CHENIERE ENERGY, INC. ANNUAL REPORT

CHENIERE

DEMONSTRATING CHENIERE'S

RESILIENCE

2020

SAFELY AND SUCCESSFULLY MANAGED OPERATIONS THROUGH MULTIPLE CHALLENGES

COVID-19 PANDEMIC

CARGO CANCELLATIONS

VOLATILE LNG PRICES

TWO MAJOR HURRICANES

DELIVERED ON FULL YEAR 2020 ORIGINAL, UNCHANGED FINANCIAL GUIDANCE

$3.8B — **$3.96B** — $4.1B

CONSOLIDATED ADJUSTED EBITDA[1]

$1.0B — $1.3B — **$1.35B**

DISTRIBUTABLE CASH FLOW[1]

2020 HIGHLIGHTS

1000TH CUMULATIVE CARGO

1000

JANUARY

CORPUS CHRISTI TRAIN 3

1ST Commissioning Cargo

DECEMBER

CARGOES EXPORTED

~400

>25 Million Tonnes

PUBLISHED

INAUGURAL CORPORATE RESPONSIBILITY REPORT

COMMITTED TO

STRATEGIC INTEGRATION OF ENVIRONMENTAL OPPORTUNITIES

Fellow Shareholders,

In my decades of experience in the energy sector, there has always been volatility – in weather, commodity prices, production, etc. – but never with the magnitude nor personal impact we have experienced throughout the COVID-19 pandemic. Unfortunately, as I write this letter, the world is still struggling to move beyond the pandemic, but there is light at the end of the tunnel.

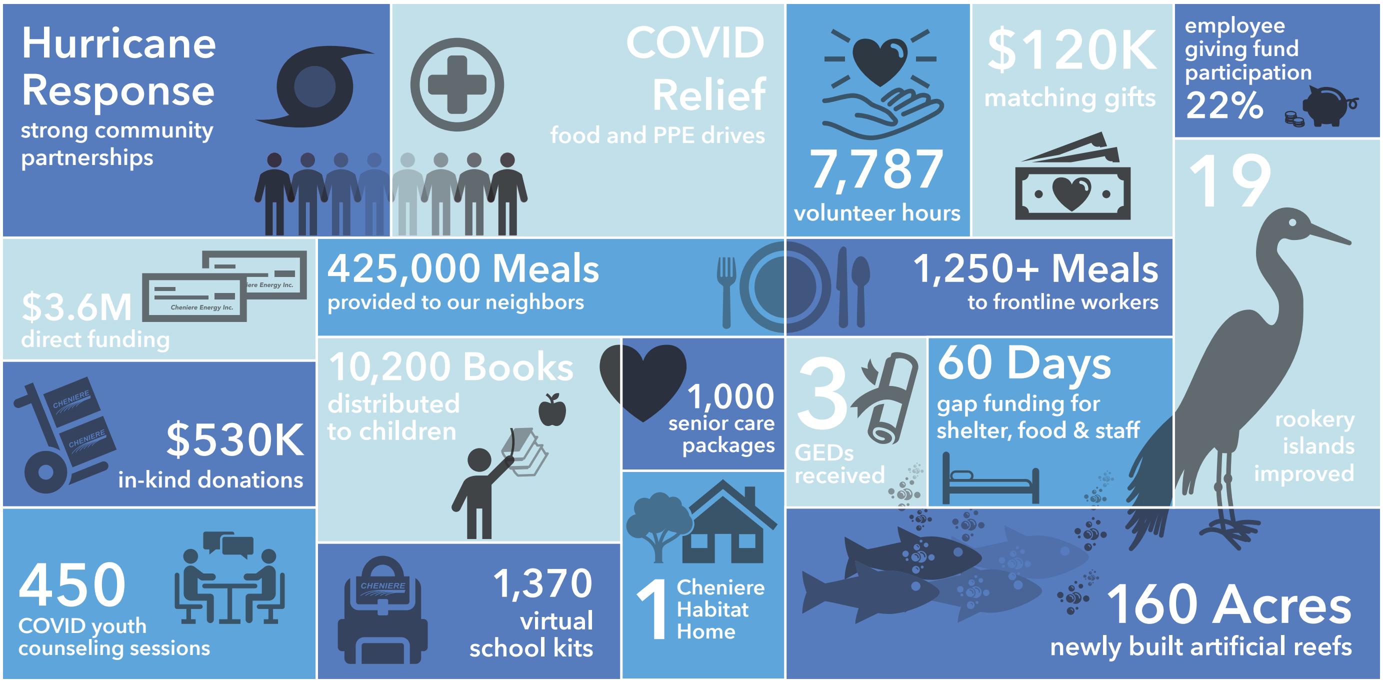
For Cheniere, 2020 was an unforgettable and pivotal year for many reasons, and a year I will look back on with a great sense of pride in our accomplishments. We maintained our business focus and executed as a team, achieving our annual goals and targets despite a myriad of logistical and operational challenges borne from both the far-reaching impacts of the pandemic and major weather events in the Gulf of Mexico. We adeptly managed and overcame these challenges to deliver on our promises to our stakeholders, leaving no doubt as to the resilience and durability of our business and our consummate ability to execute.

Beginning in the first quarter of 2020, at the onset of the pandemic, we made significant logistical and operational adjustments to keep our people and our partners safe while also ensuring the continuity of our liquefaction operations. We activated various emergency response teams, deployed policies and protocols, implemented revised work schedules and ensured our people were socially distanced, and temporarily utilized on-site housing for certain critical operations personnel at our liquefaction facilities. Our teams responded quickly and with agility, adapting to fluid circumstances while prioritizing safety and business continuity, and thus reinforcing Cheniere's reputation for operational excellence. We worked hand in hand with our long-term customers, which were feeling the effects of reduced energy demand as a result of the pandemic and needed to balance their energy needs.

Our engineering and construction professionals, along with our EPC partner Bechtel, implemented proactive pandemic protocols to mitigate the potential impacts over the thousands of construction workers at both the Sabine Pass and Corpus Christi sites. They diligently adhered to protocols and conducted thousands of COVID tests to ensure the safety of the workforce. The results of these efforts have been second to none, with

Corpus Christi Train 3 in foreground.

CHENIERE 2020 COMMUNITY GIVING HIGHLIGHTS



continued execution on accelerated timelines for the construction of Corpus Christi Train 3 and Sabine Pass Train 6. In December, the first commissioning cargo from Corpus Christi Train 3 was exported, and substantial completion of Train 3 was achieved on March 26, 2021. All eight of our operational Trains have been completed and placed into service ahead of schedule and within project budgets, a world-class effort for one of the largest infrastructure construction programs in the world.

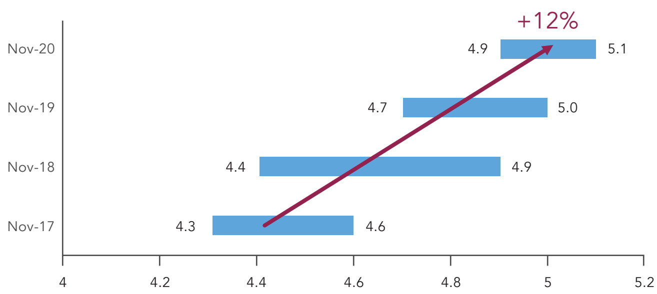
Through the summer, the global LNG market saw record low pricing as a result of the combination of pandemic-related demand shocks, two consecutive warm winters in key Asian markets, and a significant increase in worldwide LNG capacity that has entered service over the last four years. During this period of historically low LNG prices, many of our customers elected to cancel the loading of their cargoes and pay us the fixed fee as defined in our long-term contracts – a valuable contractual feature designed to give our customers flexibility to manage their energy demand while enabling us to maintain financial stability. We successfully ramped down LNG production in response to these cancellations and managed our operations efficiently through this short-term period of market weakness.

In August and September, our operational flexibility and resilience were further tested when two major hurricanes made landfall near Sabine Pass, including Hurricane Laura which was a Category 5 storm. Our facilities are designed to effectively withstand the expected weather risks of the Gulf Coast region and suffered no significant impact from either storm. Many members of our Cheniere family and neighboring communities were personally impacted, however, and we responded quickly and meaningfully with shelter, clothing, and other necessities for our employees and through community donations and supply drives. What I am most proud of for 2020 is that, at the height of the pandemic, Cheniere employees volunteered approximately 8,000 hours for philanthropic endeavors.

Despite all of these challenges, any of which would have been significant individually, our team's resolve and determination enabled Cheniere to deliver on our promises. Our people and their hard work were critical to the operational and financial results we produced for 2020, and we were one of few companies in the energy industry to maintain stable, unchanged financial guidance ranges for the full year and produce results within or above those ranges. We reported $3.96 billion of Consolidated Adjusted EBITDA[1] for 2020, just above the midpoint of our guidance range, and $1.35 billion of Distributable Cash Flow[1], above the upper end of our guidance range.

RUN RATE LIQUEFACTION CAPACITY PER TRAIN

Over 12% increase in midpoint run rate production



Note: Run rate average annual production capacity per Train includes expected impacts of planned maintenance, production reliability, potential overdesign, and debottlenecking opportunities.

Cheniere's financial professionals were extremely busy and raised a significant amount of capital in 2020 – over $8.5 billion – in support of our long-term balance sheet and financial strategy. Among key transactions, we successfully refinanced the $2 billion Sabine Pass Liquefaction 2021 notes despite capital markets volatility in the spring, issued the inaugural $2 billion Cheniere Energy, Inc. notes in September, and refinanced the CCH Holdco II convertible notes and a significant portion of the Cheniere convertible notes with debt, preventing over 40 million shares of equity dilution. Moody's Investors Service upgraded its rating of Corpus Christi Holdings to investment grade, resulting in both liquefaction projects being rated investment grade by all three credit ratings agencies. Our finance teams completed all of this amidst a Chief Financial Officer transition.

Our first liquefaction train was completed and handed over to our operations professionals in May 2016. Over the last five years, they have been busy increasing the effectiveness and efficiency of our site operations and our trains' performance through initiatives including maintenance optimization and debottlenecking. These efforts to optimize operations and maximize LNG production have yielded continual improvement and led us to increase our run rate LNG production forecasts and financial guidance in November. We increased forecast run rate production to 4.9-5.1 mtpa per Train, which is approximately 12% higher at the midpoint than our original production guidance from 2017. Compared to our original guidance, our forecast production increases have added an aggregate of up to 7 million tonnes per year of additional marketable LNG across all of our Trains, or virtually an entire additional Train worth of production, with minimal capital investment.

Increasing the operating capacity of our existing infrastructure drives increased Consolidated Adjusted EBITDA and Distributable Cash Flow and increases our return on investment. Among our increased run rate financial guidance, most notably our run-rate Distributable Cash Flow per share guidance increased 20% from our prior guidance, to a midpoint of $11.00 per share, driven by both increased run-rate Distributable Cash Flow expectations and a lower expected share count.

We believe that LNG has a significant role to play in the global transition to a lower carbon future over the coming decades, as it simultaneously supports both economic growth and emissions reduction. Our constructive long-term view for global LNG demand is reinforced by the significant investments being made in natural gas infrastructure in key LNG demand markets worldwide, in support of increasing natural gas as a primary fuel source and displacing coal, oil, and other dirtier fuels.

We are positioned to capitalize on this expected long-term LNG demand growth with our Corpus Christi Stage 3 expansion project, and we are working to ensure it is the most cost-competitive and environmentally efficient incremental LNG capacity addition in the United States. Our world-class origination team is commercializing capacity for Corpus Christi Stage 3, as well as incremental capacity from our existing Trains, and we anticipate moving forward with construction of Stage 3 after obtaining the necessary commercial support and financing for the project.

INCREASED RUN RATE FINANCIAL GUIDANCE
($ billions except per share and per unit data)

Consolidated adjusted EBITDA[1]	$ 5.3	-	$ 5.7
Distributable Cash Flow (DCF)[1]	$ 2.6	-	$ 3.0
DCF per Share	$ 10.25	-	$ 11.75
CQP DCF per Unit	$ 3.75	-	$ 3.95

Note: Assumed LNG share count of ~255mm shares.

Corpus Christi Train 3 first commissioning cargo.

Environmental, Social, and Governance (ESG) risks and opportunities were a significant area of focus for Cheniere throughout 2020. We published *First and Forward*, our inaugural corporate responsibility report, in early July, marking a significant step forward in our commitment to transparency in sustainability reporting. This report was a cross-functional effort led by a team of subject matter experts from across almost every business unit within Cheniere and forms the foundation of our ESG reporting and disclosures.

Improving environmental performance is not solely about responsibility, it also makes sound business sense. We are integrating climate opportunities into our commercial offering, reinforcing our position at the forefront of the LNG industry and our reputation for commercial innovation. We are undertaking significant operational analysis to quantify our lifecycle emissions and to identify and analyze climate-related opportunities across our value chain, with the strategic goals of resilience, transparency, avoidance, and reduction. In early 2021, we announced that we are developing cargo emissions tags, or CE Tags, which will quantify the estimated greenhouse gas emissions of our LNG cargoes from the wellhead to the cargo delivery point, a significant step toward enhanced environmental transparency, and we expect to provide these CE Tags to our customers beginning in 2022.

As we move into 2021, we are committed to further reinforcing our track record of excellence in operational execution, delivering on our financial guidance, positioning Cheniere for continued growth, and maintaining alignment with our stakeholders. In 2021, we expect to generate a meaningful amount of free cash flow for the first time in Cheniere's history, which will enable us to make significant progress on our capital allocation plans of reducing leverage and resuming capital returns. Our 2021 goals are supported by improving LNG market dynamics and, as always, the dedication and diligence of our people.

Thank you all for your continued support of Cheniere.

Sincerely,

Jack A. Fusco
President and CEO

(1) Consolidated Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures. A reconciliation of Net income (loss) 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, 2020
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 number 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)
(713) 375-5000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, $ 0.003 par value	**LNG**	**NYSE American**

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 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 every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

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.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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 $12.1 billion as of June 30, 2020.

As of February 19, 2021, the issuer had 253,529,085 shares of Common Stock outstanding.

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.

TABLE OF CONTENTS

DEFINITIONS

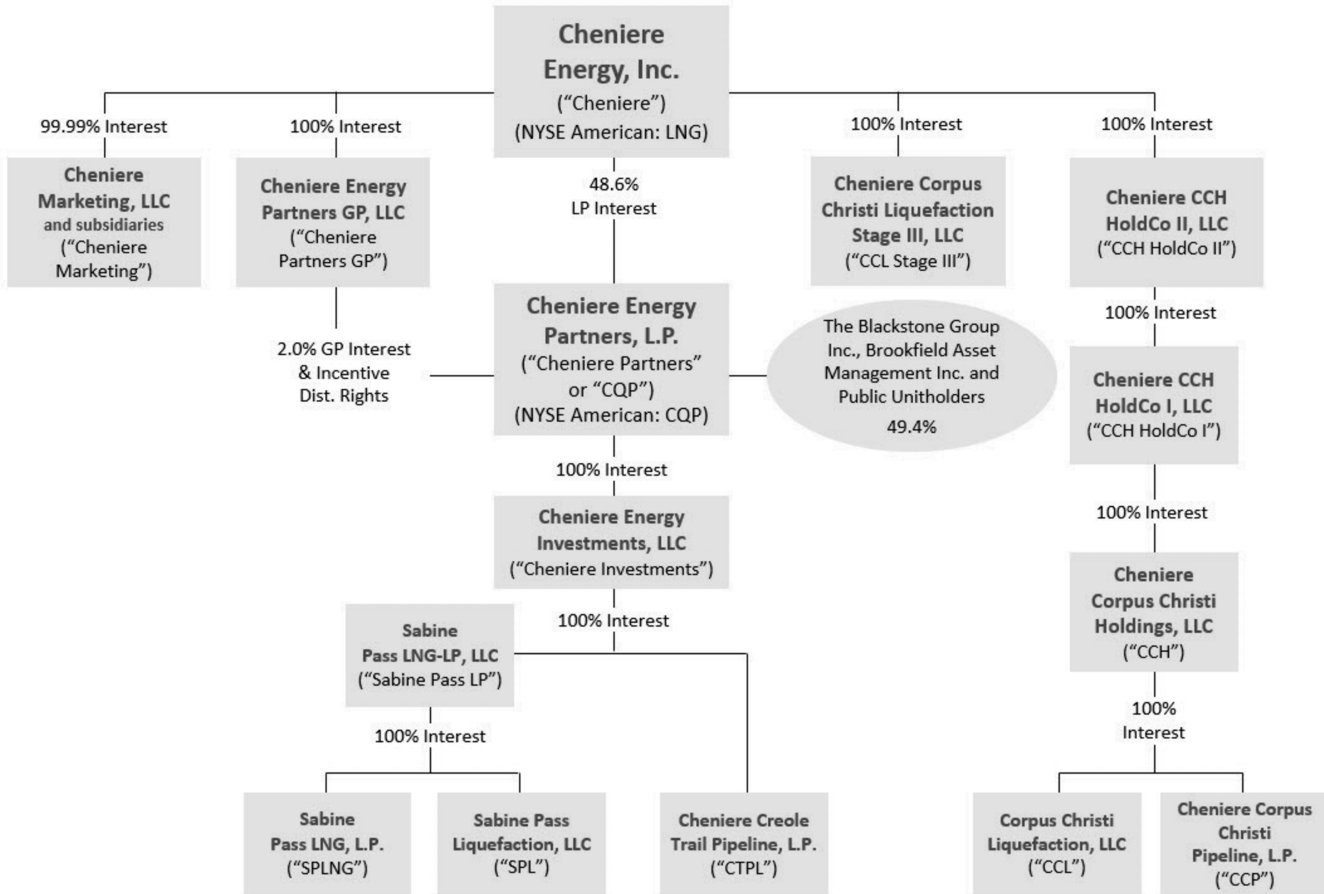
As used in this annual report, the terms listed below have the following meanings:

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, 2020, 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 subsidiary, Cheniere Partners.

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 regarding the amount and timing of share repurchases;
- 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 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 counterparties to our commercial contracts, construction contracts and other contracts;
- statements regarding our planned development and construction of additional Trains or pipelines, including the financing of such Trains or pipelines;
- 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 our anticipated LNG and natural gas marketing activities;
- statements regarding the outbreak of COVID-19 and its impact on our business and operating results, including any customers not taking delivery of LNG cargoes, the ongoing credit worthiness of our contractual counterparties, any disruptions in our operations or construction of our Trains and the health and safety of our employees, and on our customers, the global economy and the demand for LNG;
- any other statements that relate to non-historical or future information; and
- other factors described in Item 1A. Risk Factors in this Annual Report on Form 10-K.

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,” “achieve,” “anticipate,” “believe,” “contemplate,” “continue,” “estimate,” “expect,” “intend,” “plan,” “potential,” “predict,” “project,” “pursue,” “target,” 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. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. 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 Energy, Inc. ("Cheniere"), a Delaware corporation, is a Houston-based energy infrastructure company primarily engaged in LNG-related businesses. We provide clean, secure and affordable LNG to integrated energy companies, utilities and energy trading companies around the world. We aspire to conduct our business in a safe and responsible manner, delivering a reliable, competitive and integrated source of LNG to our customers.

LNG is natural gas (methane) in liquid form. The LNG we produce is shipped all over the world, turned back into natural gas (called "regasification") and then transported via pipeline to homes and businesses and used as an energy source that is essential for heating, cooking and other industrial uses. Natural gas is a cleaner-burning, abundant and affordable source of energy. When LNG is converted back to natural gas, it can be used instead of coal, which reduces the amount of pollution traditionally produced from burning fossil fuels, like sulfur dioxide and particulate matter that enters the air we breathe. Additionally, compared to coal, it produces significantly fewer carbon emissions. By liquefying natural gas, we are able to reduce its volume by 600 times so that we can load it onto special LNG carriers designed to keep the LNG cold and in liquid form for efficient transport overseas.

We own and operate the Sabine Pass LNG terminal in Louisiana, one of the largest LNG production facilities in the world, through our ownership interest in and management agreements with Cheniere Energy Partners, L.P. ("Cheniere Partners"), which is a publicly traded limited partnership that we created in 2007. As of December 31, 2020, we owned 100% of the general partner interest and 48.6% of the limited partner interest in Cheniere Partners. We also own and operate the Corpus Christi LNG terminal in Texas, which is wholly owned by us.

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, through its subsidiary Sabine Pass Liquefaction, LLC ("SPL"), is currently operating five natural gas liquefaction Trains and is constructing one additional Train that is expected to be substantially completed in the second half of 2022, for a total production capacity of approximately 30 mtpa of LNG (the "SPL Project") at the Sabine Pass LNG terminal. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' subsidiary, Sabine Pass LNG, L.P. ("SPLNG"), that include pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 17 Bcfe, two existing marine berths and one under construction that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4 Bcf/d. Cheniere Partners also owns a 94-mile pipeline through its subsidiary, Cheniere Creole Trail Pipeline, L.P. ("CTPL"), that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines (the "Creole Trail Pipeline").

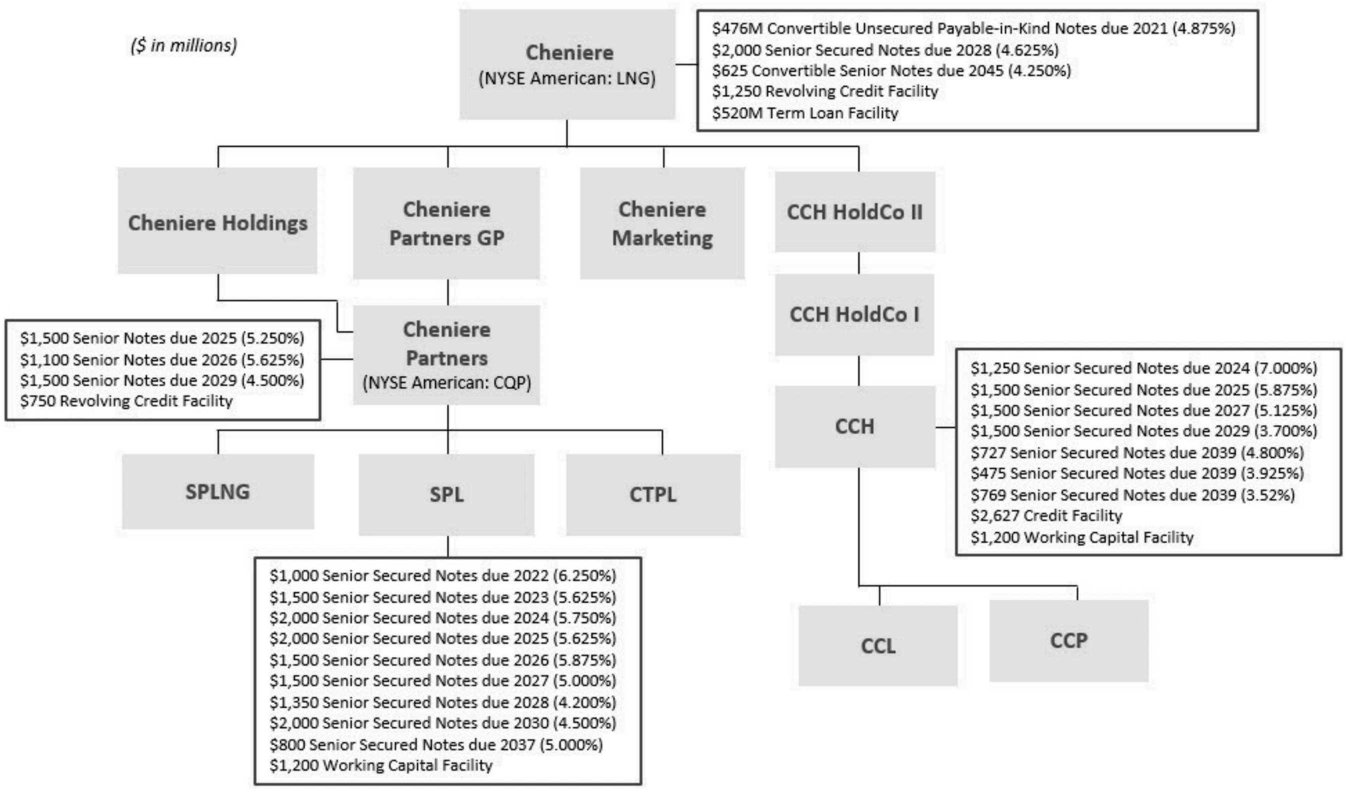
We also own the Corpus Christi LNG terminal near Corpus Christi, Texas, and are currently operating two Trains and one additional Train is undergoing commissioning for a total production capacity of approximately 15 mtpa of LNG. Additionally, we are operating a 23-mile natural gas supply pipeline that interconnects the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline" and together with the Trains, the "CCL Project") through our subsidiaries Corpus Christi Liquefaction, LLC ("CCL") and Cheniere Corpus Christi Pipeline, L.P. ("CCP"), respectively. The CCL Project, once fully constructed, will contain three LNG storage tanks with aggregate capacity of approximately 10 Bcfe and two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters.

We have contracted approximately 85% of the total production capacity from the SPL Project and the CCL Project (collectively, the "Liquefaction Projects") on a term basis, with approximately 18 years of average remaining life as of December 31, 2020. This includes volumes contracted under SPAs in which the customers are required to pay a fixed fee with respect to the contracted volumes irrespective of their election to cancel or suspend deliveries of LNG cargoes, as well as volumes contracted under integrated production marketing ("IPM") gas supply agreements.

Additionally, separate from the CCH Group, we are developing an expansion of the Corpus Christi LNG terminal adjacent to the CCL Project ("Corpus Christi Stage 3") through our subsidiary Cheniere Corpus Christi Liquefaction Stage III, LLC ("CCL Stage III") for up to seven midscale Trains with an expected total production capacity of approximately 10 mtpa of LNG. We received approval from FERC in November 2019 to site, construct and operate the expansion project.

We remain focused on operational excellence and customer satisfaction. Increasing demand of LNG has allowed us to expand our liquefaction infrastructure in a financially disciplined manner. We have increased available liquefaction capacity at our Liquefaction Projects as a result of debottlenecking and other optimization projects. We hold significant land positions at both the Sabine Pass LNG terminal and the Corpus Christi LNG terminal which provide opportunity for further liquefaction capacity expansion. The development of these sites or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, acceptable commercial and financing arrangements before we can make a final investment decision ("FID").

Although results are consolidated for financial reporting, Cheniere, Cheniere Partners, SPL and the CCH Group operate with independent capital structures. The following diagram depicts our abbreviated capital structure as of December 31, 2020:



Our Business Strategy

Our primary business strategy is to be a full service LNG provider to worldwide end-use customers. We accomplish this objective by owning, constructing and operating LNG and natural gas infrastructure facilities to meet our long-term customers' energy demands and:

- safely, efficiently and reliably operating and maintaining our assets;
- procuring natural gas and pipeline transport capacity to our facilities;
- providing value to our customers through destination flexibility, options not to lift cargoes and diversity of price and geography;
- commencing commercial delivery for our long-term SPA and IPM customers, of which we have initiated for 17 of 20 long-term SPA and IPM customers as of December 31, 2020;
- safely, on-time and on-budget completing our expansion construction projects;

- maximizing the production of LNG to serve our customers and generating steady and stable revenues and operating cash flows;
- maintaining a flexible capital structure to finance the acquisition, development, construction and operation of the energy assets needed to supply our customers; and
- strategically identifying actionable environmental solutions.

LNG Terminals and Marketing

We shipped our first LNG cargo in February 2016 and we shipped our 1,000th cargo in January 2020. Cheniere's LNG has been shipped to 35 countries and regions around the world.

