions through, for example, United States treaty commitments, direct regulation, a carbon emissions tax, or cap-and-trade programs. Such initiatives, including a future replacement rule for the Clean Power Plan could affect the demand for or cost of natural gas, which we consume at our terminals, or could increase compliance costs for our operations.

Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to or exported from our terminals, 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, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We depend on our executive officers for various activities. 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 other than our employment agreement with our President and Chief Executive Officer binding them to provide services for any particular term. The loss of the services of any of these individuals could have a material adverse effect on our business.

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 2018 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, during the three-year period ended December 31, 2017, the market price of our common stock ranged between $22.80 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 U.S. Internal Revenue Code ("IRC"), 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.

U.S. federal income tax reform could adversely affect us.

On December 22, 2017, the Tax Cuts and Jobs Act (the "TCJA") was signed into law, significantly reforming the IRC. The TCJA, among other things, includes changes to U.S. federal tax rates, imposes significant additional limitations on the deductibility of interest, allows for the expensing of capital expenditures, and imposes limitations on the use of net operating losses arising in taxable years beginning after December 31, 2017. The reduction of the U.S. corporate tax rate results in a decreased valuation of our deferred tax asset and liabilities. We continue to examine the impact the TCJA may have on our business. The estimated impact of the TCJA is based on our management's current knowledge and assumptions and recognized impacts could be materially different from current estimates based on our actual results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

LDEQ Matter

Certain of our subsidiaries are in discussions with the LDEQ to resolve self-reported deviations arising from operation of the Sabine Pass LNG terminal and the commissioning of the SPL Project, and relating to certain requirements under its Title V Permit. The matter involves deviations self-reported to LDEQ pursuant to the Title V Permit and covering the time period from January 1, 2012 through March 25, 2016. On April 11, 2016, certain of our subsidiaries received a Consolidated Compliance Order and Notice of Potential Penalty (the "Compliance Order") from LDEQ covering deviations self-reported during that time period. Certain of our subsidiaries continue to work with LDEQ to resolve the matters identified in the Compliance Order. We do not expect that any ultimate sanction will have a material adverse impact on our financial results.

PHMSA Matters

In February 2018, PHMSA issued a Corrective Action Order (the "CAO") to SPL in connection with a minor LNG leak from one tank and minor vapor release from a second tank at the Sabine Pass LNG terminal. These two tanks have been taken out of operational service while we undergo analysis, repair and remediation pursuant to the CAO. We are working with PHMSA and other appropriate regulatory authorities to resolve the matters identified in the CAO. We do not expect that the CAO and related analysis, repair and remediation will have a material adverse impact on our financial results or operations.

In February 2018, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order ("the NOPV") to CCP relating to a February 2017 inspection of the Corpus Christi Pipeline. The NOPV alleges probable violations of federal pipeline safety regulations relating to welding during the construction of the pipeline and proposes civil penalties totaling $0.2 million. We are currently reviewing the alleged violations and do not expect that the resolution of this matter will have a material adverse impact on our financial results or operations.

Parallax Litigation

In 2015, our wholly owned subsidiary, Cheniere LNG Terminals, LLC ("CLNGT"), entered into discussions with Parallax Enterprises, LLC ("Parallax Enterprises") regarding the potential joint development of two liquefaction plants in Louisiana (the "Potential Liquefaction Transactions"). While the parties negotiated regarding the Potential Liquefaction Transactions, CLNGT loaned Parallax Enterprises approximately $46 million, as reflected in a secured note dated April 23, 2015, as amended on June 30, 2015, September 30, 2015 and November 4, 2015 (the "Secured Note"). The Secured Note was secured by all assets of Parallax Enterprises and its subsidiary entities. On June 30, 2015, Parallax Enterprises' parent entity, Parallax Energy LLC ("Parallax Energy"), executed a Pledge and Guarantee Agreement further securing repayment of the Secured Note by providing a parent guaranty and a pledge of all of the equity of Parallax Enterprises in satisfaction of the Secured Note (the "Pledge Agreement"). CLNGT and Parallax Enterprises never executed a definitive agreement to pursue the Potential Liquefaction Transactions. The Secured Note matured on December 11, 2015, and Parallax Enterprises failed to make payment. On February 3, 2016, CLNGT filed an action against Parallax Energy, Parallax Enterprises and certain of Parallax Enterprises' subsidiary entities, styled Cause No. 4:16-cv-00286, Cheniere LNG Terminals, LLC v. Parallax Energy LLC, et al., in the United States District Court for the Southern District of Texas (the "Texas Federal Suit"). CLNGT asserted claims in the Texas Federal Suit for (1) recovery of all amounts due under the Secured Note and (2) declaratory relief establishing that CLNGT is entitled to enforce its rights under the Secured Note and Pledge Agreement in accordance with each instrument's terms and that CLNGT has no obligations of any sort to Parallax Enterprises concerning the Potential Liquefaction Transactions. On March 11, 2016, Parallax Enterprises and the other defendants in the Texas Federal Suit moved to dismiss the suit for lack of subject matter jurisdiction. On August 2, 2016, the court denied the defendants' motion to dismiss without prejudice and permitted the parties to pursue jurisdictional discovery.

On March 11, 2016, Parallax Enterprises filed a suit against us and CLNGT styled Civil Action No. 62-810, Parallax Enterprises LLP v. Cheniere Energy, Inc. and Cheniere LNG Terminals, LLC, in the 25th Judicial District Court of Plaquemines Parish, Louisiana (the "Louisiana Suit"), wherein Parallax Enterprises asserted claims for breach of contract, fraudulent inducement, negligent misrepresentation, detrimental reliance, unjust enrichment and violation of the Louisiana Unfair Trade Practices Act. Parallax Enterprises predicated its claims in the Louisiana Suit on an allegation that we and CLNGT breached a purported agreement to jointly develop the Potential Liquefaction Transactions. Parallax Enterprises sought $400 million in alleged economic damages and rescission of the Secured Note. On April 15, 2016, we and CLNGT removed the Louisiana Suit to the United States District Court for the Eastern District of Louisiana, which subsequently transferred the Louisiana Suit to the United States District Court for the Southern District of Texas, where it was assigned Civil Action No. 4:16-cv-01628 and transferred to the same judge presiding over the Texas Federal Suit for coordinated handling. On August 22, 2016, Parallax Enterprises voluntarily dismissed all claims asserted against CLNGT and us in the Louisiana Suit without prejudice to refiling.

On July 27, 2017, the Parallax entities named as defendants in the Texas Federal Suit reurged their motion to dismiss and simultaneously filed counterclaims against CLNGT and third party claims against us for breach of contract, breach of fiduciary duty, promissory estoppel, quantum meruit and fraudulent inducement of the Secured Note and Pledge Agreement, based on substantially the same factual allegations Parallax Enterprises made in the Louisiana Suit. These Parallax entities also simultaneously filed an action styled Cause No. 2017-49685, Parallax Enterprises, LLC, et al. v. Cheniere Energy, Inc., et al., in the 61st District Court of Harris County, Texas (the "Texas State Suit"), which asserts substantially the same claims these entities asserted in the Texas Federal Suit. On July 31, 2017, CLNGT withdrew its opposition to the dismissal of the Texas Federal Suit without prejudice on jurisdictional grounds and the federal court subsequently dismissed the Texas Federal Suit without prejudice.

We and CLNGT simultaneously filed an answer and counterclaims in the Texas State Suit, asserting the same claims CLNGT had previously asserted in the Texas Federal Suit. Additionally, CLNGT filed third party claims against Parallax principals Martin Houston, Christopher Bowen Daniels, Howard Candelet and Mark Evans, as well as Tellurian Investments, Inc., Driftwood LNG, LLC, Driftwood LNG Pipeline LLC and Tellurian Services LLC, formerly known as Parallax Services LLC, including claims for tortious interference with CLNGT's collateral rights under the Secured Note and Pledge Agreement, fraudulent transfer, conspiracy/aiding and abetting. Discovery in the Texas State Suit is ongoing. Trial is currently set for September 2018.

We do not expect that the resolution of this litigation will have a material adverse impact on our financial results.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

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 American 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 American, for each quarter during 2017 and 2016.

	High	Low
2017		
First Quarter	$ 50.53	$ 41.46
Second Quarter	51.41	43.79
Third Quarter	49.59	40.36
Fourth Quarter	54.83	43.83
2016		
First Quarter	$ 39.00	$ 22.80
Second Quarter	39.75	31.02
Third Quarter	46.00	35.86
Fourth Quarter	44.45	35.07

As of February 15, 2018, we had 237.7 million shares of common stock outstanding held by approximately 478 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, 2017:

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, 2017	159,051	$46.12	—	—
November 1 - 30, 2017	18,902	$49.28	—	—
December 1 - 31, 2017	3,028	$48.87	—	—

(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.

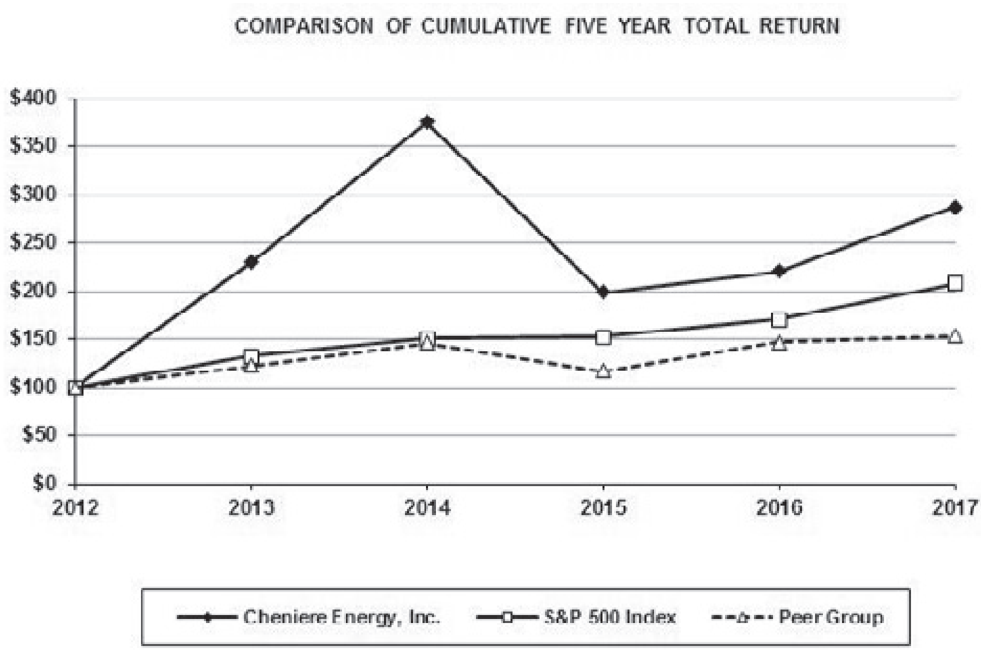
For additional information, see Note 15—Share-Based Compensation of our Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Total Stockholder Return

The following graph compares the five-year total return on our common stock, the S&P 500 Index and a customized peer group of 17 companies that 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) Enterprise Product Partners L.P. (EPD), (11) Enbridge (ENB), (12) TransCanada Corporation (TRP), (13) Spectra Energy Corp (SE), which merged with Enbridge in 2017, (14) Magellan Midstream Partners LP (MMP), (15) MarkWest Energy Partners, L.P. (MWE), which was acquired by MPLX LP in 2015, (16) ONEOK Inc. (OKE) and (17) 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 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, 2012 and that any dividends were fully reinvested.

Company / Index	2012	2013	2014	2015	2016	2017
Cheniere Energy, Inc.	100.00	229.61	374.87	198.35	220.61	286.69
S&P 500 Index	100.00	132.39	150.51	152.59	170.84	208.14
Peer Group	100.00	121.93	146.17	116.54	146.48	153.37



ITEM 6. SELECTED FINANCIAL DATA

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

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Revenues	$ 5,601	$ 1,283	$ 271	$ 268	$ 267
Income (loss) from operations	1,388	(30)	(449)	(272)	(328)
Interest expense, net of capitalized interest	(747)	(488)	(322)	(181)	(178)
Net loss attributable to common stockholders	(393)	(610)	(975)	(548)	(508)
Net loss per share attributable to common stockholders—basic and diluted	$ (1.68)	$ (2.67)	$ (4.30)	$ (2.44)	$ (2.32)
Weighted average number of common shares outstanding—basic and diluted	233.1	228.8	226.9	224.3	218.9

	December 31,				
	2017	2016	2015	2014	2013
Property, plant and equipment, net	$ 23,978	$ 20,635	$ 16,194	$ 9,247	$ 6,454
Total assets	27,906	23,703	18,809	12,433	9,571
Current debt, net	—	247	1,673	—	—
Long-term debt, net	25,336	21,688	14,920	9,665	6,474

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

Introduction

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

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

Overview of Business

Cheniere, a Delaware corporation, is a Houston-based energy company primarily engaged in LNG-related businesses. Our vision is to provide clean, secure and affordable energy to the world, while responsibly delivering a reliable, competitive and integrated source of LNG, in a safe and rewarding work environment. 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 82.7% of Cheniere Holdings, which is a publicly traded limited liability company formed in 2013 that owns a 48.6% limited partner interest in Cheniere Partners. We are currently developing and constructing two natural gas liquefaction and export facilities. The liquefaction of natural gas into LNG allows it to be shipped economically from areas of the world where natural gas is abundant and inexpensive to produce to other areas where natural gas demand and infrastructure exist to economically justify the use of LNG.

The Sabine Pass LNG terminal is located in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. Cheniere Partners is developing, constructing and operating 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 plans to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is under construction and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 4.5 mtpa of LNG and an adjusted nominal production capacity of approximately 4.3 to 4.6 mtpa of LNG. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' wholly owned subsidiary, SPLNG, that include pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. 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 (collectively, 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, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 13.5 mtpa of LNG, three LNG storage tanks with aggregate capacity of approximately 10.1 Bcfe and two marine berths that can each 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 natural gas supply pipeline that will interconnect the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline"). Stage 1 and the Corpus Christi Pipeline are currently under construction, and Train 3 is being commercialized and has all necessary regulatory approvals in place. The construction of the Corpus Christi Pipeline is nearing completion.

Additionally, we are developing an expansion of the Corpus Christi LNG terminal adjacent to the CCL Project (the "Corpus Christi Expansion Project") and recently began the process of amending our regulatory filings with FERC to incorporate a project design change, from two Trains with an expected aggregate nominal production capacity of approximately 9.0 mtpa to up to seven midscale Trains with an expected aggregate nominal production capacity of approximately 9.5 mtpa. We remain focused on expansion of our existing sites by leveraging existing infrastructure. We are also in various stages of developing other projects, including infrastructure projects in support of natural gas supply and LNG demand, which, among other things, will require acceptable commercial and financing arrangements before we make a final investment decision ("FID"). We have made an equity investment of $55 million in Midship Pipeline Company, LLC ("Midship Pipeline"), which is developing a pipeline with expected capacity of up to 1.44 million Dekatherms per day that will connect new gas production in the Anadarko Basin to Gulf Coast markets, including markets serving the SPL Project and the CCL Project.

Overview of Significant Events

Our significant accomplishments since January 1, 2017 and through the filing date of this Form 10-K include the following:

Strategic

- In February 2018, we entered into two SPAs with PetroChina International Company Limited, a subsidiary of China National Petroleum Corporation ("CNPC"), for the sale of approximately 1.2 mtpa of LNG through 2043, with a portion of the supply beginning in 2018 and the balance beginning in 2023.
- In January 2018, we entered into a 15-year SPA with Trafigura Pte Ltd ("Trafigura") for the sale of approximately 1 mtpa of LNG beginning in 2019.
- CCL entered into an amended and restated EPC contract with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for Stage 2 of the CCL Project. CCL also issued limited notice to proceed to Bechtel, and procurement and early site work has commenced.
- We entered into additional term agreements for a portion of the LNG volumes expected to be available to our integrated marketing function. To date, we have contracted for approximately 2 million tonnes of LNG from 2018-2020.
- We completed a land acquisition and acquired rights to obtain additional upland and waterfront land adjacent to the CCL Project aggregating more than 500 acres.
- We made an equity investment in Midship Pipeline through Midship Holdings, LLC ("Midship Holdings"), which is constructing an approximately 230-mile interstate natural gas pipeline with expected capacity of up to 1.44 million Dekatherms per day, to connect new production in the Anadarko Basin to Gulf Coast markets (the "Midship Project"). Additionally, Midship Holdings entered into agreements with investment funds managed by EIG Global Energy Partners ("EIG") under which EIG-managed funds have committed to make an investment of up to $500 million in the Midship Project, subject to the terms and conditions in the applicable agreements.
- In October 2017, we began the process of amending our regulatory filings with FERC related to the Corpus Christi Expansion Project to incorporate a project design change, from two Trains with an expected aggregate nominal production capacity of approximately 9.0 mtpa to up to seven midscale Trains with an expected aggregate nominal production capacity of approximately 9.5 mtpa.

Operational

- To date, approximately 300 cumulative LNG cargoes have been produced, loaded and exported from the SPL Project, with over 200 cargoes in 2017 alone, with deliveries completed to 25 countries and regions worldwide.
- SPL commenced production and shipment of LNG commissioning cargoes from Train 3 of the SPL Project in January 2017 and achieved substantial completion and commenced operating activities in March 2017.
- Commissioning activities for Train 4 of the SPL Project began in March 2017, and substantial completion was achieved in October 2017.

Financial

- In June 2017, the date of first commercial delivery was reached under the 20-year SPA with Korea Gas Corporation relating to Train 3 of the SPL Project.
- In August 2017, the date of first commercial delivery relating to Train 2 of the SPL Project was reached under the respective 20-year SPAs with Gas Natural Fenosa LNG GOM, Limited and BG Gulf Coast LNG, LLC ("BG").
- In February and March 2017, SPL issued aggregate principal amounts of $800 million of 5.00% Senior Secured Notes due 2037 (the "2037 SPL Senior Notes") and $1.35 billion, before discount, of 4.200% Senior Secured Notes due 2028 (the "2028 SPL Senior Notes"), respectively. Net proceeds of the offerings of the 2037 SPL Senior Notes and 2028 SPL Senior Notes were $789 million and $1.33 billion, respectively, after deducting the initial purchasers' commissions (for the 2028 SPL Senior Notes) and estimated fees and expenses. The net proceeds of the 2037 SPL Senior Notes, after provisioning for incremental interest required during construction, were used to prepay the outstanding borrowings under the credit facilities SPL entered into in June 2015 (the "2015 SPL Credit Facilities") and, along with the net proceeds of the 2028 SPL Senior Notes, the remainder is being used to pay a portion of the capital costs in connection with the construction of Trains 1 through 5 of the SPL Project in lieu of the terminated portion of the commitments under the 2015 SPL Credit Facilities.
- In March 2017, we entered into a $750 million revolving credit agreement ("Cheniere Revolving Credit Facility") that may be used to fund the development of the CCL Project and, provided that certain conditions are met, for general corporate purposes.
- In May 2017, CCH issued an aggregate principal amount of $1.5 billion of 5.125% Senior Secured Notes due 2027 (the "2027 CCH Senior Notes"). Net proceeds of the offering of approximately $1.4 billion, after deducting commissions, fees and expenses and after provisioning for incremental interest required under the 2027 CCH Senior Notes during construction, were used to prepay a portion of the outstanding borrowings under its credit facility (the "2015 CCH Credit Facility").
- In September 2017, Cheniere Partners issued an aggregate principal amount of $1.5 billion of 5.250% Senior Notes due 2025 ("the 2025 CQP Senior Notes"). Net proceeds of the offering of approximately $1.5 billion, after deducting commissions, fees and expenses, were used to prepay a portion of the outstanding indebtedness under Cheniere Partner's credit facilities (the "2016 CQP Credit Facilities").
- Fitch Ratings ("Fitch") assigned SPL's senior secured debt an investment grade rating of BBB- in January 2017 and an investment-grade issuer default rating of BBB- in June 2017.
- In May 2017, Moody's Investors Service ("Moody's") upgraded SPL's senior secured debt rating from Ba1 to Baa3, an investment-grade rating.
- In September 2017, Moody's, S&P Global Ratings and Fitch assigned ratings of Ba2 / BB / BB, respectively to the 2025 CQP Senior Notes.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, Cheniere, Cheniere Holdings, Cheniere Partners, SPL 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:

- SPL through project debt and borrowings and operating cash flows;
- Cheniere Partners through operating cash flows from SPLNG, SPL and CTPL and debt or equity offerings;
- Cheniere Holdings through distributions from Cheniere Partners;
- CCH Group through project debt and borrowings 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 our other subsidiaries and distributions from our investments in Cheniere Holdings and Cheniere Partners.

The following table provides a summary of our liquidity position at December 31, 2017 and 2016 (in millions):

	December 31,	
	2017	2016
Cash and cash equivalents	$ 722	$ 876
Restricted cash designated for the following purposes:		
SPL Project	544	358
Cheniere Partners and cash held by guarantor subsidiaries	1,045	247
CCL Project	227	270
Other	75	76
Available commitments under the following credit facilities:		
2015 SPL Credit Facilities	—	1,642
$1.2 billion SPL Working Capital Facility (“SPL Working Capital Facility”)	470	653
2016 CQP Credit Facilities	220	195
2015 CCH Credit Facility	2,087	3,603
$350 million CCH Working Capital Facility (“CCH Working Capital Facility”)	186	350
Cheniere Revolving Credit Facility	750	—

For additional information regarding our debt agreements, see Note 12—Debt of our Notes to Consolidated Financial Statements.

Cheniere

Convertible Notes

In November 2014, we issued an aggregate principal amount of $1.0 billion of 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. 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”). 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. We have the option to satisfy the conversion obligation for the 2021 Cheniere Convertible Unsecured Notes and the 2045 Cheniere Convertible Senior Notes with cash, common stock or a combination thereof.

Cheniere Revolving Credit Facility

In March 2017, we entered into the Cheniere Revolving Credit Facility that may be used to fund, through loans and letters of credit, equity capital contributions to CCH HoldCo II and its subsidiaries for the development of the CCL Project and, provided that certain conditions are met, for general corporate purposes. No advances or letters of credit under the Cheniere Revolving Credit Facility were available until either (1) Cheniere’s unrestricted cash and cash equivalents are less than $500 million or (2) Train 4 of the SPL Project has achieved substantial completion.

The Cheniere Revolving Credit Facility matures on March 2, 2021 and contains representations, warranties and affirmative and negative covenants customary for companies like Cheniere with lenders of the type participating in the Cheniere Revolving Credit Facility that limit our ability to make restricted payments, including distributions, unless certain conditions are satisfied, as well as limitations on indebtedness, guarantees, hedging, liens, investments and affiliate transactions. Under the Cheniere Revolving Credit Facility, we are required to ensure that the sum of our unrestricted cash and the amount of undrawn commitments under the Cheniere Revolving Credit Facility is at least equal to the lesser of (1) 20% of the commitments under the Cheniere Revolving Credit Facility and (2) $100 million.

The Cheniere Revolving Credit Facility is secured by a first priority security interest (subject to permitted liens and other customary exceptions) in substantially all of our assets, including our interests in our direct subsidiaries (excluding CCH HoldCo II).

Cash Receipts from Subsidiaries

As of December 31, 2017, we had an 82.7% direct ownership interest in Cheniere Holdings. We receive dividends on our Cheniere Holdings shares from the distributions that Cheniere Holdings receives from Cheniere Partners. We received $98 million, $15 million and $15 million in dividends on our Cheniere Holdings common shares during each of the years ended December 31, 2017, 2016 and 2015, respectively.

Our ownership interest in the Sabine Pass LNG terminal is held through Cheniere Partners. As of December 31, 2017, we owned 82.7% of Cheniere Holdings, which owned a 48.6% interest in Cheniere Partners in the form of 104.5 million common units and 135.4 million subordinated units. We also own 100% of the general partner interest and the incentive distribution rights in Cheniere Partners. We receive quarterly equity distributions from Cheniere Partners related to our 2% general partner interest.

We also receive fees for providing management services to Cheniere Holdings, Cheniere Partners, SPLNG, SPL and CTPL. We received $106 million, $119 million and $94 million in total service fees from Cheniere Holdings, Cheniere Partners, SPLNG, SPL and CTPL during the years ended December 31, 2017, 2016 and 2015, respectively.

Cheniere Partners' Class B Units

On August 2, 2017, Cheniere Partners' Class B units ("Class B units") mandatorily converted into common units in accordance with the terms of Cheniere Partners' partnership agreement. Upon conversion of the Class B units, Cheniere Holdings, Blackstone CQP Holdco LP ("Blackstone CQP Holdco") and the public owned a 48.6%, 40.3% and 9.1% interest in Cheniere Partners, respectively. Cheniere Holdings' ownership percentage includes its subordinated units and Blackstone CQP Holdco's ownership percentage excludes any common units that may be deemed to be beneficially owned by The Blackstone Group, L.P., an affiliate of Blackstone CQP Holdco.

Cheniere Partners' Class B units were 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 were 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 increased at a compounded rate of 3.5% per quarter, subject to an additional upward adjustment for certain equity and debt financings.

The Class B units were issued at a discount to the market price of Cheniere Partners' common units into which they were convertible. This discount, totaling $2,130 million, represented a beneficial conversion feature. The beneficial conversion feature was similar to a dividend that was distributed with respect to any Class B unit from its issuance date through its conversion date, which resulted in an increase in Class B unitholders' equity and a decrease in common and subordinated unitholders' equity, including our equity interest in Cheniere Partners. Cheniere Partners amortized the beneficial conversion feature through the mandatory conversion date as a non-cash adjustment. Deemed dividends represented by the amortization of the beneficial conversion feature allocated to the Class B units held by Blackstone CQP Holdco were included in net income (loss) attributable to non-controlling interest and resulted in a reduction of income available to common stockholders. The impact to net income (loss) attributable to non-controlling interest due to the amortization of the beneficial conversion feature was $748 million, $34 million and zero during the years ended December 31, 2017, 2016 and 2015, respectively.