Sabine Pass LNG Terminal

Liquefaction Facilities

The SPL Project is one of the largest LNG production facilities in the world. Through Cheniere Partners, we are currently operating five Trains and two marine berths at the SPL Project, and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, and a third marine berth. We have received authorization from the FERC to site, construct and operate Trains 1 through 6, as well as for the construction of the third marine berth. We have achieved substantial completion of the first five Trains of the SPL Project and commenced commercial operating activities for each Train at various times starting in May 2016. The following table summarizes the project completion and construction status of Train 6 of the SPL Project as of December 31, 2020:

	SPL Train 6
Overall project completion percentage	77.6%
Completion percentage of:	
Engineering	99.0%
Procurement	99.9%
Subcontract work	54.9%
Construction	49.2%
Date of expected substantial completion	2H 2022

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 and non-FTA countries through December 31, 2050, 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 and non-FTA countries through December 31, 2050, 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 through December 31, 2050 in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In December 2020, the DOE announced a new policy in which it would no longer issue short-term export authorizations separately from long-term authorizations. Accordingly, the DOE amended each of SPL's long-term authorizations to include short-term export authority, and vacated the short-term orders.

An application was filed in September 2019 seeking authorization to make additional exports from the SPL Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term in an amount up to the equivalent of approximately 153 Bcf/yr of natural gas, for a total SPL Project export capacity of approximately 1,662 Bcf/yr. The terms of the authorizations are requested to commence on the date of first commercial export from the SPL Project of the volumes contemplated in the application. In April 2020, the DOE issued an order authorizing SPL to export to FTA countries related to this application, for which the term was subsequently extended through December 31, 2050, but has not yet issued an order authorizing SPL to export to non-FTA countries for the corresponding LNG volume. A corresponding application for authorization to increase the total LNG production capacity of the SPL Project from the currently authorized level to approximately 1,662 Bcf/yr was also submitted to the FERC and is currently pending.

Customers

SPL has entered into fixed price long-term SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 17 years (plus extension rights) with eight third parties for Trains 1 through 6 of the SPL Project. 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 generally equal to approximately 115% of Henry Hub. The customers may elect to cancel or suspend deliveries of LNG cargoes, with advance notice as governed by each respective SPA, 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 generally sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation and liquefaction fuel 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.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion for Trains 1 through 5. After giving effect to an SPA that Cheniere has committed to provide to SPL, the annual fixed fee portion to be paid by the third-party SPA customers would increase to at least $3.3 billion, which is expected to occur upon the date of first commercial delivery of Train 6.

In addition, Cheniere Marketing has an agreement with SPL to purchase at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers. See *Marketing* section for additional information regarding agreements entered into by Cheniere Marketing.

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 Gulf Coast LNG, LLC ("BG"), which is guaranteed by BG Energy Holdings Limited;
- approximately $550 million from Korea Gas Corporation ("KOGAS");
- approximately $550 million from GAIL;
- approximately $450 million from Naturgy LNG GOM, Limited (formerly known as Gas Natural Fenosa LNG GOM, Limited) ("Naturgy"), which is guaranteed by Naturgy Energy Group, S.A. (formerly known as Gas Natural SDG S.A.); and
- approximately $310 million from Total Gas & Power North America, Inc. ("Total"), which is guaranteed by Total S.A.

The annual aggregate fixed fees for all of SPL's other SPAs with third-parties is approximately $490 million, prior to giving effect to an SPA that Cheniere has committed to provide to SPL.

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 variability 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, 2020, SPL had secured up to approximately 4,950 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts with remaining terms that range up to 10 years, a portion of which is subject to conditions precedent.

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 6 of the SPL Project, under which Bechtel charges a lump sum for all work performed and generally bears project cost, schedule and performance risks 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 6 of the SPL Project is approximately $2.5 billion, including estimated costs for the third marine berth that is currently under construction. As of December 31, 2020, we have incurred $1.9 billion under this contract.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4 Bcf/d and aggregate LNG storage capacity of approximately 17 Bcfe. Approximately 2 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 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually, prior to inflation adjustments, 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 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, prior to inflation adjustments, continuing until at least May 2036. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 5 of the SPL Project, SPL gained access to substantially all 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 Train 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 years ended December 31, 2020, 2019 and 2018, SPL recorded $129 million, $104 million and $30 million, respectively, 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

We are currently operating two Trains and two marine berths at the CCL Project and commissioning one additional Train that is expected to be substantially completed in the first quarter of 2021. We have received authorization from the FERC to site, construct and operate Trains 1 through 3 of the CCL Project. We completed construction of Trains 1 and 2 of the CCL Project and commenced commercial operating activities in February 2019 and August 2019, respectively. The following table summarizes the project completion and construction status of Train 3 of the CCL Project, including the related infrastructure, as of December 31, 2020:

	CCL Train 3
Overall project completion percentage	99.6%
Completion percentage of:	
Engineering	100.0%
Procurement	100.0%
Subcontract work	99.9%
Construction	99.0%
Expected date of substantial completion	1Q 2021

Separate from the CCH Group, we are also developing Corpus Christi Stage 3 through our subsidiary CCL Stage III, adjacent to the CCL Project. We received approval from FERC in November 2019 to site, construct and operate seven midscale Trains with an expected total production capacity of approximately 10 mtpa of LNG.

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 and non-FTA countries through December 31, 2050, up to a combined total of the equivalent of 767 Bcf/yr (approximately 15 mtpa) of natural gas.
- Corpus Christi Stage 3—FTA countries and non-FTA countries through December 31, 2050 in an amount equivalent to 582.14 Bcf/yr (approximately 11 mtpa) of natural gas.

In December 2020, the DOE announced a new policy in which it would no longer issue short-term export authorizations separately from long-term authorizations. Accordingly, the DOE amended each of CCL's long-term authorizations to include short-term export authority, and vacated the short-term orders.

An application was filed in September 2019 to authorize additional exports from the CCL Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term in an amount up to the equivalent of approximately 108 Bcf/yr of natural gas, for a total CCL Project export of 875.16 Bcf/yr. The terms of the authorizations are requested to commence on the date of first commercial export from the CCL Project of the volumes contemplated in the application. In April 2020, the DOE issued an order authorizing CCL to export to FTA countries related to this application, for which the term was subsequently extended through December 31, 2050, but has not yet issued an order authorizing CCL to export to non-FTA countries for the corresponding LNG volume. A corresponding application for authorization to increase the total LNG production capacity of the CCL Project from the currently authorized level to approximately 875.16 Bcf/yr was also submitted to the FERC and is currently pending.

Customers

CCL has entered into fixed price long-term SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 19 years (plus extension rights) with nine third parties for Trains 1 through 3 of the CCL Project. Under these SPAs, the customers will purchase LNG from CCL on a free on board ("FOB") basis 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. The customers may elect to cancel or suspend deliveries of LNG cargoes, with advance notice as governed by each respective SPA, 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 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 and liquefaction fuel 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 the applicable Train, as specified in each SPA.

In aggregate, the minimum annual fixed fee portion to be paid by the third-party SPA customers is approximately $1.4 billion for Trains 1 and 2 and increasing to approximately $1.8 billion following the substantial completion of Train 3 of the CCL Project.

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 through 3 of the CCL Project are:

- approximately $410 million from Endesa S.A.;
- approximately $280 million from PT Pertamina (Persero); and
- approximately $270 million from Naturgy, which is guaranteed by Naturgy Energy Group, S.A.

The annual aggregate contracted cash flow from fixed fees for all of CCL's other SPAs with third-parties is approximately $790 million.

In addition, Cheniere Marketing has agreements with CCL to purchase: (1) approximately 15 TBtu per annum of LNG with an approximate term of 23 years, (2) any LNG produced by CCL in excess of that required for other customers at Cheniere Marketing's option and (3) approximately 44 TBtu of LNG with a term of up to seven years associated with the IPM gas supply agreement between CCL and EOG Resources, Inc. See *Marketing* section for additional information regarding agreements entered into by Cheniere Marketing.

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 variability 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, 2020, CCL had secured up to approximately 2,938 TBtu of natural gas feedstock through long-term natural gas supply contracts with remaining terms that range up to 10 years, a portion of which is subject to the achievement of certain project milestones and other conditions precedent.

CCL Stage III has also entered into long-term natural gas supply contracts with third parties, and anticipates continuing to enter into such agreements, in order to secure natural gas feedstock for Corpus Christi Stage 3. As of December 31, 2020, CCL Stage III had secured up to approximately 2,361 TBtu of natural gas feedstock through long-term natural gas supply contracts with remaining terms that range up to approximately 15 years, which is subject to the achievement of certain project milestones and other conditions precedent.

A portion of the natural gas feedstock transactions for CCL and CCL Stage III are IPM transactions, in which the natural gas producers are paid based on a global gas market price less a fixed liquefaction fee and certain costs incurred by us.

Construction

CCL entered into separate lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Trains 1 through 3 of the CCL Project under which Bechtel charges a lump sum for all work performed and generally bears project cost, schedule and performance risks 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 Train 3, which is currently undergoing commissioning, is approximately $2.4 billion, reflecting amounts incurred under change orders through December 31, 2020. As of December 31, 2020, we have incurred $2.4 billion under this contract.

Final Investment Decision for Corpus Christi Stage 3

FID for Corpus Christi Stage 3 will be subject to, among other things, entering into an EPC contract, obtaining additional commercial support for the project and securing the necessary financing arrangements.

Pipeline Facilities

In November 2019, the FERC authorized CCP to construct and operate the pipeline for Corpus Christi Stage 3. The pipeline will be designed to transport 1.5 Bcf/d of natural gas feedstock required by Corpus Christi Stage 3 from the existing regional natural gas pipeline grid.

Marketing

We market and sell LNG produced by the Liquefaction Projects that is not required for other customers through our integrated marketing function. We have, and continue to develop, a portfolio of long-, medium- and short-term SPAs to transport and unload commercial LNG cargoes to locations worldwide. These volumes are expected to be primarily sourced by LNG produced by the Liquefaction Projects but supplemented by volumes procured from other locations worldwide, as needed. As of December 31, 2020, we have sold or have options to sell approximately 4,995 TBtu of LNG to be delivered to customers between 2021 and 2045, including volume from an SPA Cheniere Marketing has committed to provide to SPL. The cargoes have been sold either on a FOB basis (delivered to the customer at the Sabine Pass LNG terminal or the Corpus Christi LNG terminal, as applicable) or a delivered at terminal ("DAT") basis (delivered to the customer at their specified LNG receiving terminal). We have chartered LNG vessels to be utilized for cargoes sold on a DAT basis.

Significant Customers

The following table shows customers with revenues of 10% or greater of total revenues from external customers:

	Percentage of Total Revenues from External Customers		
	Year Ended December 31,		
	2020	2019	2018
BG and its affiliates	14%	16%	18%
Naturgy	12%	10%	14%
KOGAS	10%	11%	19%
GAIL	10%	11%	13%

Competition

If and when SPL, CCL or our integrated marketing function 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. We have proximity to our customers, with offices located in Houston, London, Singapore, Beijing and Tokyo.

SPLNG currently does not experience competition for its terminal capacity because the entire approximately 4 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 and pipelines 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. These regulatory requirements increase 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, operation, maintenance and expansion of our liquefaction facilities, the import or export of LNG and the purchase and transportation of natural gas in interstate commerce through our pipelines (including our Creole Trail Pipeline and Corpus Christi Pipeline) are highly regulated activities subject to the jurisdiction of the FERC pursuant to the Natural Gas Act of 1938, as amended (the "NGA"). Under the NGA, the FERC's jurisdiction generally extends to the transportation of natural gas in interstate commerce, to the sale for resale of natural gas in interstate commerce, to natural gas companies engaged in such transportation or sale and to the construction, operation, maintenance and expansion of LNG terminals and interstate natural gas pipelines.

The FERC's authority to regulate interstate natural gas pipelines and the services that they provide generally includes regulation of:

- rates and charges, and terms and conditions for natural gas transportation, storage and related services;
- the certification and construction of new facilities and modification of existing facilities;
- the extension and abandonment of services and facilities;

- the administration of accounting and financial reporting regulations, including the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services; and
- various other matters.

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. Those rates, terms and conditions must be public, and on file with the FERC. In contrast to pipeline regulation, the FERC does not require LNG terminal owners to provide open-access services at cost-based or regulated rates. Although the provisions that codified FERC's policy in this area expired on January 1, 2015, we see no indication that the FERC intends to change its policy in this area.

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 to our marketing affiliates. 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.

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 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, unless specifically provided otherwise in the EPAct, amendments to the NGA. For example, nothing in the EPAct amendments to the NGA were intended to affect otherwise applicable law related to any other federal agency's authorities or responsibilities related to LNG terminals or those of a state acting under federal law.

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 U.S. Court of Appeals for the District of Columbia Circuit (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 October of 2018, SPL applied to the FERC for authorization to add a third marine berth to the Sabine Pass LNG terminal facilities, which FERC approved in February of 2020.

The Creole Trail Pipeline, which interconnects with the Sabine Pass LNG terminal, holds 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 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 of feed gas to the Sabine Pass LNG terminal. 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 Creole Trail Pipeline and related facilities in order to deliver additional domestic natural gas supplies to the Sabine Pass LNG terminal, 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 Trains 1 through 3 of the CCL Project and issued a certificate of public convenience and necessity under Section 7(c) of the NGA authorizing construction and operation of 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 relevant Court of Appeals to review the December 2014 Order and the Order Denying Rehearing; that petition was denied on November 4, 2016. In June of 2018, CCL Stage III, CCL and Corpus Christi Pipeline filed an application with the FERC for authorization under Section 3 of the NGA to site, construct and operate additional facilities for the liquefaction and export of domestically-produced natural gas ("Corpus Christi Stage 3") at the existing CCL Project and pipeline locations. In November 2019, the FERC authorized Corpus Christi Stage 3. Corpus Christi Stage 3 consists of the addition of seven midscale Trains and related facilities. The order is not subject to appellate court review. In 2020, FERC authorized Corpus Christi Pipeline to construct and operate a portion of Corpus Christi Stage 3 (Sinton Compressor Station Unit No. 1) on an interim basis independently from the remaining Corpus Christi Stage 3 facilities, which received FERC approval for in-service in December 2020.

On September 27, 2019, CCL and SPL filed a request with the FERC pursuant to Section 3 of the NGA, requesting authorization to increase the total LNG production capacity of each terminal from currently authorized levels to an amount which reflects more accurately the capacity of each facility based on enhancements during the engineering, design and construction process, as well as operational experience to date. The requested authorizations do not involve construction of new facilities. Corresponding applications for authorization to export the incremental volumes were also submitted to the DOE.

The FERC's Standards of Conduct apply to interstate pipelines that conduct transmission transactions with an affiliate that engages in natural gas marketing functions. The general principles of the FERC 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 due to the improper disclosure of non-public transmission function information. We have established the required policies, procedures and training to comply with the FERC's Standards of Conduct.

All of our FERC construction, operation, reporting, accounting and other regulated activities are subject to audit by the FERC, which may conduct routine or special inspections and issue data requests designed to ensure compliance with FERC rules, regulations, policies and procedures. 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 approximately $1.3 million per day per violation, including any conduct that violates the NGA's prohibition against market manipulation.

Several other material governmental and regulatory approvals and permits will be required throughout the life of our LNG terminals and our pipelines. In addition, our FERC orders require us to comply with certain ongoing conditions, reporting obligations and maintain other regulatory agency approvals throughout the life of our facilities. For example, throughout the life of our LNG terminals and our pipelines, we are subject to regular reporting requirements to the FERC, the 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. To date, we have been able to obtain and maintain required approvals as needed, and the need for these approvals and reporting obligations have not materially affected our construction or operations.

DOE Export Licenses

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.

Under Section 3 of the NGA applications for exports of natural gas to FTA countries, which allow for national treatment for trade in natural gas, are "deemed to be consistent with the public interest" and shall be granted by the DOE without "modification or delay." FTA countries currently recognized by the DOE for exports of LNG include Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore. FTAs with Israel and Costa Rica do not require national treatment for trade in natural gas. Applications for export of LNG to non-FTA countries are considered by the DOE in a notice and comment proceeding whereby the public and other interveners are provided the opportunity to comment and may assert that such authorization would not be consistent with the public interest.

Pipeline and Hazardous Materials Safety Administration

Our LNG terminals as well as the Creole Trail Pipeline and the Corpus Christi Pipeline are subject to regulation by PHMSA. PHMSA is authorized by the applicable pipeline safety laws to establish minimum safety standards for certain pipelines and LNG facilities. The regulatory standards PHMSA has established are applicable to the design, installation, testing, construction, operation, maintenance and management of natural gas and hazardous liquid pipeline facilities and LNG facilities that affect interstate or foreign commerce. PHMSA has also established training, worker qualification and reporting requirements.

In October 2019, PHMSA published final rules revising its regulations governing the safety of certain gas transmission pipelines (effective July 1, 2020) and established new enforcement procedures for the issuance of temporary emergency orders (effective December 2, 2019).

PHMSA performs inspections of pipeline and LNG facilities and has authority to undertake enforcement actions, including issuance of civil penalties up to approximately $218,000 per day per violation, with a maximum administrative civil penalty of approximately $2 million for any related series of violations.

Other Governmental Permits, Approvals and Authorizations

Construction and operation of the Sabine Pass LNG terminal and the CCL Project require additional permits, orders, approvals and consultations to be issued by various federal and state agencies, including the DOT, U.S. Army Corps of Engineers ("USACE"), U.S. Department of Commerce, National Marine Fisheries Service, U.S. Department of the Interior, U.S. Fish and Wildlife Service ("FWS"), the U.S. Environmental Protection Agency (the "EPA"), U.S. Department of Homeland Security, the LDEQ, the Texas Commission on Environmental Quality ("TCEQ") and the Railroad Commission of Texas ("RRC").

The USACE issues its permits under the authority of the Clean Water Act ("CWA") (Section 404) and the Rivers and Harbors Act (Section 10) (the "Section 10/404 Permit"). The EPA administers the Clean Air Act, and has delegated authority to the TCEQ and LDEQ to issue the Title V Operating Permit (the "Title V Permit") and the Prevention of Significant Deterioration Permit (the "PSD Permit"). These two permits are issued by the LDEQ for the Sabine Pass LNG terminal and CTPL and by the TCEQ for the CCL Project.

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 those markets. Most of the regulations are already in effect, while other rules and regulations, including the new rules on speculative position limits that were finalized by the CFTC on October 15, 2020, are in the process of being phased in. The full impact of the CFTC's position limits rules is not yet known and these rules could have significant impact on our business.

As required by provisions of the Dodd-Frank Act, the CFTC and federal banking regulators have adopted rules to require Swap Dealers (as defined in the Dodd-Frank Act), 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 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 qualify as a non-financial-entity end user with respect to the swaps that we enter into to hedge our commercial risks.

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.

United Kingdom /European Regulations

Our European Union ("EU") trading activities, which are primarily established in the United Kingdom ("UK"), are subject to a number of EU-wide and UK specific laws and regulations, including but not limited to the European Market Infrastructure Regulation ("EMIR"), the Regulation on Wholesale Energy Market Integrity and Transparency ("REMIT"), the Markets in Financial Instruments Directive and Regulation ("MiFID II"), the Market Abuse Regulation ("MAR"), the UK's Financial Services and Markets Act 2000 ("FSMA") and Financial Services and Markets Act 2000 (Regulated Activities) Order 2001 ("RAO"). Each of these laws and regulations are and will be subject to changes arising as a result of Brexit. Further details of these are set out in the Brexit section below.

EMIR is an EU regulation (with text that is relevant across the European Economic Area ("EEA")) designed to increase the transparency and stability of the EEA derivatives markets. REMIT is an EU regulation (with EEA relevance) that prohibits market manipulation and insider trading in European wholesale energy markets and imposes various transparency and other obligations on participants active in these markets. MiFID II consists of an EU directive, a regulation and a number of delegated acts, rules and guidance, that replaced the original 2004 Markets in Financial Instruments Directive. MiFID II (with relevance throughout the EEA), sets forth an EEA-wide financial services framework, including rules for firms engaging in investment services and activities in connection with certain financial instruments in the EEA. Firms engaging in such activities must be authorized unless an exemption applies.

We are eligible to trade on our own account in commodity derivatives as a result of the "ancillary activity" exemption under MiFID II. MAR was implemented to create an enhanced EU market abuse framework and applies to all financial instruments listed or traded on EU trading venues as well as other over-the-counter ("OTC") financial instruments priced on, or impacting, the trading venue contract. FSMA governs the regulation of financial services and markets in the UK, and the RAO contains a definitive list of the specified kinds of activities and investments and products that are regulated. We currently qualify for exclusions/exemptions under both FSMA/RAO.

Any violation of the foregoing laws and regulations could result in investigations, possible fines and penalties, and in some scenarios, criminal offenses, as well as reputational damage.

Brexit

The UK withdrew from the EU ("Brexit") on January 31, 2020, with the transition period ending as of January 1, 2021. A trade deal (the "Deal") was agreed and ratified by both sides, avoiding a "no deal" Brexit. One area notably absent from the Deal was financial services. The UK and EU will work towards agreeing a memorandum of understanding (the "MoU") on access to financial services by March 2021, although such an MoU would be less far-reaching than a legal text like an international treaty.

The issue of whether the UK's financial system will be granted "equivalence" by the EU (the scenario that would result in the least disruption and would treat compliance with UK rules as being equivalent to compliance with the corresponding EU rules) remains to be resolved. It should be noted that the UK will also have the right to declare whether EU financial services rules are "equivalent" to its own rules, and each sides' equivalence decision will be made unilaterally, and could be withdrawn unilaterally as well. In contrast, the EU has taken a more limited approach. This includes, in the context of EMIR, granting a finite equivalence decision for the UK's legal regime for central counterparties ("CCPs") established in the UK until June 30, 2022. Furthermore, the EU has recognized the CCPs ICE Clear Europe Limited, LCH Limited and LME Clear Limited as third country CCPs, with the effect that they may continue to offer their services in the EU.

Additionally, there is no guarantee that any equivalence decision, if granted, will be comprehensive across all financial services. In the meantime, UK firms must comply with the UK's "onshored" versions of the core EU financial services rules, including MiFID II and EMIR.

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 administrative, 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 requiring annual reporting of greenhouse gas ("GHG") emissions from stationary sources in a variety of industries. 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. While the EPA subsequently took a number of additional actions primarily relating to GHG emissions from the electric power generation and the oil and gas exploration and production industries, those rules were largely stayed or repealed during the Trump Administration including by amendments adopted by the EPA on February 23, 2018 and additional amendments to new source performance standards for the oil and gas industry on September 14 and 15, 2020. On January 20, 2021, President Biden issued an executive order directing the EPA to consider publishing for notice and comment a proposed rule suspending, revising, or rescinding the September 2020 rule, which could result in more stringent GHG emissions rulemaking. We are supportive of regulations reducing GHG emissions over time.

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 is 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

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. When such wastes are generated in connection with the operations of our facilities, we are 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 "ESA"), the Migratory Bird Treaty Act ("MBTA"), 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 adversely affects 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.

In August 2019, the FWS announced a series of changes to the rules implementing the ESA, including revisions to the regulations governing interagency cooperation, listing species and delisting critical habitat, and prohibitions related to threatened wildlife and plants, and in August and September 2020, the FWS proposed additional changes to its regulations for designating critical habitat. The revisions are intended to streamline these processes and create more flexibility for the FWS when making ESA-related decisions.

In addition, in January 2021, the FWS issued a final rule defining the scope of the MBTA to cover only actions intentionally directed at migratory birds, their nests or their eggs.

On January 20, 2021, President Biden issued an executive order directing the heads of all agencies to immediately review all regulatory actions taken between January 20, 2017 and January 20, 2021, including FWS regulations implementing the ESA and the MBTA and EPA regulations implementing the CWA and the Oil Pollution Act, which could result in stricter requirements with respect to endangered or threatened animal, fish and plant species and/or their designated habitats, migratory birds, wetlands or other natural resources.

It is not possible at this time to predict how future regulations or legislation may address protection of species, habitats and wetlands and impact our business. However, we do not believe that our operations, or the construction and operations of our liquefaction facilities, will be materially and adversely affected by such regulatory actions.

Market Factors

Our ability to enter into additional long-term SPAs to underpin the development of additional Trains, sale of LNG by Cheniere Marketing, or development of 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. Players around the globe have shown commitments to environmental goals consistent with many policy initiatives that we believe are constructive for LNG demand and infrastructure growth. Currently, hundreds of billions of dollars are being invested across Europe and Asia in natural gas projects under construction, and if we included planned commitments, the total would exceed $1 trillion. Some examples include India's commitment to invest over $60 billion to drive its gas-based economy, Europe's commitment of well over $100 billion in gas-fired power, import terminals and pipelines, and China's hundreds of billions all along the natural gas value chain. We highlight regasification capacity, which will not only expand existing import capacities in rapidly growing markets like China and India, but also add new import markets all over the globe, raising the total to approximately 60 by 2030 from 43 today and just 15 markets as recently as 2005.

As a result of these dynamics, global demand for natural gas is projected by the International Energy Agency to grow by approximately 21 trillion cubic feet ("Tcf") between 2019 and 2030 and 42 Tcf between 2019 and 2040. LNG's share is seen growing from about 12% in 2019 to about 16% of the global gas market in 2030 and 19% in 2040. Wood Mackenzie Limited ("WoodMac") forecasts that global demand for LNG will increase by approximately 56%, from approximately 347 mtpa, or 16.6 Tcf, in 2019, to approximately 541 mtpa, or 26.0 Tcf, in 2030 and to 723 mtpa or 34.7 Tcf in 2040. WoodMac also forecasts LNG production from existing operational facilities and new facilities already under construction will be able to supply the market with approximately 476 mtpa in 2030, declining to 381 mtpa in 2040. This will result in a market need for construction of an additional approximately 65 mtpa of LNG production by 2030 and about 343 mtpa by 2040. As a cleaner burning fuel with far lower emissions than coal or liquid fuels in power generation, we expect gas and LNG to play a central role in balancing grids and contributing to a low carbon energy system globally. We believe the capital and operating costs of the uncommitted capacity of our Liquefaction Projects and Corpus Christi Stage 3 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 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 approximately 85% of the total production capacity from the Liquefaction Projects on a term basis, with approximately 18 years of average remaining life as of December 31, 2020, which includes volumes contracted under SPAs in which the customers are required to pay a fixed fee with respect to the contracted volumes irrespective of their election to cancel or suspend deliveries of LNG cargoes, as well as volumes contracted under IPM gas supply agreements. As of January 31, 2021, 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 and medium-term contracting of LNG from our terminals.

Subsidiaries

Our assets are generally held by 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.

Human Capital Resources

We are in a unique position as the first U.S. LNG company in the lower 48. As the first mover, ensuring that we have an adequate supply of skilled employees has been a crucial part of our ability to grow and succeed. As a result, attracting, developing and retaining talent is key, especially as new competitors enter the industry in the coming years in need of the same talent we have recruited and developed.

Our strength lies within the collective expertise of our diverse workforce, living our core values of teamwork, respect, accountability, integrity, nimble and safety. Our employees help drive our success, build our reputation, establish our legacy and deliver on our commitments to our customers. Attracting the best and most diverse talent is a priority. To engage them, we offer fulfilling career opportunities. To keep them engaged, we continually listen to, train, develop and reward them. Our voluntary turnover was less than 4% for 2020.

As of January 31, 2021, we had 1,519 full-time employees with approximately 1,439 located in the U.S. and 80 located outside of the U.S (primarily in the UK).

Our Chief Human Resources Officer, along with senior leadership, are tasked with managing employment-related matters and initiatives including talent attraction and retention, rewards and remuneration, employee relations, employee engagement, diversity and inclusion, and training and development. We communicate progress on our human capital programs to our Board quarterly.

Talent Attraction, Engagement and Retention

Talent Attraction

Through our recruitment efforts, we seek top diverse talent who will continue to drive our strong performance. We have a competitive offering that provides us with a solid pipeline of candidates. Internally and externally, we post openings to attract individuals with a range of backgrounds, skills and experience, offering employee bonuses for referring highly qualified candidates. In addition, we actively recruit at colleges and conduct information sessions at select universities including Historically Black Colleges and Universities (HBCUs) and Hispanic-Serving Institutions (HSIs).

We manage and measure organizational health with a view to gaining insight into employees' experiences, levels of workplace satisfaction and feelings of engagement and inclusion with the company through biannual engagement surveys.

Insights from the biannual survey are used to develop both company-wide and business unit level organizational and talent development plans and training programs.

We provide robust compensation and benefits programs to our employees. In addition to salaries, these programs (which vary by country) include annual bonuses, stock awards, a 401(k) Plan, healthcare and insurance benefits, health savings and flexible spending accounts, paid time off, family leave, family care resources, employee assistance programs and tuition assistance.

Diversity and Inclusion

We are committed to providing a diverse culture where all employees can thrive and feel welcomed and valued. To create this environment, we are committed to equal employment opportunity and to compliance with all federal, state and local laws that prohibit workplace discrimination, harassment and unlawful retaliation. Both our discrimination and harassment and equal employment opportunity policies demonstrate our commitment to building an inclusive workplace, regardless of race, beliefs, nationality, gender and sexual orientation or any other status protected by our policy. Through our targeted recruitment efforts, we attract a variety of candidates with a diversity of backgrounds, skills, experience and expertise.

We encourage our employees to leverage their unique backgrounds through involvement in various employee resource groups. Groups such as WILS (Women Inspiring Leadership Success), EPN (Emerging Professional Network) and Cultural Champions Teams (CCTs) help build a culture of inclusion.

Development and Training

As the first exporter of LNG in the lower 48 of the US, we faced the unique challenge of developing our own LNG talent. Our apprenticeship program prepares local students for careers in LNG. This program combines classroom education with training and on-site learning experiences at our facilities.

We strive to provide our people with all of the tools and support necessary for them to succeed. We actively encourage our employees to take ownership of their careers and offer a number of resources to do so. Employees undergo annual performance reviews to ensure the ongoing development of their skills and expertise. To ensure safe, reliable and efficient operations in a highly regulated environment, we offer online and site-specific learning opportunities.

Employee Safety, Health and Wellness

The safety of our employees, contractors and communities is one of our core values. Our Cheniere Integrated Management System defines our required safety programs and details safety and health related procedures. Safety efforts are led by our Executive Safety Committee, which includes the CEO, senior leaders from across the company, and representatives from each of our operating assets. We focus our efforts on continuously improving our performance. For the year ended December 31, 2020, we achieved zero employee recordable injuries, and our total recordable incident rate (employees and contractors combined) was 0.17.

To support the well-being of our employees, we provide a wellness program that offers employees incentives to maintain an active lifestyle and set personal wellness goals. Incentives include online education related to health and nutrition as well as subsidies for fitness devices and gym memberships. We also offer mammography screenings, rooms for nursing mothers and biometric screenings on site.

In response to the COVID-19 pandemic, we implemented significant changes that we determined were in the best interest of our employees, as well as the communities in which we operate, and which comply with government regulations. This includes having employees work from home where possible, while implementing additional safety measures for employees continuing essential on-site work. We kept employees informed and connected through weekly messaging, mental health recorded seminars, manager toolkits and the launch of an internal campaign to ensure we are all listening and taking care of each other. We also provided the same level of resources, aid and support for weather-related disasters.

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. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers.

Additionally, we encourage you to review our Corporate Responsibility Report (located on our internet site at www.cheniere.com), for more detailed information regarding our Human Capital programs and initiatives, as well as our response to environmental, social and governance (ESG) issues. Nothing on our website, including our Corporate Responsibility Report or sections thereof, shall be deemed incorporated by reference into this Annual Report.

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.

Risk Factor Summary

Each of the risk factors outlined below are discussed more fully following this summary:

Risks Relating to Our Financial Matters

Our operating results, cash flows and/or liquidity could be adversely affected by the following factors:

- Our existing level of cash resources and significant debt
- History of net losses and negative operating cash flow
- Dilution of our proportionate indirect interests in our assets, business operations and proposed projects from sale of equity or equity-related securities
- Stockholder dilution upon the conversion of our convertible notes
- Failure to perform by our customers under their long-term contracts with us
- Termination of our customer contracts under certain circumstances
- Restrictions in distributions under certain circumstances by our subsidiaries
- Restrictions in agreements governing us and our subsidiaries' indebtedness
- Use of hedging arrangements
- Certain rules and regulations could adversely affect our ability to hedge risks

Risks Relating to Our LNG Terminal Operations and Commercialization

The operations of our LNG terminals, construction of the remaining or additional Trains and the commercialization of the LNG produced could be adversely affected by the following factors:

- Cost overruns and delays in construction, as well as difficulties in obtaining sufficient financing to pay for such costs and delays
- Our ability to obtain additional funding for additional Trains
- Hurricanes or other disasters
- Failure to obtain and maintain approvals and permits from governmental and regulatory agencies
- Delays in construction leading to reduced revenues or termination of one or more of the SPAs by our customers
- Dependency on Bechtel and other contractors
- Unavailability of third-party pipelines and other facilities interconnected to our pipelines and facilities to transport natural gas

- Inability to purchase or receive physical delivery of sufficient natural gas to satisfy our delivery obligations under the SPAs
- Subjectivity to FERC regulation
- Pipeline safety integrity programs and repairs
- Reduction in the capacity of, or the allocations to, interconnecting third-party pipelines
- Loss of our right to situate our pipelines on property owned by third parties
- Inaccurate estimates for the future capacity ratings and performance capabilities of the Liquefaction Projects
- Failure by any significant customer to perform under agreements
- Inability to contract with customers to sell LNG produced in excess of quantities committed under third-party SPAs

Risks Relating to Our LNG Business in General

The operation or growth of our LNG business, including our customers, could be adversely affected by the following factors:

- Not constructing or operating all of our proposed or additional LNG facilities or Trains beyond those currently planned
- Cyclical or other changes in the demand for and price of LNG and natural gas
- Failure of imported or exported LNG to be a competitive source of energy for the United States or international markets
- Various economic and political factors
- Impediments to the transport of LNG, such as shortages of LNG vessels, or operational impacts on LNG shipping
- Security of firm pipeline transportation capacity on economic terms that is sufficient to meet our feed gas transportation requirements
- Competition based upon the international market price for LNG
- Terrorist attacks, cyber incidents or military campaigns

Risks Relating to Our Business in General

Our operations and business results could also be adversely affected by the following factors:

- COVID-19 global pandemic and volatility in the energy markets
- Outbreaks of infectious diseases, such as the outbreak of COVID-19, at one or more of our facilities
- Significant construction and operating hazards and uninsured risks
- Existing and future environmental and similar laws and governmental regulations
- Major health and safety incident relating to our business
- Increased labor costs, and the unavailability of skilled workers or our failure to attract and retain qualified personnel, including changes in our senior management or other key personnel
- Lack of diversification
- Impairments to goodwill or long-lived assets
- Success of our share repurchase program
- Fluctuation in the market price of our common stock

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, 2020, we had $1.6 billion of cash and cash equivalents, $449 million of current restricted cash, $1,126 million of available commitments under the $1.25 billion Cheniere Revolving Credit Facility ("Cheniere Revolving Credit Facility"), $372 million of available commitments under the $2.62 billion delayed draw term loan credit agreement (the "Cheniere Term Loan Facility"), $767 million of available commitments under the $1.2 billion CCH Working Capital Facility ("CCH Working Capital Facility"), $750 million of available commitments under Cheniere Partners' credit facilities, $787 million of available commitments under the $1.2 billion Amended and Restated SPL Working Capital Facility ("2015 SPL Working Capital Facility"), and $31.5 billion of total debt outstanding on a consolidated basis (before unamortized premium, discount and debt issuance costs), excluding $0.8 billion aggregate outstanding letters of credit and noting that borrowings under certain of our credit facilities may be restricted. 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 Corpus Christi Stage 3. 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 always been profitable historically. We may not be able to achieve sustained profitability or generate positive operating cash flow in the future.

We had a net loss attributable to common stockholders of $85 million for the year ended December 31, 2020, as well as net losses attributable to common stockholders in prior years. 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 Liquefaction Projects, Corpus Christi Stage 3 and other projects. Any delays beyond the expected development period for these projects could cause 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 third-party agreements 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 project.

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

We have historically pursued a number of alternatives in order to finance the construction of our Trains, including potential issuances and sales of additional equity or equity-related securities by our subsidiaries. Such sales, in one or more transactions, could dilute our 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 March 2015, we issued $625 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. We have the option to satisfy the 2045 Cheniere Convertible Senior Notes conversion obligation with cash, common stock or a combination thereof. 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.

The conversion of some or all of the 2045 Cheniere Convertible Senior 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 obligation of the 2045 Cheniere Convertible Senior Notes with common stock, approximately 4.5 million shares of our common stock would be issued upon the conversion, assuming the notes are converted at maturity. Any sales in the public market of the shares issuable upon conversion of the 2045 Cheniere Convertible Senior Notes could adversely affect the prevailing market prices of our common stock. In addition, the existence of the 2045 Cheniere Convertible Senior Notes may encourage short selling by market participants because the conversion of the 2045 Cheniere Convertible Senior Notes could be used to satisfy short positions, or the anticipated conversion of the 2045 Cheniere Convertible Senior 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 significant customer fails to perform its contractual obligations for any reason.

Our future results and liquidity are substantially dependent upon performance by our customers to make payments under long-term contracts. As of December 31, 2020, SPL had SPAs with eight third-party customers, CCL had SPAs with nine third-party customers and our integrated marketing function had a limited number of SPAs with third-party customers. In addition, SPLNG had TUAs with two third-party customers. We are dependent on each customer's continued willingness and ability to perform its obligations under its SPA or TUA. We are exposed to the credit risk of any guarantor of these customers' obligations under their respective agreements in the event that we must seek recourse under a guaranty. As a result of the disruptions caused by the COVID-19 pandemic and the volatility in the energy markets, we believe we are exposed to heightened credit and performance risk of our customers. Additionally, some customers have indicated to us that COVID-19 has impacted their operations and/or may impact their operations in the future. Some of our SPA customers' primary countries of business have experienced a significant number of COVID-19 cases and/or have been subject to government imposed lockdown or quarantine measures. Although we believe that impacts of the COVID-19 pandemic on LNG regasification facilities, downstream markets and broader energy demand do not constitute valid force majeure claims under our FOB LNG SPAs, if any significant customer fails to perform its obligations under its SPA or TUA, 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, if any, for a breach of the agreement.

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. We 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 generally restricted from making distributions under agreements governing its indebtedness until, among other requirements, the completion of the construction of Trains 1 through 3 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.

Our subsidiaries' inability to pay distributions to Cheniere Partners or us or 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 and CCH 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 (1) changing interest rates, (2) commodity-related marketing and price risks and (3) foreign exchange volatility, we enter into derivative financial instruments, including futures, swaps and option contracts. To the extent we hedge our exposure to commodity price, interest rate or foreign currency exchange rate exposures, we forego the benefits we would otherwise experience if commodity prices, interest rates or foreign currency exchange rates were to change favorably to our hedged position. Hedging arrangements could also expose us to risk of financial loss in some circumstances, including when:

- expected supply is less than the amount hedged or is otherwise imperfect;
- 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.

Our use of derivative financial instruments are recorded at fair value on our Consolidated Balance Sheets with changes in the fair value resulting from fluctuations in the underlying commodity prices or hedged item recognized in earnings, unless they satisfy criteria for, and we elect, the normal purchases and sales exception or hedge accounting treatment. All of our derivative financial instruments do not qualify for these exceptions from fair value reporting through earnings. As a result, our quarterly and annual results are subject to significant fluctuations caused by changes in fair value, including circumstances in which there is no underlying economic impact yet realized.

The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices, interest rates or foreign currency exchange rates change.

The 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 by the CFTC, the SEC and other federal regulators establishing federal regulation of the 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.

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.

European and UK-specific regulations, including but not limited to EMIR, MiFID II, REMIT, MAR, FSMA and RAO, govern our trading activities and our compliance with such laws may result in increased costs and risks to the business similar to the impacts stated above with respect to the Dodd-Frank Act. The increased costs may also have an adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Further, any violation of the foregoing laws and regulations could result in investigations, and possible fines and penalties, and in some scenarios, criminal offenses.

Further, although a trade deal (the "Deal") has been reached between the UK and EU following Brexit, with the terms of this deal applying as on January 1, 2021, uncertainties remain. While the UK has implemented its own versions of many key EU rules mentioned above (known as 'onshoring'), the Deal was largely focused on goods, not services. Financial services will be negotiated separately, with an initial deadline for agreement set for March 2021. Depending on the terms of this agreement, and the extent to which the UK chooses to diverge from existing EU rules, mutual equivalence decisions could be granted by each side with the effect that compliance with either financial services regime is equivalent to compliance with the corresponding regime in the eyes of each jurisdictions' regulators. Until these issues are clarified, both sides have implemented temporary measures to avoid major disruption in areas like derivatives trading and clearing.

Risks Relating to Our LNG Terminal Operations and Commercialization

Cost overruns and delays in the completion of one or more Trains, as well as difficulties in obtaining sufficient financing to pay for such costs and delays, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The actual construction costs of the Trains may be significantly higher than our current estimates as a result of many factors, including change orders under existing or future EPC contracts resulting from the occurrence of certain specified events that may give our EPC contractor 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. 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.

The COVID-19 pandemic and the resulting actions taken by governmental and regulatory authorities to prevent the spread of COVID-19 may cause a slow-down in the construction of one or more Trains. Our EPC contractor has advised us of voluntary proactive measures it is taking to protect employees and to mitigate risks associated with COVID-19, however, it has not indicated that there will be any changes to the project cost or schedule and is still performing its obligations under its EPC contracts. While the construction of Trains is continuing, if there were a major outbreak of COVID-19 at any construction site or the implementation of restrictions by the government that prevented construction for an extended period, we could experience significant delays in the construction of one or more Trains.

Delays in the construction of one or more Trains beyond the estimated development periods, as well as change orders to our existing EPC contracts or any future EPC contract related to additional Trains, could increase the cost of completion beyond the amounts that we estimate, which could require us to obtain additional sources of financing to fund our operations until the 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.

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 additional Trains, 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 additional Trains, 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, damage to our Liquefaction Projects and increased insurance costs, all of which could adversely affect us.

Hurricanes Katrina and Rita in 2005, Hurricane Ike in 2008, Hurricane Harvey in 2017 and Hurricanes Laura and Delta in 2020 caused temporary suspension in construction or operation of our Liquefaction Projects or caused minor damage to our Liquefaction Projects. In August 2020, SPL and CCL entered into an arrangement to provide the ability, in limited circumstances, to potentially fulfill commitments to LNG buyers from the other facility in the event operational conditions impact operations at either the Sabine Pass LNG terminal or the Corpus Christi terminal. During the year ended December 31, 2020, 17 TBtu was loaded at affiliate facilities pursuant to this agreement. 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, the Corpus Christi terminal or related infrastructure, as well as delays or cost increases in the construction and the development of the Liquefaction Projects, Corpus Christi Stage 3 or our other facilities and increase our insurance premiums. The U.S. Global Change Research Program has reported that the U.S.'s energy and transportation systems are expected to be increasingly disrupted by climate change and extreme weather events. An increase in frequency and severity of extreme weather events such as storms, floods, fires and rising sea levels could have an adverse effect on our 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, the development and operation of our pipelines and the export of LNG could impede operations and construction and could have a material adverse effect on us.

The design, construction and operation of interstate natural gas pipelines, LNG terminals, including the Liquefaction Projects, Corpus Christi Stage 3 and other facilities, and the import and export of LNG and the purchase and 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 the six Trains and related facilities of the SPL Project, the three Trains and related facilities of the CCL Project and the seven midscale Trains and related facilities for Corpus Christi Stage 3, as well as orders under Section 7 of the NGA authorizing the construction and operation of the Creole Trail Pipeline, the Corpus Christi Pipeline and the pipeline for Corpus Christi Stage 3, 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 regulatory 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. Additionally, government disruptions, such as a U.S. government shutdown, may delay or halt our ability to obtain and maintain necessary approvals and permits. 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.

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.

We are dependent on Bechtel and other contractors for the successful completion of the Liquefaction Projects.

Timely and cost-effective completion of the Liquefaction Projects 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 Liquefaction Projects, 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 Liquefaction Projects or result in a contractor's unwillingness to perform further work on the Liquefaction Projects. 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.

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 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 purchase and transportation of natural gas in interstate commerce, including the construction and operation of pipelines, the rates, terms and 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 are 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 causes 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.

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.

We are relying on estimates for the future capacity ratings and performance capabilities of the Liquefaction Projects, 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 Liquefaction Projects. 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.

Any failure to perform by our 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 have, and continue to develop, 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 Liquefaction Projects 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. Excess LNG from the Liquefaction Projects competes with other sources of LNG that are priced to indices other than Henry Hub, and any collapse in the spread between global LNG prices and the Henry Hub index could impact the ability of our integrated marketing function to profitably sell any such excess LNG. 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 Business 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 and the Corpus Christi 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, including extreme weather events and temperature volatility resulting from climate change;
- 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, including as a result of any potential ban on production of natural gas through hydraulic fracturing;
- 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;
- sudden decreases in demand for LNG as a result of natural disasters or public health crises, including the occurrence of a pandemic, and other catastrophic events;
- 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 the United States or 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 Liquefaction Projects are 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.

Although SPL has entered into arrangements to utilize up to approximately three-quarters of the regasification capacity at the Sabine Pass LNG terminal in connection with operations of the SPL Project, 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 Liquefaction Projects 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 Liquefaction Projects in certain markets. The cost of LNG supplies from the United States, including the Liquefaction Projects, 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 the Corpus Christi LNG terminal or from the Liquefaction Projects 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 Liquefaction Projects 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 impediments to the transport of LNG, such as shortages of LNG vessels worldwide or operational impacts on LNG shipping, including maritime transportation routes, 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. Additionally, the availability of LNG vessels and transportation costs could be impacted 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;
- shortages of or delays in the receipt of necessary construction materials;
- political or economic disturbances;
- changes in governmental regulations or maritime self-regulatory organizations;
- work stoppages or other labor disturbances;
- bankruptcy or other financial crisis of shipbuilders or shipowners;
- quality or engineering problems;
- disruptions to maritime transportation routes; and
- weather interference or a catastrophic event, such as a major earthquake, tsunami or fire.

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

We have contracted for firm capacity for our natural gas feedstock transportation requirements for the Liquefaction Projects and for Corpus Christi Stage 3. If and when we need to replace one or more of our existing 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, cyber incidents or military campaigns may adversely impact our business.

A terrorist attack, cyber incident 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 or cyber incident may also result in temporary or permanent closure of our existing facilities, 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, cyber incidents 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

The COVID-19 global pandemic and volatility in the energy markets may materially and adversely affect our business, financial condition, operating results, cash flow, liquidity and prospects.

The COVID-19 global pandemic has resulted in significant disruption globally. Actions taken by various governmental authorities, individuals and companies around the world to prevent the spread of COVID-19 have restricted travel, business operations, and the overall level of individual movement and in-person interaction across the globe. Additionally, recent disputes over production levels between members of the Organization of Petroleum Exporting Countries and other oil producing countries have resulted in increased volatility in oil and natural gas prices.

The extent, duration and magnitude of the COVID-19 pandemic's effects will depend on future developments, all of which are highly uncertain and difficult to predict, including the impact of the pandemic on global and regional economies, travel, and economic activity, as well as actions taken by governments, businesses and individuals in response to the pandemic or any future resurgence. These developments include the impact of the COVID-19 pandemic on unemployment rates, the demand for oil and natural gas, levels of consumer confidence and the post-pandemic pace of recovery.

Many uncertainties remain with respect to the COVID-19 pandemic, and we continue to monitor the rapidly evolving situation. The COVID-19 pandemic alone or coupled with continued volatility in the energy markets may materially and adversely affect our business, financial condition, operating results, cash flow, liquidity and prospects or have the effect of heightening many of the other risks described herein. The extent to which our business, contracts, financial condition, operating results, cash flow, liquidity and prospects are affected by the COVID-19 global pandemic or volatility in the energy markets will depend on various factors beyond our control and are highly uncertain, including the duration and scope of the outbreak, decreased demand for LNG and the resulting economic effects of the COVID-19 global pandemic.

Outbreaks of infectious diseases, such as the outbreak of COVID-19, at one or more of our facilities could adversely affect our operations.

Federal, state and local governments have enacted various measures to try to contain the outbreak of COVID-19, such as travel bans and restrictions, quarantines, shelter-in-place orders and business shutdowns. Our facilities at the Sabine Pass LNG terminal and Corpus Christi LNG terminal are critical infrastructure and have continued to operate during the outbreak, which means that we must keep our employees who operate our facilities safe and minimize unnecessary risk of exposure to the virus. In response, we have taken extra precautionary measures to protect the continued safety and welfare of our employees who continue to work at our facilities and have modified certain business and workforce practices, such as implementing work from home policies where appropriate, but there can be no assurances that these measures will prevent any outbreak. Furthermore, the measures taken to prevent an outbreak at our facilities have resulted in increased costs and it is unclear how long such increased costs will continue to be incurred. If a large number of our employees in those critical facilities were to contract COVID-19 at the same time, our operations could be adversely affected.

We are subject to significant construction and 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, breakdowns or failures of equipment, operational errors by vessel or tug operators, 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, rules and regulations applicable to our construction and operation activities relating to, among other things, air quality, water quality, waste management, natural resources and health and safety. 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 laws and regulations authorize regulators having jurisdiction over the construction and operation of our LNG terminals and pipelines, including FERC and PHMSA, 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, compliance orders, fines and penalties or to capital expenditures 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 2009, the EPA promulgated and finalized the Mandatory Greenhouse Gas Reporting Rule requiring annual reporting of GHG emissions from stationary sources in a variety of industries. 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. While the EPA subsequently took a number of additional actions primarily relating to GHG emissions from the electric power generation and the oil and gas exploration and production industries, those rules were largely stayed or repealed during the Trump Administration including by amendments adopted by the EPA on February 23, 2018 and additional amendments to new source performance standards for the oil and gas industry on September 14 and 15, 2020. On January 20, 2021, President Biden issued an executive order directing the EPA to consider publishing for notice and comment a proposed rule suspending, revising, or rescinding the September 2020 rule, which could result in more stringent GHG emissions rulemaking. In addition, other federal and state initiatives may be considered in the future to address GHG emissions through, for example, United States treaty commitments, direct regulation, market-based regulations such as a carbon emissions tax or cap-and-trade programs or clean energy standards. Such initiatives could affect the demand for or cost of natural gas, which we consume at our terminals, or could increase compliance costs for our operations. We are supportive of regulations reducing GHG emissions over time.

Other future legislation and regulations, such as those relating to the transportation and security of LNG imported to or exported from our terminals or climate policies of destination countries in relation to their obligations under the Paris Agreement or other national climate change-related policies, could cause additional expenditures, restrictions and delays in our business and to our proposed construction activities, 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 damages.

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, changes in applicable laws and regulations or labor disputes 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 2021 will be dependent upon our two facilities, the Sabine Pass LNG terminal located in southern Louisiana and the Corpus Christi LNG terminal in Texas. 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 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.

We cannot guarantee that our share repurchase program will be fully consummated or that it will enhance long-term stockholder value.

In June 2019, our Board authorized a three-year, $1 billion share repurchase program and as of December 31, 2020, up to $596 million remains available for repurchase. Our share repurchase program does not obligate us to acquire any particular amount of common stock. Our share repurchase program may be modified, suspended or terminated at any time, which may result in a decrease in the trading price of our common stock.

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, 2020, the market price of our common stock ranged between $27.06 and $71.03. 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;
- changes in investor sentiment regarding the energy industry and fossil fuels; 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.

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 Matter

In February 2018, the 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 conduct analysis, repair and remediation. On April 20, 2018, SPL and PHMSA executed a Consent Agreement and Order (the "Consent Order") that replaces and supersedes the CAO. On July 9, 2019, PHMSA and FERC issued a joint letter setting out operating conditions required to be met prior to SPL returning the tanks to service. We continue to coordinate with PHMSA and FERC to address the matters relating to the February 2018 leak, including repair approach and related analysis. We do not expect that the Consent Order and related analysis, repair and remediation will have a material adverse impact on our financial results or operations.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

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

Market Information, Holders and Dividends

Our common stock has traded on the NYSE American under the symbol "LNG" since March 24, 2003. As of February 19, 2021, we had 254 million shares of common stock outstanding held by 91 record owners.

We have never paid a cash dividend on our common stock. 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, 2020:

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	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans (3)
October 1 - 31, 2020	4,726	$48.20	—	$595,952,809
November 1 - 30, 2020	1,925	$49.16	—	$595,952,809
December 1 - 31, 2020	1,891	$56.74	—	$595,952,809
Total	8,542	$50.31	—	

(1) Includes issued shares surrendered to us by participants in our share-based compensation plans for payment of applicable tax withholdings on the vesting of share-based compensation awards. Associated shares surrendered by participants are repurchased pursuant to terms of the plan and award agreements and not as part of the publicly announced share repurchase plan.

(2) The price paid per share was based on the average trading price of our common stock on the dates on which we repurchased the shares.

(3) On June 3, 2019, we announced that our Board authorized a 3-year, $1 billion share repurchase program. For additional information, see Note 19—Share Repurchase Program.