Cheniere Partners

2025 CQP Senior Notes

In September 2017, Cheniere Partners issued an aggregate principal amount of $1.5 billion of the 2025 CQP Senior Notes, which are jointly and severally guaranteed by each of Cheniere Partners' subsidiaries other than SPL and, subject to certain conditions governing the release of its guarantee, Sabine Pass LNG-LP, LLC (collectively, the "CQP Guarantors"). Net proceeds of the offering of approximately $1.5 billion, after deducting the initial purchasers' commissions and estimated fees and expenses, were used to prepay a portion of the outstanding indebtedness under the 2016 CQP Credit Facilities.

The 2025 CQP Senior Notes are governed by an indenture (the "CQP Indenture"), which contains customary terms and events of default and certain covenants that, among other things, limit the ability of Cheniere Partners and the CQP Guarantors to incur liens and sell assets, enter into transactions with affiliates, enter into sale-leaseback transactions and consolidate, merge or sell, lease or otherwise dispose of all or substantially all of the applicable entity's properties or assets.

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

The 2025 CQP Senior Notes are Cheniere Partners' senior obligations, ranking equally in right of payment with Cheniere Partners' other existing and future unsubordinated debt and senior to any of its future subordinated debt. The 2025 CQP Senior Notes will be secured alongside the 2016 CQP Credit Facilities on a first-priority basis (subject to permitted encumbrances) with liens on (1) substantially all the existing and future tangible and intangible assets and rights of Cheniere Partners and the CQP Guarantors and equity interests in the CQP Guarantors (except, in each case, for certain excluded properties set forth in the 2016 CQP Credit Facilities) and (2) substantially all of the real property of SPLNG (except for excluded properties referenced in the 2016 CQP Credit Facilities). The liens securing the 2025 CQP Senior Notes would be released if (1) the aggregate principal amount of all indebtedness then outstanding under the term loans under the 2016 CQP Credit Facilities secured by such liens does not exceed $1.0 billion and (2) the aggregate amount of Cheniere Partners' secured indebtedness and the secured indebtedness of the CQP Guarantors (other than the 2025 CQP Senior Notes or any other series of notes issued under the CQP Indenture) outstanding at any one time, together with all Attributable Indebtedness (as defined in the CQP Indenture) from sale-leaseback transactions (subject to certain exceptions), does not exceed the greater of (1) $1.5 billion and (2) 10% of net tangible assets. Upon the release of the liens securing the 2025 CQP Senior Notes, the limitation on liens covenant under the CQP Indenture will continue to govern the incurrence of liens by Cheniere Partners and the CQP Guarantors.

2016 CQP Credit Facilities

In February 2016, Cheniere Partners entered into the 2016 CQP Credit Facilities. The 2016 CQP Credit Facilities consist of: (1) a $450 million CTPL tranche term loan that was used to prepay the $400 million term loan facility (the "CTPL Term Loan") in February 2016, (2) an approximately $2.1 billion SPLNG tranche term loan that was used to repay and redeem the approximately $2.1 billion of the senior notes previously issued by SPLNG (the "SPLNG Senior Notes") in November 2016, (3) a $125 million facility that may be used to satisfy a six-month debt service reserve requirement and (4) a $115 million revolving credit facility that may be used for general business purposes. In September 2017, Cheniere Partners issued the 2025 CQP Senior Notes and the net proceeds were used to prepay $1.5 billion of the outstanding indebtedness under the 2016 CQP Credit Facilities. As of December 31, 2017 and 2016, Cheniere Partners had $220 million and $195 million of available commitments, $20 million and $45 million aggregate amount of issued letters of credit and $1.1 billion and $2.6 billion of outstanding borrowings under the 2016 CQP Credit Facilities, respectively.

The 2016 CQP Credit Facilities mature on February 25, 2020, with principal payments due quarterly commencing on March 31, 2019. The outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest hedging and interest rate breakage costs. The 2016 CQP Credit Facilities contain conditions precedent for extensions of credit, as well as customary affirmative and negative covenants and limit Cheniere Partners' ability to make restricted payments, including distributions, to once per fiscal quarter as long as certain conditions are satisfied. Under the 2016 CQP Credit Facilities, Cheniere Partners is required to hedge not less than 50% of the variable interest rate exposure on its projected aggregate outstanding balance, maintain a minimum debt service coverage ratio of at least 1.15x at the end of each fiscal quarter beginning March 31, 2019 and have a projected debt service coverage ratio of 1.55x in order to incur additional indebtedness to refinance a portion of the existing obligations.

The 2016 CQP Credit Facilities are unconditionally guaranteed by each subsidiary of Cheniere Partners other than (1) SPL and (2) certain subsidiaries of Cheniere Partners owning other development projects, as well as certain other specified subsidiaries and members of the foregoing entities.

Sabine Pass LNG Terminal

Liquefaction Facilities

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

	SPL Train 5
Overall project completion percentage	83.1%
Completion percentage of:	
Engineering	100%
Procurement	100%
Subcontract work	63.4%
Construction	62.1%
Date of expected substantial completion	1H 2019

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

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

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

In January 2018, the DOE issued orders authorizing SPL to export domestically produced LNG by vessel from the Sabine Pass LNG terminal to FTA countries and non-FTA countries over a two-year period commencing January 2018, in an aggregate amount up to the equivalent of 600 Bcf of natural gas (however, exports under this order, when combined with exports under the orders above, may not exceed 1,511 Bcf/yr).

Customers

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

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $1.6 billion for Trains 1 through 3, increasing to $2.3 billion upon the date of first commercial delivery of Train 4 and to $2.9 billion upon the date of first commercial delivery of Train 5, with the applicable fixed fees starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

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

Natural Gas Transportation, Storage and Supply

To ensure SPL is able to transport adequate natural gas feedstock to the Sabine Pass LNG terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation capacity with CTPL and third-party pipeline companies. SPL has entered into firm storage services agreements with third parties to assist in managing volatility in natural gas needs for the SPL Project. SPL has also entered into enabling agreements and long-term natural gas supply contracts with third parties in order to secure natural gas feedstock for the SPL Project. As of December 31, 2017, SPL has secured up to approximately 2,214 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts.

Construction

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

The total contract price of the EPC contract for Train 5 of the SPL Project is approximately $3.1 billion reflecting amounts incurred under change orders through December 31, 2017. Total expected capital costs for Trains 1 through 5 are estimated to be between $12.5 billion and $13.5 billion before financing costs and between $17.5 billion and $18.5 billion after financing costs including, in each case, estimated owner's costs and contingencies.

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 Train 6.

Regasification Facilities

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

The remaining approximately 2.0 Bcf/d of capacity has been reserved under a TUA by SPL. SPL is obligated to make monthly capacity payments to SPLNG aggregating approximately $250 million annually, continuing until at least 20 years after SPL delivers its first commercial cargo at the SPL Project. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 3, SPL gained access to a portion of Total's capacity and other services provided under Total's TUA with SPLNG. This agreement provides SPL with additional berthing and storage capacity at the Sabine Pass LNG terminal that may be used to provide increased flexibility in managing LNG cargo loading and unloading activity, permit

SPL to more flexibly manage its LNG storage capacity and accommodate the development of Trains 5 and 6. Notwithstanding any arrangements between Total and SPL, payments required to be made by Total to SPLNG will continue to be made by Total to SPLNG in accordance with its TUA. During the year ended December 31, 2017, SPL recorded $23 million as operating and maintenance expense under this partial TUA assignment agreement.

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

Capital Resources

We currently expect that SPL's capital resources requirements with respect to Trains 1 through 5 of the SPL Project will be financed through project debt and borrowings and cash flows under the SPAs. We believe that with the net proceeds of borrowings, available commitments under the SPL Working Capital Facility and cash flows from operations, we will have adequate financial resources available to complete Train 5 of the SPL Project and to meet our currently anticipated capital, operating and debt service requirements. SPL began generating cash flows from operations from the SPL Project in May 2016, when Train 1 achieved substantial completion and initiated operating activities. Trains 2, 3 and 4 subsequently achieved substantial completion in September 2016, March 2017 and October 2017, respectively. We realized offsets to LNG terminal costs of $320 million and $214 million in the years ended December 31, 2017 and 2016, respectively, that were related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations, during the testing phase for the construction of those Trains of the SPL Project. Additionally, SPLNG generates cash flows from the TUAs, as discussed above.

The following table provides a summary of our capital resources from borrowings and available commitments for the Sabine Pass LNG Terminal, excluding equity contributions to our subsidiaries and cash flows from operations (as described in *Sources and Uses of Cash*), at December 31, 2017 and 2016 (in millions):

	December 31,	
	2017	2016
Senior notes (1)	$ 15,151	$ 11,500
Credit facilities outstanding balance (2)	1,090	3,097
Letters of credit issued (3)	730	324
Available commitments under credit facilities (3)	470	2,295
Total capital resources from borrowings and available commitments (4)	$ 17,441	$ 17,216

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

(2) Includes 2015 SPL Credit Facilities, SPL Working Capital Facility and CTPL and SPLNG tranche term loans outstanding under the 2016 CQP Credit Facilities.

(3) Includes 2015 SPL Credit Facilities and SPL Working Capital Facility. Does not include the letters of credit issued or available commitments under the 2016 CQP Credit Facilities, which are not specifically for the Sabine Pass LNG Terminal.

(4) Does not include Cheniere's additional borrowings from the 2021 Cheniere Convertible Unsecured Notes and the 2045 Cheniere Convertible Senior Notes, which may be used for the Sabine Pass LNG Terminal.

For additional information regarding our debt agreements related to the Sabine Pass LNG Terminal, see Note 12—Debt of our Notes to Consolidated Financial Statements.

SPL Senior Notes

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

At any time prior to three months before the respective dates of maturity for each series of the SPL Senior Notes (except for the 2026 SPL Senior Notes, 2027 SPL Senior Notes, 2028 SPL Senior Notes and 2037 SPL Senior Notes, in which case the time period is six months before the respective dates of maturity), SPL may redeem all or part of such series of the SPL Senior

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

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

2015 SPL Credit Facilities

In June 2015, SPL entered into the 2015 SPL Credit Facilities with commitments aggregating $4.6 billion to fund a portion of the costs of developing, constructing and placing into operation Trains 1 through 5 of the SPL Project. In February 2017, SPL issued the 2037 SPL Senior Notes and a portion of the net proceeds was used to prepay the then outstanding borrowings of $369 million under the 2015 SPL Credit Facilities. In March 2017, SPL issued the 2028 SPL Senior Notes and SPL terminated the remaining available balance of $1.6 billion under the 2015 SPL Credit Facilities.

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility, which is intended to be used for loans to SPL ("SPL Working Capital Loans"), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL ("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, 2017 and 2016, SPL had $470 million and $653 million of available commitments, $730 million and $324 million aggregate amount of issued letters of credit and zero and $224 million of loans outstanding under the SPL Working Capital Facility, respectively.

The SPL Working Capital Facility matures on December 31, 2020, and the outstanding balance may be repaid, in whole or in part, at any time without premium or penalty upon three business days' notice. Loans deemed made in connection with a draw upon a letter of credit have a term of up to one year. SPL 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 SPL Swing Line Loan is made and (3) the first borrowing date for a SPL Working Capital Loan or SPL Swing Line Loan occurring at least three business days following the date the SPL Swing Line Loan is made. SPL is required to reduce the aggregate outstanding principal amount of all SPL 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.

Corpus Christi LNG Terminal

Liquefaction Facilities

The CCL Project is being developed and constructed at the Corpus Christi LNG terminal. In December 2014, we received authorization from the FERC to site, construct and operate Stages 1 and 2 of the CCL Project. The following table summarizes the overall project status of Stage 1 of the CCL Project as of December 31, 2017:

	CCL Stage 1	
Overall project completion percentage		81.8%
Completion percentage of:		
Engineering		100%
Procurement		100%
Subcontract work		62.2%
Construction		59.2%
Expected date of substantial completion	Train 1	1H 2019
	Train 2	2H 2019

Train 3 is being commercialized and has all necessary regulatory approvals in place. Separate from the CCH Group, we are also developing the Corpus Christi Expansion Project, adjacent to the CCL Project. We commenced the regulatory approval process in June 2015 and recently began the process of amending our regulatory filings with FERC to incorporate a project design change, from two Trains with an expected aggregate nominal production capacity of approximately 9.0 mtpa to up to seven midscale Trains with an expected aggregate nominal production capacity of approximately 9.5 mtpa.

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

- CCL Project—FTA countries for a 25-year term and to non-FTA countries for a 20-year term up to a combined total of the equivalent of 767 Bcf/yr (approximately 15 mtpa) of natural gas.
- Corpus Christi Expansion Project—FTA countries for a 20-year term in an amount equivalent to 514 Bcf/yr (approximately 10 mtpa) of natural gas. The application for authorization to export that same 514 Bcf/yr of domestically produced LNG by vessel to non-FTA countries is currently pending before the DOE. We intend to amend our DOE applications consistent with the design change in our amended FERC filings.

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.

Customers

CCL entered into eight fixed-price SPAs with terms of at least 20 years (plus extension rights) with seven third parties to make available an aggregate amount of LNG that is between approximately 85% to 95% of the expected aggregate adjusted nominal production capacity of Trains 1 and 2. Under these eight SPAs, the customers will purchase LNG from CCL for a price consisting of a fixed fee per MMBtu of LNG (a portion of which is subject to annual adjustment for inflation) plus a variable fee per MMBtu of LNG equal to approximately 115% of Henry Hub. In certain circumstances, the customers may elect to cancel or suspend deliveries of LNG cargoes, in which case the customers would still be required to pay the fixed fee with respect to the contracted volumes that are not delivered as a result of such cancellation or suspension. We refer to the fee component that is applicable regardless of a cancellation or suspension of LNG cargo deliveries under the SPAs as the fixed fee component of the price under our SPAs. We refer to the fee component that is applicable only in connection with LNG cargo deliveries as the variable fee component of the price under our SPAs. The variable fee under CCL's SPAs entered into in connection with the development of Stage 1 of the CCL Project was sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation related to, and operating and maintenance costs to produce, the LNG to be sold under each such SPA. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery for Train 1 or Train 2, as specified in each SPA.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $550 million for Train 1, increasing to $1.4 billion upon the date of first commercial delivery of Train 2 of the CCL Project, with the applicable fixed fees generally starting from the date of first commercial delivery from the applicable Train, as specified in each SPA.

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

Natural Gas Transportation, Storage and Supply

To ensure CCL is able to transport adequate natural gas feedstock to the Corpus Christi LNG terminal, it has entered into transportation precedent agreements to secure firm pipeline transportation capacity with CCP and certain third-party pipeline companies. CCL has entered into a firm storage services agreement with a third party to assist in managing volatility in natural gas needs for the CCL Project. CCL has also entered into enabling agreements and long-term natural gas supply contracts with third parties, and will continue to enter into such agreements, in order to secure natural gas feedstock for the CCL Project. As of December 31, 2017, CCL has secured up to approximately 2,024 TBtu of natural gas feedstock through long-term natural gas supply contracts, a portion of which is subject to the achievement of certain project milestones and other conditions precedent.

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 price of the EPC contract for Stage 1, which does not include the Corpus Christi Pipeline, is approximately $7.8 billion, reflecting amounts incurred under change orders through December 31, 2017. Total expected capital costs for Stage 1 and the Corpus Christi Pipeline 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 and total expected capital costs for the Corpus Christi Pipeline of between $350 million and $400 million. The total contract price of the EPC contract for Stage 2, which was amended and restated in December 2017, is approximately $2.4 billion.

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, 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. The construction of the Corpus Christi Pipeline commenced in January 2017 and is nearing completion.

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, operating cash flows from CCL and CCP and equity contributions to our subsidiaries. The following table provides a summary of our capital resources from borrowings and available commitments for the CCL Project, excluding equity contributions to our subsidiaries, at December 31, 2017 and 2016 (in millions):

	December 31,	
	2017	2016
Senior notes (1)	$ 4,250	$ 2,750
11% Convertible Senior Secured Notes due 2025	1,305	1,171
Credit facilities outstanding balance (2)	2,485	2,381
Letters of credit issued (2)	164	—
Available commitments under credit facilities (2)	2,273	3,953
Total capital resources from borrowings and available commitments (3)	$ 10,477	$ 10,255

(1) Includes CCH's 7.000% Senior Secured Notes due 2024 (the "2024 CCH Senior Notes"), 5.875% Senior Secured Notes due 2025 (the "2025 CCH Senior Notes") and 2027 CCH Senior Notes (collectively, the "CCH Senior Notes").

(2) Includes 2015 CCH Credit Facility and CCH Working Capital Facility.

(3) Does not include Cheniere's additional borrowings from 2021 Cheniere Convertible Unsecured Notes, 2045 Cheniere Convertible Senior Notes and Cheniere Revolving Credit Facility, which may be used for the CCL Project.

For additional information regarding our debt agreements related to the CCL Project, see Note 12—Debt of our Notes to Consolidated Financial Statements.

2025 CCH HoldCo II Convertible Senior Notes

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") on a private placement basis. The 2025 CCH HoldCo II Convertible Senior Notes are convertible at the option of CCH HoldCo II or the holders, provided that various conditions are met. 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 service coverage ratio of 1.20:1.00 are achieved.

CCH Senior Notes

In May 2017, CCH issued an aggregate principal amount of $1.5 billion of the 2027 CCH Senior Notes, in addition to the existing 2024 CCH Senior Notes and 2025 CCH Senior Notes. The CCH Senior Notes are jointly and severally guaranteed by its subsidiaries, CCL, CCP and Corpus Christi Pipeline GP, LLC (the "CCH Guarantors").

The indenture governing the CCH Senior Notes (the "CCH Indenture") contains customary terms and events of default and certain covenants that, among other things, limit CCH's ability and the ability of CCH's restricted subsidiaries to: incur additional indebtedness or issue preferred stock; make certain investments or pay dividends or distributions on membership interests or subordinated indebtedness or purchase, redeem or retire membership interests; sell or transfer assets, including membership or partnership interests of CCH's restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries to CCH or any of CCH's restricted subsidiaries; incur liens; enter into transactions with affiliates; dissolve, liquidate, consolidate, merge, sell or lease all or substantially all of the properties or assets of CCH and its restricted subsidiaries taken as a whole; or permit any CCH Guarantor to dissolve, liquidate, consolidate, merge, sell or lease all or substantially all of its properties and assets.

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

2015 CCH Credit Facility

In May 2015, CCH entered into the 2015 CCH Credit Facility. 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. As of December 31, 2017 and 2016, CCH had $2.1 billion and $3.6 billion of available commitments and $2.5 billion and $2.4 billion of outstanding borrowings under the 2015 CCH Credit Facility, respectively.

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.

Under 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.

CCH Working Capital Facility

In December 2016, CCH entered into the $350 million CCH Working Capital Facility, which is intended to be used for loans to CCH ("CCH Working Capital Loans"), the issuance of letters of credit on behalf of CCH, as well as for swing line loans to CCH ("CCH Swing Line Loans") for certain working capital requirements related to developing and placing into operation the CCL Project. Loans under the CCH Working Capital Facility are guaranteed by the CCH Guarantors. CCH may, from time to time, request increases in the commitments under the CCH Working Capital Facility of up to the maximum allowed under the Common Terms Agreement that was entered into concurrently with the 2015 CCH Credit Facility. CCH did not have any amounts outstanding under the CCH Working Capital Facility as of both December 31, 2017 and 2016, and CCH had $164 million and zero aggregate amount of issued letters of credit as of December 31, 2017 and 2016, respectively.

The CCH Working Capital Facility matures on December 14, 2021, and CCH may prepay the CCH Working Capital Loans, CCH Swing Line Loans and loans made in connection with a draw upon any letter of credit ("CCH LC Loans") at any time without premium or penalty upon three business days' notice and may re-borrow at any time. CCH LC Loans have a term of up to one year. CCH Swing Line Loans terminate upon the earliest of (1) the maturity date or earlier termination of the CCH Working Capital Facility, (2) the date that is 15 days after such CCH Swing Line Loan is made and (3) the first borrowing date for a CCH Working Capital Loan or CCH Swing Line Loan occurring at least four business days following the date the CCH Swing Line Loan is made. CCH is required to reduce the aggregate outstanding principal amount of all CCH Working Capital Loans to zero for a period of five consecutive business days at least once each year.

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

Restrictive Debt Covenants

As of December 31, 2017, each of our issuers was in compliance with all covenants related to their respective debt agreements.

Marketing

We market and sell LNG produced by the SPL Project and the CCL Project that is not required for other customers through our integrated marketing function. We are developing a portfolio of long-, medium- and short-term SPAs to transport and unload commercial LNG cargoes to locations worldwide, which is primarily sourced by LNG produced by the SPL Project and the CCL Project but supplemented by volume procured from other locations worldwide, as needed. As of December 31, 2017, we have sold or have options to sell approximately 358 TBtu of LNG to be delivered to customers between 2018 and 2023. The cargoes have been sold either on a Free on Board basis (delivered to the customer at the Sabine Pass LNG terminal) or a Delivered at Terminal ("DAT") basis (delivered to the customer at their LNG receiving terminal). We have chartered LNG vessels to be utilized in DAT transactions. In addition, we have entered into a long-term agreement to sell LNG cargoes on a DAT basis that is conditioned upon the buyer achieving certain milestones.

Cheniere Marketing entered into uncommitted trade finance facilities for up to $450 million primarily to be used for the purchase and sale of LNG for ultimate resale in the course of its operations. The finance facilities are intended to be used for advances, guarantees or the issuance of letters of credit or standby letters of credit on behalf of Cheniere Marketing. As of December 31, 2017 and 2016, Cheniere Marketing had zero and $23 million, respectively, in loans outstanding and $2 million and $12 million, respectively, in standby letters of credit and guarantees outstanding under the finance facilities. Cheniere Marketing pays interest or fees on utilized commitments.

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, including infrastructure projects in support of natural gas supply and LNG demand, which, among other things, will require acceptable commercial and financing arrangements before we make an FID. We have made an equity investment of $55 million in Midship Pipeline, which is developing a pipeline with expected capacity of up to 1.44 million Dekatherms per day that will connect new gas production in the Anadarko Basin to Gulf Coast markets, including markets serving the SPL Project and the CCL Project.

Tax-Related Matters

Effective January 1, 2017, we adopted ASU 2016-09 which requires excess tax benefits or deficiencies for share-based payments to be recognized as income tax expense or benefit in the period shares vest rather than within equity. The adoption of ASU 2016-09 will result in future volatility of our income tax expense (as the future tax effects of share-based awards will be dependent on the price of our common stock at the time of settlement). Excess tax benefits reduced our effective tax rate by 6% for the period ending December 31, 2017.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation (Tax Cuts and Jobs Act), which reduced the top U.S. corporate income tax rate from 35% to 21%. The reduction in the corporate tax rate will likely reduce our effective tax rate in future periods. As a result of the legislation, we remeasured our December 31, 2017 U.S. deferred tax assets and liabilities. The result of the remeasurement was a $404 million reduction to our U.S. net deferred tax assets and represents a 71.4% increase to our effective tax rate. A corresponding change, reducing the effective tax rate, was recorded to the valuation allowance, and therefore there was no impact to current period income tax expense.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash, cash equivalents and restricted cash for the years ended December 31, 2017, 2016 and 2015 (in millions). The table presents capital expenditures on a cash basis; therefore, these amounts differ from the amounts of capital expenditures, including accruals, which are referred to elsewhere in this report. Additional discussion of these items follows the table.

	Year Ended December 31,		
	2017	**2016**	**2015**
Operating cash flows	$ 1,231	$ (404)	$ (483)
Investing cash flows	(3,381)	(4,413)	(6,984)
Financing cash flows	2,936	4,908	6,423
Net increase (decrease) in cash, cash equivalents and restricted cash	786	91	(1,044)
Cash, cash equivalents and restricted cash—beginning of period	1,827	1,736	2,780
Cash, cash equivalents and restricted cash—end of period	$ 2,613	$ 1,827	$ 1,736

Operating Cash Flows

Our operating cash flows during the years ended December 31, 2017, 2016 and 2015 were an inflow of $1.2 billion, an outflow of $404 million and an outflow of $483 million, respectively. The $1.6 billion increase in operating cash inflows in 2017 compared to 2016 was primarily related to increased cash receipts from the sale of LNG cargoes, partially offset by increased operating costs and expenses as a result of the of additional Trains that were operating at the SPL Project in 2017. During the year ended December 31, 2017, Trains 1 and 2 were operating for twelve months and Train 3 and Train 4 were operating for nine and three months, respectively, whereas in 2016, Train 1 was operating for seven months and Train 2 was operating for less than four months. The decrease in operating cash outflows in 2016 compared to 2015 was primarily related to increased cash receipts from the sale of LNG cargoes, partially offset by increased operating costs and expenses as a result of the commencement of operations of Trains 1 and 2 of the SPL Project and increased cash payout for phantom unit awards.

Investing Cash Flows

Investing cash outflows during the years ended December 31, 2017 and 2016 were $3.4 billion, $4.4 billion and $7.0 billion, respectively, and were primarily used to fund the construction costs for Trains 1 through 5 of the SPL Project and Trains 1 and 2 of the CCL Project. These costs are capitalized as construction-in-process until achievement of substantial completion. In addition to cash outflows for construction costs for the SPL Project and the CCL Project, during the year ended December 31, 2017, we invested $41 million in our equity method investment Midship Holdings and made payments of $19 million primarily for infrastructure to support the CCL Project and other capital projects. Partially offsetting these cash outflows was a $36 million receipt during the year ended December 31, 2017 from the return of collateral payments previously paid for the CCL Project. During the years ended December 31, 2016 and 2015, we used $57 million and 131 million, respectively, primarily for collateral payments for the CCL Project, payments to municipal water districts for water system enhancements that will increase potable water supply to our export terminals, payments made for capital assets purchased pursuant to information technology services agreements and for investments made in unconsolidated entities.

Financing Cash Flows

Financing cash inflows during the year ended December 31, 2017 were $2.9 billion, primarily as a result of:

- issuances of aggregate principal amounts of $800 million of the 2037 SPL Senior Notes and $1.35 billion of the 2028 SPL Senior Notes;
- $55 million of borrowings and $369 million of repayments made under the 2015 SPL Credit Facilities;
- $110 million of borrowings and $334 million of repayments made under the SPL Working Capital Facility;
- $1.5 billion of borrowings under the 2015 CCH Credit Facility;
- issuance of aggregate principal amount of $1.5 billion of the 2027 CCH Senior Notes, which was used to prepay $1.4 billion of outstanding borrowings under the 2015 CCH Credit Facility;
- $24 million of borrowings and $24 million of repayments made under the CCH Working Capital Facility;
- issuance of an aggregate principal amount of $1.5 billion of the 2025 CQP Senior Notes, which was used to prepay $1.5 billion of the outstanding borrowings under the 2016 CQP Credit Facilities;
- $24 million in net repayments made under the Cheniere Marketing trade finance facilities;
- $89 million of debt issuance and deferred financing costs related to up-front fees paid upon the closing of these transactions;
- $185 million of distributions and dividends to non-controlling interest by Cheniere Partners and Cheniere Holdings; and
- $12 million paid for tax withholdings for share-based compensation.

Financing cash inflows during the year ended December 31, 2016 were $4.9 billion, primarily as a result of:

- $2.6 billion of borrowings under the 2016 CQP Credit Facilities used to prepay the $400 million CTPL Term Loan and redeem and repay $2.1 billion of the SPLNG Senior Notes;
- $2.0 billion of borrowings under the 2015 SPL Credit Facilities;
- issuance of an aggregate principal amount of $1.5 billion of the 2026 SPL Senior Notes in June 2016, which was used to prepay $1.3 billion of the outstanding borrowings under the 2015 SPL Credit Facilities;
- issuance of an aggregate principal amount of $1.5 billion of the 2027 SPL Senior Notes in September 2016, which was used to prepay $1.2 billion of the outstanding borrowings under the 2015 SPL Credit Facilities and pay a portion of the capital costs in connection with the construction of Trains 1 through 5 of the SPL Project;
- $474 million of borrowings and $265 million of repayments made under the SPL Working Capital Facility;
- $2.1 billion of borrowings under the 2015 CCH Credit Facility;
- issuances of aggregate principal amounts of $1.25 billion of the 2024 CCH Senior Notes and $1.5 billion of the 2025 CCH Senior Notes in December 2016, which were used to prepay $2.4 billion of the outstanding borrowings under the 2015 CCH Credit Facility;
- $24 million in net borrowings under the Cheniere Marketing trade finance facilities;

- $172 million of debt issuance costs related to up-front fees paid upon the closing of these transactions;
- $14 million of debt extinguishment costs paid in connection with redemptions and prepayments of outstanding borrowings;
- $80 million of distributions and dividends to non-controlling interest by Cheniere Partners and Cheniere Holdings; and
- $20 million paid for tax withholdings for share-based compensation.

Financing cash inflows during the year ended December 31, 2015 were $6.4 billion, primarily as a result of:

- $860 million of borrowings under the 2015 SPL Credit Facilities;
- issuance of an aggregate principal amount of $2.0 billion of the 2025 SPL Senior Notes in March 2015;
- $2.7 billion of borrowings under the 2015 CCH Credit Facility;
- issuance of an aggregate principal amount of $625 million of the 2045 Cheniere Convertible Senior Notes in March 2015, with an original issue discount of 20% for net proceeds of $496 million;
- issuance of an aggregate principal amount of $1.0 billion of the 2025 CCH HoldCo II Convertible Senior Notes in May 2015;
- $513 million of debt issuance and deferred financing costs related to up-front fees paid upon the closing of these transactions;
- $80 million of distributions and dividends to non-controlling interest by Cheniere Partners and Cheniere Holdings; and
- $61 million paid for tax withholdings for share-based compensation.

Contractual Obligations

We are committed to make cash payments in the future pursuant to certain of our contracts. The following table summarizes certain contractual obligations in place as of December 31, 2017 (in millions):

	Payments Due By Period (1)				
	Total	2018	2019 - 2020	2021 - 2022	Thereafter
Debt (2)	$ 26,546	$ —	$ 1,090	$ 6,853	$ 18,603
Interest payments (2)	10,191	1,292	2,774	2,465	3,660
Construction obligations (3)	1,574	1,124	450	—	—
Purchase obligations (4)	7,772	2,360	2,926	1,317	1,169
Capital lease obligations (5)	200	5	20	20	155
Operating lease obligations (6)	756	140	246	134	236
Other obligations (7)	121	3	37	54	27
Total	$ 47,160	$ 4,924	$ 7,543	$ 10,843	$ 23,850

(1) Agreements in force as of December 31, 2017 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2017.

(2) Based on the total debt balance, scheduled maturities and interest rates in effect at December 31, 2017. See Note 12—Debt of our Notes to Consolidated Financial Statements.

(3) Construction obligations primarily relate to the EPC contracts for the SPL Project and the CCL Project. The estimated remaining cost pursuant to our EPC contracts as of December 31, 2017 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 19—Commitments and Contingencies of our Notes to Consolidated Financial Statements.

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

(5) Capital lease obligations consist of tug leases related to the CCL Project, as further discussed in Note 18—Leases of our Notes to Consolidated Financial Statements.

(6) Operating lease obligations primarily relate to LNG vessel time charters, 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 18—Leases of our Notes to Consolidated Financial Statements.

(7) Other obligations primarily relate to agreements with certain local taxing jurisdictions, and are based on estimated tax obligations as of December 31, 2017.

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, 2017, we had $914 million aggregate amount of issued letters of credit under our credit facilities and $1.9 billion 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

The following table summarizes the volumes of operational and commissioning LNG cargoes that were loaded from the SPL Project and recognized on our Consolidated Financial Statements during the year ended December 31, 2017:

	Year Ended December 31, 2017	
(in TBtu)	Operational	Commissioning
Volumes loaded during the current period	684	51
Volumes loaded during the prior period but recognized during the current period	19	—
Less: volumes loaded during the current period and in transit at the end of the period	(43)	—
Total volumes recognized in the current period	660	51

Our consolidated net loss attributable to common stockholders was $393 million, or $1.68 per share (basic and diluted), in the year ended December 31, 2017, compared to a net loss attributable to common stockholders of $610 million, or $2.67 per share (basic and diluted), in the year ended December 31, 2016. This $217 million decrease in net loss in 2017 was primarily a result of increased income from operations, which were partially offset by increased allocation of net income to non-controlling interest and increased interest expense, net of amounts capitalized.

In August 2017, Hurricane Harvey struck the Texas and Louisiana coasts, and the Sabine Pass LNG terminal experienced a temporary suspension in construction and LNG loading operations. Construction on the Corpus Christi LNG terminal was also suspended. Neither terminal sustained significant damage, and the effects of Hurricane Harvey did not have a material impact on our Consolidated Financial Statements.

Our consolidated net loss attributable to common stockholders was $975 million, or $4.30 per share (basic and diluted), in the year ended December 31, 2015. This $365 million decrease in net loss in 2016 compared to 2015 was primarily a result of decreased loss from operations and decreased derivative loss, net, which were partially offset by increased interest expense, net of amounts capitalized.

Revenues

	Year Ended December 31,				
(in millions)	2017	2016	Change	2015	Change
LNG revenues	$ 5,317	$ 1,016	$ 4,301	$ —	$ 1,016
Regasification revenues	260	259	1	259	—
Other revenues	21	8	13	12	(4)
Other—related party	3	—	3	—	—
Total revenues	$ 5,601	$ 1,283	$ 4,318	$ 271	$ 1,012

2017 vs. 2016 and 2016 vs. 2015

We began recognizing LNG revenues from the SPL Project following the substantial completion and the commencement of operating activities of Train 1 in May 2016. Trains 2, 3 and 4 subsequently achieved substantial completion in September 2016, March 2017 and October 2017, respectively. The increase in revenues for each of the years was attributable to both the increased volume of LNG sold that was recognized as revenues following the achievement of substantial completion of these Trains, as well as increased revenues per MMBtu. We expect our LNG revenues to increase in the future upon Train 5 becoming operational.

Prior to substantial completion of a Train, amounts received from the sale of commissioning cargoes from that Train are offset against LNG terminal construction-in-process because these amounts are earned or loaded during the testing phase for the construction of that Train. We realized offsets to LNG terminal costs of $320 million corresponding to 51 TBtu of LNG and $214 million corresponding to 45 TBtu of LNG in the years ended December 31, 2017 and 2016, respectively, that were related to the sale of commissioning cargoes.

The following table presents the components of LNG revenues (in millions) and the corresponding LNG volumes sold (in TBtu).

	Year Ended December 31,	
	2017	2016
LNG revenues *(in millions)*:		
LNG from the SPL Project sold under SPL's third party long-term SPAs	$ 2,588	$ 458
LNG from the SPL Project sold by our integrated marketing function	1,756	319
LNG procured from third parties	981	236
Other revenues and derivative gains (losses)	(8)	3
Total LNG revenues	$ 5,317	$ 1,016
Volumes sold as LNG revenues *(in TBtu)*:		
LNG from the SPL Project sold under SPL's third party long-term SPAs	427	85
LNG from the SPL Project sold by our integrated marketing function	233	47
LNG procured from third parties	98	26
Total volumes sold as LNG revenues	758	158

Operating costs and expenses

	Year Ended December 31,				
(in millions)	2017	2016	Change	2015	Change
Cost (cost recovery) of sales	$ 3,120	$ 582	$ 2,538	$ (15)	$ 597
Operating and maintenance expense	446	216	230	95	121
Development expense	10	7	3	42	(35)
Selling, general and administrative expense	256	260	(4)	363	(103)
Depreciation and amortization expense	356	174	182	83	91
Restructuring expense	6	61	(55)	61	—
Impairment expense and loss on disposal of assets	19	13	6	91	(78)
Total operating costs and expenses	$ 4,213	$ 1,313	$ 2,900	$ 720	$ 593

2017 vs. 2016

Our total operating costs and expenses increased during the year ended December 31, 2017 from the year ended 2016, primarily as a result of additional Trains that were operating between the periods. During the year ended December 31, 2017, Trains 1 and 2 were operating for twelve months and Train 3 and Train 4 were operating for nine and three months, respectively, whereas in 2016, Train 1 was operating for seven months and Train 2 was operating for less than four months.

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

Operating and maintenance expense increased during the year ended December 31, 2017 from the year ended 2016, as a result of the increase in operating Trains during 2017. Operating and maintenance expense includes costs associated with operating and maintaining the SPL Project and CCL Project. The increase during the year ended December 31, 2017 from the year ended

2016 was primarily related to natural gas transportation and storage capacity demand charges, third-party service and maintenance contract costs and payroll and benefit costs of operations personnel. Operating and maintenance expense also includes TUA reservation charges as a result of the commencement of payments under the partial TUA assignment agreement with Total, insurance and regulatory costs and other operating costs.

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

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

Partially offsetting the increases above was a decrease in restructuring expense, which was primarily due to the completion of organizational initiatives as of March 31, 2017.

Impairment expense and loss on disposal of assets increased during the year ended December 31, 2017 compared to the year ended December 31, 2016. The impairment expense and loss on disposal of assets recognized during the year ended December 31, 2017 was the result of $6 million related to damaged infrastructure as an effect of Hurricane Harvey and $13 million related to the write down of assets used in non-core operations outside of our liquefaction activities. The impairment expense and loss on disposal of assets recognized during the year ended December 31, 2016 related to write down of assets primarily used in non-core operations outside of our liquefaction activities.

2016 vs. 2015

Our total operating costs and expenses increased $592 million during the year ended December 31, 2016 compared to the year ended December 31, 2015, primarily as a result of the commencement of operations of Trains 1 and 2 of the SPL Project in May and September 2016, respectively.

Cost of sales increased during the year ended December 31, 2016 as a result of the commencement of operations at the SPL Project compared to a cost recovery recognized during the year ended December 31, 2015. This cost recovery was due to a $32 million increase in fair value for our natural gas supply contracts recorded for the period, which we recognized following the completion and placement into service of modifications to the underlying pipeline infrastructure and the resulting development of a market for physical gas delivery at locations specified in a portion of our natural gas supply contracts. Similarly, during the year ended December 31, 2016, we recognized a $68 million increase in fair value of a natural gas supply contract due to the satisfaction of conditions precedent, including completion of relevant pipeline infrastructure, for that contract. Included in cost of sales during the years ended December 31, 2016 and 2015 was vessel charter costs of $62 million and $16 million, respectively, which were incurred throughout the period, including the period prior to substantial completion of Trains 1 and 2 of the SPL Project.

Operating and maintenance expense increased during the year ended December 31, 2016 as a result of the commencement of operations at the SPL Project. Depreciation and amortization expense increased during the year ended December 31, 2016 as we began depreciation of our assets related to Trains 1 and 2 of the SPL Project upon reaching substantial completion.

Partially offsetting the increases above was a decrease in SG&A expense, which was primarily due to reallocation of costs from selling, general and administrative activities to operating and maintenance activities following commencement of operations at the SPL Project and a reduction in professional services fees. Development expense decreased during the year ended December 31, 2016 compared to the year ended December 31, 2015, due to an FID made on Train 5 of the SPL Project in June 2015 and an FID made on Trains 1 and 2 of the CCL Project in May 2015.

Impairment expense decreased during the year ended December 31, 2016 compared to the year ended December 31, 2015. The impairment expense recognized in 2016 related to a corporate airplane that was written down to fair value based on market-based appraisals, which was ultimately sold by the end of the year. The impairment was recognized due to the potential disposition of the airplane in connection with the Company having initiated organizational changes and the associated focus for financially disciplined investment. 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 million primarily associated with a liquid hydrocarbon export project in Texas along the Gulf Coast, as well as $36 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.

Additionally, in 2016 we implemented certain organizational changes to simplify our corporate structure, improve our operational efficiencies and implement a strategy for sustainable, long-term stockholder value creation through financially disciplined development, construction, operation and investment. As a result of these efforts, we recorded $61 million of restructuring charges and other costs associated with restructuring and operational efficiency initiatives during each of the years ended December 31, 2016 and 2015 substantially all related to severance and other employee-related costs.

Other expense (income)

	Year Ended December 31,				
(in millions)	2017	2016	Change	2015	Change
Interest expense, net of capitalized interest	$ 747	$ 488	$ 259	$ 322	$ 166
Loss on early extinguishment of debt	100	135	(35)	124	11
Derivative loss (gain), net	(7)	10	(17)	204	(194)
Other income	(18)	—	(18)	(2)	2
Total other expense	$ 822	$ 633	$ 189	$ 648	$ (15)

2017 vs. 2016

Interest expense, net of capitalized interest, increased during the year ended December 31, 2017 compared to the year ended December 31, 2016, primarily as a result of an increase in our indebtedness outstanding (before premium, discount and unamortized debt issuance costs), from $22.7 billion as of December 31, 2016 to $26.1 billion as of December 31, 2017, and a decrease in the portion of total interest costs that could be capitalized as Trains 1 through 4 of the SPL Project completed construction. For the year ended December 31, 2017, we incurred $1.5 billion of total interest cost, of which we capitalized $779 million which was directly related to the construction of the SPL Project and the CCL Project. For the year ended December 31, 2016, we incurred $1.3 billion of total interest cost, of which we capitalized $813 million which was directly related to the construction of the SPL Project and the CCL Project.

Loss on early extinguishment of debt decreased during the year ended December 31, 2017, as compared to the year ended December 31, 2016. Loss on early extinguishment of debt recognized in 2017 was attributable to the write-offs of debt issuance costs of (1) $42 million in March 2017 upon termination of the remaining available balance of $1.6 billion under the 2015 SPL Credit Facilities in connection with the issuance of the 2028 SPL Senior Notes; (2) $33 million in May 2017 upon the prepayment of approximately $1.4 billion of outstanding borrowings under the 2015 CCH Credit Facility in connection with the issuance of the 2027 CCH Senior Notes; and (3) $25 million in September 2017 related to the prepayment of $1.5 billion of the outstanding indebtedness under the 2016 CQP Credit Facilities in connection with the issuance of the 2025 CQP Senior Notes. Loss on early extinguishment of debt during the year ended December 31, 2016 was attributable to (1) $52 million write-off of debt issuance costs and payment of fees related to the $2.6 billion prepayment of outstanding borrowings and termination of commitments under the 2015 SPL Credit Facilities in connection with the issuance of the 2026 SPL Senior Notes and the 2027 SPL Senior Notes, (2) $63 million write-off of debt issuance costs related to the $2.4 billion prepayment of outstanding borrowings under the 2015 CCH Credit Facility in connection with the issuance of the 2024 CCH Senior Notes and the 2025 CCH Senior Notes and (3) $20 million write-off of debt issuance costs and unamortized discount in connection with the prepayment of the CTPL Term Loan and the redemption of the 2020 SPLNG Senior Notes.

Derivative gain, net increased from a loss during year ended December 31, 2016 to a gain during the year ended December 31, 2017, primarily due to a favorable shift in the long-term forward LIBOR curve between the periods, partially offset by a $7 million loss in March 2017 upon the settlement of interest rate swaps associated with approximately $1.6 billion of commitments that were terminated under the 2015 SPL Credit Facilities and a $13 million loss in May 2017 in conjunction with the termination of approximately $1.4 billion of commitments under the 2015 CCH Credit Facility.

2016 vs. 2015

Interest expense, net of capitalized interest, increased $166 million in the year ended December 31, 2016, as compared to the year ended December 31, 2015, primarily as a result of an increase in our indebtedness outstanding (before premium, discount and unamortized debt issuance costs), from $17 billion as of December 31, 2015 to $23 billion as of December 31, 2016, and a decrease in the portion of total interest costs that could be capitalized as Trains 1 and 2 of the SPL Project were no longer in construction. For the year ended December 31, 2015, we incurred $997 million of total interest cost, of which we capitalized $675 million which was directly related to the construction of the SPL Project and the CCL Project.

Loss on early extinguishment of debt increased $11 million in the year ended December 31, 2016, as compared to the year ended December 31, 2015. Loss on early extinguishment of debt during the year ended December 31, 2015 was attributable to (1) $96 million associated with the termination of approximately $1.8 billion of commitments under SPL's previous credit facilities that were replaced by the 2015 SPL Credit Facilities in June 2015, (2) $16 million associated with the termination of a portion of the original commitments under the 2015 CCH Credit Facility and (3) $11 million associated with the termination of additional commitments made available under the 2025 CCH HoldCo II Convertible Senior Note.

Derivative loss, net decreased $194 million in the year ended December 31, 2016, as compared to the year ended December 31, 2015, primarily due to a relative increase in the long-term forward LIBOR curve. Included in derivative loss, net recognized during the year ended December 31, 2015 was a $50 million loss recognized upon meeting the contingency related to the CCH Interest Rate Derivatives, as well as the loss recognized upon the termination of interest rate swaps associated with approximately $1.8 billion of commitments that were terminated under the previous SPL credit facilities.

Other

	Year Ended December 31,				
(in millions)	2017	2016	Change	2015	Change
Income tax provision	$ (3)	$ (2)	$ (1)	$ —	$ (2)
Net income (loss) attributable to non-controlling interest	956	(55)	1,011	(122)	67

2017 vs. 2016

Net income attributable to non-controlling interest increased during the year ended December 31, 2017 from the year ended 2016 primarily due to the amortization of the beneficial conversion feature on Cheniere Partners' Class B units and increase in consolidated net income recognized by Cheniere Partners in which the non-controlling interest is held. Net income attributable to non-controlling interest was increased by $714 million for non-cash amortization of the beneficial conversion feature on Cheniere Partners' Class B units during the year ended December 31, 2017. Although the amortization of the beneficial conversion feature on Cheniere Partners' Class B units ceased upon the conversion of these units into common units on August 2, 2017, the share of Cheniere Partners' net income (loss) that is attributed to non-controlling interest holders has increased from that date as a result of the increased ownership percentage by non-controlling interest holders. The consolidated net income recognized by Cheniere Partners increased from a net loss of $171 million in the year ended December 31, 2016, respectively, to net income of $490 million in the year ended December 31, 2017, primarily as a result of the additional Trains that were operating at the SPL Project between the periods, which was partially offset by increased interest expense, net of amounts capitalized.

2016 vs. 2015

Net loss attributable to non-controlling interest decreased $67 million in the year ended December 31, 2016 as compared to the year ended December 31, 2015, primarily due to the decrease in consolidated net loss recognized by Cheniere Partners in which the non-controlling interest is held. The consolidated net loss recognized by Cheniere Partners decreased from $319 million in the year ended December 31, 2015 to $171 million in the year ended December 31, 2016 primarily due to increased income from operations as a result of the commencement of operations of Trains 1 and 2 of the SPL Project, decreased derivative loss, net and decreased loss on early extinguishment of debt, which were partially offset by increased interest expense, net of amounts capitalized. Additionally, net loss attributable to non-controlling interest was reduced by $34 million in amortization of the beneficial conversion feature on Cheniere Partners' Class B units.

Off-Balance Sheet Arrangements

We have interests in an unconsolidated variable interest entity ("VIE") as discussed in Note 8—Other Non-Current Assets of our Notes to Consolidated Financial Statements in this annual report, which we consider to be an off-balance sheet arrangement. We believe that this VIE does not have a current or future material effect on our consolidated financial position or operating results.

Summary of Critical Accounting Estimates

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

Derivative Instruments

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

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

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

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 approaches 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.

Income Taxes

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance if, based on all available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. In determining the need for a valuation allowance we consider current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. We have recorded a full valuation allowance on our net federal and state deferred tax assets as of both December 31, 2017 and 2016. We intend to maintain a valuation allowance on our net federal and state deferred tax assets until there is sufficient evidence to support the reversal of these allowances. Given our current earnings and anticipated future earnings, we believe that there is a reasonable possibility that in the foreseeable future, sufficient positive evidence may become available to allow us to reach a conclusion that a significant portion of the valuation allowance will no longer be needed. Release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change on the basis of the level of profitability that we are able to actually achieve.

We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. The largest amount of the tax benefit that is greater than 50 percent likely of being effectively settled is recorded. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

See Note 14—Income Taxes of our Notes to Consolidated Financial Statements for further discussion of our accounting for income taxes.

Recent Accounting Standards

For descriptions of recently issued accounting standards, see Note 22—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 supply contracts to secure natural gas feedstock for the SPL Project and the CCL Project ("Liquefaction Supply Derivatives"). We have also entered into 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"). In order to test the sensitivity of the fair value of the Liquefaction Supply Derivatives and the LNG Trading Derivatives to changes in underlying commodity prices, management modeled a 10% change in the commodity price for natural gas for each delivery location and a 10% change in the commodity price for LNG, respectively, as follows (in millions):

	December 31, 2017		December 31, 2016	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ 55	$ 5	$ 73	$ 6
LNG Trading Derivatives	(8)	2	(3)	—

Interest Rate Risk

SPL, Cheniere Partners and CCH have 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"), the 2016 CQP Credit Facilities ("CQP Interest Rate Derivatives") and the 2015 CCH Credit Facility ("CCH Interest Rate Derivatives" and collectively, with the SPL Interest Rate Derivatives and the CQP Interest Rate Derivatives, the "Interest Rate Derivatives"), respectively. In order to test the sensitivity of the fair value of the Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward 1-month LIBOR curve across the remaining terms of the Interest Rate Derivatives as follows (in millions):

	December 31, 2017		December 31, 2016	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
SPL Interest Rate Derivatives	$ —	$ —	$ (6)	$ 2
CQP Interest Rate Derivatives	21	5	13	6
CCH Interest Rate Derivatives	(32)	44	(86)	52

Foreign Currency Exchange Risk

We have entered into foreign currency exchange ("FX") contracts to hedge exposure to currency risk associated with operations in countries outside of the United States ("FX Derivatives"). In order to test the sensitivity of the fair value of the FX Derivatives to changes in FX rates, management modeled a 10% change in FX rate between the U.S. dollar and the applicable foreign currencies. This 10% change in FX rates would have resulted in an immaterial change in the fair value of the FX Derivatives as of both December 31, 2017 and December 31, 2016.

See Note 7—Derivative Instruments for additional details about our derivative instruments.

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, 2017, 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, 2017, 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/ Jack A. Fusco	By:	/s/ Michael J. Wortley
	Jack A. Fusco		Michael J. Wortley
	President and Chief Executive Officer (Principal Executive Officer)		Executive Vice President and Chief Financial Officer (Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Cheniere Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement schedule I (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 20, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

KPMG LLP

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

Houston, Texas
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
Cheniere Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Cheniere Energy, Inc.'s and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement schedule I (collectively, the consolidated financial statements), and our report dated February 20, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company'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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the 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.