Total Stockholder Return

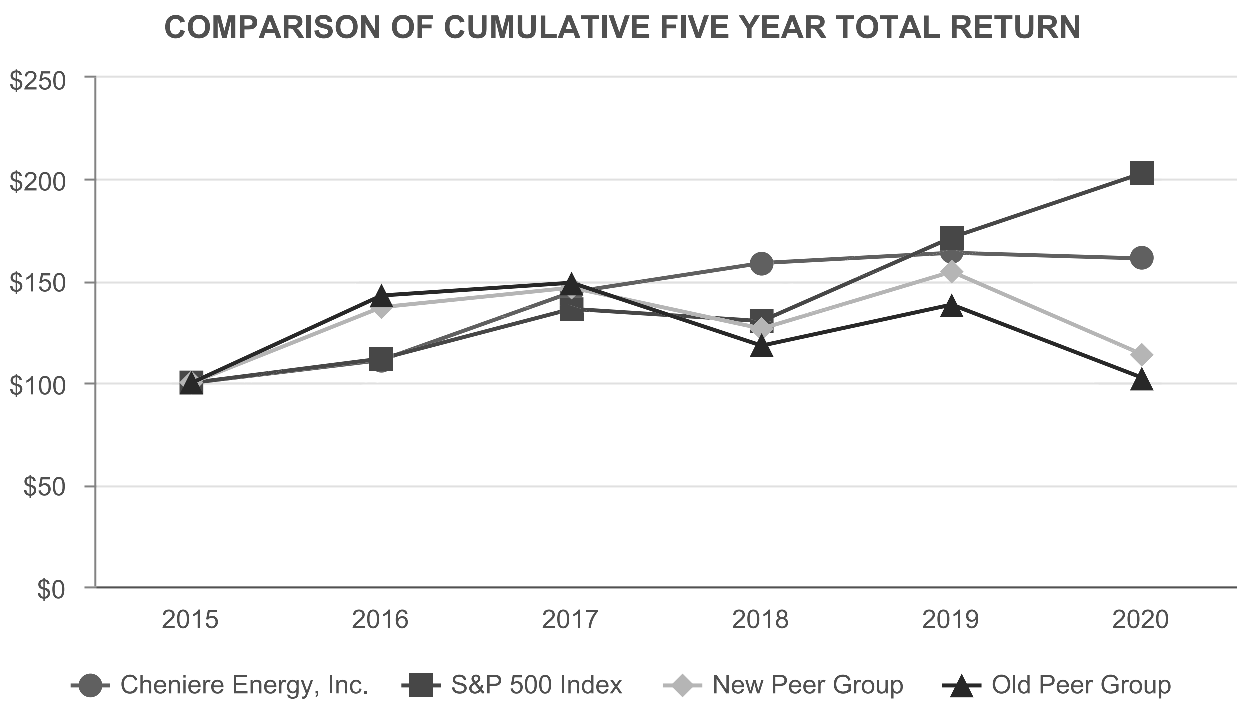
The following is a customized peer group consisting of 17 companies (the "New Peer Group") that were selected because they are publicly traded companies that have: (1) comparable Global Industries Classification Standards, (2) similar market capitalization, (3) similar enterprise values and (4) similar operating characteristics and capital intensity:

New Peer Group	
Air Products and Chemicals, Inc. (APD)	Marathon Petroleum Corporation (MPC)
Baker Hughes Company (BKR)	Occidental Petroleum Corporation (OXY)
ConocoPhillips (COP)	ONEOK, Inc. (OKE)
Enterprise Products Partners L.P. (EPD)	Phillips 66 (PSX)
EOG Resources, Inc. (EOG)	Suncor Energy Inc. (SU)
Halliburton Company (HAL)	Targa Resources Corp. (TRGP)
Hess Corporation (HES)	Valero Energy Corporation (VLO)
Kinder Morgan, Inc. (KMI)	The Williams Companies, Inc. (WMB)
LyondellBasell Industries N.V. (LYB)	

The New Peer Group companies were revised during 2020 to (1) focus on companies of more comparable size based on relative enterprise value and assets, (2) distribute more evenly the sub-industry representation across oil and gas sectors (i.e., fewer upstream companies) and (3) remove companies that were acquired, left the industry or that did not offer adequate business comparisons for us. Our previous peer group consisted of 27 companies (the "Old Peer Group"), which included, in addition to the 17 companies in the New Peer Group, the following companies: Apache Corporation (APA), Concho Resources Inc. (CXO), Continental Resources, Inc. (CLR), Devon Energy Corporation (DVN), Diamondback Energy, Inc. (FANG), Freeport-McMoRan Inc. (FCX), Marathon Oil Corporation (MRO), Noble Energy, Inc. (NBL), Pioneer Natural Resources Company (PXD) and Schlumberger Limited (SLB).

The following graph compares the five-year total return on our common stock, the S&P 500 Index, the New Peer Group and the Old Peer Group. The graph was constructed on the assumption that $100 was invested in our common stock, the S&P 500 Index, the New Peer Group and the Old Peer Group on December 31, 2015 and that any dividends were fully reinvested.

Company / Index	2015	2016	2017	2018	2019	2020
Cheniere Energy, Inc.	$ 100.00	$ 111.22	$ 144.54	$ 158.90	$ 163.95	$ 161.15
S&P 500 Index	100.00	111.95	136.38	130.39	171.44	202.96
New Peer Group	100.00	137.20	146.83	126.67	154.65	114.12
Old Peer Group	100.00	142.95	149.23	118.31	138.48	102.62


COMPARISON OF CUMULATIVE FIVE YEAR TOTAL RETURN
$250
$200
$150
$100
$50
$0
2015
2016
2017
2018
2019
2020
Cheniere Energy, Inc.
S&P 500 Index
New Peer Group
Old Peer Group

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,				
	2020	2019	2018	2017	2016
Consolidated Statement of Operations Data:					
Revenues	$ 9,358	$ 9,730	$ 7,987	$ 5,601	$ 1,283
Income (loss) from operations	2,631	2,361	2,024	1,388	(30)
Interest expense, net of capitalized interest	(1,525)	(1,432)	(875)	(747)	(488)
Net income (loss)	501	1,232	1,200	563	(665)
Net income (loss) attributable to common stockholders	(85)	648	471	(393)	(610)
Common Stock Data:					
Net income (loss) per share attributable to common stockholders—basic	$ (0.34)	$ 2.53	$ 1.92	$ (1.68)	$ (2.67)
Net income (loss) per share attributable to common stockholders—diluted	$ (0.34)	$ 2.51	$ 1.90	$ (1.68)	$ (2.67)
Weighted average number of common shares outstanding—basic	252.4	256.2	245.6	233.1	228.8
Weighted average number of common shares outstanding—diluted	252.4	258.1	248.0	233.1	228.8

	December 31,				
	2020	2019	2018	2017	2016
Consolidated Balance Sheet Data:					
Property, plant and equipment, net	$ 30,421	$ 29,673	$ 27,245	$ 23,978	$ 20,635
Total assets	35,697	35,492	31,987	27,906	23,703
Current debt, net	372	—	239	—	247
Long-term debt, net	30,471	30,774	28,179	25,336	21,688

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

Cheniere, a Delaware corporation, is a Houston-based energy infrastructure company primarily engaged in LNG-related businesses. We provide clean, secure and affordable LNG to integrated energy companies, utilities and energy trading companies around the world. We aspire to conduct our business in a safe and responsible manner, delivering a reliable, competitive and integrated source of LNG to our customers. We own and operate the Sabine Pass LNG terminal in Louisiana, one of the largest LNG production facilities in the world, through our ownership interest in and management agreements with Cheniere Partners, which is a publicly traded limited partnership that we created in 2007. As of December 31, 2020, we owned 100% of the general partner interest and 48.6% of the limited partner interest in Cheniere Partners. We also own and operate the Corpus Christi LNG terminal in Texas, which is wholly owned by us.

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, through its subsidiary SPL, is currently operating five natural gas liquefaction Trains and is constructing one additional Train that is expected to be substantially completed in the second half of 2022, for a total production capacity of approximately 30 mtpa of LNG (the "SPL Project") at the Sabine Pass LNG terminal. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' subsidiary, SPLNG, that include pre-existing infrastructure of five LNG storage tanks with aggregate capacity of approximately 17 Bcfe, two existing marine berths and one under construction that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters and vaporizers with regasification capacity of approximately 4 Bcf/d. Cheniere Partners also owns a 94-mile pipeline through its subsidiary, CTPL, that interconnects the Sabine Pass LNG terminal with a number of large interstate pipelines.

We also own the Corpus Christi LNG terminal near Corpus Christi, Texas, and are currently operating two Trains and one additional Train is undergoing commissioning for a total production capacity of approximately 15 mtpa of LNG. Additionally, we are operating a 23-mile natural gas supply pipeline that interconnects the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline" and together with the Trains, the "CCL Project") through our subsidiaries CCL and CCP, respectively. The CCL Project, once fully constructed, will contain three LNG storage tanks with aggregate capacity of approximately 10 Bcfe and two marine berths that can each accommodate vessels with nominal capacity of up to 266,000 cubic meters.

We have contracted approximately 85% of the total production capacity from the SPL Project and the CCL Project (collectively, the "Liquefaction Projects") on a term basis, with approximately 18 years of average remaining life as of December 31, 2020. This includes volumes contracted under SPAs in which the customers are required to pay a fixed fee with respect to the contracted volumes irrespective of their election to cancel or suspend deliveries of LNG cargoes, as well as volumes contracted under integrated production marketing ("IPM") gas supply agreements.

Additionally, separate from the CCH Group, we are developing an expansion of the Corpus Christi LNG terminal adjacent to the CCL Project ("Corpus Christi Stage 3") through our subsidiary CCL Stage III for up to seven midscale Trains with an expected total production capacity of approximately 10 mtpa of LNG. We received approval from FERC in November 2019 to site, construct and operate the expansion project.

We remain focused on operational excellence and customer satisfaction. Increasing demand of LNG has allowed us to expand our liquefaction infrastructure in a financially disciplined manner. We have increased available liquefaction capacity at our Liquefaction Projects as a result of debottlenecking and other optimization projects. We hold significant land positions at both the Sabine Pass LNG terminal and the Corpus Christi LNG terminal which provide opportunity for further liquefaction capacity expansion. The development of these sites or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, acceptable commercial and financing arrangements before we can make a final investment decision ("FID").

Overview of Significant Events

Our significant events since January 1, 2020 and through the filing date of this Form 10-K include the following:

Operational

- As of February 19, 2021, approximately 1,425 cumulative LNG cargoes totaling over 95 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Projects.
- In December 2020, CCL commenced shipment of LNG commissioning cargoes from Train 3 of the CCL Project.

Financial

- We completed the following financing transactions:
    - In February 2021, SPL entered into a note purchase agreement for the sale of approximately $147 million aggregate principal amount of 2.95% Senior Secured Notes due 2037 (the "2.95% SPL 2037 Senior Secured Notes") on a private placement basis. The 2.95% SPL 2037 Senior Secured Notes are expected to be issued in December 2021, and the net proceeds are expected to be used to refinance a portion of SPL's outstanding Senior Secured Notes due 2022. The 2.95% SPL 2037 Senior Secured Notes will be fully amortizing, with a weighted average life of over 10 years.
    - In September 2020, we issued an aggregate principal amount of $2.0 billion of 4.625% Senior Secured Notes due 2028 (the "2028 Cheniere Senior Secured Notes"). The net proceeds were used to prepay approximately $2.0 billion of outstanding indebtedness of the Cheniere Term Loan Facility.
    - In August 2020, CCH issued an aggregate principal amount of approximately $769 million of 3.52% Senior Secured Notes due 2039 (the "3.52% CCH Senior Secured Notes"). The net proceeds of these notes were used to repay a portion of the outstanding borrowings under CCH's amended and restated credit facility ("CCH Credit Facility"), pay costs associated with certain interest rate derivative instruments that were settled and pay certain fees, costs and expenses incurred in connection with these transactions.
    - In June 2020, we entered into the Cheniere Term Loan Facility with original commitments of $2.62 billion, which in July 2020 was subsequently increased to $2.695 billion. In July 2020, borrowings under the Cheniere Term Loan Facility were used to (1) redeem the remaining outstanding principal amount of the 11% Convertible Senior Secured Notes due 2025 (the "2025 CCH HoldCo II Convertible Senior Notes"), subsequent to the $300 million redemption in March 2020, pursuant to the amended and restated note purchase agreement for the 2025 CCH HoldCo II Convertible Senior Notes which allowed CCH HoldCo II to redeem the outstanding notes with cash at a price of $1,080 per $1,000 principal amount, (2) repurchase $844 million in aggregate principal amount of outstanding 4.875% Convertible Unsecured Notes due 2021 (the "2021 Cheniere Convertible Unsecured Notes") at individually negotiated prices from a small number of investors and (3) pay the related fees and expenses. The remaining available commitments under the Cheniere Term Loan Facility of $372 million are expected to be used to repay and/or repurchase a portion of

the remaining outstanding principal amount of the 2021 Cheniere Convertible Unsecured Notes and for the payment of related fees and expenses.

  ◦ In May 2020, SPL issued an aggregate principal amount of $2.0 billion of 4.500% Senior Secured Notes due 2030 (the "2030 SPL Senior Notes"). Net proceeds of the offering, along with available cash, were used to redeem all of SPL's outstanding 5.625% Senior Secured Notes due 2021 (the "2021 SPL Senior Notes").

  ◦ In March 2020, SPL entered into a $1.2 billion Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement (the "2020 SPL Working Capital Facility"), which refinanced its previous working capital facility, reduced the interest rate and extended the maturity date to March 2025.

- During the year ended December 31, 2020, in line with our previously announced capital allocation priorities, with available cash, we: (1) prepaid $200 million of the borrowings made during the year under the $2.695 billion delayed draw term loan credit agreement (the "Cheniere Term Loan Facility") and (2) redeemed $300 million of the 2025 CCH HoldCo II Convertible Senior Notes.
- In December 2020, we loaded and shipped the first two LNG cargoes under the 25-year SPA with CPC Corporation, Taiwan, which were delivered in January 2021.
- In May 2020, the date of first commercial delivery was reached under the 20-year SPAs with PT Pertamina (Persero), Naturgy LNG GOM, Limited, Woodside Energy Trading Singapore Pte Ltd, Iberdrola Generación España, S.A.U. (assigned by Iberdrola, S.A.) and Électricité de France, S.A. relating to Train 2 of the CCL Project.
- In February 2021, Fitch Ratings upgraded the outlook of SPL's senior secured notes rating to positive from stable.

Impact of COVID-19 and Market Environment

The LNG business environment in 2020 was impacted by the coronavirus pandemic and its economic ramifications. Lockdown measures across the globe reduced economic activity and resulted in lower energy needs throughout most of the year. However, LNG demand proved relatively resilient as compared to other hydrocarbons, showing an annual gain of approximately 1.4%, or 5 MT, to 364 MT in 2020. While the economic recovery in Asia, and particularly in China, lifted LNG demand in the second half of the year, uncertainty about the pandemic's track remains the primary near-term risk to LNG trade. A slow return towards normal is expected to occur in the coming months, depending on the speed of vaccine rollout within regions, vaccine effectiveness against mutations and the speed and shape of economic recovery across the LNG importing nations. The continued improvements in global economic indicators seen in the fourth quarter is encouraging especially in China, which represents one of the key countries for LNG demand growth.

In the fourth quarter of 2020, natural gas and LNG spot prices significantly increased in line with the increase in economic activity and with seasonal norms. After falling to all-time lows in the second quarter, global LNG price benchmarks have made an impressive climb and exited the year at the highest levels since March 2019. As an example, the Dutch Title Transfer Facility ("TTF"), a virtual trading point for natural gas in the Netherlands, settled December at $5.08/MMBtu, $3.94/MMBtu higher than its June 2020 settlement. Similarly, the Japan Korea Marker ("JKM"), an LNG benchmark price assessment for spot physical cargoes delivered ex-ship into certain key markets in Asia, settled December at $6.90/MMBtu, which is $4.84/MMBtu higher than its all-time low July 2020 settlement. Record-low winter temperatures, supply outages and transportation bottlenecks contributed to drive JKM prices up to all-time highs by mid-January 2021. In a projection published in July 2020, IHS Markit estimated LNG demand to reach 383 MT in 2021, implying a return to higher growth in 2021.

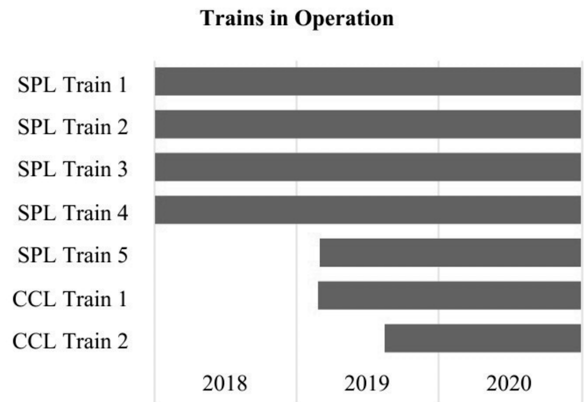
We have limited exposure to the fluctuations in oil and LNG spot prices as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements linked to a Henry Hub price. For this reason, we do not expect price fluctuations to have a material impact on our forecasted financial results for 2021.

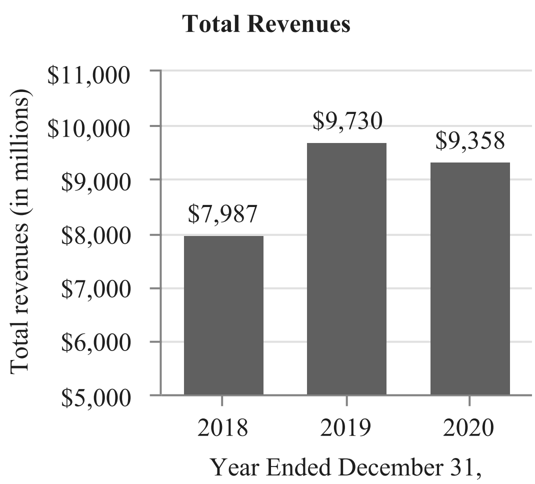
The number of LNG cargoes for which customers notified us that they would not take delivery has reduced from this summer, a sign that the market is continuing to adjust and rebalance toward equilibrium. We do not expect these events to have a material adverse impact on our forecasted financial results for 2021, due to the highly contracted nature of our business and the fact that customers continue to be obligated to pay fixed fees for cargoes with respect to which they have exercised their contractual right to cancel. As such, during the year ended December 31, 2020, we recognized $969 million in LNG revenues associated with LNG cargoes for which customers notified us that they would not take delivery, of which $38 million would have been recognized subsequent to December 31, 2020, if the cargoes were lifted pursuant to the delivery schedules with the customers. We experienced decreased revenues during the year ended December 31, 2020 associated with LNG cargoes that were scheduled for delivery for which customers notified us that they would not take delivery of such cargoes.

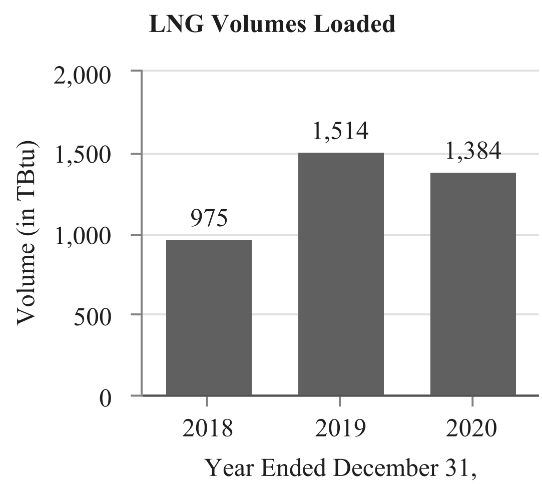
In addition, in response to the COVID-19 pandemic, we have modified certain business and workforce practices to protect the safety and welfare of our employees who continue to work at our facilities and offices worldwide, as well as implemented certain mitigation efforts to ensure business continuity. In March 2020, we began consulting with a medical advisor, and implemented social distancing through revised shift schedules, work from home policies and designated remote work locations where appropriate, restricted non-essential business travel and began requiring self-screening for employees and contractors. In April 2020, we began providing temporary housing for our workforce for our facilities, implemented temperature testing, incorporated medical and social workers to support employees, implemented prior self-isolation and screening for temporary housing and implemented marine operations with zero contact during loading activities. These measures have resulted in increased costs. While response measures continue to evolve and in most cases have moderated or ceased, we expect to incur incremental operating costs associated with business continuity and protection of our workforce until the risks associated with the pandemic diminish. We have incurred approximately $69 million of such costs during the year ended December 31, 2020.

Results of Operations

The following charts summarize the number of Trains that were in operation during the years ended December 31, 2020, 2019 and 2018 and total revenues and total LNG volumes loaded from our Liquefaction Projects (including both operational and commissioning volumes) for the respective periods:







The following table summarizes the volumes of operational and commissioning LNG cargoes that were loaded from the Liquefaction Projects, which were recognized on our Consolidated Financial Statements during the year ended December 31, 2020:

	Year Ended December 31, 2020	
(in TBtu)	**Operational**	**Commissioning**
Volumes loaded during the current period	1,378	6
Volumes loaded during the prior period but recognized during the current period	33	—
Less: volumes loaded during the current period and in transit at the end of the period	(26)	(3)
Total volumes recognized in the current period	1,385	3

Our consolidated net loss attributable to common stockholders was $85 million, or $0.34 per share (basic and diluted), for the year ended December 31, 2020, compared to net income attributable to common stockholders of $648 million, or $2.53 per share—basic and $2.51 per share—diluted, in the year ended December 31, 2019. This $733 million decrease in net income attributable to common stockholders in 2020 was primarily attributable to increases in: (1) losses from commodity derivatives to secure natural gas feedstock for the Liquefaction Projects, (2) income tax provision, (3) losses on modification or extinguishment of debt, (4) operating and maintenance expense, (5) depreciation and amortization expense, (6) interest rate derivative losses and (7) interest expense, net of capitalized interest. This loss was partially offset by increased gross margins primarily due to additional LNG volume available to be sold from additional Trains that have reached substantial completion between the periods, a portion of which the customers elected not to take delivery but were required to pay a fixed fee with respect to the contracted volumes.

Our consolidated net income attributable to common stockholders was $471 million, or $1.92 per share—basic and $1.90 per share—diluted, in the year ended December 31, 2018. This $177 million increase in net income in 2019 compared to 2018 was primarily attributable to (1) increased gross margins due to increased volume of LNG sold partially offset by decreased pricing on LNG, (2) increased tax benefit from the release of a significant portion of the valuation allowance previously recorded against our deferred tax assets, (3) increased LNG revenues as a result of derivative gains on commodity derivatives and (4) decreased net income attributable to non-controlling interest, which were partially offset by an increase in (1) interest expense, net of amounts capitalized, (2) operating and maintenance expense, (3) derivative losses, net, associated with our interest rate derivatives, (4) depreciation and amortization expense and (5) losses on equity method investments.

We enter into derivative instruments to manage our exposure to (1) changing interest rates, (2) commodity-related marketing and price risks and (3) foreign exchange volatility. Derivative instruments are reported at fair value on our Consolidated Financial Statements. In some cases, the underlying transactions economically hedged receive accrual accounting treatment, whereby revenues and expenses are recognized only upon delivery, receipt or realization of the underlying transaction. Because the recognition of derivative instruments at fair value has the effect of recognizing gains or losses relating to future period exposure, use of derivative instruments may increase the volatility of our results of operations based on changes in market pricing, counterparty credit risk and other relevant factors.

Revenues

	Year Ended December 31,				
(in millions)	2020	2019	Change	2018	Change
LNG revenues	$ 8,924	$ 9,246	$ (322)	$ 7,572	$ 1,674
Regasification revenues	269	266	3	261	5
Other revenues	165	218	(53)	154	64
Total revenues	$ 9,358	$ 9,730	$ (372)	$ 7,987	$ 1,743

2020 vs. 2019 and 2019 vs. 2018

Total revenues decreased during the year ended December 31, 2020 from the comparable period in 2019, primarily as a result of decreased revenues recognized by our integrated marketing function due to the recent downturn in the energy market and the absence of variable fees for cargoes in which customers notified us they would not take delivery. During the year ended December 31, 2020, we recognized $969 million in revenues associated with LNG cargoes for which customers notified us that they would not take delivery, of which $38 million would have been recognized subsequent to December 31, 2020, if the cargoes were lifted pursuant to the delivery schedules with the customers. The increase in revenue attributable to LNG volume sold during the year ended December 31, 2019 from the comparable period in 2018 was due to increased volume of LNG sold following the achievement of substantial completion of Trains between the years, partially offset by decreased LNG revenues per MMBtu, which was primarily affected by market prices realized for volumes sold by our integrated marketing function. We expect our LNG revenues to increase in the future upon Train 3 of the CCL Project and Train 6 of the SPL Project 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. During the years ended years ended December 31, 2020, 2019 and 2018, we realized offsets to LNG terminal costs of $19 million, $301 million and $140 million, corresponding to 3 TBtu, 51 TBtu and 17 TBtu, respectively, that were related to the sale of commissioning cargoes from the Liquefaction Projects.

Also included in LNG revenues are sale of unutilized natural gas procured for the liquefaction process, gains and losses from derivative instruments, which include the realized value associated with a portion of derivative instruments that settle through physical delivery, and revenues from arrangements in which we financially settled previously-scheduled LNG cargo sales without physical delivery. We recognized revenues of $436 million, $693 million and $163 million during the years ended December 31, 2020, 2019 and 2018, respectively, related to these transactions.

The following table presents the components of LNG revenues and the corresponding LNG volumes sold:

	Year Ended December 31,		
	2020	2019	2018
LNG revenues *(in millions)*:			
LNG from the Liquefaction Projects sold under third party long-term agreements (1)	$ 6,303	$ 6,342	$ 4,762
LNG from the Liquefaction Projects sold by our integrated marketing function under short-term agreements	802	1,943	1,902
LNG procured from third parties	414	268	745
LNG revenues associated with cargoes not delivered per customer notification (2)	969	—	—
Other revenues and derivative gains	436	693	163
Total LNG revenues	$ 8,924	$ 9,246	$ 7,572
Volumes delivered as LNG revenues *(in TBtu)*:			
LNG from the Liquefaction Projects sold under third party long-term agreements (1)	1,158	1,090	761
LNG from the Liquefaction Projects sold by our integrated marketing function under short-term agreements	227	368	212
LNG procured from third parties	103	40	84
Total volumes delivered as LNG revenues	1,488	1,498	1,057

(1) Long-term agreements include agreements with an initial tenure of 12 months or more.

(2) LNG revenues include revenues with no corresponding volumes due to revenues attributable to LNG cargoes for which customers notified us that they would not take delivery.

Operating costs and expenses

	Year Ended December 31,				
(in millions)	2020	2019	Change	2018	Change
Cost of sales	$ 4,161	$ 5,079	$ (918)	$ 4,597	$ 482
Operating and maintenance expense	1,320	1,154	166	613	541
Development expense	6	9	(3)	7	2
Selling, general and administrative expense	302	310	(8)	289	21
Depreciation and amortization expense	932	794	138	449	345
Impairment expense and loss on disposal of assets	6	23	(17)	8	15
Total operating costs and expenses	$ 6,727	$ 7,369	$ (642)	$ 5,963	$ 1,406

2020 vs. 2019 and 2019 vs. 2018

Our total operating costs and expenses decreased during the year ended December 31, 2020 from the year ended December 31, 2019, primarily as a result of decreased cost of sales, partially offset by increased operating and maintenance expense and depreciation and amortization expense from additional operating Trains between the periods. Our total operating costs and expenses increased during the year ended December 31, 2019 from the year ended December 31, 2018 primarily as a result of the increase in operating Trains between each of the periods, and further due to increased third-party service and maintenance costs from turnaround and related activities at the SPL Project.

Cost of sales includes costs incurred directly for the production and delivery of LNG from the Liquefaction Projects, to the extent those costs are not utilized for the commissioning process. Cost of sales decreased during the year ended December 31, 2020 from the comparable 2019 period, primarily due to decreased pricing of natural gas feedstock between the periods and decreased vessel charter costs. Partially offsetting this decrease was decreased fair value of commodity derivatives to secure natural gas feedstock for the Liquefaction Projects due to unfavorable shifts in long-term forward prices relative to our hedged position and increases in costs associated with sale of unutilized natural gas procured for the liquefaction process and a portion of derivative instruments that settle through physical delivery. Cost of sales increased during the year ended December 31, 2019 from the year ended December 31, 2018 due to increased volume of natural gas feedstock partially offset by decreased pricing and increased vessel charter costs. Partially offsetting this increase was increased derivative gains from an increase in fair value of the derivatives associated with economic hedges to secure natural gas feedstock for the Liquefaction Projects, primarily due to a favorable shift in long-term forward prices. Cost of sales also includes port and canal fees, variable transportation and storage costs and the sale of natural gas procured for the liquefaction process and other costs to convert natural gas into LNG.