/s/ KPMG LLP

KPMG LLP

Houston, Texas
February 20, 2018

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in millions, except share data)

	December 31,	
	2017	2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 722	$ 876
Restricted cash	1,880	860
Accounts and other receivables	369	218
Accounts receivable—related party	2	—
Inventory	243	160
Derivative assets	57	24
Other current assets	96	100
Total current assets	3,369	2,238
Non-current restricted cash	11	91
Property, plant and equipment, net	23,978	20,635
Debt issuance costs, net	149	277
Non-current derivative assets	34	83
Goodwill	77	77
Other non-current assets, net	288	302
Total assets	$ 27,906	$ 23,703
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 25	$ 49
Accrued liabilities	1,078	637
Current debt	—	247
Deferred revenue	111	73
Derivative liabilities	37	71
Total current liabilities	1,251	1,077
Long-term debt, net	25,336	21,688
Non-current deferred revenue	1	5
Non-current derivative liabilities	19	45
Other non-current liabilities	59	49
Commitments and contingencies (see Note 19)		
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, 2017 and 2016		
Issued: 250.1 million shares at December 31, 2017 and 2016		
Outstanding: 237.6 million shares and 238.0 million shares at December 31, 2017 and 2016, respectively	1	1
Treasury stock: 12.5 million shares and 12.2 million shares at December 31, 2017 and 2016, respectively, at cost	(386)	(374)
Additional paid-in-capital	3,248	3,211
Accumulated deficit	(4,627)	(4,234)
Total stockholders' deficit	(1,764)	(1,396)
Non-controlling interest	3,004	2,235
Total equity	1,240	839
Total liabilities and equity	$ 27,906	$ 23,703

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

	Year Ended December 31,		
	2017	2016	2015
Revenues			
LNG revenues	$ 5,317	$ 1,016	$ —
Regasification revenues	260	259	259
Other revenues	21	8	12
Other—related party	3	—	—
Total revenues	5,601	1,283	271
Operating costs and expenses			
Cost (cost recovery) of sales (excluding depreciation and amortization expense shown separately below)	3,120	582	(15)
Operating and maintenance expense	446	216	95
Development expense	10	7	42
Selling, general and administrative expense	256	260	363
Depreciation and amortization expense	356	174	83
Restructuring expense	6	61	61
Impairment expense and loss on disposal of assets	19	13	91
Total operating costs and expenses	4,213	1,313	720
Income (loss) from operations	1,388	(30)	(449)
Other income (expense)			
Interest expense, net of capitalized interest	(747)	(488)	(322)
Loss on early extinguishment of debt	(100)	(135)	(124)
Derivative gain (loss), net	7	(10)	(204)
Other income	18	—	2
Total other expense	(822)	(633)	(648)
Income (loss) before income taxes and non-controlling interest	566	(663)	(1,097)
Income tax provision	(3)	(2)	—
Net income (loss)	563	(665)	(1,097)
Less: net income (loss) attributable to non-controlling interest	956	(55)	(122)
Net loss attributable to common stockholders	$ (393)	$ (610)	$ (975)
Net loss per share attributable to common stockholders—basic and diluted (1)	$ (1.68)	$ (2.67)	$ (4.30)
Weighted average number of common shares outstanding—basic and diluted	233.1	228.8	226.9

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

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in millions)

	Total Stockholders' Equity							
	Common Stock		Treasury Stock					
	Shares	Par Value Amount	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Non-controlling Interest	Total Equity
Balance at December 31, 2014	236.7	$ 1	10.6	$ (293)	$ 2,777	$ (2,649)	$ 2,666	$ 2,502
Exercise of stock options	0.1	—	—	—	2	—	—	2
Forfeitures of restricted stock	(0.2)	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	90	—	—	90
Shares repurchased related to share-based compensation	(1.0)	—	1.0	(61)	—	—	—	(61)
Excess tax benefit from share-based compensation	—	—	—	—	2	—	—	2
Loss attributable to non-controlling interest	—	—	—	—	—	—	(122)	(122)
Equity portion of convertible notes, net	—	—	—	—	205	—	—	205
Distributions to non-controlling interest	—	—	—	—	—	—	(80)	(80)
Net loss	—	—	—	—	—	(975)	—	(975)
Balance at December 31, 2015	235.6	1	11.6	(354)	3,076	(3,624)	2,464	1,563
Issuances of restricted stock	0.4	—	—	—	—	—	—	—
Issuance of stock to acquire additional interest in Cheniere Holdings	3.0	—	—	—	94	—	(94)	—
Forfeitures of restricted stock	(0.4)	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	40	—	—	40
Shares repurchased related to share-based compensation	(0.6)	—	0.6	(20)	—	—	—	(20)
Loss attributable to non-controlling interest	—	—	—	—	—	—	(55)	(55)
Equity portion of convertible notes, net	—	—	—	—	1	—	—	1
Distributions to non-controlling interest	—	—	—	—	—	—	(80)	(80)
Net loss	—	—	—	—	—	(610)	—	(610)
Balance at December 31, 2016	238.0	1	12.2	(374)	3,211	(4,234)	2,235	839
Issuances of restricted stock	0.1	—	—	—	—	—	—	—
Issuance of stock to acquire additional interest in Cheniere Holdings	—	—	—	—	2	—	(2)	—
Forfeitures of restricted stock	(0.2)	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	34	—	—	34
Shares repurchased related to share-based compensation	(0.3)	—	0.3	(12)	—	—	—	(12)
Net income attributable to non-controlling interest	—	—	—	—	—	—	956	956
Equity portion of convertible notes, net	—	—	—	—	1	—	—	1
Distributions to non-controlling interest	—	—	—	—	—	—	(185)	(185)
Net loss	—	—	—	—	—	(393)	—	(393)
Balance at December 31, 2017	237.6	$ 1	12.5	$ (386)	$ 3,248	$ (4,627)	$ 3,004	$ 1,240

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net income (loss)	$ 563	$ (665)	$ (1,097)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Non-cash LNG inventory write-downs	—	—	18
Depreciation and amortization expense	356	174	83
Share-based compensation expense	91	101	172
Non-cash interest expense	75	77	59
Amortization of debt issuance costs, deferred commitment fees, premium and discount	69	62	48
Loss on early extinguishment of debt	100	135	124
Total losses (gains) on derivatives, net	62	(28)	168
Net cash used for settlement of derivative instruments	(106)	(45)	(100)
Impairment expense and loss on disposal of assets	19	13	91
Other	(4)	4	1
Changes in operating assets and liabilities:			
Accounts and other receivables	(139)	(207)	(1)
Accounts receivable—related party	(2)	—	—
Inventory	(73)	(119)	(28)
Accounts payable and accrued liabilities	225	64	2
Deferred revenue	34	42	(4)
Other, net	(39)	(12)	(19)
Net cash provided by (used in) operating activities	1,231	(404)	(483)
Cash flows from investing activities			
Property, plant and equipment, net	(3,357)	(4,356)	(6,853)
Investment in equity method investment	(41)	—	—
Other	17	(57)	(131)
Net cash used in investing activities	(3,381)	(4,413)	(6,984)
Cash flows from financing activities			
Proceeds from issuances of debt	6,854	12,865	7,073
Repayments of debt	(3,632)	(7,671)	—
Debt issuance and deferred financing costs	(89)	(172)	(513)
Debt extinguishment costs	—	(14)	—
Distributions and dividends to non-controlling interest	(185)	(80)	(80)
Proceeds from exercise of stock options	—	—	2
Payments related to tax withholdings for share-based compensation	(12)	(20)	(61)
Other	—	—	2
Net cash provided by financing activities	2,936	4,908	6,423
Net increase (decrease) in cash, cash equivalents and restricted cash	786	91	(1,044)
Cash, cash equivalents and restricted cash—beginning of period	1,827	1,736	2,780
Cash, cash equivalents and restricted cash—end of period	$ 2,613	$ 1,827	$ 1,736

Balances per Consolidated Balance Sheets:

	December 31,	
	2017	2016
Cash and cash equivalents	$ 722	$ 876
Restricted cash	1,880	860
Non-current restricted cash	11	91
Total cash, cash equivalents and restricted cash	$ 2,613	$ 1,827

The accompanying notes are an integral part of these 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 82.7% of Cheniere Holdings, which is a publicly traded limited liability company formed in 2013 that owns a 48.6% 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 in Cameron Parish, Louisiana, on the Sabine-Neches Waterway less than four miles from the Gulf Coast. Cheniere Partners is developing, constructing and operating natural gas liquefaction facilities (the "SPL Project") at the Sabine Pass LNG terminal adjacent to the existing regasification facilities (described below) through a wholly owned subsidiary, SPL. Cheniere Partners plans to construct up to six Trains, which are in various stages of development, construction and operations. Trains 1 through 4 are operational, Train 5 is under construction and Train 6 is being commercialized and has all necessary regulatory approvals in place. Each Train is expected to have a nominal production capacity, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 4.5 mtpa and an adjusted nominal production capacity of approximately 4.3 to 4.6 mtpa of LNG. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' wholly owned subsidiary, SPLNG, that include pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 16.9 Bcfe, two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4.0 Bcf/d. 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 (collectively, 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, which is prior to adjusting for planned maintenance, production reliability and potential overdesign, of approximately 13.5 mtpa of LNG, three LNG storage tanks with aggregate capacity of approximately 10.1 Bcfe and two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters. The CCL Project is being developed in stages. The first stage 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 ("Stage 1"). The second stage includes Train 3, one LNG storage tank and the completion of the second partial berth ("Stage 2"). The CCL Project also includes a 23-mile natural gas supply pipeline that will interconnect the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline"), which is being constructed concurrently with the first stage. Trains 1 and 2 are currently under construction, and Train 3 is being commercialized and has all necessary regulatory approvals in place. The construction of the Corpus Christi Pipeline is nearing completion.

Additionally, we are developing an expansion of the Corpus Christi LNG terminal adjacent to the CCL Project and recently amended our regulatory filings with FERC to incorporate a project design change, from two Trains with an expected aggregate nominal production capacity of approximately 9.0 mtpa to up to seven midscale Trains with an expected aggregate nominal production capacity of approximately 9.5 mtpa. We remain focused on leveraging infrastructure through the expansion of our existing sites. We are also in various stages of developing other projects, including infrastructure projects in support of natural gas supply and LNG demand, which, among other things, will require acceptable commercial and financing arrangements before we make a final investment decision ("FID").

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our Consolidated Financial Statements have been prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of Cheniere, 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 our proportionate share of earnings, losses and distributions. Investments in non-controlled entities, over which Cheniere does not have the ability to exercise significant influence, are accounted for using the cost method. Under the cost method the investments are initially recognized at cost and dividends received from the accumulated earnings of an investee are recorded as income. Dividends received in excess of the accumulated earnings of an investee are recorded as a reduction in the investment. We periodically assess our cost method investments for indicators of impairment. An impairment is recorded if an indicator is identified, the carrying value of our investment exceeds its fair value, and the impairment is considered to be other than temporary. Investments accounted for using the equity method and cost method are reported as a component of other assets.

We make a determination at the inception of each arrangement whether an entity in which we have made an investment or in which we have other variable interests is considered a variable interest entity ("VIE"). Generally, a VIE is an entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, whose equity investors lack any characteristics of a controlling financial interest or which was established with non-substantive voting. We consolidate VIEs when we are deemed to be the primary beneficiary. The primary beneficiary of a VIE is the party that both: (1) has the power to make decisions that most significantly affect the economic performance of the VIE and (2) has the obligation to absorb losses or the right to receive benefits that in either case could potentially be significant to the VIE. If we are not deemed to be the primary beneficiary of a VIE, we account for the investment or other variable interests in a VIE in accordance with applicable GAAP.

Certain reclassifications have been made to conform prior period information to the current presentation. The reclassifications did not have a material effect on our consolidated financial position, results of operations or cash flows.

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, derivative instruments, asset retirement obligations ("AROs"), income taxes including valuation allowances for 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 approaches used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

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

Recurring fair-value measurements are performed for derivative instruments as disclosed in Note 7—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 12—Debt, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments using observable or unobservable inputs. Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination, intangible assets, goodwill and AROs.

Revenue Recognition

Fees received pursuant to SPAs are recognized as LNG revenues after substantial completion of the respective Train. Prior to substantial completion, sales generated during the commissioning phase are offset against the cost of construction for the respective Train, as the production and removal of LNG from storage is necessary to test the facility and bring the asset to the condition necessary for its intended use. LNG revenues are recognized when LNG is delivered to the customer, either at the Sabine Pass LNG terminal or at the customer's LNG receiving terminal, based on the terms of the contract. LNG revenues generated by our integrated marketing function are reported on a gross or net basis based on an assessment of whether it is acting as the principal or the agent in the transaction.

LNG regasification capacity reservation fees are recognized as regasification revenues 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 revenue as SPLNG performs the services set forth in each customer's TUA. We also recognize tug services fees, which were historically included in regasification revenues but are now included within other revenues on our Consolidated Statements of Operations, that are received by Sabine Pass Tug Services, LLC, a wholly owned subsidiary of SPLNG.

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.

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. We did not recognize any impairment expense related to accounts and notes receivable during the years ended December 31, 2017 and 2016. During the year ended December 31, 2015, we recognized bad debt expense of $36 million which was primarily attributable to a reserve against funds loaned to Parallax Enterprises, LLC, as further discussed in Note 19—Commitments and Contingencies. This charge was recorded as impairment expense on our Consolidated Statements of Operations.

Inventory

LNG and natural gas inventory are recorded at the lower of weighted average cost and net realizable value. Materials and other inventory are recorded at the lower of cost and net realizable value and subsequently charged to expense when issued. During the year ended December 31, 2015, we recognized $18 million as operating and maintenance expense as a result of write-down for LNG inventory purchased to maintain the cryogenic readiness of the regasification facilities at the Sabine Pass LNG terminal. We did not recognize any operating and maintenance expense related to inventory write-downs during the years ended December 31, 2017 and 2016.

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, is amortized over the estimated useful life of the asset.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for construction and commissioning activities, major renewals and betterments that extend the useful life of an asset are capitalized, while expenditures for maintenance and repairs (including those for planned major maintenance projects) to maintain property, plant and equipment in operating condition are generally expensed as incurred. 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, 2017, we recognized $6 million of impairment expense related to damaged infrastructure as an effect of Hurricane Harvey and $6 million of impairment expense related to write down of assets used in non-core operations outside of our liquefaction activities.

During the year ended December 31, 2016, we recorded $10 million of impairment expense related to a corporate airplane that was written down to fair value based on market-based appraisals, which was ultimately sold by the end of the year. The impairment was recognized due to the potential disposition of the airplane in connection with the Company having initiated organizational changes and the associated operational focus for financially disciplined investment.

During the year ended December 31, 2015, we recorded, primarily in relation to a liquid hydrocarbon export project in Texas along the Gulf Coast, $55 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.

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 interest rate, commodity price and foreign currency exchange ("FX") 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 for and we elect the normal purchases and sales exception. When we have the contractual right and intend to net settle, derivative assets and liabilities are reported on a net basis.

Changes in the fair value of our derivative instruments are recorded in earnings, unless we elect to apply hedge accounting and meet specified criteria, including completing contemporaneous hedge documentation. We did not have any derivative instruments designated as cash flow hedges during the years ended December 31, 2017, 2016 and 2015. See Note 7—Derivative Instruments for additional details about our derivative instruments.

Concentration of Credit Risk

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

The use of derivative instruments exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. Certain of our commodity derivative transactions are executed through over-the-counter contracts which are subject to nominal credit risk as these transactions are settled on a daily margin basis with investment grade financial institutions. Collateral deposited for such contracts is recorded as other current asset. Our interest rate and FX 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.

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

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

Goodwill

Goodwill is the excess of acquisition cost of a business over the estimated fair value of net assets acquired. Goodwill is not amortized but is tested for impairment at least annually or more frequently if events or circumstances indicate goodwill is more likely than not impaired. Goodwill impairment evaluation requires a comparison of the estimated fair value of a reporting unit to its carrying value. Cheniere tests goodwill for impairment by either performing a qualitative assessment or a quantitative test. The qualitative assessment is an assessment of historical information and relevant events and circumstances to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill. Cheniere may elect not to perform the qualitative assessment and instead perform a quantitative impairment test. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests.

As a result of finalization of organizational changes to simplify our corporate structure, improve our operational efficiencies and implement a strategy for sustainable, long-term stockholder value creation through financially disciplined development, construction, operation and investment, we revised the way we manage our business, which resulted in a change in our reporting units. Accordingly, Cheniere reallocated goodwill to our single reporting unit following finalization of organizational changes. We performed our annual goodwill impairment test on October 1st using a quantitative assessment and concluded that the estimated fair value of our reporting unit substantially exceeded its carrying value and, therefore, goodwill was not impaired. 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 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. There were no changes in the carrying value of goodwill during the year ended December 31, 2017.

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 Consolidated Balance Sheets at par value adjusted for unamortized discount or premium and net of unamortized debt issuance costs related to term notes. Discounts, premiums and debt issuance costs directly related to the issuance of debt are amortized over the life of the debt and are recorded in interest expense, net of capitalized interest using the effective interest method. Gains and losses on the extinguishment of debt are recorded in 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 a direct deduction from the debt liability unless incurred in connection with a line of credit arrangement, in which case they are presented as an asset on our Consolidated Balance Sheet. Debt issuance costs are amortized to interest expense or property, plant and equipment over the term of the related debt facility. Upon early retirement of debt or amendment to a debt agreement, certain fees are written off to loss on 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 assessment of AROs is described below.

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

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

Share-based Compensation

We have awarded share-based compensation in the form of stock, restricted stock, restricted stock units, performance stock units and phantom units that are more fully described in Note 15—Share-based Compensation. We recognize share-based compensation based upon the estimated fair value of awards. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period. For equity-classified share-based compensation awards (which include stock, restricted stock, restricted stock units and performance stock units to employees and non-employee directors), compensation cost is recognized based on the grant-date fair value reduced by the present value of dividends expected to be paid on the underlying shares during the requisite service period, discounted at the appropriate risk-free interest rate 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 solely on service conditions and using the accelerated recognition method for awards that vest based on performance conditions. For awards with both time and performance-based conditions, we generally recognize compensation cost based on the probable outcome of the performance condition at each reporting period. For liability-classified share-based compensation awards (which include phantom units), compensation cost is initially recognized on the grant date using estimated payout levels, and subsequently adjusted quarterly to reflect the updated estimated payout levels based on the changes in the our stock price. We account for forfeitures as they occur.

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 generally recognized within equity. See Note 10—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.

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. The dilutive effect of unvested stock is calculated using the treasury-stock method and the dilutive effect of convertible securities is calculated using the if-converted method.

Business Segment

During the first quarter of 2017, we finalized organizational changes to simplify our corporate structure, improve our operational efficiencies and implement a strategy for sustainable, long-term stockholder value creation through financially disciplined development, construction, operation and investment. As a result of these efforts, we revised the way we manage our business, which resulted in a change to our reportable segments. We previously had two reportable segments: LNG terminal segment and LNG and natural gas marketing segment. We have now determined that we operate as a single operating and reportable segment. Our chief operating decision maker makes resource allocation decisions and assesses performance based on financial information presented on a consolidated basis in the delivery of an integrated source of LNG to our customers.

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. As of December 31, 2017 and 2016, restricted cash consisted of the following (in millions):

	December 31,	
	2017	2016
Current restricted cash		
SPL Project	$ 544	$ 358
Cheniere Partners and cash held by guarantor subsidiaries	1,045	247
CCL Project	227	197
Cash held by our subsidiaries restricted to Cheniere	64	58
Total current restricted cash	$ 1,880	$ 860
Non-current restricted cash		
CCL Project	$ —	$ 73
Other	11	18
Total non-current restricted cash	$ 11	$ 91

In February 2016, Cheniere Partners entered into the $2.8 billion credit facilities (the "2016 CQP Credit Facilities"). Cheniere Partners, as well as Cheniere Investments, SPLNG and CTPL as Cheniere Partners' guarantor subsidiaries, are subject to limitations on the use of cash under the terms of the 2016 CQP Credit Facilities and the related depositary agreement governing the extension of credit to Cheniere Partners. Specifically, Cheniere Partners, Cheniere Investments, SPLNG and CTPL may only withdraw funds from collateral accounts held at a designated depositary bank on a monthly basis and for specific purposes, including for the payment of operating expenses. In addition, distributions and capital expenditures may only be made quarterly and are subject to certain restrictions.

NOTE 4—ACCOUNTS AND OTHER RECEIVABLES

As of December 31, 2017 and 2016, accounts and other receivables consisted of the following (in millions):

	December 31,	
	2017	2016
Trade receivables		
SPL	$ 185	$ 88
Cheniere Marketing	163	121
Other accounts receivable	21	9
Total accounts and other receivables	$ 369	$ 218

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

NOTE 5—INVENTORY

As of December 31, 2017 and 2016, inventory consisted of the following (in millions):

	December 31, 2017	December 31, 2016
Natural gas	$ 17	$ 15
LNG	44	50
LNG in-transit	130	58
Materials and other	52	37
Total inventory	$ 243	$ 160

NOTE 6—PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2017	December 31, 2016
LNG terminal costs		
LNG terminal	$ 12,687	$ 7,978
LNG terminal construction-in-process	11,932	12,995
LNG site and related costs	86	41
Accumulated depreciation	(882)	(555)
Total LNG terminal costs, net	23,823	20,459
Fixed assets and other		
Computer and office equipment	14	13
Furniture and fixtures	19	17
Computer software	92	85
Leasehold improvements	41	43
Land	59	61
Other	16	22
Accumulated depreciation	(86)	(65)
Total fixed assets and other, net	155	176
Property, plant and equipment, net	$ 23,978	$ 20,635

Depreciation expense during the years ended December 31, 2017, 2016 and 2015 was $354 million, $173 million and $82 million, respectively.

We realized offsets to LNG terminal costs of $320 million and $214 million in the years ended December 31, 2017 and 2016, respectively, that were related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations of the respective Train of the SPL Project, during the testing phase for its construction.

LNG Terminal Costs

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

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

Fixed Assets and Other

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

NOTE 7—DERIVATIVE INSTRUMENTS

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

- interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under certain credit facilities ("Interest Rate Derivatives");
- commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the SPL Project and the CCL Project ("Physical Liquefaction Supply Derivatives") and associated economic hedges ("Financial Liquefaction Supply Derivatives," and collectively with the Physical Liquefaction Supply Derivatives, the "Liquefaction Supply Derivatives");
- 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"); and
- foreign currency exchange ("FX") contracts to hedge exposure to currency risk associated with both LNG Trading Derivatives and operations in countries outside of the United States ("FX Derivatives").

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

The following table shows the fair value of our derivative instruments that are required to be measured at fair value on a recurring basis as of December 31, 2017 and 2016, which are classified as derivative assets, non-current derivative assets, derivative liabilities or non-current derivative liabilities in our Consolidated Balance Sheets (in millions).

	Fair Value Measurements as of							
	December 31, 2017				December 31, 2016			
	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
SPL Interest Rate Derivatives liability	$ —	$ —	$ —	$ —	$ —	$ (6)	$ —	$ (6)
CQP Interest Rate Derivatives asset	—	21	—	21	—	13	—	13
CCH Interest Rate Derivatives liability	—	(32)	—	(32)	—	(86)	—	(86)
Liquefaction Supply Derivatives asset (liability)	2	10	43	55	(4)	(2)	79	73
LNG Trading Derivatives asset (liability)	(13)	5	—	(8)	2	(5)	—	(3)
FX Derivatives liability	—	(1)	—	(1)	—	—	—	—

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

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

We include a portion of our Physical Liquefaction Supply Derivatives as Level 3 within the valuation hierarchy as the fair value is developed through the use of internal models which may be impacted by inputs that are unobservable in the marketplace. The curves used to generate the fair value of our Physical Liquefaction Supply Derivatives are based on basis adjustments applied to forward curves for a liquid trading point. In addition, there may be observable liquid market basis information in the near term, but terms of a Physical Liquefaction Supply Derivatives contract may exceed the period for which such information is available, resulting in a Level 3 classification. In these instances, the fair value of the contract incorporates extrapolation assumptions made in the determination of the market basis price for future delivery periods in which applicable commodity basis prices were either not observable or lacked corroborative market data. As of December 31, 2017, some of our Physical Liquefaction Supply Derivatives existed within markets for which the pipeline infrastructure is under development to accommodate marketable physical gas flow.

The Level 3 fair value measurements of our Physical Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas market basis spreads due to the contractual notional amount represented by our Level 3 positions, which is a substantial portion of our overall Physical Liquefaction Supply portfolio. The following table includes quantitative information for the unobservable inputs for our Level 3 Physical Liquefaction Supply Derivatives as of December 31, 2017:

	Net Fair Value Asset (in millions)	Valuation Approach	Significant Unobservable Input	Significant Unobservable Inputs Range
Physical Liquefaction Supply Derivatives	$43	Market approach incorporating present value techniques	Basis Spread	$(0.703) - $0.432

The following table shows the changes in the fair value of our Level 3 Physical Liquefaction Supply Derivatives during the years ended December 31, 2017, 2016 and 2015 (in millions):

	Year Ended December 31,		
	2017	2016	2015
Balance, beginning of period	$ 79	$ 32	$ —
Realized and mark-to-market gains (losses):			
Included in cost of sales (1)	(37)	48	32
Purchases and settlements:			
Purchases	14	1	—
Settlements (1)	(12)	(2)	—
Transfers out of Level 3	(1)	—	—
Balance, end of period	$ 43	$ 79	$ 32
Change in unrealized gains relating to instruments still held at end of period	$ (37)	$ 49	$ 32

(1) Does not include the decrease in fair value of $1 million related to the realized gains capitalized during the year ended December 31, 2016.

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

Interest Rate Derivatives

SPL had entered into interest rate swaps ("SPL Interest Rate Derivatives") to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the credit facilities it entered into in June 2015 (the "2015 SPL Credit Facilities"), based on a portion of the expected outstanding borrowings over the term of the 2015 SPL Credit Facilities. In March 2017, SPL settled the SPL Interest Rate Derivatives and recognized a derivative loss of $7 million in conjunction with the termination of approximately $1.6 billion of commitments under the 2015 SPL Credit Facilities, as discussed in Note 12—Debt.

CCH has entered into interest rate swaps ("CCH Interest Rate Derivatives") to protect against volatility of future cash flows and hedge a portion of the variable interest payments on its credit facility (the "2015 CCH Credit Facility"), based on a portion of the expected outstanding borrowings over the term of the 2015 CCH Credit Facility. In May 2017, CCH settled a portion of the CCH Interest Rate Derivatives and recognized a derivative loss of $13 million in conjunction with the termination of approximately $1.4 billion of commitments under the 2015 CCH Credit Facility, as discussed in Note 12—Debt.

Cheniere Partners has entered into interest rate swaps ("CQP Interest Rate Derivatives") to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the 2016 CQP Credit Facilities, based on a portion of the expected outstanding borrowings over the term of the 2016 CQP Credit Facilities.

As of December 31, 2017, 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
CQP Interest Rate Derivatives	$225 million	$1.3 billion	March 22, 2016	February 29, 2020	1.19%	One-month LIBOR
CCH Interest Rate Derivatives	$29 million	$4.9 billion	May 20, 2015	May 31, 2022	2.29%	One-month LIBOR

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

	December 31, 2017				December 31, 2016			
Balance Sheet Location	SPL Interest Rate Derivatives	CQP Interest Rate Derivatives	CCH Interest Rate Derivatives	Total	SPL Interest Rate Derivatives	CQP Interest Rate Derivatives	CCH Interest Rate Derivatives	Total
Derivative assets	$ —	$ 7	$ —	$ 7	$ —	$ —	$ —	$ —
Non-current derivative assets	—	14	3	17	—	16	—	16
Total derivative assets	—	21	3	24	—	16	—	16
Derivative liabilities	—	—	(20)	(20)	(4)	(3)	(43)	(50)
Non-current derivative liabilities	—	—	(15)	(15)	(2)	—	(43)	(45)
Total derivative liabilities	—	—	(35)	(35)	(6)	(3)	(86)	(95)
Derivative asset (liability), net	$ —	$ 21	$ (32)	$ (11)	$ (6)	$ 13	$ (86)	$ (79)

The following table shows the changes in the fair value and settlements of our Interest Rate Derivatives recorded in derivative gain (loss), net on our Consolidated Statements of Operations during the years ended December 31, 2017, 2016 and 2015 (in millions):

	Year Ended December 31,		
	2017	2016	2015
SPL Interest Rate Derivatives loss	$ (2)	$ (6)	$ (42)
CQP Interest Rate Derivatives gain	6	12	—
CCH Interest Rate Derivatives gain (loss)	3	(16)	(162)

Commodity Derivatives

Liquefaction Supply Derivatives

SPL and CCL have entered into index-based physical natural gas supply contracts and associated economic hedges, if applicable, to purchase natural gas for the commissioning and operation of the SPL Project and the CCL Project. The terms of the noncurrent physical natural gas supply contracts range from approximately one to seven years, most of which commence upon the satisfaction of certain conditions precedent, if not already met, such as the date of first commercial delivery of specified Trains of the SPL Project and the CCL Project.

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

LNG Trading Derivatives

We have entered into, and may from time to time enter into, financial LNG Trading 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 LNG purchase and sale transactions.

The following table shows the fair value and location of our Liquefaction Supply Derivatives and LNG Trading Derivatives (collectively, "Commodity Derivatives") on our Consolidated Balance Sheets (in millions, except notional amount):

	December 31, 2017			December 31, 2016		
Balance Sheet Location	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives (2)	Total	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives (2)	Total
Derivative assets	$ 41	$ 9	$ 50	$ 13	$ 7	$ 20
Non-current derivative assets	17	—	17	67	—	67
Total derivative assets	58	9	67	80	7	87
Derivative liabilities	—	(17)	(17)	(7)	(10)	(17)
Non-current derivative liabilities	(3)	—	(3)	—	—	—
Total derivative liabilities	(3)	(17)	(20)	(7)	(10)	(17)
Derivative asset (liability), net	$ 55	$ (8)	$ 47	$ 73	$ (3)	$ 70
Notional amount (in TBtu) (3)	2,539	25		1,117	—	

(1) Does not include collateral call of $1 million and collateral deposit of $6 million for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2017 and 2016, respectively.

(2) Does not include collateral of $28 million and $10 million deposited for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2017 and 2016, respectively.

(3) SPL had secured up to approximately 2,214 TBtu and 1,994 TBtu of natural gas feedstock through natural gas supply contracts as of December 31, 2017 and 2016, respectively. CCL has secured up to approximately 2,024 TBtu and zero TBtu of natural gas feedstock through natural gas supply contracts, a portion of which is subject to the achievement of certain project milestones and other conditions precedent, as of December 31, 2017 and 2016, respectively.

The following table shows the changes in the fair value, settlements and location of our Commodity Derivatives recorded on our Consolidated Statements of Operations during the years ended December 31, 2017, 2016 and 2015 (in millions):

		Year Ended December 31,		
	Statement of Operations Location (1)	2017	2016	2015
LNG Trading Derivatives gain (loss)	LNG revenues	$ (44)	$ (4)	1
Liquefaction Supply Derivatives loss (gain) (2)	Cost (cost recovery) of sales	24	(42)	(33)

(1) Fair value fluctuations associated with commodity derivative activities are classified and presented consistently with the item economically hedged and the nature and intent of the derivative instrument.

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

FX Derivatives

Cheniere Marketing has entered into FX Derivatives to protect against the volatility in future cash flows attributable to changes in international currency exchange rates. The FX Derivatives economically hedge the foreign currency exposure arising from cash flows expended for both physical and financial LNG transactions and selling, general and administrative expenses related to operations in countries outside of the United States.

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

		Fair Value Measurements as of	
	Balance Sheet Location	December 31, 2017	December 31, 2016
FX Derivatives	Derivative assets	$ —	$ 4
FX Derivatives	Derivative liabilities	—	(4)
FX Derivatives	Non-current derivative liabilities	(1)	—

The total notional amount of our FX Derivatives was $27 million and $11 million as of December 31, 2017 and 2016, respectively.

The following table shows the changes in the fair value of our FX Derivatives recorded on our Consolidated Statements of Operations during the years ended December 31, 2017, 2016 and 2015 (in millions):

		Year Ended December 31,		
	Statement of Operations Location	2017	2016	2015
FX Derivatives loss	LNG revenues	$ (1)	$ —	$ —
FX Derivatives loss	Other income	—	(1)	—

Balance Sheet Presentation

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

Offsetting Derivative Assets (Liabilities)	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
As of December 31, 2017			
CQP Interest Rate Derivatives	$ 21	$ —	$ 21
CCH Interest Rate Derivatives	3	—	3
CCH Interest Rate Derivatives	(35)	—	(35)
Liquefaction Supply Derivatives	64	(6)	58
Liquefaction Supply Derivatives	(3)	—	(3)
LNG Trading Derivatives	9	—	9
LNG Trading Derivatives	(37)	20	(17)
FX Derivatives	(1)	—	(1)
As of December 31, 2016			
SPL Interest Rate Derivatives	$ (6)	$ —	$ (6)
CQP Interest Rate Derivatives	16	—	16
CQP Interest Rate Derivatives	(3)	—	(3)
CCH Interest Rate Derivatives	(95)	9	(86)
Liquefaction Supply Derivatives	82	(2)	80
Liquefaction Supply Derivatives	(11)	4	(7)
LNG Trading Derivatives	21	(15)	6
LNG Trading Derivatives	(17)	8	(9)
FX Derivatives	5	(1)	4
FX Derivatives	(4)	—	(4)

NOTE 8—OTHER NON-CURRENT ASSETS

As of December 31, 2017 and 2016, other non-current assets, net consisted of the following (in millions):

	December 31,	
	2017	2016
Advances made under EPC and non-EPC contracts	$ 26	$ 69
Advances made to municipalities for water system enhancements	97	99
Advances and other asset conveyances to third parties to support LNG terminals	48	53
Tax-related payments and receivables	29	31
Equity method investments	64	10
Other	24	40
Total other non-current assets, net	$ 288	$ 302

Equity Method Investments

As of December 31, 2016, our equity method investments consisted of interests in privately-held companies. During the second quarter of 2017, we acquired an equity interest in Midship Holdings, LLC ("Midship Holdings"), which manages the business and affairs of Midship Pipeline Company, LLC ("Midship Pipeline"). Midship Pipeline is pursuing the development, construction, operation and maintenance of an approximately 230-mile natural gas pipeline project (the "Midship Project") that connects new production in the Anadarko Basin to Gulf Coast markets. Midship Holdings entered into agreements with investment funds managed by EIG Global Energy Partners ("EIG") under which EIG-managed funds committed to make an investment of up to $500 million (the "EIG Investment") in the Midship Project, subject to the terms and conditions contained in the applicable agreements. The EIG Investment, when combined with equity contributed by us, is intended to ensure the Midship Project has the equity funding expected to be required to develop and construct the project. Midship Holdings requires acceptable financing arrangements and regulatory and other approvals before construction of the proposed Midship Project commences.

We have determined that Midship Holdings is a variable interest entity ("VIE") because it is thinly capitalized at formation such that the total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support. We do not consolidate Midship Holdings because we do not have power to direct the activities that most significantly impact its economic performance. We continually monitor both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause a change in our identification of a VIE or determination of the primary beneficiary to a VIE. We account for our investment in Midship Holdings under the equity method as we have the ability to exercise significant influence over the operating and financial policies of Midship Holdings through our non-controlling voting rights on its board of managers. Our investment in Midship Holdings at December 31, 2017 was $55 million. Obligations to make additional investments in Midship Holdings are not significant and we have not provided financial support to Midship Holdings beyond amounts contractually required.

Cheniere LNG O&M Services, LLC ("O&M Services"), our wholly owned subsidiary, provides the development, construction, operation and maintenance services associated with the Midship Project pursuant to agreements in which O&M Services receives an agreed upon fee and reimbursement of costs incurred. O&M Services recorded $3 million of income in other—related party during the year ended December 31, 2017 and $2 million of accounts receivable—related party as of December 31, 2017 for services provided to Midship Pipeline under these agreements. CCL has entered into transportation precedent agreements with Midship Pipeline to secure firm pipeline transportation capacity for a period of 10 years following commencement of the Midship Project.

NOTE 9—VARIABLE INTEREST ENTITIES

Cheniere Holdings

Cheniere Holdings is a limited liability company formed by us in 2013 to hold our Cheniere Partners limited partner interests. As of December 31, 2017 and 2016, we owned 82.7% and 82.6%, respectively, of Cheniere Holdings as well as the director voting share. The director voting share is the sole share entitled to vote in the election of Cheniere Holdings' board of directors and allows us to remove members of the board of directors at any time and for any reason. If we cease to own greater than 25% of the common shares of Cheniere Holdings or if we choose to relinquish the director voting share, the director voting share will be extinguished.

The board of directors makes all major operating and financial decisions on behalf of Cheniere Holdings. Because ownership of the director voting share allows us to control Cheniere Holdings, irrespective of our majority ownership interest, and the director voting share cannot be removed from our control by the other equity holders of Cheniere Holdings, we have determined that Cheniere Holdings is a variable interest entity. We consolidate Cheniere Holdings in our Consolidated Financial Statements as we have determined that we are its primary beneficiary.

Cheniere Partners

Cheniere Partners is a limited partnership formed by us in 2006 to own and operate the Sabine Pass LNG terminal and related assets. As a result of the mandatory conversion of Cheniere Partners' Class B units ("Class B units") on August 2, 2017, as of December 31, 2017, Cheniere Holdings owned a 48.6% limited partner interest in Cheniere Partners in the form of 104.5 million common units and 135.4 million subordinated units, with the remaining non-controlling interest held by Blackstone CQP Holdco LP ("Blackstone CQP Holdco") and the public. Prior to the conversion, as of December 31, 2016, Cheniere Holdings owned 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, with the remaining non-controlling interest held by Blackstone CQP Holdco and the public. 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 2012, Cheniere Partners, Cheniere and Blackstone CQP Holdco entered into a unit purchase agreement (the "Blackstone Unit Purchase Agreement") whereby Cheniere Partners sold 100.0 million Class B units to Blackstone CQP Holdco in a private placement. 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 10—NON-CONTROLLING INTEREST

Cheniere Holdings was formed by us in 2013 to hold our Cheniere Partners limited partner interests. As of December 31, 2017 and 2016, we owned 82.7% and 82.6%, respectively, of Cheniere Holdings as well as the director voting share, with the remaining non-controlling interest held by the public. In December 2016, we increased our ownership percentage of Cheniere Holdings by acquiring additional publicly-owned shares of Cheniere Holdings in exchange with unregistered shares of our common stock.

Our ownership of Cheniere Partners interests is further discussed in Note 9—Variable Interest Entity.

NOTE 11—ACCRUED LIABILITIES

As of December 31, 2017 and 2016, accrued liabilities consisted of the following (in millions):

	December 31,	
	2017	2016
Interest costs and related debt fees	$ 397	$ 273
Compensation and benefits	141	56
LNG terminals and related pipeline costs	490	284
Other accrued liabilities	50	24
Total accrued liabilities	$ 1,078	$ 637

NOTE 12—DEBT

As of December 31, 2017 and 2016, our debt consisted of the following (in millions):

	December 31, 2017	December 31, 2016
Long-term debt:		
SPL		
5.625% Senior Secured Notes due 2021 (“2021 SPL Senior Notes”), net of unamortized premium of $6 and $7	$ 2,006	$ 2,007
6.25% Senior Secured Notes due 2022 (“2022 SPL Senior Notes”)	1,000	1,000
5.625% Senior Secured Notes due 2023 (“2023 SPL Senior Notes”), net of unamortized premium of $5 and $6	1,505	1,506
5.75% Senior Secured Notes due 2024 (“2024 SPL Senior Notes”)	2,000	2,000
5.625% Senior Secured Notes due 2025 (“2025 SPL Senior Notes”)	2,000	2,000
5.875% Senior Secured Notes due 2026 (“2026 SPL Senior Notes”)	1,500	1,500
5.00% Senior Secured Notes due 2027 (“2027 SPL Senior Notes”)	1,500	1,500
4.200% Senior Secured Notes due 2028 (“2028 SPL Senior Notes”), net of unamortized discount of $1 and zero	1,349	—
5.00% Senior Secured Notes due 2037 (“2037 SPL Senior Notes”)	800	—
2015 SPL Credit Facilities	—	314
Cheniere Partners		
5.250% Senior Notes due 2025 (“2025 CQP Senior Notes”)	1,500	—
2016 CQP Credit Facilities	1,090	2,560
CCH		
7.000% Senior Secured Notes due 2024 (“2024 CCH Senior Notes”)	1,250	1,250
5.875% Senior Secured Notes due 2025 (“2025 CCH Senior Notes”)	1,500	1,500
5.125% Senior Secured Notes due 2027 (“2027 CCH Senior Notes”)	1,500	—
2015 CCH Credit Facility	2,485	2,381
CCH HoldCo II		
11.0% Convertible Senior Notes due 2025 (“2025 CCH HoldCo II Convertible Senior Notes”)	1,305	1,171
Cheniere		
4.875% Convertible Unsecured Notes due 2021 (“2021 Cheniere Convertible Unsecured Notes”), net of unamortized discount of $121 and $146	1,040	960
4.25% Convertible Senior Notes due 2045 (“2045 Cheniere Convertible Senior Notes”), net of unamortized discount of $314 and $317	311	308
$750 million Cheniere Revolving Credit Facility (“Cheniere Revolving Credit Facility”)	—	—
Unamortized debt issuance costs	(305)	(269)
Total long-term debt, net	25,336	21,688
Current debt:		
$1.2 billion SPL Working Capital Facility (“SPL Working Capital Facility”)	—	224
$350 million CCH Working Capital Facility (“CCH Working Capital Facility”)	—	—
Cheniere Marketing trade finance facilities	—	23
Total current debt	—	247
Total debt, net	$ 25,336	$ 21,935

Below is a schedule of future principal payments that we are obligated to make, based on current construction schedules, on our outstanding debt at December 31, 2017 (in millions):

Years Ending December 31,	Principal Payments
2018	$ —
2019	55
2020	1,035
2021	3,161
2022	3,485
Thereafter	18,330
Total	$ 26,066

Senior Notes

SPL Senior Notes

In February 2017, SPL issued an aggregate principal amount of $800 million of the 2037 SPL 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 of 1933, as amended. In March 2017, SPL issued an aggregate principal amount of $1.35 billion, before discount, of the 2028 SPL Senior Notes. Net proceeds of the offerings of the 2037 SPL Senior Notes and the 2028 SPL Senior Notes were $789 million and $1.33 billion, respectively, after deducting the initial purchasers' commissions (for the 2028 SPL Senior Notes) and estimated fees and expenses. The net proceeds of the 2037 SPL Senior Notes, after provisioning for incremental interest required during construction, were used to prepay the then outstanding borrowings of $369 million under the 2015 SPL Credit Facilities and, along with the net proceeds of the 2028 SPL Senior Notes, the remainder is being used to pay a portion of the capital costs in connection with the construction of Trains 1 through 5 of the SPL Project in lieu of the terminated portion of the commitments under the 2015 SPL Credit Facilities.

In connection with the issuance of the 2037 SPL Senior Notes and the 2028 SPL Senior Notes, SPL terminated the remaining available balance of $1.6 billion under the 2015 SPL Credit Facilities, resulting in a write-off of debt issuance costs associated with the 2015 SPL Credit Facilities of $42 million during the year ended December 31, 2017.

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

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

2025 CQP Senior Notes

In September 2017, Cheniere Partners issued an aggregate principal amount of $1.5 billion of the 2025 CQP Senior Notes, which are jointly and severally guaranteed by each of Cheniere Partners' subsidiaries other than SPL and, subject to certain conditions governing the release of its guarantee, Sabine Pass LNG-LP, LLC (collectively, the "CQP Guarantors"). Net proceeds of the offering of approximately $1.5 billion, after deducting the initial purchasers' commissions and estimated fees and expenses, were used to prepay a portion of the outstanding indebtedness under the 2016 CQP Credit Facilities, resulting in a write-off of debt issuance costs associated with the 2016 CQP Credit Facilities of $25 million during the year ended December 31, 2017.

Borrowings under the 2025 CQP Senior Notes accrue interest at a fixed rate of 5.250%, and interest on the 2025 CQP Senior Notes is payable semi-annually in arrears. The 2025 CQP Senior Notes are governed by an indenture (the "CQP Indenture"), which contains customary terms and events of default and certain covenants that, among other things, limit the ability of Cheniere Partners and the CQP Guarantors to incur liens and sell assets, enter into transactions with affiliates, enter into sale-leaseback transactions and consolidate, merge or sell, lease or otherwise dispose of all or substantially all of the applicable entity's properties or assets.

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

The 2025 CQP Senior Notes are Cheniere Partners' senior obligations, ranking equally in right of payment with Cheniere Partners' other existing and future unsubordinated debt and senior to any of its future subordinated debt. The 2025 CQP Senior Notes will be secured alongside the 2016 CQP Credit Facilities on a first-priority basis (subject to permitted encumbrances) with liens on (1) substantially all the existing and future tangible and intangible assets and rights of Cheniere Partners and the CQP Guarantors and equity interests in the CQP Guarantors (except, in each case, for certain excluded properties set forth in the 2016 CQP Credit Facilities) and (2) substantially all of the real property of SPLNG (except for excluded properties referenced in the 2016 CQP Credit Facilities). The liens securing the 2025 CQP Senior Notes would be released if (1) the aggregate principal amount of all indebtedness then outstanding under the term loans under the 2016 CQP Credit Facilities secured by such liens does not exceed $1.0 billion and (2) the aggregate amount of Cheniere Partners' secured indebtedness and the secured indebtedness of the CQP Guarantors (other than the 2025 CQP Senior Notes or any other series of notes issued under the CQP Indenture) outstanding at any one time, together with all Attributable Indebtedness (as defined in the CQP Indenture) from sale-leaseback transactions (subject to certain exceptions), does not exceed the greater of (1) $1.5 billion and (2) 10% of net tangible assets. Upon the release of the liens securing the 2025 CQP Senior Notes, the limitation on liens covenant under the CQP Indenture will continue to govern the incurrence of liens by Cheniere Partners and the CQP Guarantors.

In connection with the closing of the sale of the 2025 CQP Senior Notes, Cheniere Partners and the CQP Guarantors entered into a registration rights agreement (the "CQP Registration Rights Agreement"). Under the CQP Registration Rights Agreement, Cheniere Partners and the CQP Guarantors have agreed to use commercially reasonable efforts to file with the SEC and cause to become effective a registration statement relating to an offer to exchange any and all of the 2025 CQP Senior Notes for a like aggregate principal amount of debt securities of Cheniere Partners with terms identical in all material respects to the 2025 CQP Senior Notes sought to be exchanged (other than with respect to restrictions on transfer or to any increase in annual interest rate), within 360 days after September 18, 2017. Under specified circumstances, Cheniere Partners and the CQP Guarantors have also agreed to use commercially reasonable efforts to cause to become effective a shelf registration statement relating to resales of the 2025 CQP Senior Notes. Cheniere Partners will be obligated to pay additional interest on the 2025 CQP Senior Notes if it fails to comply with its obligation to register the 2025 CQP Senior Notes within the specified time period.

CCH Senior Notes

In May 2017, CCH issued an aggregate principal amount of $1.5 billion of the 2027 CCH Senior Notes. Net proceeds of the offering of approximately $1.4 billion, after deducting commissions, fees and expenses and provisioning for incremental interest required under the 2027 CCH Senior Notes during construction, were used to prepay a portion of the outstanding borrowings under the 2015 CCH Credit Facility, resulting in a write-off of debt issuance costs associated with the 2015 CCH Credit Facility of $33 million during the year ended December 31, 2017. Borrowings under the 2027 CCH Senior Notes accrue interest at a fixed rate of 5.125%.

The 2024 CCH Senior Notes, 2025 CCH Senior Notes and 2027 CCH Senior Notes (collectively, the "CCH Senior Notes") are jointly and severally guaranteed by CCH's subsidiaries, CCL, CCP and Corpus Christi Pipeline GP, LLC (the "CCH Guarantors"). The indenture governing the CCH Senior Notes (the "CCH Indenture") contains customary terms and events of default and certain covenants that, among other things, limit CCH's ability and the ability of CCH's restricted subsidiaries to: incur additional indebtedness or issue preferred stock; make certain investments or pay dividends or distributions on membership interests or subordinated indebtedness or purchase, redeem or retire membership interests; sell or transfer assets, including membership or partnership interests of CCH's restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries to CCH or any of CCH's restricted subsidiaries; incur liens; enter into transactions with affiliates; dissolve, liquidate, consolidate, merge, sell or lease all or substantially all of the properties or assets of CCH and its restricted subsidiaries taken as a whole; or permit any CCH Guarantor to dissolve, liquidate, consolidate, merge, sell or lease all or substantially all of its properties and assets. Interest on the CCH Senior Notes is payable semi-annually in arrears.

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

Credit Facilities

Below is a summary of our credit facilities outstanding as of December 31, 2017 (in millions):

	SPL Working Capital Facility	2016 CQP Credit Facilities	2015 CCH Credit Facility	CCH Working Capital Facility	Cheniere Revolving Credit Facility
Original facility size	$ 1,200	$ 2,800	$ 8,404	$ 350	$ 750
Less:					
Outstanding balance	—	1,090	2,485	—	—
Commitments prepaid or terminated	—	1,470	3,832	—	—
Letters of credit issued	730	20	—	164	—
Available commitment	$ 470	$ 220	$ 2,087	$ 186	$ 750
Interest rate	LIBOR plus 1.75% or base rate plus 0.75%	LIBOR plus 2.25% or base rate plus 1.25% (1)	LIBOR plus 2.25% or base rate plus 1.25% (2)	LIBOR plus 1.50% - 2.00% or base rate plus 0.50% - 1.00%	LIBOR plus 3.25% or base rate plus 2.25%
Maturity date	December 31, 2020, with various terms for underlying loans	February 25, 2020, with principal payments due quarterly commencing on March 31, 2019	Earlier of May 13, 2022 or second anniversary of CCL Trains 1 and 2 completion date	December 14, 2021, with various terms for underlying loans	March 2, 2021

(1) There is a 0.50% step-up for both LIBOR and base rate loans beginning on February 25, 2019.

(2) There is a 0.25% step-up for both LIBOR and base rate loans following the completion of Trains 1 and 2 of the CCL Project as defined in the common terms agreement.

SPL Working Capital Facility

In September 2015, SPL entered into the SPL Working Capital Facility, which is intended to be used for loans to SPL ("SPL Working Capital Loans"), the issuance of letters of credit on behalf of SPL, as well as for swing line loans to SPL ("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.