Operating and maintenance expense primarily includes costs associated with operating and maintaining the Liquefaction Projects. During the year ended December 31, 2020, operating and maintenance expense also included costs incurred in response to the COVID-19 pandemic, as further described above in *Impact of COVID-19 and Market Environment*. Excluding the costs incurred in response to the COVID-19 pandemic, operating and maintenance expense (including affiliates) increased during the year ended December 31, 2020 from the comparable period in 2019, primarily due to increased natural gas transportation and storage capacity demand charges, increased TUA reservation charges due to Total Gas & Power North America, Inc. ("Total") under the partial TUA assignment agreement and increased payroll and benefit costs from increased headcount from additional Trains operating at the Liquefaction Projects between the periods. The increase during the year ended December 31, 2019 from the comparable period in 2018 was primarily related to: (1) increased natural gas transportation and storage capacity demand charges from operating Train 5 of the SPL Project and Trains 1 and 2 of the CCL Project following the respective substantial completions, (2) increased cost of turnaround and related activities at the SPL Project, (3) increased TUA reservation charges paid to Total from payments under the partial TUA assignment agreement and (4) increased payroll and benefit costs from increased headcount to operate Train 5 of the SPL Project and Trains 1 and 2 of the CCL Project. Operating and maintenance expense also includes insurance and regulatory and other operating costs.

Depreciation and amortization expense increased during each of the years ended December 31, 2020 and 2019 as a result of an increased number of operational Trains, as the related assets began depreciating upon reaching substantial completion.

Impairment expense and loss on disposal of assets decreased during the year ended December 31, 2020 compared to the year ended December 31, 2019 and increased during the year ended December 31, 2019 compared to the year ended December 31, 2018. The higher impairment expense and loss on disposal of assets recognized during the year ended December 31, 2019 was primarily related to the write down of assets used in non-core operations outside of our liquefaction activities, including losses from uncollectible notes receivable.

We expect our operating costs and expenses to generally increase in the future upon Train 3 of the CCL Project and Train 6 of the SPL Project achieving substantial completion, although we expect certain costs will not proportionally increase with the number of operational Trains as cost efficiencies will be realized.

Other income (expense)

	Year Ended December 31,				
(in millions)	**2020**	**2019**	**Change**	**2018**	**Change**
Interest expense, net of capitalized interest	$ 1,525	$ 1,432	$ 93	$ 875	$ 557
Loss on modification or extinguishment of debt	217	55	162	27	28
Interest rate derivative loss (gain), net	233	134	99	(57)	191
Other expense (income), net	112	25	87	(48)	73
Total other expense	$ 2,087	$ 1,646	$ 441	$ 797	$ 849

2020 vs. 2019 and 2019 vs. 2018

Interest expense, net of capitalized interest, increased during the year ended December 31, 2020 from the comparable 2019 and 2018 periods as a result of a decrease in the portion of total interest costs that is eligible for capitalization as additional Trains of the Liquefaction Projects completed construction between the periods. During the years ended December 31, 2020, 2019 and 2018, we incurred $1.8 billion, $1.8 billion and $1.7 billion of total interest cost, respectively, of which we capitalized $248 million, $414 million and $803 million, respectively, which was primarily related to interest costs incurred for the construction of the Liquefaction Projects.

Loss on modification or extinguishment of debt increased during the year ended December 31, 2020 from the comparable periods in 2019 and 2018. The loss on modification or extinguishment of debt in each of the years included the incurrence of fees paid to lenders, third party fees and write off of unamortized debt issuance costs recognized upon the redemption and repurchase of convertible senior notes, refinancing our credit facilities with senior notes, refinancing of senior notes, prepayment of the outstanding indebtedness of our term loan facility and paydown of our credit facilities as part of the capital allocation framework.

Interest rate derivative loss, net increased during the year ended December 31, 2020 compared to the comparable 2019 and 2018 periods, primarily due to an unfavorable shift in the long-term forward LIBOR curve between the periods.

Other expense, net increased during the year ended December 31, 2020 from the comparable periods in 2019 and 2018, due to an impairment loss recognized related to our equity method investments. During the year ended December 31, 2020, we recognized other-than-temporary impairment losses of $129 million related to our investment in Midship Holdings, LLC ("Midship Holdings") which was precipitated primarily due to declining market conditions in the energy industry and customer credit risk, resulting in a reduction in the fair value of our equity interests. We recognized losses of $87 million during the year ended December 31, 2019 related to our investments in certain equity method investees, including Midship Holdings. Impairments were primarily the result of cost overruns and extended construction timelines for operating infrastructure of our investees' projects, resulting in a reduction of the expected fair value of our equity interests. In each of the years, these impairment losses were partially offset by interest income earned on our cash and cash equivalents.

Income tax benefit (provision)

	Year Ended December 31,				
(in millions)	**2020**	**2019**	**Change**	**2018**	**Change**
Income before income taxes and non-controlling interest	$ 544	$ 715	$ (171)	$ 1,227	$ (512)
Income tax benefit (provision)	(43)	517	(560)	(27)	544
Effective tax rate	7.9 %	(72.3)%		2.2 %	

2020 vs. 2019 and 2019 vs. 2018

The effective tax rate of 7.9% for the year ended December 31, 2020 was lower than the 21% federal statutory tax rate primarily due to income allocated to non-controlling interest that is not taxable to Cheniere. The effective tax rate of (72.3)% for the year ended December 31, 2019 was primarily attributable to a one-time tax benefit resulting from the release of a significant portion of our deferred tax asset valuation allowance. The effective tax rate of 2.2% for the year ended December 31, 2018 was lower than the 21% statutory rate primarily as a result of maintaining a valuation allowance against our federal and state net deferred tax assets. Our effective tax rate may continue to experience volatility prospectively due to variability in our pre-tax and taxable earnings and the proportion of such earnings attributable to non-controlling interests.

Net income attributable to non-controlling interest

	Year Ended December 31,				
(in millions)	**2020**	**2019**	**Change**	**2018**	**Change**
Net income attributable to non-controlling interest	$ 586	$ 584	$ 2	$ 729	$ (145)

2020 vs. 2019

Net income attributable to non-controlling interest slightly increased during the year ended December 31, 2020 from the year ended December 31, 2019 primarily due to an increase in consolidated net income recognized by Cheniere Partners, primarily a result of increased margins due to lower pricing of natural gas feedstock, partially offset by increases in (1) loss on modification or extinguishment of debt incurred in conjunction with the refinancing of the 2021 SPL Senior Notes, (2) interest expense, net of capitalized interest and (3) depreciation and amortization expense.

2019 vs. 2018

Net income attributable to non-controlling interest decreased during the year ended December 31, 2019 from the year ended December 31, 2018 primarily due to the annualized decrease of non-controlling interest as a result of our merger with Cheniere Holdings in September 2018, in which all publicly-held shares of Cheniere Holdings were canceled and the non-controlling interest in Cheniere Holdings was reduced to zero. The consolidated net income recognized by Cheniere Partners decreased from $1.3 billion in the year ended December 31, 2018 to $1.2 billion in the year ended December 31, 2019 primarily due a decrease in income from operations from higher operating and maintenance expense and an increase in interest expense, net of capitalized interest and increased depreciation and amortization expense, partially offset by increased margins due to higher volumes of LNG sold but decreased pricing on LNG.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, SPL, Cheniere Partners, CCH Group and Cheniere operate with independent capital structures. Our capital requirements include capital and investment expenditures, repayment of long-term debt and repurchase of our shares. 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, operating cash flows and equity contributions from Cheniere Partners;
- Cheniere Partners through operating cash flows from SPLNG, SPL and CTPL and debt or equity offerings;
- CCH Group through operating cash flows from CCL and CCP, project debt and borrowings and equity contributions from Cheniere; and
- Cheniere through existing unrestricted cash, debt and equity offerings by us or our subsidiaries, operating cash flows, borrowings, services fees from our subsidiaries and distributions from our investment in Cheniere Partners.

The following table provides a summary of our liquidity position at December 31, 2020 and 2019 (in millions):

	December 31,	
	2020	**2019**
Cash and cash equivalents (1)	$ 1,628	$ 2,474
Restricted cash designated for the following purposes:		
SPL Project	97	181
CCL Project	70	80
Other	282	259
Available commitments under the following credit facilities:		
$1.2 billion Amended and Restated SPL Working Capital Facility ("2015 SPL Working Capital Facility")	—	786
2020 SPL Working Capital Facility	787	—
CQP Credit Facilities executed in 2019 ("2019 CQP Credit Facilities")	750	750
CCH Credit Facility	—	—
$1.2 billion CCH Working Capital Facility ("CCH Working Capital Facility")	767	729
$1.25 billion Cheniere Revolving Credit Facility ("Cheniere Revolving Credit Facility")	1,126	665
Cheniere Term Loan Facility	372	—

(1) Amounts presented include balances held by our consolidated variable interest entity ("VIE"), Cheniere Partners, as discussed in Note 9—Non-controlling Interest and Variable Interest Entity of our Notes to Consolidated Financial Statements. As of December 31, 2020 and 2019, assets of Cheniere Partners, which are included in our Consolidated Balance Sheets, included $1.2 billion and $1.8 billion, respectively, of cash and cash equivalents.

Sabine Pass LNG Terminal

Liquefaction Facilities

The SPL Project is one of the largest LNG production facilities in the world. Through Cheniere Partners, we are currently operating five Trains and two marine berths at the SPL Project, and are constructing one additional Train that is expected to be substantially completed in the second half of 2022, and a third marine berth. We have received authorization from the FERC to site, construct and operate Trains 1 through 6, as well as for the construction of the third marine berth. We have achieved substantial completion of the first five Trains of the SPL Project and commenced commercial operating activities for each Train at various times starting in May 2016. The following table summarizes the project completion and construction status of Train 6 of the SPL Project as of December 31, 2020:

	SPL Train 6
Overall project completion percentage	77.6%
Completion percentage of:	
Engineering	99.0%
Procurement	99.9%
Subcontract work	54.9%
Construction	49.2%
Date of expected substantial completion	2H 2022

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 and non-FTA countries through December 31, 2050, 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 and non-FTA countries through December 31, 2050, 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 through December 31, 2050, in an amount up to a combined total of 503.3 Bcf/yr of natural gas (approximately 10 mtpa).

In December 2020, the DOE announced a new policy in which it would no longer issue short-term export authorizations separately from long-term authorizations. Accordingly, the DOE amended each of SPL's long-term authorizations to include short-term export authority, and vacated the short-term orders.

An application was filed in September 2019 seeking authorization to make additional exports from the SPL Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term in an amount up to the equivalent of approximately 153 Bcf/yr of natural gas, for a total SPL Project export capacity of approximately 1,662 Bcf/yr. The terms of the authorizations are requested to commence on the date of first commercial export from the SPL Project of the volumes contemplated in the application. In April 2020, the DOE issued an order authorizing SPL to export to FTA countries related to this application, for which the term was subsequently extended through December 31, 2050, but has not yet issued an order authorizing SPL to export to non-FTA countries for the corresponding LNG volume. A corresponding application for authorization to increase the total LNG production capacity of the SPL Project from the currently authorized level to approximately 1,662 Bcf/yr was also submitted to the FERC and is currently pending.

Customers

SPL has entered into fixed price long-term SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 17 years (plus extension rights) with eight third parties for Trains 1 through 6 of the SPL Project. 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 generally equal to approximately 115% of Henry Hub. The customers may elect to cancel or suspend deliveries of LNG cargoes, with advance notice as governed by each respective SPA, 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 generally sized at the time of entry into each SPA with the intent to cover the costs of gas purchases and transportation and liquefaction fuel 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.

In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $2.9 billion for Trains 1 through 5. After giving effect to an SPA that Cheniere has committed to provide to SPL, the annual fixed fee portion to be paid by the third-party SPA customers would increase to at least $3.3 billion, which is expected to occur upon the date of first commercial delivery of Train 6.

In addition, Cheniere Marketing has an agreement with SPL to purchase at Cheniere Marketing's option, any LNG produced by SPL in excess of that required for other customers. See *Marketing* section for additional information regarding agreements entered into by Cheniere Marketing.

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 variability 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, 2020, SPL had secured up to approximately 4,950 TBtu of natural gas feedstock through long-term and short-term natural gas supply contracts with remaining terms that range up to 10 years, a portion of which is subject to conditions precedent.

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 6 of the SPL Project, under which Bechtel charges a lump sum for all work performed and generally bears project cost, schedule and performance risks 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 6 of the SPL Project is approximately $2.5 billion, including estimated costs for the third marine berth that is currently under construction. As of December 31, 2020, we have incurred $1.9 billion under this contract.

Regasification Facilities

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4 Bcf/d and aggregate LNG storage capacity of approximately 17 Bcfe. Approximately 2 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 Bcf/d of regasification capacity and is obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually, prior to inflation adjustments, 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 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, prior to inflation adjustments, continuing until at least May 2036. SPL entered into a partial TUA assignment agreement with Total, whereby upon substantial completion of Train 5 of the SPL Project, SPL gained access to substantially all 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 Train 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 years ended December 31, 2020, 2019 and 2018, SPL recorded $129 million, $104 million and $30 million, respectively, 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 the SPL Project will be financed through project debt and borrowings, cash flows under the SPAs and equity contributions from Cheniere Partners. We believe that with the net proceeds of borrowings, available commitments under the 2020 SPL Working Capital Facility, 2019 CQP Credit Facilities, cash flows from operations and equity contributions from Cheniere Partners, SPL will have adequate financial resources available to meet its currently anticipated capital, operating and debt service requirements with respect to Trains 1 through 6 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, 2020 and 2019 (in millions):

	December 31,	
	2020	2019
Senior notes (1)	$ 17,750	$ 17,750
Credit facilities outstanding balance (2)	—	—
Letters of credit issued (3)	413	414
Available commitments under credit facilities (3)	1,537	1,536
Total capital resources from borrowings and available commitments (4)	$ 19,700	$ 19,700

(1) Includes SPL's 2021 SPL Senior Notes, 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, 5.875% Senior Secured Notes due 2026 (the "2026 SPL Senior Notes"), 5.00% Senior Secured Notes due 2027 (the "2027 SPL Senior Notes"), 4.200% Senior Secured Notes due 2028 (the "2028 SPL Senior Notes"), 2030 SPL Senior Notes and 5.00% Senior Secured Notes due 2037 (the "2037 SPL Senior Notes") (collectively, the "SPL Senior Notes"), as well as Cheniere Partners' $1.5 billion of 5.250% Senior Notes due 2025 (the "2025 CQP Senior Notes"), $1.1 billion of 5.625% Senior Notes due 2026 (the "2026 CQP Senior Notes") and the 4.500% Senior Notes due 2029 (the "2029 CQP Senior Notes") (collectively, the "CQP Senior Notes").

(2) Includes outstanding balances under the 2015 SPL Working Capital Facility, 2020 SPL Working Capital Facility and 2019 CQP Credit Facilities, inclusive of any portion of the 2020 SPL Working Capital Facility and 2019 CQP Credit Facilities that may be used for general corporate purposes.

(3) Consists of 2015 SPL Working Capital Facility, 2020 SPL Working Capital Facility and 2019 CQP Credit Facilities.

(4) Does not include equity contributions that may be available from Cheniere's borrowings and available cash and cash equivalents.

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 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.

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, 2030 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, 2030 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 2037 SPL Senior Notes Indenture and 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 2020 SPL Working Capital Facility. 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 and are fully amortizing according to a fixed sculpted amortization schedule.

2015 SPL Working Capital Facility

In March 2020, SPL terminated the remaining commitments under the 2015 SPL Working Capital Facility. As of December 31, 2019, SPL had $786 million of available commitments, $414 million aggregate amount of issued letters of credit and no outstanding borrowings under the 2015 SPL Working Capital Facility.

2020 SPL Working Capital Facility

In March 2020, SPL entered into the 2020 SPL Working Capital Facility with aggregate commitments of $1.2 billion, which replaced the 2015 SPL Working Capital Facility. The 2020 SPL Working Capital Facility is intended to be used for loans to SPL, swing line loans to SPL and the issuance of letters of credit on behalf of SPL, primarily for (1) the refinancing of the 2015 SPL Working Capital Facility, (2) fees and expenses related to the 2020 SPL Working Capital Facility, (3) SPL and its future subsidiaries' gas purchase obligations and (4) SPL and certain of its future subsidiaries' general corporate purposes. SPL may, from time to time, request increases in the commitments under the 2020 SPL Working Capital Facility of up to $800 million. As of December 31, 2020, SPL had $787 million of available commitments, $413 million aggregate amount of issued letters of credit and no outstanding borrowings under the 2020 SPL Working Capital Facility.

The 2020 SPL Working Capital Facility matures on March 19, 2025, but may be extended with consent of the lenders. The 2020 SPL Working Capital Facility provides for mandatory prepayments under customary circumstances.

The 2020 SPL Working Capital Facility contains customary conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. SPL is restricted from making certain distributions under agreements governing its indebtedness generally until, among other requirements, satisfaction of a 12-month forward-looking and backward-looking 1.25:1.00 debt service reserve ratio test. The obligations of SPL under the 2020 SPL Working Capital Facility are secured by substantially all of the assets of SPL as well as a pledge of all of the membership interests in SPL and certain future subsidiaries of SPL on a *pari passu* basis by a first priority lien with the SPL Senior Notes.

Cheniere Partners

CQP Senior Notes

The CQP Senior Notes are jointly and severally guaranteed by each of Cheniere Partners' subsidiaries other than SPL and, subject to certain conditions governing its guarantee, Sabine Pass LP (each a "Guarantor" and collectively, the "CQP Guarantors"). The CQP Senior Notes are governed by the same base indenture (the "CQP Base Indenture"). The 2025 CQP Senior Notes are further governed by the First Supplemental Indenture, the 2026 CQP Senior Notes are further governed by the Second Supplemental Indenture and the 2029 CQP Senior Notes are further governed by the Third Supplemental Indenture. The indentures governing the CQP Senior Notes contain 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, 2021 for the 2026 CQP Senior Notes and October 1, 2024 for the 2029 CQP Senior Notes, Cheniere Partners may redeem all or a part of the applicable CQP Senior Notes at a redemption price equal to 100% of the aggregate principal amount of the CQP Senior Notes redeemed, plus the "applicable premium" set forth in the respective indentures governing the CQP Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption. In addition, at any time prior to October 1, 2021 for the 2026 CQP Senior Notes and October 1, 2024 for the 2029 CQP Senior Notes, Cheniere Partners may redeem up to 35% of the aggregate principal amount of the 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 105.625% of the aggregate principal amount of the 2026 CQP Senior Notes and 104.5% of the aggregate principal amount of the 2029 CQP Senior Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption. Cheniere Partners also may at any time through the maturity date of October 1, 2025 for the 2025 CQP Senior Notes, October 1, 2021 through the maturity date of October 1, 2026 for the 2026 CQP Senior Notes and October 1, 2024 through the maturity date of October 1, 2029 for the 2029 CQP Senior Notes, redeem the CQP Senior Notes, in whole or in part, at the redemption prices set forth in the respective indentures governing the CQP Senior Notes.

The 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. In the event that the aggregate amount of Cheniere Partners' secured indebtedness and the secured indebtedness of the CQP Guarantors (other than the CQP Senior Notes or any other series of notes issued under the CQP Base Indenture) outstanding at any one time exceeds the greater of (1) $1.5 billion and (2) 10% of net tangible assets, the CQP Senior Notes will be secured to the same extent as such obligations under the 2019 CQP Credit Facilities. The obligations under the 2019 CQP Credit Facilities are secured on a first-priority basis (subject to permitted encumbrances) with liens on 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 2019 CQP Credit Facilities). The liens securing the CQP Senior Notes, if applicable, will be shared equally and ratably (subject to permitted liens) with the holders of other senior secured obligations, which include the 2019 CQP Credit Facilities obligations and any future additional senior secured debt obligations.

2019 CQP Credit Facilities

In May 2019, Cheniere Partners entered into the 2019 CQP Credit Facilities, which consisted of the $750 million term loan ("CQP Term Facility"), which was prepaid and terminated upon issuance of the 2029 CQP Senior Notes in September 2019, and the $750 million revolving credit facility ("CQP Revolving Facility"). Borrowings under the 2019 CQP Credit Facilities will be used to fund the development and construction of Train 6 of the SPL Project and for general corporate purposes, subject to a sublimit, and the 2019 CQP Credit Facilities are also available for the issuance of letters of credit. As of both December 31, 2020 and 2019, Cheniere Partners had $750 million of available commitments and no letters of credit issued or loans outstanding under the 2019 CQP Credit Facilities.

The 2019 CQP Credit Facilities mature on May 29, 2024. Any outstanding balance may be repaid, in whole or in part, at any time without premium or penalty, except for interest rate breakage costs. The 2019 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 and one true-up per fiscal quarter as long as certain conditions are satisfied.

The 2019 CQP Credit Facilities are unconditionally guaranteed and secured by a first priority lien (subject to permitted encumbrances) on substantially all of Cheniere Partners' and the CQP Guarantors' existing and future tangible and intangible assets and rights and equity interests in the CQP Guarantors (except, in each case, for certain excluded properties set forth in the 2019 CQP Credit Facilities).

Corpus Christi LNG Terminal

Liquefaction Facilities

We are currently operating two Trains and two marine berths at the CCL Project and commissioning one additional Train that is expected to be substantially completed in the first quarter of 2021. We have received authorization from the FERC to site, construct and operate Trains 1 through 3 of the CCL Project. We completed construction of Trains 1 and 2 of the CCL Project and commenced commercial operating activities in February 2019 and August 2019, respectively. The following table summarizes the project completion and construction status of Train 3 of the CCL Project, including the related infrastructure, as of December 31, 2020:

	CCL Train 3
Overall project completion percentage	99.6%
Completion percentage of:	
Engineering	100.0%
Procurement	100.0%
Subcontract work	99.9%
Construction	99.0%
Expected date of substantial completion	1Q 2021

Separate from the CCH Group, we are also developing Corpus Christi Stage 3 through our subsidiary CCL Stage III, adjacent to the CCL Project. We received approval from FERC in November 2019 to site, construct and operate seven midscale Trains with an expected total production capacity of approximately 10 mtpa of LNG.

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 and non-FTA countries through December 31, 2050, up to a combined total of the equivalent of 767 Bcf/yr (approximately 15 mtpa) of natural gas.
- Corpus Christi Stage 3—FTA countries and non-FTA countries through December 31, 2050 in an amount equivalent to 582.14 Bcf/yr (approximately 11 mtpa) of natural gas.

In December 2020, the DOE announced a new policy in which it would no longer issue short-term export authorizations separately from long-term authorizations. Accordingly, the DOE amended each of CCL's long-term authorizations to include short-term export authority, and vacated the short-term orders.

An application was filed in September 2019 to authorize additional exports from the CCL Project to FTA countries for a 25-year term and to non-FTA countries for a 20-year term in an amount up to the equivalent of approximately 108 Bcf/yr of natural gas, for a total CCL Project export of 875.16 Bcf/yr. The terms of the authorizations are requested to commence on the date of first commercial export from the CCL Project of the volumes contemplated in the application. In April 2020, the DOE issued an order authorizing CCL to export to FTA countries related to this application, for which the term was subsequently extended through December 31, 2050, but has not yet issued an order authorizing CCL to export to non-FTA countries for the corresponding LNG volume. A corresponding application for authorization to increase the total LNG production capacity of the CCL Project from the currently authorized level to approximately 875.16 Bcf/yr was also submitted to the FERC and is currently pending.

Customers

CCL has entered into fixed price long-term SPAs generally with terms of 20 years (plus extension rights) and with a weighted average remaining contract length of approximately 19 years (plus extension rights) with nine third parties for Trains 1 through 3 of the CCL Project. Under these SPAs, the customers will purchase LNG from CCL on a free on board ("FOB") basis 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. The customers may elect to cancel or suspend deliveries of LNG cargoes, with advance notice as governed by each respective SPA, 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 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 and liquefaction fuel 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 the applicable Train, as specified in each SPA.

In aggregate, the minimum annual fixed fee portion to be paid by the third-party SPA customers is approximately $1.4 billion for Trains 1 and 2 and increasing to approximately $1.8 billion following the substantial completion of Train 3 of the CCL Project.

In addition, Cheniere Marketing has agreements with CCL to purchase: (1) approximately 15 TBtu per annum of LNG with an approximate term of 23 years, (2) any LNG produced by CCL in excess of that required for other customers at Cheniere Marketing's option and (3) approximately 44 TBtu of LNG with a term of up to seven years associated with the IPM gas supply agreement between CCL and EOG Resources, Inc. See *Marketing* section for additional information regarding agreements entered into by Cheniere Marketing.

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 variability 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, 2020, CCL had secured up to approximately 2,938 TBtu of natural gas feedstock through long-term natural gas supply contracts with remaining terms that range up to 10 years, a portion of which is subject to the achievement of certain project milestones and other conditions precedent.

CCL Stage III has also entered into long-term natural gas supply contracts with third parties, and anticipates continuing to enter into such agreements, in order to secure natural gas feedstock for Corpus Christi Stage 3. As of December 31, 2020, CCL Stage III had secured up to approximately 2,361 TBtu of natural gas feedstock through long-term natural gas supply contracts with remaining terms that range up to approximately 15 years, which is subject to the achievement of certain project milestones and other conditions precedent.

A portion of the natural gas feedstock transactions for CCL and CCL Stage III are IPM transactions, in which the natural gas producers are paid based on a global gas market price less a fixed liquefaction fee and certain costs incurred by us.

Construction

CCL entered into separate lump sum turnkey contracts with Bechtel for the engineering, procurement and construction of Trains 1 through 3 of the CCL Project under which Bechtel charges a lump sum for all work performed and generally bears project cost, schedule and performance risks 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 Train 3, which is currently undergoing commissioning, is approximately $2.4 billion, reflecting amounts incurred under change orders through December 31, 2020. As of December 31, 2020, we have incurred $2.4 billion under this contract.

Final Investment Decision for Corpus Christi Stage 3

FID for Corpus Christi Stage 3 will be subject to, among other things, entering into an EPC contract, obtaining additional commercial support for the project and securing the necessary financing arrangements.

Pipeline Facilities

In November 2019, the FERC authorized CCP to construct and operate the pipeline for Corpus Christi Stage 3. The pipeline will be designed to transport 1.5 Bcf/d of natural gas feedstock required by Corpus Christi Stage 3 from the existing regional natural gas pipeline grid.

Capital Resources

The CCH Group expects to finance the construction costs of the CCL Project from one or more of the following: operating cash flows from CCL and CCP, project debt and equity contributions from Cheniere. The following table provides a summary of the capital resources of the CCH Group from borrowings and available commitments for the CCL Project, excluding equity contributions from Cheniere, at December 31, 2020 and December 31, 2019 (in millions):

	December 31,	
	2020	2019
Senior notes (1)	$ 7,721	$ 6,952
2025 CCH HoldCo II Convertible Senior Notes (2)	—	1,000
Credit facilities outstanding balance (3)	2,767	3,283
Letters of credit issued (3)	293	471
Available commitments under credit facilities (3)	767	729
Total capital resources from borrowings and available commitments (4)	$ 11,548	$ 12,435

(1) Includes CCH's 7.000% Senior Secured Notes due 2024, 5.875% Senior Secured Notes due 2025, 5.125% Senior Secured Notes due 2027, 3.700% Senior Secured Notes due 2029, 4.80% Senior Secured Notes due 2039, 3.925% Senior Secured Notes due 2039 and 3.52% CCH Senior Secured Notes (collectively, the "CCH Senior Notes").