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

SPL pays (1) a commitment fee equal to an annual rate of 0.70% on the average daily amount of the excess of the total commitment amount over the principal amount outstanding without giving effect to any outstanding SPL 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 "SPL LC Draw") to be deemed an SPL LC Loan, SPL is required to pay the full amount of the SPL LC Draw on or prior to the business day following the notice of the SPL LC Draw. An SPL LC Draw accrues interest at an annual rate of 2.0% plus the base rate. As of December 31, 2017, no SPL 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. SPL LC Loans have a term of up to one year. SPL 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 SPL Swing Line Loan is made and (3) the first borrowing date for a SPL Working Capital Loan or SPL Swing Line Loan occurring at least three business days following the date the SPL Swing Line Loan is made. SPL is required to reduce the aggregate outstanding principal amount of all SPL 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.

2016 CQP Credit Facilities

In February 2016, Cheniere Partners entered into the 2016 CQP Credit Facilities. The 2016 CQP Credit Facilities consist of: (1) a $450 million CTPL tranche term loan that was used to prepay the $400 million term loan facility (the "CTPL Term Loan") in February 2016, (2) an approximately $2.1 billion SPLNG tranche term loan that was used to repay and redeem the approximately $2.1 billion of the senior notes previously issued by SPLNG in November 2016, (3) a $125 million debt service reserve credit facility (the "DSR Facility") that may be used to satisfy a six-month debt service reserve requirement and (4) a $115 million revolving credit facility that may be used for general business purposes. In September 2017, Cheniere Partners issued the 2025 CQP Senior Notes and the net proceeds of the issuance were used to prepay $1.5 billion of the outstanding indebtedness under the 2016 CQP Credit Facilities.

The 2016 CQP Credit Facilities accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of the prime rate, the federal funds effective rate, as published by the Federal Reserve Bank of New York, plus 0.50% and adjusted one month LIBOR plus 1.0%), plus the applicable margin. The applicable margin for LIBOR loans is 2.25% per annum, and the applicable margin for base rate loans is 1.25% per annum, in each case with a 0.50% step-up beginning on February 25, 2019. Interest on LIBOR loans is due and payable at the end of each applicable LIBOR period (and at the end of every three month period within the LIBOR period, if any), and interest on base rate loans is due and payable at the end of each calendar quarter.

Cheniere Partners pays a commitment fee equal to an annual rate of 40% of the margin for LIBOR loans multiplied by the average daily amount of the undrawn commitment, payable quarterly in arrears. The DSR Facility and the revolving credit facility are both available for the issuance of letters of credit, which incur a fee equal to an annual rate of 2.25% of the undrawn portion with a 0.50% step-up beginning on February 25, 2019.

The 2016 CQP Credit Facilities mature on February 25, 2020, with principal payments due quarterly commencing on March 31, 2019. The outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest hedging and interest rate breakage costs. The 2016 CQP Credit Facilities contain conditions precedent for extensions of credit, as well as customary affirmative and negative covenants and limit Cheniere Partners' ability to make restricted payments, including distributions, to once per fiscal quarter as long as certain conditions are satisfied. Under the 2016 CQP Credit Facilities, Cheniere Partners is required to hedge not less than 50% of the variable interest rate exposure on its projected aggregate outstanding balance, maintain a minimum debt service coverage ratio of at least 1.15x at the end of each fiscal quarter beginning March 31, 2019 and have a projected debt service coverage ratio of 1.55x in order to incur additional indebtedness to refinance a portion of the existing obligations.

The 2016 CQP Credit Facilities are unconditionally guaranteed by each subsidiary of Cheniere Partners other than (1) SPL and (2) certain subsidiaries of Cheniere Partners owning other development projects, as well as certain other specified subsidiaries and members of the foregoing entities.

2015 CCH Credit Facility

In May 2015, CCH entered into the 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. 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.

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 of Trains 1 and 2 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 Trains 1 and 2 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. 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 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.

CCH Working Capital Facility

In December 2016, CCH entered into the $350 million CCH Working Capital Facility, which is intended to be used for loans to CCH ("CCH Working Capital Loans"), the issuance of letters of credit on behalf of CCH, as well as for swing line loans to CCH ("CCH Swing Line Loans") for certain working capital requirements related to developing and placing into operation the CCL Project. Loans under the CCH Working Capital Facility are guaranteed by the CCH Guarantors. CCH may, from time to time, request increases in the commitments under the CCH Working Capital Facility of up to the maximum allowed under the Common Terms Agreement that was entered into concurrently with the 2015 CCH Credit Facility.

Loans under the CCH Working Capital Facility, including CCH Working Capital Loans, CCH Swing Line Loans and loans made in connection with a draw upon any letter of credit ("CCH LC Loans" and collectively, the "Revolving Loans") accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of (1) the federal funds rate, plus 0.50%, (2) the prime rate and (3) one month LIBOR plus 0.50%), plus the applicable margin. The applicable margin for LIBOR Revolving Loans ranges from 1.50% to 2.00% per annum, and the applicable margin for base rate Revolving Loans ranges from 0.50% to 1.00% per annum. Interest on CCH Working Capital Loans, CCH Swing Line Loans and CCH LC Loans is due and payable on the date the loan becomes due. Interest on LIBOR Revolving Loans is due and payable at the end of each LIBOR period, and interest on base rate Revolving Loans is due and payable at the end of each quarter.

CCH pays (1) a commitment fee equal to an annual rate of 40% of the applicable margin for LIBOR Revolving Loans on the average daily amount of the excess of the total commitment amount over the principal amount outstanding without giving effect to any outstanding CCH Swing Line Loans, (2) a letter of credit fee equal to an annual rate equal to the applicable margin for LIBOR Revolving Loans on the undrawn portion of all letters of credit issued under the CCH Working Capital Facility and (3) a letter of credit fronting fee equal to an annual rate of 0.20% of the undrawn portion of all letters of credit. Each of these fees is payable quarterly in arrears.

If draws are made upon a letter of credit issued under the CCH Working Capital Facility and CCH does not elect for such draw (a "CCH LC Draw") to be deemed a CCH LC Loan, CCH is required to pay the full amount of the CCH LC Draw on or prior to the business day following the notice of the CCH LC Draw. A CCH LC Draw accrues interest at an annual rate of 2.00% plus the base rate.

The CCH Working Capital Facility matures on December 14, 2021, and CCH may prepay the Revolving Loans at any time without premium or penalty upon three business days' notice and may re-borrow at any time. CCH LC Loans have a term of up to one year. CCH Swing Line Loans terminate upon the earliest of (1) the maturity date or earlier termination of the CCH Working Capital Facility, (2) the date that is 15 days after such CCH Swing Line Loan is made and (3) the first borrowing date for a CCH Working Capital Loan or CCH Swing Line Loan occurring at least four business days following the date the CCH Swing Line Loan is made. CCH is required to reduce the aggregate outstanding principal amount of all CCH Working Capital Loans to zero for a period of five consecutive business days at least once each year.

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

Cheniere Revolving Credit Facility

In March 2017, we entered into the Cheniere Revolving Credit Facility that may be used to fund, through loans and letters of credit, equity capital contributions to CCH HoldCo II and its subsidiaries for the development of the CCL Project and, provided that certain conditions are met, for general corporate purposes. No advances or letters of credit under the Cheniere Revolving Credit Facility were available until either (1) Cheniere's unrestricted cash and cash equivalents are less than $500 million or (2) Train 4 of the SPL Project has achieved substantial completion. We incurred $16 million of debt issuance costs related to the Cheniere Revolving Credit Facility during the year ended December 31, 2017.

Loans under the Cheniere Revolving Credit Facility accrue interest at a variable rate per annum equal to LIBOR or the base rate (equal to the highest of (1) the prime rate, (2) the federal funds rate plus 0.50% and (3) one month LIBOR plus 1.00%), plus the applicable margin. The applicable margin for LIBOR loans is 3.25% per annum, and the applicable margin for base rate loans is 2.25% per annum. 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 calendar quarter. We will also pay (1) a commitment fee on the average daily amount of undrawn commitments at an annual rate of 0.75%, payable quarterly in arrears and (2) a letter of credit fee at an annual rate equal to the applicable margin for LIBOR loans on the undrawn portion of all letters of credit issued under the Cheniere Revolving Credit Facility. Draws on any letters of credit will accrue interest at an annual rate equal to the base rate plus 2.0%.

The Cheniere Revolving Credit Facility matures on March 2, 2021 and contains representations, warranties and affirmative and negative covenants customary for companies like Cheniere with lenders of the type participating in the Cheniere Revolving Credit Facility that limit our ability to make restricted payments, including distributions, unless certain conditions are satisfied, as well as limitations on indebtedness, guarantees, hedging, liens, investments and affiliate transactions. Under the Cheniere Revolving Credit Facility, we are required to ensure that the sum of our unrestricted cash and the amount of undrawn commitments under the Cheniere Revolving Credit Facility is at least equal to the lesser of (1) 20% of the commitments under the Cheniere Revolving Credit Facility and (2) $100 million.

The Cheniere Revolving Credit Facility is secured by a first priority security interest (subject to permitted liens and other customary exceptions) in substantially all of our assets, including our interests in our direct subsidiaries (excluding CCH HoldCo II).

Convertible Notes

Below is a summary of our convertible notes outstanding as of December 31, 2017 (in millions):

	2021 Cheniere Convertible Unsecured Notes	2025 CCH HoldCo II Convertible Senior Notes	2045 Cheniere Convertible Senior Notes
Aggregate original principal	$ 1,000	$ 1,000	$ 625
Debt component, net of discount	$ 1,040	$ 1,305	$ 311
Equity component	$ 206	$ —	$ 194
Maturity date	May 28, 2021	March 1, 2025	March 15, 2045
Contractual interest rate	4.875%	11.0%	4.25%
Effective interest rate (1)	8.3%	11.9%	9.4%
Remaining debt discount and debt issuance costs amortization period (2)	3.4 years	2.8 years	27.2 years

(1) Rate to accrete the discounted carrying value of the convertible notes to the face value over the remaining amortization period.

(2) We amortize any debt discount and debt issuance costs using the effective interest over the period through contractual maturity except for the 2025 CCH HoldCo II Convertible Senior Notes, which are amortized through the date they are first convertible by holders into our common stock.

2021 Cheniere Convertible Unsecured Notes

In November 2014, we issued 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 $809 million and the residual value of the equity component was $191 million as of the issuance date. As of December 31, 2017 and 2016, the carrying value of the equity component was $206 million and $205 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 8.3% as of both December 31, 2017 and 2016. As of December 31, 2017, 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 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, us 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. 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.

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.

2045 Cheniere Convertible Senior Notes

In March 2015, we issued 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 million and the residual value of the equity component was $196 million as of the issuance date, excluding debt issuance costs. As of both December 31, 2017 and 2016, the carrying value of the equity component, net of debt issuance costs, was $194 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 both December 31, 2017 and 2016. As of December 31, 2017, the if-converted value of the 2045 Cheniere Convertible Senior Notes did not exceed the principal balance.

Restrictive Debt Covenants

As of December 31, 2017, each of our issuers was in compliance with all covenants related to their respective debt agreements.

Interest Expense

Total interest expense, including interest expense related to our convertible notes, consisted of the following (in millions):

	Year Ended December 31,		
	2017	2016	2015
Interest cost on convertible notes:			
Interest per contractual rate	$ 219	$ 202	$ 146
Amortization of debt discount	29	31	28
Amortization of debt issuance costs	7	5	3
Total interest cost related to convertible notes	255	238	177
Interest cost on debt excluding convertible notes	1,271	1,063	820
Total interest cost	1,526	1,301	997
Capitalized interest	(779)	(813)	(675)
Total interest expense, net	$ 747	$ 488	$ 322

Fair Value Disclosures

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

	December 31, 2017		December 31, 2016	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes, net of premium or discount (1)	$ 18,610	$ 20,075	$ 14,263	$ 15,210
2037 SPL Senior Notes (2)	800	871	—	—
Credit facilities (3)	3,575	3,575	5,502	5,502
2021 Cheniere Convertible Unsecured Notes, net of discount (2)	1,040	1,136	960	983
2025 CCH HoldCo II Convertible Senior Notes (2)	1,305	1,535	1,171	1,328
2045 Cheniere Convertible Senior Notes, net of discount (4)	311	447	308	375

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

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

(3) Includes 2015 SPL Credit Facilities, SPL Working Capital Facility, 2016 CQP Credit Facilities, 2015 CCH Credit Facility, CCH Working Capital Facility, Cheniere Revolving Credit Facility and Cheniere Marketing trade finance facilities. The Level 3 estimated fair value approximates the principal amount because the interest rates are variable and reflective of market rates and the debt may be repaid, in full or in part, at any time without penalty.

(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 13—RESTRUCTURING EXPENSE

During 2015 and 2016, we initiated and implemented certain organizational changes to simplify our corporate structure, improve our operational efficiencies and implement a strategy for sustainable, long-term stockholder value creation through financially disciplined development, construction, operation and investment. These organizational initiatives were completed as of the first quarter of 2017. As a result of these efforts, we recorded $6 million, $61 million and $61 million during the years ended December 31, 2017, 2016 and 2015, respectively, of restructuring charges and other costs associated with restructuring and operational efficiency initiatives for which the majority of these charges required cash expenditure. Included in these amounts were $3 million, $47 million and $58 million for share-based compensation during the years ended December 31, 2017, 2016 and

2015, respectively. All charges were recorded within the line item entitled "restructuring expense" on our Consolidated Statements of Operations and substantially all related to severance and other employee-related costs. As of December 31, 2016, we had $6 million of accrued restructuring charges and other costs that were recorded as part of accrued liabilities on our Consolidated Balance Sheets.

NOTE 14—INCOME TAXES

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

	Year Ended December 31,		
	2017	2016	2015
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Foreign	(6)	—	(2)
Total current	(6)	—	(2)
Deferred:			
Federal	—	—	—
State	—	—	—
Foreign	3	(2)	2
Total deferred	3	(2)	2
Total income tax provision	$ (3)	$ (2)	$ —

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

	Year Ended December 31,		
	2017	2016	2015
U.S. federal statutory tax rate	35.0 %	35.0 %	35.0 %
Non-controlling interest	2.9 %	(2.1)%	(2.3)%
State tax rate	(0.2)%	1.8 %	1.9 %
U.S. tax reform rate change	71.4 %	— %	— %
Share-based compensation	(6.2)%	— %	— %
Nondeductible interest expense	8.5 %	(6.6)%	(2.6)%
Other	(1.2)%	(0.9)%	(1.8)%
Valuation allowance	(109.7)%	(27.5)%	(30.1)%
Effective tax rate	0.5 %	(0.3)%	0.1 %

Significant components of our deferred tax assets and liabilities at December 31, 2017 and 2016 are as follows (millions):

	December 31,	
	2017	2016
Deferred tax assets		
Net operating loss carryforwards and credits		
Federal and foreign	$ 960	$ 1,060
State	188	183
Deferred gain	46	77
Share-based compensation expense	16	53
Derivative instruments	15	47
Long-term debt	16	18
Other	30	13
Less: valuation allowance	(806)	(1,252)
Total deferred tax assets	465	199
Deferred tax liabilities		
Investment in limited partnership	(391)	(76)
Convertible debt	(65)	(118)
Property, plant and equipment	(6)	(5)
Total deferred tax liabilities	(462)	(199)
Net deferred tax assets	$ 3	$ —

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.

Effective January 1, 2017, we adopted ASU 2016-09 which requires excess tax benefits or deficiencies for share-based payments to be recognized as income tax expense or benefit in the period shares vest rather than within equity. The adoption of ASU 2016-09 may result in future volatility of our income tax expense (as the future tax effects of share-based awards will be dependent on the price of our common stock at the time of settlement). Excess tax benefits reduced our effective tax rate by 6.2% for the period ending December 31, 2017.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation (Tax Cuts and Jobs Act), which reduced the top U.S. corporate income tax rate from 35% to 21%. As a result of the legislation, we remeasured our December 31, 2017 U.S. deferred tax assets and liabilities. The result of the remeasurement was a $404 million reduction to our U.S. net deferred tax assets and represents a 71.4% increase to our effective tax rate. A corresponding change, reducing the effective tax rate, was recorded to the valuation allowance, and therefore there was no impact to current period income tax expense.

At December 31, 2017, we had federal and state net operating loss (“NOL”) carryforwards of approximately $4.7 billion and $2.3 billion, respectively. These NOL carryforwards will expire between 2021 and 2037. At December 31, 2017, we had federal and state tax credit carryforwards of $18 million and $4 million, respectively. These tax credit carryforwards expire between 2027 and 2036.

Due to historical losses and other available evidence 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, 2017 and 2016. We will continue to evaluate the realizability of our deferred tax assets in the future. As a result of increased profitability in the U.K., we released the $9 million U.K. valuation allowance during 2017. The decrease in the valuation allowance was $446 million for the year ended December 31, 2017.

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

	Year Ended December 31,	
	2017	2016
Balance at beginning of the year	$ 103	$ 104
Additions based on tax positions related to current year	—	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	(1)	(1)
Settlements	—	—
U.S. tax reform rate change	(40)	—
Balance at end of the year	$ 62	$ 103

Any settlement of uncertain tax positions would result in an adjustment to our NOL carryforward which, if utilized, will reduce taxable income in a future year. As a result, the tabular rollforward reflects the unrecognized tax benefits at the reduced corporate income tax rate of 21%.

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 U.S. 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 NOL carryforwards.

We are subject to tax in the U.S. and various state and foreign jurisdictions. We remain subject to periodic audits and reviews by taxing authorities; however, we do not expect these audits will have a material effect on our tax provision. Federal and state tax returns for the years after 2013 remain open for examination. Tax authorities may have the ability to review and adjust carryover attributes that were generated prior to these periods if utilized in an open tax year.

NOTE 15—SHARE-BASED COMPENSATION

We have granted restricted stock shares, restricted stock units, performance stock units and phantom units to employees and non-employee directors under the Amended and Restated 2003 Stock Incentive Plan, as amended (the "2003 Plan"), 2011 Incentive Plan, as amended (the "2011 Plan"), the 2015 Employee Inducement Incentive Plan (the "Inducement Plan") and the 2015 Long-Term Cash Incentive Plan (the "2015 Plan").

Total share-based compensation consisted of the following (in millions):

	Year Ended December 31,		
	2017	2016	2015
Share-based compensation costs, pre-tax:			
Equity awards	$ 34	$ 41	$ 90
Liability awards	80	76	105
Total share-based compensation	114	117	195
Capitalized share-based compensation	(23)	(16)	(23)
Total share-based compensation expense	$ 91	$ 101	$ 172
Tax benefit associated with share-based compensation expense	$ 5	$ —	$ —

The total unrecognized compensation cost at December 31, 2017 relating to non-vested share-based compensation arrangements consisted of the following:

	Unrecognized Compensation Cost (in millions)	Recognized over a weighted average period (years)
Restricted Stock Share Awards	$ 7	1.5
Restricted Share Unit and Performance Stock Unit Awards	$ 44	1.5
Phantom Units Awards	$ 49	1.1

We have disclosed the deferred tax benefit realized from share-based compensation exercised during the annual period in Note 14—Income Taxes.

Restricted Stock Share Awards

Restricted stock share 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 us prior to the lapse of the restrictions. These awards vest based on service conditions (one, two, three or four-year service periods) and performance conditions. All performance conditions of the awards have been achieved as of December 31, 2017.

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 various share-based performance awards deemed by the Compensation Committee of our Board (the "Compensation Committee").

The Inducement Plan initially provided for the issuance of up to 1.0 million shares of our common stock in the form of stock-based awards deemed by the Compensation Committee to provide us with an opportunity to attract employees. As of December 31, 2017, 0.2 million shares of restricted stock have been granted under the Inducement Plan. In December 2016, the Compensation Committee recommended, and our Board approved, reducing the remaining shares available for issuance under the Inducement Plan to zero.

The table below provides a summary of our restricted stock outstanding (in millions, except for per share information):

	Shares	Weighted Average Grant Date Fair Value Per Share
Non-vested at January 1, 2017	5.7	$ 24.12
Granted	—	—
Vested	(3.3)	23.80
Forfeited	(0.2)	28.28
Non-vested at December 31, 2017	2.2	$ 24.29

The fair value of restricted stock share awards vested for the years ended December 31, 2017, 2016 and 2015 were $78 million, $36 million and $50 million, respectively.

Restricted Share Unit and Performance Stock Unit Awards

Restricted share unit and performance stock unit awards are share awards that entitle the holder to receive shares of our common stock upon vesting, subject to restrictions on transfer and to a risk of forfeiture if the recipient terminates employment with us prior to the lapse of the restrictions. Restricted share units vest ratably over service conditions (two, three or four-year service periods). Performance stock units provide for three-year cliff vesting with payouts based on our cumulative distributable cash flow per share from January 1, 2018 through December 31, 2019 compared to a pre-established performance target. The number of shares that may be earned at the end of the vesting period ranges from 50 to 200 percent of the target award amount if the threshold performance is met.

In January 2017, the issuance of awards with respect to 7.8 million shares of common stock available for issuance under the 2011 Plan was approved at a special meeting of our shareholders.

The table below provides a summary of our restricted share unit and performance stock unit awards outstanding assuming payout at target for awards containing performance conditions (in millions, except for per unit information):

	Units	Weighted Average Grant Date Fair Value Per Unit
Non-vested at January 1, 2017	—	$ —
Granted (1)	1.4	47.16
Vested	—	—
Forfeited	(0.1)	46.71
Non-vested at December 31, 2017	1.3	$ 47.18

(1) This number excludes 0.2 million performance stock units, which represent the maximum number of common units that would be issued if the maximum level of performance under the target awards amount is achieved.

The table below provides a summary of restricted share unit and performance stock unit awards issued:

	Year Ended December 31,		
	2017	2016	2015
Units Issued (in millions)	1.4	—	—
Weighted Average Grant Date Fair Value Per Unit	$ 47.16	$ —	$ —
Fair Value vested (in millions)	$ 1	$ —	$ —

Phantom Units Awards

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. For the years ended December 31, 2017, 2016 and 2015, we issued zero, 1.8 million and 5.9 million phantom units, respectively, to our employees and non-employee directors. Phantom units are not eligible to receive quarterly distributions. These awards vest based on service conditions (two, three or four-year service periods).

The 2015 Plan generally provides for cash-settled awards. 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 2015 Plan. The Compensation Committee recommended and our Board approved the termination of the 2014-2018 LTIP in October 2016.

The table below provides a summary of our phantom units outstanding (in millions):

	Units
Non-vested at January 1, 2017	3.9
Granted	—
Vested	(1.8)
Forfeited	(0.3)
Non-vested at December 31, 2017	1.8

The value of phantom units vested during the years ended December 31, 2017, 2016 and 2015 was $86 million, $78 million, $50 million, respectively, of which $1 million was recorded as part of accrued liabilities on our Consolidated Balance Sheets as of December 31, 2016.

NOTE 16—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 deferrals (contributions) up to 6% 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 $7 million, $6 million and $5 million for the years ended December 31, 2017, 2016 and 2015, respectively. We have made no discretionary contributions to the 401(k) Plan to date.

NOTE 17—NET LOSS PER SHARE ATTRIBUTABLE TO COMMON STOCKHOLDERS

The following table reconciles basic and diluted weighted average common shares outstanding for the years ended December 31, 2017, 2016 and 2015 (in millions, except per share data):

	Year Ended December 31,		
	2017	2016	2015
Weighted average common shares outstanding:			
Basic	233.1	228.8	226.9
Dilutive unvested stock	—	—	—
Diluted	233.1	228.8	226.9
Basic and diluted net loss per share attributable to common stockholders	$ (1.68)	$ (2.67)	$ (4.30)

Potentially dilutive securities that were not included in the diluted net loss per share computations because their effects would have been anti-dilutive were as follows (in millions):

	Year Ended December 31,		
	2017	2016	2015
Stock options and unvested stock (1)	3.4	0.6	2.1
Convertible notes (2)	16.9	16.3	15.8
Total potentially dilutive common shares	20.3	16.9	17.9

(1) Does not include 0.2 million shares, 5.0 million shares and 5.4 million shares for the years ended December 31, 2017, 2016 and 2015, respectively, of unvested stock because the performance conditions had not yet been satisfied as of December 31, 2017, 2016 and 2015, respectively.

(2) Includes number of shares in aggregate issuable upon conversion of the 2021 Cheniere Convertible Unsecured Notes and the 2045 Cheniere Convertible Senior Notes. There were no shares included in the computation of diluted net loss per share for the 2025 CCH HoldCo II Convertible Senior Notes because substantive non-market-based contingencies underlying the eligible conversion date have not been met as of December 31, 2017.

NOTE 18—LEASES

During the years ended December 31, 2017, 2016 and 2015, we recognized rental expense for all operating leases of $199 million, $86 million and $41 million, respectively, related primarily to office space, land sites and LNG vessel time charters. Our land site leases for the Sabine Pass LNG terminal have initial terms varying up to 30 years with multiple options to renew up to an additional 60 years.

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

Years Ending December 31,	Operating Leases (1)
2018 (2)	$ 140
2019 (2)	127
2020	119
2021	76
2022	58
Thereafter	236
Total	$ 756

(1) Includes certain lease option renewals that are reasonably assured.
(2) Does not include $19 million in aggregate payments we will receive from our LNG vessel time charter subleases.

Capital Leases

In December 2015, we entered into a lease agreement for tug services related to the CCL Project that was accounted for as a capital lease. As of December 31, 2017, 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 millions):

Years Ending December 31,	Capital Leases
2018	$ 5
2019	10
2020	10
2021	10
2022	10
Thereafter	154
Total	$ 199

NOTE 19—COMMITMENTS AND CONTINGENCIES

We have various contractual obligations which are recorded as liabilities in our Consolidated Financial Statements. Other items, such as certain purchase commitments and other executed contracts which do not meet the definition of a liability as of December 31, 2017, are not recognized as liabilities but require disclosures in our Consolidated Financial Statements.