(2) Aggregate original principal amount before debt discount and debt issuance costs and interest paid-in-kind.

(3) Includes the CCH Credit Facility and CCH Working Capital Facility.

(4) Does not include equity contributions that may be available from Cheniere's borrowings and available cash and cash equivalents.

2025 CCH HoldCo II Convertible Senior Notes

In May 2015, CCH HoldCo II issued $1.0 billion aggregate principal amount of the 2025 CCH HoldCo II Convertible Senior Notes in a private placement. In May 2018, the amended and restated note purchase agreement under which the 2025 CCH HoldCo II Convertible Senior Notes were issued was subsequently amended in connection with commercialization and financing of Train 3 of the CCL Project and to provide the note holders with certain prepayment rights related thereto consistent with those under the CCH Credit Facility. In February 2020, the amended and restated note purchase agreement for the 2025 CCH HoldCo II Convertible Senior Notes was further amended to allow CCH HoldCo II the option to redeem all or a portion of the outstanding notes with cash at a price of $1,080 per $1,000 principal amount, at the time of any CCH HoldCo II or noteholder-initiated conversion through September 2, 2020. In March 2020, CCH HoldCo II redeemed an aggregate outstanding principal amount of $300 million and in July 2020, redeemed the remaining outstanding principal amount with borrowings under the Cheniere Term Loan Facility.

CCH Senior Notes

The CCH Senior Notes are jointly and severally guaranteed by CCH's subsidiaries, CCL, CCP and Corpus Christi Pipeline GP, LLC (each a "CCH Guarantor" and collectively, the "CCH Guarantors"). The indentures governing the CCH Senior Notes contain 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. The covenants included in the respective indentures that govern the CCH Senior Notes are subject to a number of important limitations and exceptions.

The CCH Senior Notes are CCH's senior secured obligations, ranking senior in right of payment to any and all of CCH's future indebtedness that is subordinated to the CCH Senior Notes and equal in right of payment with CCH's other existing and future indebtedness that is senior and secured by the same collateral securing the CCH Senior Notes. The CCH Senior Notes are secured by a first-priority security interest in substantially all of CCH's and the CCH Guarantors' assets.

At any time prior to six months before the respective dates of maturity for each 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 appropriate indenture, plus accrued and unpaid interest, if any, to the date of redemption. At any time within six months of the respective dates of maturity for each of the CCH Senior Notes, CCH may 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.

CCH Credit Facility

In May 2018, CCH amended and restated the CCH Credit Facility to increase total commitments under the CCH Credit Facility from \$4.6 billion to \$6.1 billion. The obligations of CCH under the 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. There were no available commitments under the CCH Credit Facility as of both December 31, 2020 and 2019. CCH had \$2.6 billion and \$3.3 billion of loans outstanding under the CCH Credit Facility as of December 31, 2020 and 2019, respectively.

The CCH Credit Facility matures on June 30, 2024, with principal payments due quarterly commencing on the earlier of (1) the first quarterly payment date occurring more than three calendar months following the completion of the CCL Project as defined in the common terms agreement and (2) a set date determined by reference to the date under which a certain LNG buyer linked to the last Train of the CCL Project to become operational 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 completion of Trains 1 through 3 and designed to achieve a minimum projected fixed debt service coverage ratio of 1.50:1.

Under the 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 certain distributions under agreements governing its indebtedness generally until, among other requirements, the completion of the construction of Trains 1 through 3 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 June 2018, CCH amended and restated the CCH Working Capital Facility to increase total commitments under the CCH Working Capital Facility from \$350 million to \$1.2 billion. The CCH Working Capital Facility is intended to be used for loans to CCH ("CCH Working Capital Loans") and the issuance of letters of credit on behalf of CCH for certain working capital requirements related to developing and operating the CCL Project and for related business purposes. 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 for working capital under the Common Terms Agreement that was entered into concurrently with the CCH Credit Facility. As of December 31, 2020 and 2019, CCH had \$767 million and \$729 million of available commitments, \$293 million and \$471 million aggregate amount of issued letters of credit and \$140 million and zero of loans outstanding under the CCH Working Capital Facility, respectively.

The CCH Working Capital Facility matures on June 29, 2023, and CCH may prepay the CCH Working Capital 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 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 CCH Credit Facility.

Cheniere

Senior Notes

In September 2020, we issued an aggregate principal amount of $2.0 billion of 2028 Cheniere Senior Secured Notes, the proceeds of which were used to prepay a portion of the outstanding indebtedness under the Cheniere Term Loan Facility and to pay related fees and expenses. The associated indentures ("Cheniere Indenture") contain customary terms and events of default and certain covenants that, among other things, limit our ability to create liens or other encumbrances, enter into sale-leaseback transactions and merge or consolidate with other entities or sell all or substantially all of our assets. The Cheniere Indenture covenants are subject to a number of important limitations and exceptions.

At any time prior to October 15, 2023, we may redeem all or a part of the 2028 Cheniere Senior Secured Notes at a redemption price equal to 100% of the aggregate principal amount thereof, plus the "applicable premium" and accrued and unpaid interest, if any, to but not including the date of redemption. We also may, at any time prior to October 15, 2023, redeem up to 40% of the aggregate principal amount of the 2028 Cheniere Senior Secured Notes with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price equal to 104.625% of the aggregate principal amount of the notes being redeemed, plus accrued and unpaid interest, if any, to but not including, the date of redemption. At any time on or after October 15, 2023 through the maturity date of October 15, 2028, we may redeem all or part of the 2028 Cheniere Senior Secured Notes at the redemption prices described in the Cheniere Indenture.

The 2028 Cheniere Senior Secured Notes are our general senior obligations and rank senior in right of payment to all of our future obligations that are, by their terms, expressly subordinated in right of payment to the 2028 Cheniere Senior Secured Notes and equally in right of payment with all of our other existing and future unsubordinated indebtedness. The 2028 Cheniere Senior Secured Notes will initially be secured on a first-priority basis by a lien on substantially all of our assets and equity interests in our direct subsidiaries (other than certain excluded subsidiaries) (the "Collateral"), which liens will rank *pari passu* with the liens securing the Cheniere Revolving Credit Facility and Cheniere Term Loan Facility. The 2028 Cheniere Senior Secured Notes will remain secured as long as (1) there are any obligations or undrawn commitments outstanding under the Cheniere Term Loan Facility that are secured by liens on the Collateral or (2) the outstanding aggregate principal amount of our secured indebtedness exceeds $1.25 billion. As of December 31, 2020, the 2028 Cheniere Senior Secured Notes are not guaranteed by any of our subsidiaries. In the future, the 2028 Cheniere Senior Secured Notes will be guaranteed by our subsidiaries who guarantee our other material indebtedness.

Convertible Notes

In November 2014, we issued an aggregate principal amount of $1.0 billion of 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 July 2020, we repurchased $844 million in aggregate principal amount of the outstanding 2021 Cheniere Convertible Unsecured Notes at individually negotiated prices from a small number of investors.

In March 2015, we issued $625 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 December 2018, we amended and restated the Cheniere Revolving Credit Facility to increase total commitments under the Cheniere Revolving Credit Facility from $750 million to $1.25 billion. The Cheniere Revolving Credit Facility is intended 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. As of December 31, 2020 and 2019, we had $1.1 billion and $665 million of available commitments, $124 million and $585 million aggregate amount of issued letters of credit and no loans outstanding under the Cheniere Revolving Credit Facility, respectively.

The Cheniere Revolving Credit Facility matures on December 13, 2022 and contains representations, warranties and affirmative and negative covenants customary for companies like us 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) $200 million (the "Liquidity Covenant"). However, at any time that the aggregate principal amount of outstanding loans plus drawn and unreimbursed letters of credit under the Cheniere Revolving Credit Facility is greater than 30% of aggregate commitments under the Cheniere Revolving Credit Facility, the Liquidity Covenant will not apply and we will instead be governed by a quarterly non-consolidated leverage ratio covenant not to exceed 5.75:1.00 (the "Springing Leverage Covenant").

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 and certain other subsidiaries).

Cheniere Term Loan Facility

In June 2020, we entered into the Cheniere Term Loan Facility, which was subsequently increased to $2.695 billion in July 2020. In July 2020, borrowings under the Cheniere Term Loan Facility were used to (1) redeem the outstanding principal amount of the 2025 CCH HoldCo II Convertible Senior Notes, (2) repurchase $844 million in aggregate principal amount of outstanding 2021 Cheniere Convertible Unsecured Notes at individually negotiated prices from a small number of investors and (3) pay the related fees and expenses. The remaining commitments under the Cheniere Term Loan Facility are expected to be used to repay and/or repurchase a portion of the remaining principal amount of the 2021 Cheniere Convertible Unsecured Notes and for the payment of related fees and expenses. In September 2020, we prepaid approximately $2.1 billion of the outstanding indebtedness of the Cheniere Term Loan Facility with net proceeds from the 2028 Cheniere Senior Secured Notes and available cash. As of December 31, 2020, we had $372 million of available commitments and $148 million of loans outstanding under the Cheniere Term Loan Facility.

The Cheniere Term Loan Facility matures on June 18, 2023. Loans under the Cheniere Term Loan Facility may be voluntarily prepaid, in whole or in part, at any time, without premium or penalty. Borrowings under the Cheniere Term Loan Facility are subject to customary conditions precedent. The Cheniere Term Loan Facility includes representations, warranties, affirmative and negative covenants and events of default customary for companies like us with lenders of the type participating in the Cheniere Term Loan Facility and consistent with the equivalent provisions contained in the Cheniere Revolving Credit Facility.

The Cheniere Term Loan Facility is secured by a first priority security interest (subject to permitted liens and other customary exceptions) on a *pari passu* basis with the Cheniere Revolving Credit Facility in substantially all of our assets and equity interests in direct subsidiaries (other than certain excluded subsidiaries). Upon redemption of the 2025 CCH HoldCo II Convertible Senior Notes in July 2020, the equity interests in CCH HoldCo II were pledged as collateral to secure the obligations under the Cheniere Revolving Credit Facility and the Cheniere Term Loan Facility.

Cash Receipts from Subsidiaries

Our ownership interest in the Sabine Pass LNG terminal is held through Cheniere Partners. As of December 31, 2020, we owned a 48.6% limited partner interest in Cheniere Partners in the form of 239.9 million common units. In July 2020, the financial tests required for conversion of Cheniere Partners' subordinated units, all of which were held by us, were met under the terms of Cheniere Partners' partnership agreement and effective August 17, 2020, the first business day following the payment of the quarterly distribution with respect to the quarter ended June 30, 2020, all of Cheniere Partners' subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated. We also own 100% of the general partner interest and the incentive distribution rights in Cheniere Partners. We are eligible to receive quarterly equity distributions from Cheniere Partners related to our ownership interests and our incentive distribution rights.

We also receive fees for providing management services to some of our subsidiaries. We received $120 million, $119 million and $85 million in total service fees from these subsidiaries during the each of the years ended December 31, 2020, 2019 and 2018, respectively.

Share Repurchase Program

On June 3, 2019, we announced that our Board of Directors ("Board") authorized a 3-year, $1.0 billion share repurchase program. The following table presents information with respect to repurchases of common stock during the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
Aggregate common stock repurchased	2,875,376	4,000,424
Weighted average price paid per share	$ 53.88	$ 62.27
Total amount paid (in millions)	$ 155	$ 249

As of December 31, 2020, we had up to $596 million of the share repurchase program available. Under the share repurchase program, repurchases can be made from time to time using a variety of methods, which may include open market purchases, privately negotiated transactions or otherwise, all in accordance with the rules of the SEC and other applicable legal requirements. The timing and amount of any shares of our common stock that are repurchased under the share repurchase program will be determined by our management based on market conditions and other factors. The share repurchase program does not obligate us to acquire any particular amount of common stock, and may be modified, suspended or discontinued at any time or from time to time at our discretion.

Marketing

We market and sell LNG produced by the Liquefaction Projects that is not required for other customers through our integrated marketing function. We have, and continue to develop, a portfolio of long-, medium- and short-term SPAs to transport and unload commercial LNG cargoes to locations worldwide. These volumes are expected to be primarily sourced by LNG produced by the Liquefaction Projects but supplemented by volumes procured from other locations worldwide, as needed. As of December 31, 2020, we have sold or have options to sell approximately 4,995 TBtu of LNG to be delivered to customers between 2021 and 2045, including volume from an SPA Cheniere Marketing has committed to provide to SPL. The cargoes have been sold either on a FOB basis (delivered to the customer at the Sabine Pass LNG terminal or the Corpus Christi LNG terminal, as applicable) or a delivered at terminal ("DAT") basis (delivered to the customer at their specified LNG receiving terminal). We have chartered LNG vessels to be utilized for cargoes sold on a DAT basis.

Cheniere Marketing entered into uncommitted trade finance facilities with available credit of $241 million as of December 31, 2020, 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, 2020 and 2019, Cheniere Marketing had $34 million and $41 million, respectively, in standby letters of credit and guarantees outstanding under the finance facilities. As of December 31, 2020 and 2019, there were no loans 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. The development of our sites or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, acceptable commercial and financing arrangements before we make an FID.

We have made an equity investment in Midship Holdings, which manages the business and affairs of Midship Pipeline. Midship Pipeline operates the Midship Project with current capacity of up to 1.1 million Dekatherms per day that connects new gas production in the Anadarko Basin to Gulf Coast markets, including markets serving the Liquefaction Projects. The Midship Project was placed in service in April 2020.

Restrictive Debt Covenants

As of December 31, 2020, each of our issuers was in compliance with all covenants related to their respective debt agreements.

LIBOR

The use of LIBOR is expected to be phased out by the end of 2021. It is currently unclear whether LIBOR will be utilized beyond that date or whether it will be replaced by a particular rate. We intend to continue working with our lenders and counterparties to pursue any amendments to our debt and derivative agreements that are currently subject to LIBOR and will continue to monitor, assess and plan for the phase out of LIBOR.

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, 2020, 2019 and 2018 (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,		
	2020	**2019**	**2018**
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$ 1,265	$ 1,833	$ 1,990
Proceeds from issuances of debt	7,823	6,434	4,285
Other	3	4	14
	$ 9,091	$ 8,271	$ 6,289
Uses of cash, cash equivalents and restricted cash:			
Property, plant and equipment, net	$ (1,839)	$ (3,056)	$ (3,643)
Investment in equity method investment	(100)	(105)	(25)
Repayments of debt	(6,940)	(4,346)	(1,391)
Debt issuance and other financing costs	(125)	(51)	(66)
Debt modification or extinguishment costs	(172)	(15)	(17)
Distributions and dividends to non-controlling interest	(626)	(590)	(576)
Payments related to tax withholdings for share-based compensation	(43)	(19)	(20)
Repurchase of common stock	(155)	(249)	—
Other	(8)	(2)	(8)
	(10,008)	(8,433)	(5,746)
Net increase (decrease) in cash, cash equivalents and restricted cash	$ (917)	$ (162)	$ 543

Operating Cash Flows

Our operating cash net inflows during the years ended December 31, 2020, 2019 and 2018 were $1,265 million, $1,833 million and $1,990 million, respectively. The $568 million decrease in operating cash inflows in 2020 compared to 2019 was primarily related to repayment of paid-in-kind interest related to the redemption of the 2025 CCH HoldCo II Convertible Senior Notes, repurchase of a portion of the 2021 Cheniere Convertible Unsecured Notes and an increase in cash paid for interest, partially offset by the increased cash receipts from the sale of LNG cargoes due to additional LNG volume available to be sold from additional Trains that have reached substantial completion between the periods, a portion of which the customers elected not to take delivery but were required to pay a fixed fee with respect to the contracted volumes. The $157 million decrease in operating cash inflows in 2019 compared to 2018 was primarily related to increased operating costs and expenses, which were partially offset by increased cash receipts from the sale of LNG cargoes, as a result of the additional Trains that were operating at the Liquefaction Projects in 2019.

Proceeds from Issuance of Debt, Repayments of Debt, Debt Issuance and Other Financing Costs and Debt Modification or Extinguishment Costs

During the year ended December 31, 2020, we issued an aggregate principal amount of $4.8 billion in senior secured notes to refinance our near-term debt and repay or prepay the outstanding indebtedness under our credit facilities and convertible notes. Borrowings of $3.1 billion under our credit facilities were used to redeem or repurchase our convertible notes, to fund our working capital requirements or for general corporate purposes. We incurred $125 million of debt issuance costs primarily related to up-front fees paid and $172 million of debt modification or extinguishment costs upon the closing of these transactions.

During the year ended December 31, 2019, we issued an aggregate principal amount of $4.2 billion in senior notes to prepay the outstanding indebtedness under our credit facilities. Borrowings of $2.2 billion under our credit facilities were used for funding future capital expenditures in connection with the construction costs for the Liquefaction Projects, to fund our working capital requirements or for general corporate purposes. We incurred $51 million of debt issuance costs primarily related to up-front fees paid and $15 million of debt modification or extinguishment costs upon the closing of these transactions.

During the year ended December 31, 2018, we issued an aggregate principal amount of $1.1 billion in senior notes to prepay the outstanding indebtedness under our credit facilities. Borrowings of $3.2 billion under our credit facilities during the year were used for funding future capital expenditures in connection with the construction costs for the Liquefaction Projects, to fund our working capital requirements or for general corporate purposes. We incurred $66 million of debt issuance costs primarily related to up-front fees paid and $17 million of debt modification or extinguishment costs upon the closing of these transactions.

Property, Plant and Equipment, net

Cash outflows for property, plant and equipment were primarily for the construction costs for the Liquefaction Projects. These costs are capitalized as construction-in-process until achievement of substantial completion.

Distributions and Dividends to Non-controlling Interest

We own a 48.6% limited partner interest in Cheniere Partners, with the remaining non-controlling interest held by The Blackstone Group Inc., Brookfield Asset Management Inc. and the public, to whom we paid distributions and dividends during the years ended December 31, 2020, 2019 and 2018.

Investment in Equity Method Investment

We invested $100 million, $105 million and $25 million in Midship Holdings, our equity method investment, during the years ended December 31, 2020, 2019 and 2018, respectively.

Repurchase of Common Stock

During the years ended December 31, 2020 and 2019, we paid $155 million and $249 million, respectively, to repurchase approximately 3 million shares and 4 million shares, respectively, of our common stock under the share repurchase program.

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, 2020 (in millions):

	Payments Due By Period (1)				
	Total	2021	2022 - 2023	2024 - 2025	Thereafter
Debt (2)	$ 30,986	$ 566	$ 2,838	$ 10,579	$ 17,003
Interest payments (2)	10,213	1,700	2,868	2,187	3,458
Operating lease obligations (3)	941	197	277	215	252
Finance lease obligations (4)	177	10	20	20	127
Purchase obligations: (5)					
Construction obligations (6)	662	399	263	—	—
Natural gas supply, transportation and storage service agreements (7)	15,417	4,477	4,428	2,507	4,005
Other purchase obligations (8)	1,544	222	305	303	714
Total	$ 59,940	$ 7,571	$ 10,999	$ 15,811	$ 25,559

(1) Agreements in force as of December 31, 2020 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2020.

(2) Based on the total debt balance, scheduled maturities and fixed or estimated forward interest rates in effect at December 31, 2020. Debt balance is presented net of $501 million in debt discount for outstanding convertible notes with significant spread between the coupon rate and the effective interest rate. The debt discount and the repayment of paid in kind interest are included in interest payments, which is consistent with the presentation in our Consolidated Statements of Cash Flows. Interest payment obligations exclude adjustments for interest rate swap agreements. A discussion of our debt obligations can be found in Note 11—Debt of our Notes to Consolidated Financial Statements.

(3) Operating lease obligations primarily relate to LNG vessel time charters, land sites related to the Liquefaction Projects and corporate office leases. Operating lease obligations do not include $1.6 billion of legally binding minimum lease payments for vessel charters which were executed as of December 31, 2020 but will commence between 2021 and 2022 and have fixed minimum lease terms of up to seven years. A discussion of our lease obligations can be found in Note 12—Leases of our Notes to Consolidated Financial Statements.

(4) Finance lease obligations consist of tug leases supporting the CCL Project, as further discussed in Note 12—Leases of our Notes to Consolidated Financial Statements.

(5) Purchase obligations consist of agreements to purchase goods or services that are enforceable and legally binding that specify fixed or minimum quantities to be purchased. We include only contracts for which conditions precedent have been met. As project milestones and other conditions precedent are achieved, our obligations are expected to increase accordingly. We include contracts for which we have an early termination option if the option is not expected to be exercised.

(6) Construction obligations primarily consist of the estimated remaining cost pursuant to our EPC contracts as of December 31, 2020 for projects with respect to which we have made an FID to commence construction. A discussion of these obligations can be found at Note 20—Commitments and Contingencies of our Notes to Consolidated Financial Statements.

(7) Pricing of natural gas supply agreements is based on estimated forward prices and basis spreads as of December 31, 2020. Natural gas supply, transportation and storage service agreements includes $1.5 billion in payments under agreements with related parties as discussed in Note 14—Related Party Transactions of our Notes to Consolidated Financial Statements.

(8) Other purchase obligations primarily relate to payments under SPL's partial TUA assignment agreement with Total as discussed in Note 13—Revenues from Contracts with Customers of our Notes to Consolidated Financial Statements.

In addition, as of December 31, 2020, we had $830 million aggregate amount of issued letters of credit under our credit facilities. We also had tax agreements with certain local taxing jurisdictions for an aggregate amount of $196 million to be paid through 2033, based on estimated tax obligations as of December 31, 2020.

Off-Balance Sheet Arrangements

As of December 31, 2020, we had no transactions that met the definition of off-balance sheet arrangements that may have a current or future material effect on our consolidated financial position or operating results.

Summary of Critical Accounting Estimates

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

Fair Value of 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, 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. We estimate the fair values of our FX derivative instruments using observable FX rates and other relevant data.

Valuation of our physical commodity contracts is predominantly driven by observable and unobservable market commodity prices and, as applicable to our natural gas supply contracts, our assessment of the associated events deriving fair value, including evaluating whether the respective market is available as pipeline infrastructure is developed. The fair value of our physical commodity contracts incorporates risk premiums related to the satisfaction of conditions precedent, such as completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow. A portion of our physical commodity contracts require us to make critical accounting estimates that involve significant judgment, as the fair value is developed through the use of internal models which incorporate significant unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks, such as future prices of energy units for unobservable periods, liquidity, volatility and contract duration.

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.

Recent Accounting Standards

For descriptions of recently issued accounting standards, see Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Marketing and Trading Commodity Price Risk

We have entered into commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the SPL Project, the CCL Project and potential future development of Corpus Christi Stage 3 ("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, 2020		December 31, 2019	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ 240	$ 204	$ 149	$ 179
LNG Trading Derivatives	(134)	44	165	22

Interest Rate Risk

We are exposed to interest rate risk primarily when we incur debt related to project financing. Interest rate risk is managed in part by replacing outstanding floating-rate debt with fixed-rate debt with varying maturities. CCH has entered into interest rate swaps to hedge the exposure to volatility in a portion of the floating-rate interest payments under the CCH Credit Facility ("CCH Interest Rate Derivatives") and to hedge against changes in interest rates that could impact anticipated future issuance of debt by CCH ("CCH Interest Rate Forward Start Derivatives"). In order to test the sensitivity of the fair value of the CCH Interest Rate Derivatives to changes in interest rates, management modeled a 10% change in the forward one-month LIBOR curve across the remaining terms of the CCH Interest Rate Derivatives and CCH Interest Rate Forward Start Derivatives as follows (in millions):

	December 31, 2020		December 31, 2019	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
CCH Interest Rate Derivatives	$ (140)	$ 1	$ (81)	$ 19
CCH Interest Rate Forward Start Derivatives	—	—	(8)	15

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 as follows (in millions):

	December 31, 2020		December 31, 2019	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
FX Derivatives	$ (22)	$ 2	$ 4	$ —

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, 2020, 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, 2020, 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/ Zach Davis
	Jack A. Fusco		Zach Davis
	President and Chief Executive Officer (Principal Executive Officer)		Senior 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, 2020 and 2019, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes and financial statement schedules I to II (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, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, 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, 2020, 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 23, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of ASU 2016-02, Leases (Topic 842), and subsequent amendments thereto.

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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Fair value of the level 3 physical liquefaction supply derivatives

As discussed in Notes 2 and 7 to the consolidated financial statements, the Company recorded fair value of level 3 physical liquefaction supply derivatives of $241 million, as of December 31, 2020. The physical liquefaction supply derivatives consist of natural gas supply contracts for the operation of the liquefied natural gas facilities. The fair value of the level 3 physical liquefaction supply derivatives is developed through the use of internal models which incorporate significant unobservable inputs.

We identified the evaluation of the fair value of the level 3 physical liquefaction supply derivatives as a critical audit matter. Specifically, there is subjectivity in certain assumptions used to estimate the fair value, including assumptions for future prices of energy units for unobservable periods and liquidity. Additionally, the fair value for certain of the liquefaction supply derivatives is derived through the use of complex models, which also include assumptions for volatility.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the valuation of the level 3 physical liquefaction supply derivatives. This included controls related to the assumptions for significant unobservable inputs and the fair value models. For the level 3 liquefaction supply derivatives selected, we involved valuation professionals with specialized skills who assisted in:

- assessing the models and volatility used by the Company in its valuation by developing independent fair value estimates and comparing the independently developed estimates to the Company's fair value estimates
- testing the future prices of energy units for unobservable periods and liquidity assumptions by comparing to market data, including quoted or published forward prices for similar commodities.

In addition, we evaluated the Company's assumptions for future prices of energy units for unobservable periods and liquidity by comparing to market or third-party data, including adjustments for third party quoted transportation prices.

/s/ KPMG LLP

KPMG LLP

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

Houston, Texas
February 23, 2021

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. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2020, 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, 2020, 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, 2020 and 2019, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes and financial statement schedules I to II (collectively, the consolidated financial statements), and our report dated February 23, 2021 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 23, 2021

CHENIERE ENERGY, INC. AND SUBSIDIARIES

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

	Year Ended December 31,		
	2020	2019	2018
Revenues			
LNG revenues	$ 8,924	$ 9,246	$ 7,572
Regasification revenues	269	266	261
Other revenues	165	218	154
Total revenues	9,358	9,730	7,987
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	4,161	5,079	4,597
Operating and maintenance expense	1,320	1,154	613
Development expense	6	9	7
Selling, general and administrative expense	302	310	289
Depreciation and amortization expense	932	794	449
Impairment expense and loss on disposal of assets	6	23	8
Total operating costs and expenses	6,727	7,369	5,963
Income from operations	2,631	2,361	2,024
Other income (expense)			
Interest expense, net of capitalized interest	(1,525)	(1,432)	(875)
Loss on modification or extinguishment of debt	(217)	(55)	(27)
Interest rate derivative gain (loss), net	(233)	(134)	57
Other income (expense), net	(112)	(25)	48
Total other expense	(2,087)	(1,646)	(797)
Income before income taxes and non-controlling interest	544	715	1,227
Income tax benefit (provision)	(43)	517	(27)
Net income	501	1,232	1,200
Less: net income attributable to non-controlling interest	586	584	729
Net income (loss) attributable to common stockholders	$ (85)	$ 648	$ 471
Net income (loss) per share attributable to common stockholders—basic	$ (0.34)	$ 2.53	$ 1.92
Net income (loss) per share attributable to common stockholders—diluted	$ (0.34)	$ 2.51	$ 1.90
Weighted average number of common shares outstanding—basic	252.4	256.2	245.6
Weighted average number of common shares outstanding—diluted	252.4	258.1	248.0

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (1)
(in millions, except share data)

	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,628	$ 2,474
Restricted cash	449	520
Accounts and other receivables, net	647	491
Inventory	292	312
Derivative assets	32	323
Other current assets	121	92
Total current assets	3,169	4,212
Property, plant and equipment, net	30,421	29,673
Operating lease assets, net	759	439
Non-current derivative assets	376	174
Goodwill	77	77
Deferred tax assets	489	529
Other non-current assets, net	406	388
Total assets	$ 35,697	$ 35,492
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 35	$ 66
Accrued liabilities	1,175	1,281
Current debt	372	—
Deferred revenue	138	161
Current operating lease liabilities	161	236
Derivative liabilities	313	117
Other current liabilities	2	13
Total current liabilities	2,196	1,874
Long-term debt, net	30,471	30,774
Non-current operating lease liabilities	597	189
Non-current finance lease liabilities	57	58
Non-current derivative liabilities	151	151
Other non-current liabilities	7	11
Commitments and contingencies (see Note 20)		
Stockholders' equity		
Preferred stock, $0.0001 par value, 5.0 million shares authorized, none issued	—	—
Common stock, $0.003 par value, 480.0 million shares authorized		
Issued: 273.1 million shares and 270.7 million shares at December 31, 2020 and 2019, respectively		
Outstanding: 252.3 million shares and 253.6 million shares at December 31, 2020 and 2019, respectively	1	1
Treasury stock: 20.8 million shares and 17.1 million shares at December 31, 2020 and 2019, respectively, at cost	(872)	(674)
Additional paid-in-capital	4,273	4,167
Accumulated deficit	(3,593)	(3,508)
Total stockholders' deficit	(191)	(14)
Non-controlling interest	2,409	2,449
Total equity	2,218	2,435
Total liabilities and stockholders' equity	$ 35,697	$ 35,492

(1) Amounts presented include balances held by our consolidated variable interest entity ("VIE"), Cheniere Partners, as further discussed in Note 9— Non-controlling Interest and Variable Interest Entity. As of December 31, 2020, total assets and liabilities of Cheniere Partners, which are included in our Consolidated Balance Sheets, were $18.8 billion and $18.5 billion, respectively, including $1.2 billion of cash and cash equivalents and $0.1 billion of restricted cash.

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, 2017	237.6	$ 1	12.5	$ (386)	$ 3,248	$ (4,627)	$ 3,004	$ 1,240
Vesting of restricted stock units	0.5	—	—	—	—	—	—	—
Issuance of stock to acquire additional interest in Cheniere Holdings and other merger related adjustments	19.2	—	—	—	694	—	(702)	(8)
Share-based compensation	—	—	—	—	90	—	—	90
Shares withheld from employees related to share-based compensation, at cost	(0.3)	—	0.3	(20)	—	—	—	(20)
Net income attributable to non-controlling interest	—	—	—	—	—	—	729	729
Equity portion of convertible notes, net	—	—	—	—	3	—	—	3
Distributions and dividends to non-controlling interest	—	—	—	—	—	—	(576)	(576)
Net income	—	—	—	—	—	471	—	471
Balance at December 31, 2018	257.0	1	12.8	(406)	4,035	(4,156)	2,455	1,929
Vesting of restricted stock units	0.9	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	131	—	—	131
Shares withheld from employees related to share-based compensation, at cost	(0.3)	—	0.3	(19)	—	—	—	(19)
Shares repurchased, at cost	(4.0)	—	4.0	(249)	—	—	—	(249)
Net income attributable to non-controlling interest	—	—	—	—	—	—	584	584
Equity portion of convertible notes, net	—	—	—	—	1	—	—	1
Distributions and dividends to non-controlling interest	—	—	—	—	—	—	(590)	(590)
Net income	—	—	—	—	—	648	—	648
Balance at December 31, 2019	253.6	1	17.1	(674)	4,167	(3,508)	2,449	2,435
Vesting of restricted stock units and performance stock units	2.4	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	114	—	—	114
Issued shares withheld from employees related to share-based compensation, at cost	(0.8)	—	0.8	(43)	—	—	—	(43)
Shares repurchased, at cost	(2.9)	—	2.9	(155)	—	—	—	(155)
Net loss attributable to non-controlling interest	—	—	—	—	—	—	586	586
Reacquisition of equity component of convertible notes, net of tax	—	—	—	—	(8)	—	—	(8)
Distributions and dividends to non-controlling interest	—	—	—	—	—	—	(626)	(626)
Net loss	—	—	—	—	—	(85)	—	(85)
Balance at December 31, 2020	252.3	$ 1	20.8	$ (872)	$ 4,273	$ (3,593)	$ 2,409	$ 2,218

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,		
	2020	2019	2018
Cash flows from operating activities			
Net income	$ 501	$ 1,232	$ 1,200
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization expense	932	794	449
Share-based compensation expense	110	131	113
Non-cash interest expense	51	143	74
Amortization of debt issuance costs, premium and discount	114	103	69
Non-cash operating lease costs	291	350	—
Loss on modification or extinguishment of debt	217	55	27
Total losses (gains) on derivatives, net	211	(400)	51
Net cash provided by settlement of derivative instruments	74	138	17
Impairment expense and loss on disposal of assets	6	23	8
Impairment or loss on equity method investments	126	88	—
Deferred taxes	40	(521)	(5)
Repayment of paid-in-kind interest related to repurchase of convertible notes	(911)	—	—
Other	2	—	(5)
Changes in operating assets and liabilities:			
Accounts and other receivables, net	(154)	1	(133)
Inventory	21	11	(73)
Other current assets	(27)	(18)	(15)
Accounts payable and accrued liabilities	54	52	188
Deferred revenue	(23)	22	26
Operating lease liabilities	(277)	(366)	—
Finance lease liabilities	—	1	—
Other, net	(93)	(6)	(1)
Net cash provided by operating activities	1,265	1,833	1,990
Cash flows from investing activities			
Property, plant and equipment, net	(1,839)	(3,056)	(3,643)
Investment in equity method investment	(100)	(105)	(25)
Other	(8)	(2)	14
Net cash used in investing activities	(1,947)	(3,163)	(3,654)
Cash flows from financing activities			
Proceeds from issuances of debt	7,823	6,434	4,285
Repayments of debt	(6,940)	(4,346)	(1,391)
Debt issuance and other financing costs	(125)	(51)	(66)
Debt modification or extinguishment costs	(172)	(15)	(17)
Distributions and dividends to non-controlling interest	(626)	(590)	(576)
Payments related to tax withholdings for share-based compensation	(43)	(19)	(20)
Repurchase of common stock	(155)	(249)	—
Other	3	4	(8)
Net cash provided by (used in) financing activities	(235)	1,168	2,207
Net decrease in cash, cash equivalents and restricted cash	(917)	(162)	543
Cash, cash equivalents and restricted cash—beginning of period	2,994	3,156	2,613
Cash, cash equivalents and restricted cash—end of period	$ 2,077	$ 2,994	$ 3,156

Balances per Consolidated Balance Sheets:

	December 31,	
	2020	2019
Cash and cash equivalents	$ 1,628	$ 2,474
Restricted cash	449	520
Total cash, cash equivalents and restricted cash	$ 2,077	$ 2,994

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 infrastructure company primarily engaged in LNG-related businesses. We are operating and constructing two natural gas liquefaction and export facilities at Sabine Pass and Corpus Christi.

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, through its subsidiary SPL, is currently operating five natural gas liquefaction Trains and is constructing one additional Train that is expected to be substantially completed in the second half of 2022, for a total production capacity of approximately 30 mtpa of LNG (the "SPL Project") at the Sabine Pass LNG terminal. The Sabine Pass LNG terminal has operational regasification facilities owned by Cheniere Partners' subsidiary, SPLNG, that include pre-existing infrastructure of five LNG storage tanks, two marine berths and vaporizers and an additional marine berth that is under construction. 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 its subsidiary, CTPL. As of December 31, 2020, we owned 100% of the general partner interest and 48.6% of the limited partner interest in Cheniere Partners.

The Corpus Christi LNG terminal is located near Corpus Christi, Texas and is operated and constructed by our subsidiary, CCL. We are currently operating two Trains and one additional Train is undergoing commissioning for a total production capacity of approximately 15 mtpa of LNG. We also operate a 23-mile natural gas supply pipeline that interconnects the Corpus Christi LNG terminal with several interstate and intrastate natural gas pipelines (the "Corpus Christi Pipeline" and together with the Trains, the "CCL Project") through our subsidiary, CCP. The CCL Project, once fully constructed, will contain three LNG storage tanks and two marine berths.

Additionally, separate from the CCH Group, we are developing an expansion of the Corpus Christi LNG terminal adjacent to the CCL Project ("Corpus Christi Stage 3") through our subsidiary CCL Stage III, for up to seven midscale Trains with an expected total production capacity of approximately 10 mtpa of LNG. We received approval from FERC in November 2019 to site, construct and operate the expansion project.

We remain focused on operational excellence and customer satisfaction. Increasing demand of LNG has allowed us to expand our liquefaction infrastructure in a financially disciplined manner. We have increased available liquefaction capacity at our Liquefaction Projects as a result of debottlenecking and other optimization projects. We hold significant land positions at both the Sabine Pass LNG terminal and the Corpus Christi LNG terminal which provide opportunity for further liquefaction capacity expansion. The development of these sites or other projects, including infrastructure projects in support of natural gas supply and LNG demand, will require, among other things, 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 Partners and its wholly owned subsidiaries. For those consolidated subsidiaries in which our ownership is less than 100%, the portion of the net income or loss attributable to the non-controlling interest is reported as net income (loss) attributable to non-controlling interest on our Consolidated Statement of Operations. All 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 of accounting, with our share of earnings or losses reported in other income (expense) on our Consolidated Statement of Operations. 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 accounted for using the equity method of accounting are reported as a component of other noncurrent 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 generally 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.

Recent Accounting Standards

In August 2020, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2020-06, *Debt—Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging—Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*. This guidance simplifies the accounting for convertible instruments primarily by eliminating the existing cash conversion and beneficial conversion models within Subtopic 470-20, which will result in fewer embedded conversion options being accounted for separately from the debt host. The guidance also amends and simplifies the calculation of earnings per share relating to convertible instruments. This guidance is effective for annual periods beginning after December 15, 2021, including interim periods within that reporting period, with earlier adoption permitted for fiscal years beginning after December 15, 2020, including interim periods within that reporting period, using either a full or modified retrospective approach. We plan to adopt this guidance on January 1, 2022 and are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures.

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*. This guidance primarily provides temporary optional expedients which simplify the accounting for contract modifications to existing debt agreements expected to arise from the market transition from LIBOR to alternative reference rates. The optional expedients were available to be used upon issuance of this guidance but we have not yet applied the guidance because we have not yet modified any of our existing contracts for reference rate reform. Once we apply an optional expedient to a modified contract and adopt this standard, the guidance will be applied to all subsequent applicable contract modifications until December 31, 2022, at which time the optional expedients are no longer available.

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 fair value measurements, revenue recognition, property, plant and equipment, derivative instruments, leases, goodwill, asset retirement obligations ("AROs"), share-based compensation and income taxes including valuation allowances for deferred tax assets, as further discussed under the respective sections within this note. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Measurements

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 that are directly or indirectly observable for the asset or liability, other than quoted prices included within Level 1. 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 11—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 intangible assets, goodwill and AROs.

Revenue Recognition

We recognize revenues when we transfer control of promised goods or services to our customers in an amount that reflects the consideration to which we expect to be entitled to in exchange for those goods or services. Revenues from the sale of LNG are recognized as LNG revenues, including LNG revenues generated by our integrated marketing function that 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 payments are recognized as regasification revenues. See Note 13—Revenues from Contracts with Customers for further discussion of revenues.

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 or legally 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 any current expected credit losses. Notes receivable that are not classified as trade receivables are recorded within other current assets in our Consolidated Balance Sheets. Current expected credit losses consider the risk of loss based on past events, current conditions and reasonable and supportable forecasts. A counterparty's ability to pay is assessed through a credit review process that considers payment terms, the counterparty's established credit rating or our assessment of the counterparty's credit worthiness, contract terms, payment status, and other risks or available financial assurances. Adjustments to current expected credit losses are recorded in selling, general and administrative expense in our Consolidated Statements of Operations. As of December 31, 2020 and 2019, we had current expected credit losses on our accounts and notes receivable of $5 million and zero, respectively.

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.

Accounting for LNG Activities

Generally, we begin capitalizing the costs of our LNG terminals 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 preliminary front-end engineering and design work, costs of securing necessary regulatory approvals and other preliminary investigation and development activities related to our LNG terminals.

Generally, costs that are capitalized prior to a project meeting the criteria otherwise necessary for capitalization include: land acquisition costs, detailed engineering design work 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 land or lease is obtained, the costs are expensed.

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. We realize offsets to LNG terminal costs for sales of commissioning cargoes that were earned or loaded prior to the start of commercial operations of the respective Train during the testing phase for its construction. 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 impairment expense and loss (gain) on disposal of assets.

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.

We did not record any impairments related to property, plant and equipment during the years ended December 31, 2020, 2019 and 2018.

Interest Capitalization

We capitalize interest costs during the construction period of our LNG terminals and related assets as construction-in-process. Upon commencement of operations, these costs are transferred out of construction-in-process into terminal and interconnecting pipeline facilities assets and are amortized over the estimated useful life of the asset.

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. We did not have any derivative instruments designated as cash flow or fair value hedges during the years ended December 31, 2020, 2019 and 2018. See Note 7—Derivative Instruments for additional details about our derivative instruments.

Leases

We adopted Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)*, and subsequent amendments thereto ("ASC 842") on January 1, 2019 using the optional transition approach to apply the standard at the beginning of the first quarter of 2019 with no retrospective adjustments to prior periods. The adoption of the standard resulted in the recognition of right-of-use assets and lease liabilities for operating leases of approximately $550 million on our Consolidated Balance Sheets, with no material impact on our Consolidated Statements of Operations or Consolidated Statements of Cash Flows.

We determine if an arrangement is, or contains, a lease at inception of the arrangement. When we determine the arrangement is, or contains, a lease, we classify the lease as either an operating lease or a finance lease. Operating and finance leases are recognized on our Consolidated Balance Sheets 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. Operating and finance lease right-of-use assets and liabilities are generally recognized based on the present value of lease payments over the lease term. In determining the present value of lease payments, we use the implicit interest rate in the lease if readily determinable. In the absence of a readily determinable implicitly interest rate, we discount our expected future lease payments using our relevant subsidiary's incremental borrowing rate. The incremental borrowing rate is an estimate of the interest rate that a given subsidiary would have to pay to borrow on a collateralized basis over a similar term to that of the lease term. Options to renew a lease are included in the lease term and recognized as part of the right-of-use asset and lease liability, only to the extent they are reasonably certain to be exercised. We have elected practical expedients to (1) omit leases with an initial term of 12 months or less from recognition on our balance sheet and (2) to combine both the lease and non-lease components of an arrangement in calculating the right-of-use asset and lease liability for all classes of leased assets.

Lease expense for operating lease payments is recognized on a straight-line basis over the lease term. Lease expense for finance leases is recognized as the sum of the amortization of the right-of-use assets on a straight-line basis and the interest on lease liabilities using the effective interest method over the lease term.

Operating leases are included in operating lease assets, net, current operating lease liabilities and non-current operating lease liabilities on our Consolidated Balance Sheets. Finance leases are included in property, plant and equipment, net, other current liabilities and non-current finance lease liabilities on our Consolidated Balance Sheets. See Note 12—Leases for additional details about our leases.

Concentration of Credit Risk

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. 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 within other current assets. 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 fixed price long-term SPAs generally with terms of 20 years with eight third parties, CCL has entered into fixed price long-term SPAs generally with terms of 20 years with nine third parties and our integrated marketing function has entered into a limited number of long-term SPAs with third parties. We are dependent on the respective customers' creditworthiness and their willingness to perform under their respective SPAs. See Note 21—Customer Concentration for additional details about our customer concentration.

SPLNG has entered into two long-term TUAs with 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. We test 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. We 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 quantitative goodwill impairment tests.

We completed our annual assessment of goodwill impairment as of October 1st by performing a qualitative assessment; the tests indicated it is more likely than not that there was no impairment. Our last quantitative assessment indicated that the reporting unit's fair value substantially exceeded its carrying value. As discussed above regarding our use of estimates, our judgments and assumptions are inherent in our estimate of future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of impairment charges in the Consolidated Financial Statements. A lower fair value estimate in the future for our reporting unit could result in an impairment of goodwill. Factors that could trigger a lower fair value estimate include significant negative industry or economic trends, cost increases, disruptions to our business, regulatory or political environment changes or other unanticipated events.

Debt

Our debt consists of current and long-term secured and unsecured 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. Debt issuance costs consist primarily of arrangement fees, professional fees, legal fees and printing costs. If debt issuance costs are incurred in connection with a line of credit arrangement or on undrawn funds, they are presented as an asset on our Consolidated Balance Sheets. 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 or modification of debt are recorded in gain (loss) on modification or extinguishment of debt on our Consolidated Statements of Operations.

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.

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 16—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 and not subsequently remeasured unless modified. 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 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 costs are remeasured at fair value through settlement or maturity. 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 9—Non-controlling Interest and Variable Interest Entities 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 our Consolidated Financial

Statements. Deferred tax assets and liabilities are included in our 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 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.

Net Income (Loss) Per Share

Basic net income (loss) per share attributable to common stockholders ("EPS") excludes dilution and is computed by dividing net income (loss) attributable to common stockholders 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) attributable to common stockholders 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. The dilutive effect of unvested stock is calculated using the treasury-stock method and the dilutive effect of convertible securities is calculated using the treasury or if-converted method.

Business Segment

We have 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 or legally 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, 2020 and 2019, restricted cash consisted of the following (in millions):

	December 31,	
	2020	2019
Current restricted cash		
SPL Project	$ 97	$ 181
CCL Project	70	80
Cash held by our subsidiaries that is restricted to Cheniere	282	259
Total current restricted cash	$ 449	$ 520

Pursuant to the accounts agreements entered into with the collateral trustees for the benefit of SPL's debt holders and CCH's debt holders, SPL and CCH are required to deposit all cash received into reserve accounts controlled by the collateral trustees. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the SPL Project and the CCL Project (collectively, the "Liquefaction Projects") and other restricted payments. The majority of the cash held by our subsidiaries that is restricted to Cheniere relates to advance funding for operation and construction needs of the Liquefaction Projects.

NOTE 4—ACCOUNTS AND OTHER RECEIVABLES

As of December 31, 2020 and 2019, accounts and other receivables, net consisted of the following (in millions):

	December 31, 2020	December 31, 2019
Trade receivables		
SPL and CCL	$ 482	$ 328
Cheniere Marketing	113	113
Other accounts receivable	52	50
Total accounts and other receivables, net	$ 647	$ 491

NOTE 5—INVENTORY

As of December 31, 2020 and 2019, inventory consisted of the following (in millions):

	December 31, 2020	December 31, 2019
Natural gas	$ 26	$ 16
LNG	27	67
LNG in-transit	88	93
Materials and other	151	136
Total inventory	$ 292	$ 312

NOTE 6—PROPERTY, PLANT AND EQUIPMENT

As of December 31, 2020 and 2019, property, plant and equipment, net consisted of the following (in millions):

	December 31, 2020	December 31, 2019
LNG terminal costs		
LNG terminal and interconnecting pipeline facilities	$ 27,475	$ 27,305
LNG site and related costs	324	322
LNG terminal construction-in-process	5,378	3,903
Accumulated depreciation	(2,935)	(2,049)
Total LNG terminal costs, net	30,242	29,481
Fixed assets and other		
Computer and office equipment	25	23
Furniture and fixtures	19	22
Computer software	117	110
Leasehold improvements	45	42
Land	59	59
Other	25	21
Accumulated depreciation	(164)	(141)
Total fixed assets and other, net	126	136
Assets under finance lease		
Tug vessels	60	60
Accumulated depreciation	(7)	(4)
Total assets under finance lease, net	53	56
Property, plant and equipment, net	$ 30,421	$ 29,673

The following table shows depreciation expense and offsets to LNG terminal costs during the years ended December 31, 2020 and 2019 (in millions):

	Year Ended December 31,		
	2020	2019	2018
Depreciation expense	$ 926	$ 788	$ 445
Offsets to LNG terminal costs (1)	19	301	140

(1) We realize offsets to LNG terminal costs related to the sale of commissioning cargoes because these amounts were earned or loaded prior to the start of commercial operations of the respective Trains of the Liquefaction Projects during the testing phase for its construction.

LNG Terminal Costs

Our LNG terminals are depreciated using the straight-line depreciation method applied to groups of LNG terminal assets with varying useful lives. The identifiable components of our LNG terminals have depreciable lives between 7 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
Water pipelines	30
Regasification processing equipment	30
Sendout pumps	20
Liquefaction processing equipment	7-50
Other	10-30

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 (“CCH Interest Rate Derivatives”) to hedge the exposure to volatility in a portion of the floating-rate interest payments on CCH’s amended and restated credit facility (the “CCH Credit Facility”) and previously, to hedge against changes in interest rates that could impact anticipated future issuance of debt by CCH (“CCH Interest Rate Forward Start Derivatives” and, collectively with the CCH Interest Rate Derivatives, the “Interest Rate Derivatives”);
- commodity derivatives consisting of natural gas supply contracts for the commissioning and operation of the Liquefaction Projects and potential future development of Corpus Christi Stage 3 (“Physical Liquefaction Supply Derivatives”) and associated economic hedges (collectively, 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 or fair value 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, 2020 and 2019, 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, 2020				December 31, 2019			
	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
CCH Interest Rate Derivatives liability	$ —	$ (140)	$ —	$ (140)	$ —	$ (81)	$ —	$ (81)
CCH Interest Rate Forward Start Derivatives liability	—	—	—	—	—	(8)	—	(8)
Liquefaction Supply Derivatives asset (liability)	5	(6)	241	240	5	6	138	149
LNG Trading Derivatives asset (liability)	(3)	(131)	—	(134)	—	165	—	165
FX Derivatives asset (liability)	—	(22)	—	(22)	—	4	—	4

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 a market or option-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 observable and unobservable market commodity prices and, as applicable to our natural gas supply contracts, our assessment of the associated events deriving fair value, including evaluating whether the respective market is available as pipeline infrastructure is developed. The fair value of our Physical Liquefaction Supply Derivatives incorporates risk premiums related to the satisfaction of conditions precedent, such as completion and placement into service of relevant pipeline infrastructure to accommodate marketable physical gas flow. As of December 31, 2020 and 2019, some of our Physical Liquefaction Supply Derivatives existed within markets for which the pipeline infrastructure was under development to accommodate marketable physical gas flow.

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 incorporate significant unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks, such as future prices of energy units for unobservable periods, liquidity, volatility and contract duration.

The Level 3 fair value measurements of natural gas positions within our Physical Liquefaction Supply Derivatives could be materially impacted by a significant change in certain natural gas and international LNG prices. The following table includes quantitative information for the unobservable inputs for our Level 3 Physical Liquefaction Supply Derivatives as of December 31, 2020:

	Net Fair Value Asset (in millions)	Valuation Approach	Significant Unobservable Input	Range of Significant Unobservable Inputs / Weighted Average (1)
Physical Liquefaction Supply Derivatives	$241	Market approach incorporating present value techniques	Henry Hub basis spread	$(0.532) - $0.092 / $(0.030)
		Option pricing model	International LNG pricing spread, relative to Henry Hub (2)	117% - 480% / 155%

(1) Unobservable inputs were weighted by the relative fair value of the instruments.

(2) Spread contemplates U.S. dollar-denominated pricing.

Increases or decreases in basis or pricing spreads, in isolation, would decrease or increase, respectively, the fair value of our Physical Liquefaction Supply Derivatives.

The following table shows the changes in the fair value of our Level 3 Physical Liquefaction Supply Derivatives during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
Balance, beginning of period	$ 138	$ (29)	$ 43
Realized and mark-to-market gains (losses):			
Included in cost of sales	156	(77)	(13)
Purchases and settlements:			
Purchases	5	199	(31)
Settlements	(65)	44	(29)
Transfers into Level 3, net (1)	7	1	1
Balance, end of period	$ 241	$ 138	$ (29)
Change in unrealized gain (loss) relating to instruments still held at end of period	$ 156	$ (77)	$ (13)

(1) Transferred into Level 3 as a result of unobservable market for the underlying natural gas purchase agreements.

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 the unconditional right of set-off in the event of default. 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, counterparties are at risk that we will be unable to meet our commitments in instances where our derivative instruments are in a liability position. We incorporate both our own nonperformance risk and the respective counterparty's nonperformance risk in fair value measurements. In adjusting the fair value of our derivative contracts for the effect of nonperformance risk, we have considered the impact of any applicable credit enhancements, such as collateral postings, set-off rights and guarantees.

Interest Rate Derivatives

CCH has entered into interest rate swaps to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the CCH Credit Facility. CCH previously also had interest rate swaps to hedge against changes in interest rates that could impact anticipated future issuance of debt. In August 2020, we settled the outstanding CCH Interest Rate Forward Start Derivatives.

Cheniere Partners previously had interest rate swaps ("CQP Interest Rate Derivatives") to hedge a portion of the variable interest payments on its credit facilities. In October 2018, Cheniere Partners terminated the CQP Interest Rate Derivatives related to the 2016 CQP Credit Facilities.

As of December 31, 2020, we had the following Interest Rate Derivatives outstanding:

	Notional Amounts				
	December 31, 2020	December 31, 2019	Maturity Date	Weighted Average Fixed Interest Rate Paid	Variable Interest Rate Received
CCH Interest Rate Derivatives	$4.6 billion	$4.5 billion	May 31, 2022	2.30%	One-month LIBOR

The following table shows the changes in the fair value and settlements of our Interest Rate Derivatives recorded in interest rate derivative gain (loss), net on our Consolidated Statements of Operations during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
CCH Interest Rate Derivatives gain (loss)	$ (138)	$ (101)	$ 43
CCH Interest Rate Forward Start Derivatives loss	(95)	(33)	—
CQP Interest Rate Derivatives gain	—	—	14

Commodity Derivatives

SPL, CCL and CCL Stage III have entered into physical natural gas supply contracts and associated economic hedges to purchase natural gas for the commissioning and operation of the Liquefaction Projects and potential future development of Corpus Christi Stage 3, respectively, which are primarily indexed to the natural gas market and international LNG indices. The remaining terms of the index-based physical natural gas supply contracts range up to approximately 15 years, some of which commence upon the satisfaction of certain events or states of affairs.

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 notional amounts of our Liquefaction Supply Derivatives and LNG Trading Derivatives (collectively, "Commodity Derivatives"):

	December 31, 2020		December 31, 2019	
	Liquefaction Supply Derivatives	LNG Trading Derivatives	Liquefaction Supply Derivatives	LNG Trading Derivatives
Notional amount, net (in TBtu) (1)	10,483	20	9,177	4

(1) Includes notional amounts for natural gas supply contracts that SPL and CCL have with related parties. See Note 14—Related Party Transactions.

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, 2020, 2019 and 2018 (in millions):

	Consolidated Statements of Operations Location (1)	Year Ended December 31,		
		2020	2019	2018
LNG Trading Derivatives gain (loss)	LNG revenues	$ (26)	$ 402	$ (25)
LNG Trading Derivatives loss	Cost of sales	(42)	(89)	—
Liquefaction Supply Derivatives gain (loss) (2)	LNG revenues	(1)	2	(1)
Liquefaction Supply Derivatives gain (loss) (2)	Cost of sales	94	194	(100)

(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.