LNG Terminal Commitments and Contingencies

Obligations under EPC Contracts

SPL has lump sum turnkey contract with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for the engineering, procurement and construction of Train 5 of the SPL Project. The EPC contract for SPL Train 5 provides that SPL will pay Bechtel a contract price of $3.1 billion, subject to adjustment by change order. SPL has the right to terminate the 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 million depending on the termination date.

CCL has lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Stage 1 and Stage 2 of the CCL Project. The EPC contract for Stage 2 of the CCL Project was amended and restated in December 2017. The EPC contract prices for Stage 1 of the CCL Project and Stage 2 of the CCL Project are approximately $7.8 billion and $2.4 billion, respectively, reflecting amounts incurred under change orders through December 31, 2017. 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 for Stage 1 of the CCL Project is terminated, Bechtel will also be paid a lump sum of up to $30 million depending on the termination date. If the amended and restated EPC contract for Stage 2 of the CCL Project is terminated, Bechtel will be paid a lump sum of up to $2.5 million if the termination date is prior to the issuance of the notice to proceed, or Bechtel will be paid a lump sum of up to $30 million if the termination date is after the issuance of the notice to proceed, depending on the termination date.

Obligations under SPAs

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

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

Obligations under LNG TUAs

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

Obligations under Natural Gas Supply, Transportation and Storage Service Agreements

SPL and CCL have index-based physical natural gas supply contracts to secure natural gas feedstock for the SPL Project and CCL Project, respectively. The terms of these contracts primarily range from approximately one to six years and commence upon the occurrence of conditions precedent, including declaration by SPL or CCL 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 or CCL Project. As of December 31, 2017, SPL and CCL have secured up to approximately 2,214 TBtu and 2,024 TBtu, respectively, of natural gas feedstock through natural gas supply contracts, a portion of which are considered purchase obligations if the conditions precedent were met.

Additionally, SPL has transportation and storage service agreements for the SPL Project. The initial terms of the transportation agreements range from one to 20 years, with renewal options for certain contracts, and commences upon the occurrence of conditions precedent. The term of the SPL storage service agreements ranges from three to ten years.

As of December 31, 2017, our obligations under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent were met were as follows (in millions):

Years Ending December 31,	Payments Due (1)
2018	$ 2,274
2019	1,527
2020	1,397
2021	981
2022	336
Thereafter	1,169
Total	$ 7,684

(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, 2017.

Restricted Net Assets

At December 31, 2017, our restricted net assets of consolidated subsidiaries were approximately $3.4 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, 2017 and 2016, 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 18—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.

Parallax Litigation

In 2015, our wholly owned subsidiary, Cheniere LNG Terminals, LLC ("CLNGT"), entered into discussions with Parallax Enterprises, LLC ("Parallax Enterprises") regarding the potential joint development of two liquefaction plants in Louisiana (the "Potential Liquefaction Transactions"). While the parties negotiated regarding the Potential Liquefaction Transactions, CLNGT loaned Parallax Enterprises approximately $46 million, as reflected in a secured note dated April 23, 2015, as amended on June 30, 2015, September 30, 2015 and November 4, 2015 (the "Secured Note"). The Secured Note was secured by all assets of Parallax Enterprises and its subsidiary entities. On June 30, 2015, Parallax Enterprises' parent entity, Parallax Energy LLC ("Parallax Energy"), executed a Pledge and Guarantee Agreement further securing repayment of the Secured Note by providing a parent guaranty and a pledge of all of the equity of Parallax Enterprises in satisfaction of the Secured Note (the "Pledge Agreement"). CLNGT and Parallax Enterprises never executed a definitive agreement to pursue the Potential Liquefaction Transactions. The Secured Note matured on December 11, 2015, and Parallax Enterprises failed to make payment. On February 3, 2016, CLNGT filed an action against Parallax Energy, Parallax Enterprises and certain of Parallax Enterprises' subsidiary entities, styled Cause No. 4:16-cv-00286, Cheniere LNG Terminals, LLC v. Parallax Energy LLC, et al., in the United States District Court for the Southern District of Texas (the "Texas Federal Suit"). CLNGT asserted claims in the Texas Federal Suit for (1) recovery of all amounts due under the Secured Note and (2) declaratory relief establishing that CLNGT is entitled to enforce its rights under the Secured Note and Pledge Agreement in accordance with each instrument's terms and that CLNGT has no obligations of any sort to Parallax Enterprises concerning the Potential Liquefaction Transactions. On March 11, 2016, Parallax Enterprises and the other defendants in the Texas Federal Suit moved to dismiss the suit for lack of subject matter jurisdiction. On August 2, 2016, the court denied the defendants' motion to dismiss without prejudice and permitted the parties to pursue jurisdictional discovery.

On March 11, 2016, Parallax Enterprises filed a suit against us and CLNGT styled Civil Action No. 62-810, Parallax Enterprises LLP v. Cheniere Energy, Inc. and Cheniere LNG Terminals, LLC, in the 25th Judicial District Court of Plaquemines Parish, Louisiana (the "Louisiana Suit"), wherein Parallax Enterprises asserted claims for breach of contract, fraudulent inducement, negligent misrepresentation, detrimental reliance, unjust enrichment and violation of the Louisiana Unfair Trade Practices Act. Parallax Enterprises predicated its claims in the Louisiana Suit on an allegation that we and CLNGT breached a purported agreement to jointly develop the Potential Liquefaction Transactions. Parallax Enterprises sought $400 million in alleged economic damages and rescission of the Secured Note. On April 15, 2016, we and CLNGT removed the Louisiana Suit to the United States District Court for the Eastern District of Louisiana, which subsequently transferred the Louisiana Suit to the United States District Court for the Southern District of Texas, where it was assigned Civil Action No. 4:16-cv-01628 and transferred to the same judge presiding over the Texas Federal Suit for coordinated handling. On August 22, 2016, Parallax Enterprises voluntarily dismissed all claims asserted against CLNGT and us in the Louisiana Suit without prejudice to refiling.

On July 27, 2017, the Parallax entities named as defendants in the Texas Federal Suit reurged their motion to dismiss and simultaneously filed counterclaims against CLNGT and third party claims against us for breach of contract, breach of fiduciary duty, promissory estoppel, quantum meruit and fraudulent inducement of the Secured Note and Pledge Agreement, based on substantially the same factual allegations Parallax Enterprises made in the Louisiana Suit. These Parallax entities also simultaneously filed an action styled Cause No. 2017-49685, Parallax Enterprises, LLC, et al. v. Cheniere Energy, Inc., et al., in the 61st District Court of Harris County, Texas (the "Texas State Suit"), which asserts substantially the same claims these entities asserted in the Texas Federal Suit. On July 31, 2017, CLNGT withdrew its opposition to the dismissal of the Texas Federal Suit without prejudice on jurisdictional grounds and the federal court subsequently dismissed the Texas Federal Suit without prejudice. We and CLNGT simultaneously filed an answer and counterclaims in the Texas State Suit, asserting the same claims CLNGT had previously asserted in the Texas Federal Suit. Additionally, CLNGT filed third party claims against Parallax principals Martin Houston, Christopher Bowen Daniels, Howard Candelet and Mark Evans, as well as Tellurian Investments, Inc., Driftwood LNG, LLC, Driftwood LNG Pipeline LLC and Tellurian Services LLC, formerly known as Parallax Services LLC, including claims for tortious interference with CLNGT's collateral rights under the Secured Note and Pledge Agreement, fraudulent transfer, conspiracy/aiding and abetting. Discovery in the Texas State Suit is ongoing. Trial is currently set for September 2018.

We do not expect that the resolution of this litigation will have a material adverse impact on our financial results.

NOTE 20—CUSTOMER CONCENTRATION

The following table shows customers with revenues of 10% or greater of total third-party revenues and customers with accounts receivable balances of 10% or greater of total accounts receivable from third parties:

	Percentage of Total Third-Party Revenues			Percentage of Accounts Receivable from Third Parties	
	Year Ended December 31,			December 31,	
	2017	2016	2015	2017	2016
Customer A	24%	39%	—%	28%	34%
Customer B	14%	*	—%	16%	21%
Customer C	14%	—%	—%	14%	—%
Customer D	17%	—%	—%	—%	—%
Customer E	*	13%	—%	—%	—%
Customer F	*	*	—%	15%	28%
Customer G	*	*	—%	—%	12%

* Less than 10%

During the year ended December 31, 2017, revenues from external customers that were derived from domestic customers was $1.6 billion and from customers outside of the United States was $4.0 billion, of which $1.2 billion, $787 million and $762 million were derived from customers in Japan, Ireland and South Korea, respectively. During the year ended December 31, 2016, revenues from external customers that were derived from domestic customers was $769 million and from customers outside of the United States was $514 million, of which $162 million was derived from a customer in Japan. Substantially all of our revenues from external customers for the year ended December 31, 2015 were attributed to the United States. We attribute revenues from external customers to the country in which the party to the applicable agreement has its principal place of business. Substantially all of our long-lived assets are located in the United States.

NOTE 21—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2017	2016	2015
Cash paid during the period for interest, net of amounts capitalized	$ 305	$ 66	$ 123
Contribution of assets to equity method investee	14	—	—
Non-cash conveyance of assets	—	—	13

The balance in property, plant and equipment, net funded with accounts payable and accrued liabilities was $521 million, $395 million and $301 million as of December 31, 2017, 2016 and 2015, respectively.

NOTE 22—RECENT ACCOUNTING STANDARDS

The following table provides a brief description of recent accounting standards that had not been adopted by us as of December 31, 2017:

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)*, and subsequent amendments thereto	This standard provides a single, comprehensive revenue recognition model which replaces and supersedes most existing revenue recognition guidance and requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard requires that the costs to obtain and fulfill contracts with customers should be recognized as assets and amortized to match the pattern of transfer of goods or services to the customer if expected to be recoverable. The standard also requires enhanced disclosures. This guidance may be adopted either retrospectively to each prior reporting period presented subject to allowable practical expedients ("full retrospective approach") or as a cumulative-effect adjustment as of the date of adoption ("modified retrospective approach").	January 1, 2018	We will adopt this standard on January 1, 2018 using the full retrospective approach. The adoption of this standard will not have a material impact upon our Consolidated Financial Statements but will result in significant additional disclosure regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, including significant judgments and assumptions used in applying the standard.
ASU 2016-02, *Leases (Topic 842)*, and subsequent amendments thereto	This standard requires a lessee to recognize leases on its balance sheet by recording a lease liability representing the obligation to make future lease payments and a right-of-use asset representing the right to use the underlying asset for the lease term. A lessee is permitted to make an election not to recognize lease assets and liabilities for leases with a term of 12 months or less. The standard also modifies the definition of a lease and requires expanded disclosures. This guidance may be early adopted, and must be adopted using a modified retrospective approach with certain available practical expedients.	January 1, 2019	We continue to evaluate the effect of this standard on our Consolidated Financial Statements. Preliminarily, we anticipate a material impact from the requirement to recognize all leases upon our Consolidated Balance Sheets. Because this assessment is preliminary and the accounting for leases is subject to significant judgment, this conclusion could change as we finalize our assessment. We have not yet determined the impact of the adoption of this standard upon our results of operations or cash flows. We expect to elect the practical expedient to retain our existing accounting for land easements which were not previously accounted for as leases. We have not yet determined whether we will elect any other practical expedients upon transition.
ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*	This standard requires the immediate recognition of the tax consequences of intercompany asset transfers other than inventory. This guidance may be early adopted, but only at the beginning of an annual period, and must be adopted using a modified retrospective approach.	January 1, 2018	We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures.

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

Standard	Description	Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 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. This guidance may be early adopted and must be adopted prospectively.	January 1, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or related disclosures.
ASU 2016-09, *Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*	This standard primarily requires the recognition of excess tax benefits for share-based awards in the statement of operations and the classification of excess tax benefits as an operating activity within the statement of cash flows. The guidance also allows an entity to elect to account for forfeitures when they occur. This guidance may be early adopted, but all of the guidance must be adopted in the same period.	January 1, 2017	Upon adoption of this guidance, we made a cumulative effect adjustment to accumulated deficit for all excess tax benefits not previously recognized, offset by the change in valuation allowance, and for our election to account for forfeitures as they occur. The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or related disclosures.
ASU 2017-04, *Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*	This standard simplifies the measurement of goodwill impairment by eliminating the requirement for an entity to perform a hypothetical purchase price allocation. An entity will instead measure the impairment as the difference between the carrying amount and the fair value of the reporting unit. This guidance may be early adopted beginning January 1, 2017, and must be adopted prospectively.	January 1, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or related disclosures.
ASU 2017-09, *Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting*	This standard clarifies when changes to the terms or conditions of a share-based payment award must be accounted for as modifications. An entity will not apply modification accounting to a share-based payment award if the award's fair value, vesting conditions and classification as an equity or liability award are the same prior to and after the change. This guidance may be early adopted and must be adopted prospectively.	June 30, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or related disclosures.

CHENIERE ENERGY, INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION TO CONSOLIDATED FINANCIAL STATEMENTS
SUMMARIZED QUARTERLY FINANCIAL DATA
(unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2017:				
Revenues	$ 1,211	$ 1,241	$ 1,403	$ 1,746
Income from operations	376	274	297	441
Net income	172	21	90	280
Net income (loss) attributable to common stockholders	54	(285)	(289)	127
Net income (loss) per share attributable to common stockholders—basic and diluted (1)	0.23	(1.23)	(1.24)	0.54
Year ended December 31, 2016:				
Revenues	$ 69	$ 177	$ 465	$ 572
Income (loss) from operations	(91)	(76)	15	122
Net income (loss)	(349)	(335)	(131)	150
Net income (loss) attributable to common stockholders	(321)	(298)	(101)	110
Net income (loss) per share attributable to common stockholders—basic and diluted (1)	(1.41)	(1.31)	(0.44)	0.48

(1) The sum of the quarterly net income (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, 2017, 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 65 and is incorporated herein by reference.

ITEM 9B. OTHER INFORMATION

None.

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, 2017.

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 Partners, Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and the Company (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)
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)

Exhibit No.	Description
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 the Company, 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)
3.7	Amendment No. 1 to the Amended and Restated Bylaws of the Company, dated September 15, 2016 (Incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on September 19, 2016)
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 February 1, 2013, by and among SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on February 4, 2013)
4.3	Form of 5.625% Senior Secured Note due 2021 (Included as Exhibit A-1 to Exhibit 4.2 above)
4.4	First Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013)
4.5	Second Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on April 16, 2013)
4.6	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.5 above)
4.7	Third Supplemental Indenture, dated as of November 25, 2013, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on November 25, 2013)
4.8	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.7 above)
4.9	Fourth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.10	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.9 above)
4.11	Fifth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on May 22, 2014)
4.12	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.11 above)
4.13	Sixth Supplemental Indenture, dated as of March 3, 2015, between SPL and The Bank of New York Mellon, as Trustee (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on March 3, 2015)
4.14	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.13 above)
4.15	Seventh Supplemental Indenture, dated as of June 14, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on June 14, 2016)
4.16	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.15 above)
4.17	Eighth Supplemental Indenture, dated as of September 19, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 23, 2016)
4.18	Ninth Supplemental Indenture, dated as of September 23, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 23, 2016)
4.19	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.18 above)

Exhibit No.	Description
4.20	Tenth Supplemental Indenture, dated as of March 6, 2017, between SPL and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on March 6, 2017)
4.21	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.20 above)
4.22	Indenture, dated as of February 24, 2017, between SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on February 27, 2017)
4.23	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.22 above)
4.24	Indenture, dated as of November 28, 2014, by and between the Company, 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)
4.25	Form of 4.875% Unsecured PIK Convertible Note due 2021 (Included as Exhibit A to Exhibit 4.24 above)
4.26	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)
4.27	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)
4.28	Form of 4.25% Convertible Senior Note due 2045 (Included as Exhibit A to Exhibit 4.27 above)
4.29	Indenture, dated as of May 18, 2016, among CCH, as Issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as 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 May 18, 2016)
4.30	Form of 7.000% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.29 above)
4.31	First Supplemental Indenture, dated as of December 9, 2016, among CCH, as Issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as 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 December 9, 2016)
4.32	Form of 5.875% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.31 above)
4.33	Second Supplemental Indenture, dated as of May 19, 2017, among CCH, as issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as Guarantors, and The Bank of New York Mellon, as trustee (Incorporated by reference to Exhibit 4.1 to CCH's Current Report on Form 8-K (SEC File No. 333-215435), filed on May 19, 2017)
4.34	Form of 5.125% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.33 above)
4.35	Indenture, dated as of September 18, 2017, between Cheniere Partners, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 18, 2017)
4.36	First Supplemental Indenture, dated as of September 18, 2017, between Cheniere Partners, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture (Incorporated by reference to Exhibit 4.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 18, 2017)
4.37	Form of 5.250% Senior Note due 2025 (Included as Exhibit A-1 to Exhibit 4.36 above)
4.38	Amended and Restated Note Purchase Agreement, dated as of March 1, 2015, by and among CCH HoldCo II, 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)
4.39	Amendment to Amended and Restated Note Purchase Agreement, dated as of March 16, 2015, by and among CCH HoldCo II, 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)
4.40	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 CCH Hold Co II, 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)

Exhibit No.	Description
4.41	Form of 11.0% Senior Secured Note 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 SPLNG (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 SPLNG (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 SPLNG (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 SPLNG (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 SPLNG (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)
10.6	Letter Agreement, dated September 11, 2012, between Total Gas & Power North America, Inc. and SPLNG (Incorporated by reference to Exhibit 10.1 to 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 SPLNG (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 SPLNG (Incorporated by reference to Exhibit 10.28 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.9	Amendment of LNG Terminal Use Agreement, dated June 16, 2010, by and between Chevron U.S.A. Inc. and SPLNG (Incorporated by reference to Exhibit 10.3 to 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 SPLNG (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 SPLNG (Incorporated by reference to Exhibit 10.12 to SPLNG's Registration Statement on Form S-4 (SEC File No. 333-138916), filed on November 22, 2006)
10.12	Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between SPL and SPLNG (Incorporated by reference to Exhibit 10.1 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.13	Letter Agreement, dated May 28, 2013, by and between SPL and SPLNG (Incorporated by reference to Exhibit 10.1 to SPLNG's Quarterly Report on Form 10-Q (SEC File No. 333-138916), filed on August 2, 2013)
10.14	Guarantee Agreement, dated as of July 31, 2012, by Cheniere Partners in favor of SPLNG (Incorporated by reference to Exhibit 10.2 to SPLNG's Current Report on Form 8-K (SEC File No. 333-138916), filed on August 6, 2012)
10.15†	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)
10.16†	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)
10.17†	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)
10.18†	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)

Exhibit No.	Description
10.19†	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)
10.20†	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)
10.21†	Form of 2011 - 2013 Bonus Plan Restricted Stock Grant (Train 3 and Train 4) under the Cheniere Energy, Inc. Amended and Restated 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)
10.22†	Cheniere Energy, Inc. 2011 Incentive Plan (as amended through April 13, 2017) (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 8, 2017)
10.23†	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)
10.24†	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)
10.25†	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)
10.26†	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)
10.27†	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)
10.28†	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)
10.29†	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)
10.30†	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)
10.31†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grades 18-20) (Incorporated by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.32†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grades 18-20) (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 4, 2017)
10.33†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 17) (Incorporated by reference to Exhibit 10.38 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.34†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 17) (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 4, 2017)
10.35†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Key Executive Severance Plan) (Incorporated by reference to Exhibit 10.39 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.36†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Severance Pay Plan) (Incorporated by reference to Exhibit 10.40 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)

Exhibit No.	Description
10.37†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 16 and Below) (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 4, 2017)
10.38†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Singapore) (Grade 16 and Below) (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 4, 2017)
10.39†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Chile) (Grade 16 and Below) (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 4, 2017)
10.40†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grades 18-20) (Incorporated by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.41†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grades 18-20) (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 4, 2017)
10.42†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 17) (Incorporated by reference to Exhibit 10.42 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.43†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 17) (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 4, 2017)
10.44†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Key Executive Severance Plan) (Incorporated by reference to Exhibit 10.43 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.45†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Severance Pay Plan) (Incorporated by reference to Exhibit 10.44 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.46†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 16 and Below) (Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 4, 2017)
10.47†	Form of Milestone Award Letter (Incorporated by reference to Exhibit 10.45 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.48†	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)
10.49†	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)
10.50†	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)
10.51†	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)
10.52†	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)
10.53†	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)
10.54†	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)
10.55†	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)

Exhibit No.	Description
10.56†	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)
10.57†	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)
10.58*†	Amended and Restated Cheniere Energy, Inc. Key Executive Severance Pay Plan (Effective as of January 11, 2018) and Summary Plan Description
10.59†	Employment Agreement between the Company and Jack A. Fusco, dated May 12, 2016 (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 12, 2016)
10.60†	Cheniere Energy, Inc. Retirement Policy, dated effective February 17, 2017 (Incorporated by reference to Exhibit 10.65 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 24, 2017)
10.61†	Form of Indemnification Agreement for officers of the Company (Incorporated by reference to Exhibit 10.73 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 19, 2016)
10.62†	Form of Indemnification Agreement for directors of the Company (Incorporated by reference to Exhibit 10.74 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 19, 2016)
10.63	Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated as of September 4, 2015, among SPL, as Borrower, The Bank of Nova Scotia, as Senior Issuing Bank and Senior Facility Agent, ABN Amro Capital USA LLC, HSBC Bank USA, National Association and ING Capital LLC, as Senior Issuing Banks, Société Générale, as Swing Line Lender and Common Security Trustee, and the senior lenders party thereto from time to time (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 11, 2015)
10.64	Amended and Restated Subscription Agreement, dated as of November 26, 2014, by and among the Company, RRJ Capital II Ltd, Baytree Investments (Mauritius) Pte Ltd and Seatown Lionfish Pte. Ltd. relating to convertible PIK notes of the Company (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)
10.65	Common Terms Agreement, dated May 13, 2015, among CCH, as Borrower, CCL, CCP, and 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)
10.66	Consent for Amendment to the Common Terms Agreement, dated September 7, 2017, among CCH, as Borrower, CCL, CCP, and 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 10.52 to CCH's Registration Statement on Form S-4 (SEC File No. 333-221307), filed on November 2, 2017)
10.67	Common Security and Account Agreement, dated May 13, 2015, among CCH, as Company, CCL, CCP, 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 Current Report on Form 8-K (SEC File No. 001-16383), filed on May 13, 2015)
10.68	Consent for Amendment to the Common Security and Account Agreement, dated September 7, 2017, among CCH, as Company, CCL, CCP, 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 10.51 to CCH's Registration Statement on Form S-4 (SEC File No. 333-221307), filed on November 2, 2017)
10.69	Pledge Agreement, dated May 13, 2015, between CCH HoldCo I, 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)
10.70	Corpus Christi Liquefied Natural Gas Project Term Loan Facility Agreement, dated May 13, 2015, among CCH, as Borrower, CCL, CCP, and 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)
10.71	Equity Contribution Agreement, dated May 13, 2015, among CCH 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
10.72	Registration Rights Agreement for 11.0% Senior Secured Notes due 2025, dated May 13, 2015, among the Company, CCH HoldCo II 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)
10.73	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)
10.74	Pledge Agreement, dated May 13, 2015, among CCH HoldCo II, 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)
10.75	Working Capital Facility Agreement, dated as of December 14, 2016, among CCH, as Borrower, CCL, CCP, and Corpus Christi Pipeline GP, as Guarantors, The Bank of Nova Scotia, as Working Capital Facility Agent, The Bank of Nova Scotia and Sumitomo Mitsui Banking Corporation, as Issuing Banks, Mizuho Bank, Ltd., as Swing Line Lender, and the lenders 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 December 20, 2016)
10.76	First Amendment to Working Capital Facility Agreement, dated December 20, 2016, among CCH, as Borrower, CCL, CCP, and Corpus Christi Pipeline GP, LLC, as Guarantors, The Bank of Nova Scotia, as Working Capital Facility Agent, The Bank of Nova Scotia and Sumitomo Mitsui Banking Corporation, as Issuing Banks, Mizuho Bank, Ltd., as Swing Line Lender, and the lenders party thereto from time to time (Incorporated by reference to Exhibit 10.42 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.77	Credit and Guaranty Agreement, dated as of February 25, 2016, among Cheniere Partners, as Borrower, certain subsidiaries of Cheniere Partners, as Subsidiary Guarantors, the lenders from time to time party thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Issuing Bank, Administrative Agent and Coordinating Lead Arranger, and certain arrangers and other participants (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on March 2, 2016)
10.78	Administrative Amendment, dated August 7, 2017, to the Credit and Guaranty Agreement among Cheniere Partners, as Borrower, certain subsidiaries of Cheniere Partners, as Subsidiary Guarantors, the lenders from time to time party thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent (Incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 9, 2017)
10.79	Depositary Agreement, dated as of February 25, 2016, among Cheniere Partners, as Borrower, certain subsidiaries of Cheniere Partners, as Subsidiary Guarantors, MUFG Union Bank, N.A., as Collateral Agent and Depositary Bank (Incorporated by reference to Exhibit 10.2 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on March 2, 2016)
10.80	Omnibus Amendment and Waiver, dated as of October 14, 2016, to (a) the Credit and Guaranty Agreement, dated as of February 25, 2016 among Cheniere Partners, as Borrower, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent, the lenders party thereto from time to time, and each other person party thereto from time to time and to (b) the Depositary Agreement, dated as of February 25, 2016, among Borrower, MUFG Union Bank, N.A., as Collateral Agent and Depositary Agent and each other person party thereto from time to time (Incorporated by reference to Exhibit 10.27 to Cheniere Partners' Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 24, 2017)
10.81*	Second Omnibus Amendment, dated as of September 28, 2017 to (a) the Credit and Guaranty Agreement, dated as of February 25, 2016, as amended by the Omnibus Amendment and Waiver, dated October 14, 2016, by and among Cheniere Partners, as Borrower, The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Administrative Agent, the lenders party thereto from time to time, and each other person party thereto from time to time, to (b) the Depositary Agreement, dated as of February 25, 2016, as amended by the Omnibus Amendment and Waiver, dated October 14, 2016, by and among Borrower, MUFG Union Bank, N.A., as Collateral Agent and Depositary Agent and each other person party thereto from time to time and to (c) the Intercreditor Agreement, dated as of February 25, 2016 by and among the Borrower, the Administrative Agent, the Collateral Agent, and each other person party thereto from time to time
10.82	Revolving Credit Agreement, dated as of March 2, 2017, among the Company, as Borrower, the Lenders and Issuing Banks party thereto, Goldman Sachs Bank USA, Morgan Stanley Senior Funding, Inc. and SG Americas Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners, and Société Générale, as Administrative Agent (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 8, 2017)

Exhibit No.	Description
10.83	Registration Rights Agreement, dated as of September 18, 2017, between Cheniere Partners, the guarantors party thereto and Credit Suisse Securities (USA) LLC (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on September 18, 2017)
10.84	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)
10.85	LNG Lease Agreement, dated June 24, 2008, between Cheniere Marketing, Inc. and SPLNG (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)
10.86	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)
10.87	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K/A (SEC File No. 001-33366), filed on July 1, 2015)
10.88	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00001 Currency and Fuel Provisional Sum Adjustment, dated June 25, 2015 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on July 30, 2015)
10.89	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00002 Credit to EPC Contract Value for TSA Work, dated September 17, 2015 (Incorporated by reference to Exhibit 10.2 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on October 30, 2015)
10.90	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00003 Perimeter Fencing Scope Removal, East Meter Piping Scope Change, Additional Bathroom Facilities, dated November 18, 2015 (Incorporated by reference to Exhibit 10.45 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 19, 2016)
10.91	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00004 DOE Regulation Change Impacts, RECON Schedule Change, Addition of Dry Flare Connection, Fuel Gas Supply Transfer to Train 5 and East Meter Fuel Gas, dated February 18, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on May 5, 2016)
10.92	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00005 Performance and Attendance Bonus (PAB) Incentive Program Provisional Sum, dated March 16, 2016, (ii) the Change Order CO-00006 Additional Bechtel Hours to Support RECON, Temporary Access Rd., Addition of Flash Liquid Expander, Removal of Vibration Monitor System, To-Date Reconciliation of Soils Preparation Provisional Sum, dated March 22, 2016, (iii) the Change Order CO-00007 Additional Support for FERC Document Requests, dated May 10, 2016, (iv) the Change Order CO-00008 Water System Scope Changes and Seal Design & Seal Gas Modification, dated May 4, 2016, (v) the Change Order CO-00009 Re-Orientation of PSV Bypass Valves, dated May 17, 2016, and (vi) the Change Order CO-00010 Deletion of Chlorine Analyzer, dated June 15, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.4 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on August 9, 2016)
10.93	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00011 Site Drainage Design Change: Professional Service Hours, dated July 26, 2016 (Incorporated by reference to Exhibit 10.3 to SPL's Quarterly Report on Form 10-Q (SEC File No. 333-192373), filed on November 3, 2016)

Exhibit No.	Description
10.94	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00012 Addition of Check Valves to Condensate Lines and Change of Tie-in Point, dated September 12, 2016, (ii) the Change Order CO-00013 LNG Rundown Line Reroute, dated September 12, 2016, (iii) the Change Order CO-00014 Pre-EPC HAZOP Action Item Closure, dated September 27, 2016, (iv) the Change Order CO-00015 Study for Enclosed Ground Flare and Process Flare, dated September 27, 2016, (v) the Change Order CO-00016 Upgrades to Gas Turbine Generators, dated October 19, 2016, and (vi) the Change Order CO-00017 Site Drainage Design Change: Temporary Drainage Implementation, dated December 1, 2016 (Incorporated by reference to Exhibit 10.59 to SPL's Registration Statement on Form S-4 (SEC File No. 333-215882), filed on February 3, 2017)
10.95	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00018 Stage 3 Process Flare Modification, dated March 10, 2017, (ii) the Change Order CO-00019 Site Drainage Design Change: Permanent Drainage Implementation, dated March 10, 2017 and (iii) the Change Order CO-00020 Soils Provisional Sum Partial True-up RECON 2, dated March 13, 2017 (Incorporated by reference to Exhibit 10.64 to SPL's Registration Statement on Form S-4 (SEC File No. 333-218646), filed on June 9, 2017)
10.96	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00021 Soils Preparation Provisional Sum Partial True-Up RECON 3, dated August 24, 2017 (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 9, 2017)
10.97*	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 3 Liquefaction Facility, dated as of May 4, 2015, between SPL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00022 OSHA Handrail and Guardrail Modifications, dated October 24, 2017, (ii) the Change Order CO-00023 Operating Spare Part Provisional Sum Closeout, dated October 31, 2017 and (iii) the Change Order CO-00024, dated November 28, 2017
10.98	Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 1 Liquefaction Facility, dated December 6, 2013, between CCL and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-16383), filed on December 10, 2013)
10.99	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00001 Cost Impacts Associated with Delay in NTP, dated March 9, 2015, (ii) the Change Order CO-00002 DLE/IAC Scope Change, dated March 25, 2015, (iii) the Change Order CO-00003 Currency and Fuel Provisional Sum Closures, dated May 13, 2015 and (iv) 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)
10.100	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00005 Revised Buildings to Include Jetty and Geo-Tech Impact to Buildings, dated June 4, 2015, (ii) the Change Order CO-00006 Marine and Dredging Execution Change, dated June 16, 2015, (iii) 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, (iv) 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, (v) the Change Order CO-00009 Post FEED Studies, dated July 1, 2015, (vi) 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, (vii) the Change Order CO-00011 Credit to EPC Contract Value for TSA Work, dated July 7, 2015, and (viii) 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)

Exhibit No.	Description
10.101	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 CCL 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 been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.134 to the Company's Annual Report on Form 10-K (SEC File No. 001-16383), filed on February 19, 2016)
10.102	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00014 Stage 1 Isolation, dated January 11, 2016, (ii) the Change Order CO-00015 IAC Conversion to Lump Sum, dated January 20, 2016, and (iii) the Change Order CO-00016 Permanent Plant Buildings, dated January 20, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on May 5, 2016)
10.103	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00017 Process and Utility Tie-Ins Studies and Associated Scopes (138 kV Pricing, Transfer Line, Connections for Future LNG Truck Loading Facility), dated May 24, 2016, (ii) the Change Order CO-00018 FERC Conditions 40, 63, 64, 80, dated May 4, 2016, (iii) the Change Order CO-00019 Trelleborg Marine Equipment, BOG Compressor Tie-In, Multiplexer Credit, Additional FERC Hours, dated May 4, 2016, and (iv) the Change Order CO-00020 Impact Due to Overhead Power Transmission Lines on La Quinta Road and Flare System Modification Evaluation, dated May 31, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on August 9, 2016)
10.104	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00022 Permanent Plant Building Modifications, dated June 20, 2016 and (ii) the Change Order CO-00024 N2 Dewar Interface, Temporary Power to Air Cooler, Condensate Pipeline Maximum Allowable Operating Pressure, dated June 28, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.) (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 3, 2016)
10.105	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00026 Changes to Outfall (P1, P2, and P5) to LaQuinta Ditch, dated August 31, 2016, (ii) the Change Order CO-00028 Anti-Dumping Duties, dated September 26, 2016, and (iii) the Change Order CO-00029 Additional Flare System Evaluation, dated September 26, 2016 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment) (Incorporated by reference to Exhibit 10.12 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.106	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00021 Secondary Access Road, DMPA-1 Scope and Use, Credit for Material Disposal, Power Pole Relocation, dated June 29, 2016, (ii) the Change Order CO-00023 Differing Soil Conditions and Bed 24 Over-Excavation Due to Differing Soil Condition, dated June 29, 2016, (iii) the Change Order CO-00025 Priority 6 Roads Differing Soil Conditions and 102-J01 Over-Excavation due to Differing Soil Conditions, dated August 23, 2016, (iv) the Change Order CO-00027 Lines Traversing Laydown Area Access Road and Underground Utilities for Temporary Facilities, dated September 26, 2016, and (v) the Change Order CO-00032 Integrated Security System, dated February 3, 2017 (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 CCH's Registration Statement on Form S-4/A (SEC File No. 333-215435), filed on March 8, 2017)
10.107	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00030, dated November 1, 2016 (Incorporated by reference to Exhibit 10.46 to Amendment No. 1 to CCH's Registration Statement on Form S-4/A (SEC File No. 333-215435), filed on March 8, 2017)

Exhibit No.	Description
10.108	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: the Change Order CO-00031 Flare System Modification Implementation, dated January 17, 2017 (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. 2 to CCH's Registration Statement on Form S-4/A (SEC File No. 333-215435), filed on March 23, 2017)
10.109	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00033 Marine Ground Flare, dated February 27, 2017 (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 CCH's Quarterly Report on Form 10-Q (SEC File No. 333-215435), filed on May 4, 2017)
10.110	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00034 Condensate Tie-In, Utility Water Tie-In, and Feed Gas Tie-In Relocation, dated April 18, 2017 and (ii) the Change Order CO-00035 Nitrogen Tie-In Relocation, dated April 21, 2017 (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 CCH's Quarterly Report on Form 10-Q (SEC File No. 333-215435), filed on August 8, 2017)
10.111	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 CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00036 Security Fencing Revisions, 138kV Overhead Power Stop Work, Additional Permanent Plant Access Control System Changes, and Wet/Dry Flare Expansion Loop Relocation, dated August 3, 2017 and (ii) the Change Order CO-00037 9% Nickel Lump Sum Conversion, dated September 14, 2017 (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 10.50 to CCH's Registration Statement on Form S-4 (SEC File No. 333-221307), filed on November 2, 2017)
10.112*	Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated December 12, 2017, by and between CCL 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.)
10.113	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)
10.114	LNG Sale and Purchase Agreement (FOB), dated November 21, 2011, between SPL (Seller) and Gas Natural Aprovisionamientos SDG S.A. (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on November 21, 2011)
10.115	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated April 3, 2013, between SPL (Seller) and Gas Natural Aprovisionamientos SDG S.A. (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Quarterly Report on Form 10-Q (SEC File No. 001-33366), filed on May 3, 2013)
10.116	Amendment of LNG Sale and Purchase Agreement (FOB), dated January 12, 2017, between SPL (Seller) and Gas Natural Fenosa LNG GOM, Limited (assignee of Gas Natural Aprovisionamientos SDG S.A.) (Buyer) (Incorporated by reference to Exhibit 10.3 to SPL's Registration Statement on Form S-4 (SEC File No. 333-215882), filed on February 3, 2017)
10.117	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between SPL (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on December 12, 2011)
10.118	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and GAIL (India) Limited (Buyer) (Incorporated by reference to Exhibit 10.18 to Cheniere Partners' Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.119	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between SPL (Seller) and BG Gulf Coast LNG, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on January 26, 2012)

Exhibit No.	Description
10.120	Letter agreement, dated May 12, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB) between SPL and BG Gulf Coast LNG, LLC dated January 25, 2012 (Incorporated by reference to Exhibit 10.7 to SPL's Registration Statement on Form S-4 (SEC File No. 333-215882), filed on February 3, 2017)
10.121	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between SPL (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on January 30, 2012)
10.122	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and Korea Gas Corporation (Buyer) (Incorporated by reference to Exhibit 10.19 to Cheniere Partners' Annual Report on Form 10-K (SEC File No. 001-33366), filed on February 22, 2013)
10.123	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL (Seller) and Cheniere Marketing, LLC (Buyer) (Incorporated by reference to Exhibit 10.1 to SPL's Current Report on Form 8-K (SEC File No. 333-192373), filed on August 11, 2014)
10.124	Letter agreement, dated December 8, 2016, amending the Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL and Cheniere Marketing International LLP (as assignee of Cheniere Marketing, LLC) (Incorporated by reference to Exhibit 10.14 to SPL's Annual Report on Form 10-K (SEC File No. 333-192373), filed on February 24, 2017)
10.125	LNG Sale and Purchase Agreement (FOB), dated April 1, 2014, between CCL (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)
10.126	LNG Sale and Purchase Agreement (FOB), dated April 7, 2014, between CCL (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)
10.127	Assignment and Amendment Agreement, dated April 7, 2014, among Endesa Generación S.A., Endesa S.A. and CCL (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)
10.128	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated July 23, 2015, between Endesa S.A. (Buyer) and CCL (Seller) (Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on October 30, 2015)
10.129	Amendment No. 2 of LNG Sale and Purchase Agreement (FOB), dated July 23, 2015, between Endesa S.A. (Buyer) and CCL (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)
10.130	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated March 20, 2015, between CCL (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)
10.131	Amendment No. 1, dated February 4, 2016, to Amended and Restated LNG Sale and Purchase Agreement (FOB) between CCL and PT Pertamina (Persero), dated March 20, 2015 (Incorporated by reference to Exhibit 10.22 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.132	LNG Sale and Purchase Agreement (FOB), dated June 2, 2014, between CCL (Seller) and Gas Natural Fenosa LNG SL (subsequently assigned to Gas Natural Fenosa LNG GOM, Limited) (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)
10.133	Amended and Restated Base LNG Sale and Purchase Agreement (FOB), dated as of November 28, 2014, between CCL and Cheniere Marketing International LLP (Incorporated by reference to Exhibit 10.32 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.134	Amendment No. 1, dated June 26, 2015, to Amended and Restated Base LNG Sale and Purchase Agreement (FOB), dated as of November 28, 2014, between CCL and Cheniere Marketing International LLP (Incorporated by reference to Exhibit 10.33 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.135	Amendment No. 2, dated December 27, 2016, to Amended and Restated Base LNG Purchase Agreement (FOB), dated as of November 28, 2014, between CCL and Cheniere Marketing International LLP (Incorporated by reference to Exhibit 10.34 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.136	Amended and Restated Foundation Customer LNG Sale and Purchase Agreement (FOB), dated as of November 28, 2014 between CCL and Cheniere Marketing International LLP (Incorporated by reference to Exhibit 10.35 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)

Exhibit No.	Description
10.137	Amendment No. 1, dated June 26, 2015, to Amended and Restated Foundation Customer LNG Sale and Purchase Agreement (FOB), dated as of November 28, 2014 between CCL and Cheniere Marketing International LLP (Incorporated by reference to Exhibit 10.36 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.138	Amendment No. 2, dated December 27, 2016, to Amended and Restated Foundation Customer LNG Sale and Purchase Agreement (FOB), dated as of November 28, 2014, between CCL and Cheniere Marketing LLP (Incorporated by reference to Exhibit 10.37 to CCH's Registration Statement on Form S-4 (SEC File No. 333-215435), filed on January 5, 2017)
10.139	Cooperative Endeavor Agreement & Payment in Lieu of Tax Agreement with eleven Cameron Parish taxing authorities, dated October 23, 2007, by and between Cheniere Marketing, Inc. and SPLNG (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-16383), filed on November 6, 2007)
10.140	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among the Company, Cheniere Energy Partners GP, LLC, Cheniere Partners, Cheniere Class B Units Holdings, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time (Incorporated by reference to Exhibit 10.1 to Cheniere Partners' Current Report on Form 8-K (SEC File No. 001-33366), filed on August 6, 2012)
10.141	Fourth Amended and Restated Agreement of Limited Partnership of Cheniere Partners, dated February 14, 2017 (Incorporated by reference to Exhibit 3.1 to Cheniere Partners' Current Report on Form 8-K (File No. 001-33366) filed on February 21, 2017)
10.142	Amended and Restated Limited Liability Company Agreement of Cheniere Holdings, 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)
10.143	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)
10.144	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 the Company
23.1*	Consent of KPMG LLP
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2*	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1**	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

CONDENSED BALANCE SHEETS
(in millions)

	December 31,	
	2017	2016
ASSETS		
Cash and cash equivalents	$ —	$ —
Non-current restricted cash	—	7
Property, plant and equipment, net	15	15
Debt issuance and deferred financing costs, net	12	—
Investments in affiliates	(435)	(145)
Total assets	$ (408)	$ (123)
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities	$ 8	$ 8
Long-term debt, net	1,348	1,265
Stockholders' deficit	(1,764)	(1,396)
Total liabilities and stockholders' deficit	$ (408)	$ (123)

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
(in millions)

	Year Ended December 31,		
	2017	2016	2015
General and administrative expense	$ 7	$ 6	$ —
Other income (expense)			
Interest expense, net	(118)	(104)	(93)
Interest expense, net—affiliates	—	(7)	(9)
Interest income—affiliates	—	24	34
Equity loss of affiliates	(268)	(517)	(907)
Total other expense	(386)	(604)	(975)
Net loss attributable to common stockholders	$ (393)	$ (610)	$ (975)

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 millions)

	Year Ended December 31,		
	2017	2016	2015
Net cash used in operating activities	$ (4)	$ (102)	$ (176)
Cash flows from investing activities			
Investments in affiliates	209	202	(181)
Net cash provided by (used in) investing activities	209	202	(181)
Cash flows from financing activities			
Proceeds from issuance of debt	—	—	500
Debt issuance and deferred financing costs	(15)	—	(4)
Distribution and dividends to non-controlling interest	(185)	(80)	(80)
Proceeds from exercise of stock options	—	—	2
Payments related to tax withholdings for share-based compensation	(12)	(20)	(61)
Other	—	—	1
Net cash provided by (used in) financing activities	(212)	(100)	358
Net increase (decrease) in cash, cash equivalents and restricted cash	(7)	—	1
Cash, cash equivalents and restricted cash—beginning of period	7	7	6
Cash, cash equivalents and restricted cash—end of period	$ —	$ 7	$ 7

Balances per Condensed Balance Sheets:

	December 31	
	2017	2016
Cash and cash equivalents	$ —	$ —
Non-current restricted cash	—	7
Total cash, cash equivalents and restricted cash	$ —	$ 7

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 Condensed 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, 2017 and 2016, our debt consisted of the following (in millions):

	December 31,	
	2017	2016
Long-term debt:		
4.875% Convertible Unsecured Notes due 2021, net of unamortized discount of $121 and $146	$ 1,040	$ 960
4.25% Convertible Senior Notes due 2045, net of unamortized discount of $314 and $317	311	308
$750 million Cheniere Revolving Credit Facility	—	—
Unamortized debt issuance costs	(3)	(3)
Total long-term debt, net	$ 1,348	$ 1,265

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2017 (in millions):

Years Ending December 31,	Principal Payments
2018	$ —
2019	—
2020	—
2021	1,161
2022	—
Thereafter	625
Total	$ 1,786

In October 2016, Cheniere LNG Terminals, LLC ("Cheniere Terminals"), a wholly owned subsidiary of Cheniere, forgave Cheniere's total previously outstanding current debt—affiliate balance, which was composed of a $94 million note and $57 million in related accumulated interest payable to Cheniere Terminals. This $151 million forgiveness of debt during the year ended December 31, 2016 was recorded as a non-cash equity contribution to our subsidiaries on our Condensed Balance Sheet.

NOTE 3—GUARANTEES

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, 2017 and 2016, there were no liabilities recognized under these guarantee arrangements.

NOTE 4 —SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2017	2016	2015
Non-cash capital contributions (1)	$ (268)	$ (517)	$ (907)
Non-cash capital contribution from subsidiaries for forgiveness of debt	—	151	—
Non-cash capital distribution to subsidiaries for forgiveness of debt	—	(868)	—
Issuance of stock to acquire additional interest in Cheniere Holdings	2	94	—

(1) Amounts represent equity losses of affiliates.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

CHENIERE ENERGY, INC.
(Registrant)

By: /s/ Jack A. Fusco
Jack A. Fusco
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 20, 2018

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/ Jack A. Fusco Jack A. Fusco	President and Chief Executive Officer and Director (Principal Executive Officer)	February 20, 2018
/s/ Michael J. Wortley Michael J. Wortley	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 20, 2018
/s/ Leonard Travis Leonard Travis	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 20, 2018
/s/ G. Andrea Botta G. Andrea Botta	Chairman of the Board	February 20, 2018
/s/ Vicky A. Bailey Vicky A. Bailey	Director	February 20, 2018
/s/ Nuno Brandolini Nuno Brandolini	Director	February 20, 2018
/s/ Andrew Langham Andrew Langham	Director	February 20, 2018
/s/ David I. Foley David I. Foley	Director	February 20, 2018
/s/ David B. Kilpatrick David B. Kilpatrick	Director	February 20, 2018
/s/ John J. Lipinski John J. Lipinski	Director	February 20, 2018
/s/ Donald F. Robillard, Jr. Donald F. Robillard, Jr.	Director	February 20, 2018
/s/ Neal A. Shear Neal A. Shear	Director	February 20, 2018
/s/ Heather R. Zichal Heather R. Zichal	Director	February 20, 2018

APPENDIX

Consolidated Adjusted EBITDA and Distributable Cash Flow

The following table reconciles our actual Consolidated Adjusted EBITDA and Distributable Cash Flow to Net loss attributable to common stockholders for 2017 (in billions):

	2017
Net loss attributable to common stockholders	$ (0.4)
Net income attributable to non-controlling interest	1.0
Income tax provision (benefit)	0.0
Interest expense, net of capitalized interest	0.7
Loss on early extinguishment of debt	0.1
Derivative loss (gain), net	(0.0)
Other expense (income)	(0.0)
Income from operations	**$ 1.4**
Adjustments to reconcile income from operations to Consolidated Adjusted EBITDA:	
Depreciation and amortization expense	0.4
Loss from changes in fair value of commodity and FX derivatives, net	0.0
Total non-cash compensation expense	0.0
Impairment expense and loss on disposal of assets	0.0
Consolidated Adjusted EBITDA	**$ 1.8**
Distributions and dividends to CQP / CQH non-controlling interest	(0.3)
SPL and CQP cash retained / SPL interest expense / other	(0.7)
CQP interest expense	(0.1)
CEI interest expense	(0.0)
Distributable Cash Flow	**$ 0.6**

**Note: Totals may not sum due to rounding*

CORPORATE INFORMATION

BOARD OF DIRECTORS

Jack A. Fusco
President and Chief Executive Officer,
Cheniere Energy, Inc.

G. Andrea Botta
Chairman of the Board,
Cheniere Energy, Inc.
President, Glenco, LLC

Vicky A. Bailey
President,
Anderson Stratton International, LLC

Nuno Brandolini
Former General Partner,
Scorpion Capital Partners, L.P.

David Foley
Senior Managing Director,
The Blackstone Group, L.P.

David B. Kilpatrick
President,
Kilpatrick Energy Group

Andrew Langham
General Counsel,
Icahn Enterprises, L.P.

Jack Lipinski
Retired Chief Executive Officer and
President and Director,
CVR Energy

Donald F. Robillard, Jr.
Former Executive Vice President,
Chief Financial Officer and Chief Risk Officer,
Hunt Consolidated, Inc. and
Former Chief Executive Officer and
Chairman, ES Xplore, LLC

Neal A. Shear
Senior Advisor and Chair of
Advisory Committee,
Onyxpoint Global Management, LP

Heather R. Zichal
Managing Director
of Corporate Engagement,
The Nature Conservancy

SENIOR MANAGEMENT

Jack A. Fusco
President and Chief Executive Officer

Michael J. Wortley
Executive Vice President and
Chief Financial Officer

Anatol Feygin
Executive Vice President and
Chief Commercial Officer

Tom Bullis
Executive Vice President and
Chief Administrative Officer

Sean N. Markowitz
General Counsel and Corporate Secretary

Ed Lehotsky
Senior Vice President,
Engineering and Construction

Douglas D. Shanda
Senior Vice President, Operations

Corey Grindal
Senior Vice President, Gas Supply

Christopher Smith
Senior Vice President,
Policy, Government, and Public Affairs

Eric Bensaude
Managing Director,
Commercial Operations and Asset
Optimization

Ramzi Mroueh
Managing Director, Origination

Hilary Ware
Chief Human Resources Officer

OFFICERS

Randy Bhatia
Vice President, Investor Relations

Eben Burnham-Snyder
Vice President, Communications

Rina Chang
Vice President, Environmental

Lisa Cohen
Vice President and Treasurer

David Craft
Vice President, Major Project Development

Zach Davis
Vice President, Finance and Planning

Michael Dove
Vice President and Chief Information Officer

Olivier Herbelot
Chief Risk Officer

William L. Knittle
Vice President, Supply Chain Management

Michael Manteris
Vice President, Upstream Infrastructure

Deanna L. Newcomb
Chief Compliance and Ethics Officer,
Vice President, Internal Audit

Mitch Price
Vice President and Chief Security Risk Officer

Aaron Stephenson
Vice President and General Manager

Len Travis
Vice President and Chief Accounting Officer

Oliver Tuckerman
Vice President, Commercial Structuring and
Corporate Development

Tim Wyatt
Vice President, Commercial Operations

Sean Bunk
Assistant Corporate Secretary

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Houston, TX

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CHENIERE

Cheniere Energy, Inc. is a Houston-based energy company developing, constructing and operating a leading LNG platform along the U.S. Gulf Coast.

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