The total notional amount of our FX Derivatives was $786 million and $827 million as of December 31, 2020 and 2019, respectively.

The following table shows the changes in the fair value, settlements and location of our FX Derivatives recorded on our Consolidated Statements of Operations during the years ended December 31, 2020, 2019 and 2018 (in millions):

		Year Ended December 31,		
	Consolidated Statements of Operations Location	2020	2019	2018
FX Derivatives gain (loss)	LNG revenues	$ (3)	$ 25	$ 18

Fair Value and Location of Derivative Assets and Liabilities on the Consolidated Balance Sheets

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

	December 31, 2020					
Consolidated Balance Sheets Location	CCH Interest Rate Derivatives	CCH Interest Rate Forward Start Derivatives	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives (2)	FX Derivatives	Total
Derivative assets	$ —	$ —	$ 27	$ —	$ 5	$ 32
Non-current derivative assets	—	—	376	—	—	376
Total derivative assets	—	—	403	—	5	408
Derivative liabilities	(100)	—	(54)	(134)	(25)	(313)
Non-current derivative liabilities	(40)	—	(109)	—	(2)	(151)
Total derivative liabilities	(140)	—	(163)	(134)	(27)	(464)
Derivative asset (liability), net	$ (140)	$ —	$ 240	$ (134)	$ (22)	$ (56)

	December 31, 2019					
Consolidated Balance Sheets Location	CCH Interest Rate Derivatives	CCH Interest Rate Forward Start Derivatives	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives (2)	FX Derivatives	Total
Derivative assets	$ —	$ —	$ 93	$ 225	$ 5	$ 323
Non-current derivative assets	—	—	174	—	—	174
Total derivative assets	—	—	267	225	5	497
Derivative liabilities	(32)	(8)	(16)	(60)	(1)	(117)
Non-current derivative liabilities	(49)	—	(102)	—	—	(151)
Total derivative liabilities	(81)	(8)	(118)	(60)	(1)	(268)
Derivative asset (liability), net	$ (81)	$ (8)	$ 149	$ 165	$ 4	$ 229

(1) Does not include collateral posted with counterparties by us of $9 million and $7 million for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively. Includes derivative assets for natural gas supply contracts that SPL and CCL have with related parties. See Note 14—Related Party Transactions.

(2) Does not include collateral posted with counterparties by us of $7 million and $5 million deposited for such contracts, which are included in other current assets in our Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively.

Consolidated Balance Sheets 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):

	CCH Interest Rate Derivatives	CCH Interest Rate Forward Start Derivatives	Liquefaction Supply Derivatives	LNG Trading Derivatives	FX Derivatives
As of December 31, 2020					
Gross assets	$ —	$ —	$ 452	$ —	$ 6
Offsetting amounts	—	—	(49)	—	(1)
Net assets	$ —	$ —	$ 403	$ —	$ 5
Gross liabilities	$ (140)	$ —	$ (184)	$ (163)	$ (62)
Offsetting amounts	—	—	21	29	35
Net liabilities	$ (140)	$ —	$ (163)	$ (134)	$ (27)
As of December 31, 2019					
Gross assets	$ —	$ —	$ 281	$ 229	$ 9
Offsetting amounts	—	—	(14)	(4)	(4)
Net assets	$ —	$ —	$ 267	$ 225	$ 5
Gross liabilities	$ (81)	$ (8)	$ (126)	$ (60)	$ (6)
Offsetting amounts	—	—	8	—	5
Net liabilities	$ (81)	$ (8)	$ (118)	$ (60)	$ (1)

NOTE 8—OTHER NON-CURRENT ASSETS

As of December 31, 2020 and 2019, other non-current assets, net consisted of the following (in millions):

	December 31,	
	2020	2019
Advances made to municipalities for water system enhancements	$ 84	$ 87
Advances and other asset conveyances to third parties to support LNG terminals	60	55
Advances made under EPC and non-EPC contracts	9	29
Equity method investments	81	108
Debt issuance costs and debt discount, net	42	45
Tax-related payments and receivables	20	20
Contract assets, net	80	18
Other	30	26
Total other non-current assets, net	$ 406	$ 388

Equity Method Investments

Our equity method investments consist of interests in privately-held companies. In 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 currently operating an approximately 200-mile natural gas pipeline project (the "Midship Project") that connects production in the Anadarko Basin to Gulf Coast markets. The Midship Project commenced operations in April 2020.

During the year ended December 31, 2020, we recognized other-than-temporary impairment losses of $129 million related to our investment in Midship Holdings. Impairment was precipitated primarily due to declining market conditions in the energy industry and customer credit risk, resulting in a reduction in the fair value of our equity interests. During the year ended December 31, 2019, we recognized losses of $87 million related to our investments in certain equity method investees, including Midship Holdings. Impairments were primarily the result of cost overruns and extended construction timelines for operating infrastructure of our investees' projects, resulting in a reduction of the fair value of our equity interests. The fair values of our equity interests were measured using an income approach, which utilized level 3 fair value inputs such as projected earnings and discount rates, and/or market approach. Impairment losses associated with our equity method investments are presented in other expense, net.

Our investment in Midship Holdings, net of impairment losses, was \$80 million and \$105 million at December 31, 2020 and 2019, respectively.

NOTE 9—NON-CONTROLLING INTEREST AND VARIABLE INTEREST ENTITY

We own a 48.6% limited partner interest in Cheniere Partners in the form of 239.9 million common units, with the remaining non-controlling interest held by The Blackstone Group Inc., Brookfield Asset Management Inc. and the public. In July 2020, the board of directors of Cheniere Partners' general partner confirmed and approved that, following the distribution with respect to the three months ended June 30, 2020, the financial tests required for conversion of Cheniere Partners' subordinated units, all of which were held by us, were met under the terms of Cheniere Partners' partnership agreement. Accordingly, effective August 17, 2020, the first business day following the payment of the distribution, all of Cheniere Partners' subordinated units were automatically converted into common units on a one-for-one basis and the subordination period was terminated. We also own 100% of the general partner interest and the incentive distribution rights in Cheniere Partners. Cheniere Partners is accounted for as a consolidated VIE.

Cheniere Partners is a limited partnership formed by us in 2006 to own and operate the Sabine Pass LNG terminal and related assets. Our subsidiary, Cheniere Partners GP, is the general partner of Cheniere Partners. In 2012, Cheniere Partners, Cheniere and Blackstone CQP Holdco entered into a 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 20% of outstanding common units and subordinated units.

We have determined that Cheniere Partners GP is a VIE 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 VIE based on certain criteria. As a result, we consolidate Cheniere Partners in our Consolidated Financial Statements.

The following table presents the summarized assets and liabilities (in millions) of Cheniere Partners, our consolidated VIE, which are included in our Consolidated Balance Sheets. The assets in the table below may only be used to settle obligations of Cheniere Partners. In addition, there is no recourse to us for the consolidated VIE's liabilities. The assets and liabilities in the table below include third-party assets and liabilities of Cheniere Partners only and exclude intercompany balances that eliminate in consolidation.

	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,210	$ 1,781
Restricted cash	97	181
Accounts and other receivables, net	318	297
Other current assets	182	184
Total current assets	1,807	2,443
Property, plant and equipment, net	16,723	16,368
Other non-current assets, net	287	309
Total assets	$ 18,817	$ 19,120
LIABILITIES		
Current liabilities		
Accrued liabilities	$ 658	$ 709
Other current liabilities	171	210
Total current liabilities	829	919
Long-term debt, net	17,580	17,579
Other non-current liabilities	126	104
Total liabilities	$ 18,535	$ 18,602

NOTE 10—ACCRUED LIABILITIES

As of December 31, 2020 and 2019, accrued liabilities consisted of the following (in millions):

	December 31, 2020	December 31, 2019
Interest costs and related debt fees	$ 245	$ 293
Accrued natural gas purchases	576	460
LNG terminals and related pipeline costs	147	327
Compensation and benefits	123	115
Accrued LNG inventory	4	6
Other accrued liabilities	80	80
Total accrued liabilities	$ 1,175	$ 1,281

NOTE 11—DEBT

As of December 31, 2020 and 2019, our debt consisted of the following (in millions):

	December 31, 2020	December 31, 2019
Long-term debt:		
SPL — 4.200% to 6.25% senior secured notes due between 2022 and 2037 and working capital facility ("2020 SPL Working Capital Facility")	$ 13,650	$ 13,650
Cheniere Partners — 4.500% to 5.625% senior notes due between 2025 and 2029 and credit facilities ("2019 CQP Credit Facilities")	4,100	4,100
CCH — 3.52% to 7.000% senior secured notes due between 2024 and 2039 and CCH Credit Facility	10,217	10,235
CCH HoldCo II —11.0% Convertible Senior Secured Notes due 2025 ("2025 CCH HoldCo II Convertible Senior Notes")	—	1,578
Cheniere — 4.625% Senior Secured Notes due 2028 (the "2028 Cheniere Senior Secured Notes"), convertible notes, revolving credit facility ("Cheniere Revolving Credit Facility") and term loan facility ("Cheniere Term Loan Facility")	3,145	1,903
Unamortized premium, discount and debt issuance costs, net	(641)	(692)
Total long-term debt, net	30,471	30,774
Current debt:		
SPL — $1.2 billion Amended and Restated SPL Working Capital Facility ("2015 SPL Working Capital Facility")	—	—
CCH — $1.2 billion CCH Working Capital Facility ("CCH Working Capital Facility") and current portion of CCH Credit Facility	271	—
Cheniere Marketing — trade finance facilities	—	—
Cheniere — current portion of 4.875% Convertible Unsecured Notes due 2021 ("2021 Cheniere Convertible Unsecured Notes")	104	—
Unamortized premium, discount and debt issuance costs, net	(3)	—
Total current debt	372	—
Total debt, net	$ 30,843	$ 30,774

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, 2020 (in millions):

Years Ending December 31,	Principal Payments
2021	$ 747
2022	1,089
2023	1,749
2024	5,556
2025	5,023
Thereafter	17,323
Total	$ 31,487

Issuances and Repayments

The following table shows the issuances and repayments of long-term debt during the year ended December 31, 2020 (in millions):

Issuances and Long-Term Borrowings	Principal Amount Issued
SPL — 4.500% Senior Secured Notes due 2030 (the "2030 SPL Senior Notes") (1)	$ 2,000
CCH — 3.52% Senior Secured Notes due 2039 (the "3.52% CCH Senior Secured Notes") (2)	769
Cheniere — 2028 Cheniere Senior Secured Notes (3)	2,000
Cheniere — Cheniere Term Loan Facility	2,323
Cheniere — Cheniere Revolving Credit Facility	455
Year Ended December 31, 2020 total	$ 7,547

Repayments, Redemptions and Repurchases	Amount Repaid/ Redeemed/Repurchased
SPL — 5.625% Senior Secured Notes due 2021 (the "2021 SPL Senior Notes") (1)	$ (2,000)
CCH HoldCo II — 2025 CCH HoldCo II Convertible Senior Notes (3)	(1,578)
CCH — CCH Credit Facility (2)	(656)
Cheniere — 2021 Cheniere Convertible Unsecured Notes (3)	(844)
Cheniere — Cheniere Term Loan Facility (3)	(2,175)
Cheniere — Cheniere Revolving Credit Facility	(455)
Year Ended December 31, 2020 total	$ (7,708)

(1) Proceeds of the 2030 SPL Senior Notes, along with available cash, were used to redeem all of SPL's outstanding 2021 SPL Senior Notes, resulting in the recognition of debt extinguishment costs of $43 million for the year ended December 31, 2020 relating to the payment of early redemption fees and write off of unamortized debt premium and issuance costs.

(2) Proceeds of the 3.52% CCH Senior Secured Notes were used to repay a portion of the outstanding borrowings under the CCH Credit Facility, pay costs associated with certain interest rate derivative instruments that were settled and pay certain fees, costs and expenses incurred in connection with these transactions. The repayment of the CCH Credit Facility resulted in the recognition of debt extinguishment costs of $9 million for the year ended December 31, 2020 relating to the write off of unamortized debt discounts and issuance costs.

(3) Proceeds of the 2028 Cheniere Senior Secured Notes, along with $200 million in available cash, were used to prepay approximately $2.1 billion of the outstanding indebtedness of the Cheniere Term Loan Facility, resulting in the recognition of debt extinguishment costs of $16 million for the year ended December 31, 2020. The borrowings under the Cheniere Term Loan Facility, which was entered into in June 2020 with available commitments of $2.62 billion and subsequently increased to $2.695 billion in July 2020, were used to (1) redeem the outstanding principal amount of the 2025 CCH HoldCo II Convertible Senior Notes remaining after the redemption of an aggregate outstanding principal amount of $300 million with available cash in March 2020, including paid-in-kind interest, with cash at a price of $1,080 per $1,000 principal amount, (2) repurchase $844 million in aggregate principal amount of outstanding 2021 Cheniere Convertible Unsecured Notes, including paid-in-kind interest, at individually negotiated prices from a small number of investors and (3) pay the related fees and expenses. The redemption of the 2025 CCH HoldCo II Convertible Senior Notes and the repurchase of the 2021 Cheniere Convertible Unsecured Notes resulted in the recognition of debt extinguishment costs of $149 million and a reduction in equity associated with reacquisition of the embedded conversion option of $10 million.

Credit Facilities and Delayed Draw Term Loan

Below is a summary of our credit facilities and delayed draw term loan outstanding as of December 31, 2020 (in millions):

	2020 SPL Working Capital Facility (1)	2019 CQP Credit Facilities	CCH Credit Facility (2)	CCH Working Capital Facility	Cheniere Revolving Credit Facility	Cheniere Term Loan Facility (3)
Original facility size	$ 1,200	$ 1,500	$ 8,404	$ 350	$ 750	$ 2,620
Incremental commitments	—	—	1,566	850	500	75
Less:						
Outstanding balance	—	—	2,627	140	—	148
Commitments prepaid or terminated	—	750	7,343	—	—	2,175
Letters of credit issued	413	—	—	293	124	—
Available commitment	$ 787	$ 750	$ —	$ 767	$ 1,126	$ 372
Priority ranking	Senior secured	Senior secured	Senior secured	Senior secured	Senior secured	Senior secured
Interest rate on available balance	LIBOR plus 1.125% - 1.750% or base rate plus 0.125% - 0.750%	LIBOR plus 1.25% - 2.125% or base rate plus 0.25% - 1.125%	LIBOR plus 1.75% or base rate plus 0.75%	LIBOR plus 1.25% - 1.75% or base rate plus 0.25% - 0.75%	LIBOR plus 1.75% - 2.50% or base rate plus 0.75% - 1.50%	(4)
Weighted average interest rate of outstanding balance	n/a	n/a	1.90%	1.40%	n/a	2.15%
Maturity date	March 19, 2025	May 29, 2024	June 30, 2024	June 29, 2023	December 13, 2022	June 18, 2023

(1) The 2020 SPL Working Capital Facility contains customary conditions precedent for extensions of credit, as well as customary affirmative and negative covenants. SPL pays a commitment fee equal to an annual rate of 0.1% to 0.3% (depending on the then-current rating of SPL), which accrues on the daily amount of the total commitment less the sum of (1) the outstanding principal amount of loans, (2) letters of credit issued and (3) the outstanding principal amount of swing line loans.

(2) We prepaid $656 million of outstanding borrowings under the CCH Credit Facility during the year ended December 31, 2020 using proceeds from the issuance of the 3.52% CCH Senior Secured Notes.

(3) Borrowings under the Cheniere Term Loan Facility are subject to customary conditions precedent. The remaining commitments under the Cheniere Term Loan Facility are expected to be used to repay and/or repurchase a portion of the remaining principal amount of the 2021 Cheniere Convertible Unsecured Notes and for the payment of related fees and expenses. We pay a commitment fee equal to 30% of the margin for LIBOR loans multiplied by the average daily amount of undrawn commitments. If the Cheniere Term Loan Facility is still outstanding on the first anniversary of the Closing Date, as defined by the credit agreement, we will pay duration fees in an amount equal to 0.25% of the aggregate amount of commitments as of July 10, 2020, which was the date the loans were first borrowed under the Cheniere Term Loan Facility (the “Payment Date”). Furthermore, if the Cheniere Term Loan Facility is still outstanding on the second anniversary of the Closing Date, as defined by the credit agreement, we will pay 0.50% of the aggregate amount of commitments as of the Payment Date. Annual administrative fees must also be paid to the administrative agent for the Cheniere Term Loan Facility. Subject to customary exceptions, we are required to make mandatory prepayments with respect to the Cheniere Term Loan Facility using the net proceeds of certain events on a *pro rata* basis and on terms consistent with required prepayments under the Cheniere Revolving Credit Facility.

(4) LIBOR plus (1) 2.00% to 2.75% per annum in the first year, (2) 2.50% to 3.25% per annum in the second year and (3) 3.00% to 3.75% per annum in the third year until maturity, or base rate plus (1) 1.00% to 1.75% per annum in the first year, (2) 1.50% to 2.25% per annum in the second year and (3) 2.00% to 2.75% per annum in the third year until maturity.

Convertible Notes

Below is a summary of our convertible notes outstanding as of December 31, 2020 (in millions):

	2021 Cheniere Convertible Unsecured Notes (1)	2045 Cheniere Convertible Senior Notes
Aggregate original principal	$ 1,000	$ 625
Add: interest paid-in-kind	320	—
Less: aggregate principal redeemed	(844)	—
Aggregate remaining principal	$ 476	$ 625
Debt component, net of discount and debt issuance costs	$ 470	$ 317
Equity component	$ 201	$ 194
Interest payment method	Paid-in-kind	Cash
Conversion by us (2)	—	(3)
Conversion by holders (2)	(4)	(5)
Conversion basis	Cash and/or stock	Cash and/or stock
Conversion value in excess of principal	$ —	$ —
Maturity date	May 28, 2021	March 15, 2045
Contractual interest rate	4.875 %	4.25 %
Effective interest rate (6)	8.1 %	9.4 %
Remaining debt discount and debt issuance costs amortization period (7)	0.4 years	24.2 years

(1) $372 million of the 2021 Cheniere Convertible Unsecured Notes is categorized as long-term debt because the remaining available commitments under the Cheniere Term Loan Facility are expected to be used to repay and/or repurchase a portion of the remaining outstanding principal amount of the 2021 Cheniere Convertible Unsecured Notes.

(2) Conversion is subject to various limitations and conditions.

(3) Redeemable at any time at a redemption price payable in cash equal to the accreted amount of the $625 million aggregate principal amount of 4.25% Convertible Senior Notes due 2045 (the "2045 Cheniere Convertible Senior Notes") to be redeemed, plus accrued and unpaid interest, if any, to such redemption date.

(4) Initially convertible at $93.64 (subject to adjustment upon the occurrence of certain specified events), provided that the closing price of our common stock is greater than or equal to the conversion price on the conversion date.

(5) Prior to December 15, 2044, convertible only under certain circumstances as specified in the indenture; thereafter, holders may convert their notes regardless of these circumstances. 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 (subject to adjustment upon the occurrence of certain specified events).

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

(7) We amortize any debt discount and debt issuance costs using the effective interest over the period through contractual maturity.

Restrictive Debt Covenants

The indentures governing our senior notes and other agreements underlying our debt contain customary terms and events of default and certain covenants that, among other things, may limit us, our subsidiaries' and its restricted subsidiaries' ability to make certain investments or pay dividends or distributions.

As of December 31, 2020, each of our issuers was in compliance with all covenants related to their respective debt agreements.

Interest Expense

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

	Year Ended December 31,		
	2020	2019	2018
Interest cost on convertible notes:			
Interest per contractual rate	$ 152	$ 256	$ 237
Amortization of debt discount	45	40	35
Amortization of debt issuance costs	8	12	9
Total interest cost related to convertible notes	205	308	281
Interest cost on debt and finance leases excluding convertible notes	1,568	1,538	1,397
Total interest cost	1,773	1,846	1,678
Capitalized interest	(248)	(414)	(803)
Total interest expense, net of capitalized interest	$ 1,525	$ 1,432	$ 875

Fair Value Disclosures

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

	December 31, 2020		December 31, 2019	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes — Level 2 (1)	$ 24,700	$ 27,897	$ 22,700	$ 24,650
Senior notes — Level 3 (2)	2,771	3,423	2,002	2,259
Credit facilities (3)	2,915	2,915	3,283	3,283
2021 Cheniere Convertible Unsecured Notes (2)	476	480	1,278	1,312
2025 CCH HoldCo II Convertible Senior Notes (2)	—	—	1,578	1,807
2045 Cheniere Convertible Senior Notes (4)	625	496	625	498

(1) 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) 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 12—LEASES

Our leased assets consist primarily of (1) LNG vessel time charters (“vessel charters”), (2) tug vessels, (3) office space and facilities and (4) land sites, all of which are classified as operating leases except for our tug vessels at the Corpus Christi LNG terminal, which are classified as finance leases.

Our policy is to recognize leases on our 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. As our leases generally do not provide an implicit rate, in order to calculate the lease liability, we discounted our expected future lease payments using our relevant subsidiary’s incremental borrowing rate at the later of January 1, 2019 or the commencement date of the lease. The incremental borrowing rate is an estimate of the rate of interest that a given subsidiary would have to pay to borrow on a collateralized basis over a similar term to that of the lease term.

Many of our leases contain renewal options exercisable at our sole discretion. Options to renew a lease are included in the lease term and recognized as part of the right-of-use asset and lease liability only to the extent they are reasonably certain to be exercised, such as when necessary to satisfy obligations that existed at the execution of the lease or when the non-renewal would otherwise result in a significant economic penalty.

We have elected the practical expedient to omit leases with an initial term of 12 months or less ("short-term lease") from recognition on the balance sheet. We recognize short-term lease payments on a straight-line basis over the lease term and variable payments under short-term leases in the period in which the obligation is incurred.

Certain of our leases contain non-lease components which are not separated from the lease components when calculating the right-of-use asset and lease liability per our use of the practical expedient to combine both components of an arrangement for all classes of leased assets.

Certain of our leases also contain variable payments, such as inflation, that are not included when calculating the right-of-use asset and lease liability unless the payments are in-substance fixed.

We recognize lease expense for operating leases on a straight-line basis over the lease term. We recognize lease expense for finance leases as the sum of the amortization of the right-of-use assets on a straight-line basis and the interest on lease liabilities using the effective interest method over the lease term.

The following table shows the classification and location of our right-of-use assets and lease liabilities on our Consolidated Balance Sheets (in millions):

		December 31,			
	Consolidated Balance Sheets Location	**2020**		**2019**	
Right-of-use assets—Operating	Operating lease assets, net	$	759	$	439
Right-of-use assets—Financing	Property, plant and equipment, net		53		56
Total right-of-use assets		$	812	$	495
Current operating lease liabilities	Current operating lease liabilities	$	161	$	236
Current finance lease liabilities	Other current liabilities		2		1
Non-current operating lease liabilities	Non-current operating lease liabilities		597		189
Non-current finance lease liabilities	Non-current finance lease liabilities		57		58
Total lease liabilities		$	817	$	484

The following table shows the classification and location of our lease costs on our Consolidated Statements of Operations (in millions):

		Year Ended December 31,			
	Consolidated Statements of Operations Location	**2020**		**2019**	
Operating lease cost (a)	Operating costs and expenses (1)	$	432	$	612
Finance lease cost:					
Amortization of right-of-use assets	Depreciation and amortization expense		2		3
Interest on lease liabilities	Interest expense, net of capitalized interest		7		10
Total lease cost		$	441	$	625
(a) Included in operating lease cost:					
Short-term lease costs		$	93	$	230
Variable lease costs paid to the lessor			16		7

(1) Presented in cost of sales, operating and maintenance expense or selling, general and administrative expense consistent with the nature of the asset under lease.

During the year ended December 31, 2018, we recognized lease expense for all operating leases of $335 million.

Future annual minimum lease payments for operating and finance leases as of December 31, 2020 are as follows (in millions):

Years Ending December 31,	Operating Leases (1)	Finance Leases
2021	$ 197	$ 10
2022	156	10
2023	121	10
2024	119	10
2025	96	10
Thereafter	252	127
Total lease payments	941	177
Less: Interest	(183)	(118)
Present value of lease liabilities	$ 758	$ 59

(1) Does not include $1.6 billion of legally binding minimum lease payments primarily for vessel charters which were executed as of December 31, 2020 but will commence in future period primarily in the next two years and have fixed minimum lease terms of up to seven years.

The following table shows the weighted-average remaining lease term and the weighted-average discount rate for our operating leases and finance leases:

	December 31, 2020		December 31, 2019	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted-average remaining lease term (in years)	8.2	17.7	8.4	18.7
Weighted-average discount rate (1)	5.4%	16.2%	5.2%	16.2%

(1) The finance leases commenced prior to the adoption of the current leasing standard under GAAP. In accordance with previous accounting guidance, the implied rate is based on the fair value of the underlying assets.

The following table includes other quantitative information for our operating and finance leases (in millions):

	Year Ended December 31,	
	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 309	$ 389
Operating cash flows from finance leases	10	9
Right-of-use assets obtained in exchange for new operating lease liabilities	615	235

LNG Vessel Subcharters

From time to time, we sublease certain LNG vessels under charter to third parties while retaining our existing obligation to the original lessor. As of December 31, 2020 and 2019, we had zero and $9 million in future minimum sublease payments to be received from LNG vessel subcharters, respectively. The following table shows the sublease income recognized in other revenues on our Consolidated Statements of Operations (in millions):

	Year Ended December 31,	
	2020	2019
Fixed Income	$ 68	$ 122
Variable Income	27	22
Total sublease income	$ 95	$ 144

NOTE 13—REVENUES FROM CONTRACTS WITH CUSTOMERS

The following table represents a disaggregation of revenue earned from contracts with customers during the years ended December 31, 2020, 2019 and 2018 (in millions):

	Year Ended December 31,		
	2020	2019	2018
LNG revenues (1)	$ 8,954	$ 8,817	$ 7,581
Regasification revenues	269	266	261
Other revenues	70	74	54
Total revenues from customers	9,293	9,157	7,896
Net derivative gain (loss) (2)	(30)	429	(9)
Other (3)	95	144	100
Total revenues	$ 9,358	$ 9,730	$ 7,987

(1) LNG revenues include revenues for LNG cargoes in which our customers exercised their contractual right to not take delivery but remained obligated to pay fixed fees irrespective of such election. During the year ended December 31, 2020, we recognized $969 million in LNG revenues associated with LNG cargoes for which customers notified us that they would not take delivery, of which $38 million would have been recognized subsequent to December 31, 2020, if the cargoes were lifted pursuant to the delivery schedules with the customers. Revenue is generally recognized upon receipt of irrevocable notice that a customer will not take delivery because our customers have no contractual right to take delivery of such LNG cargo in future periods and our performance obligations with respect to such LNG cargo have been satisfied.

(2) See Note 7—Derivative Instruments for additional information about our derivatives.

(3) Includes revenues from LNG vessel subcharters. See Note 12—Leases for additional information about our subleases.

LNG Revenues

We have entered into numerous SPAs with third party customers for the sale of LNG on a free on board ("FOB") (delivered to the customer at either the Sabine Pass or Corpus Christi LNG terminal) or delivered at terminal ("DAT") (delivered to the customer at their LNG receiving terminal) basis. Our customers generally purchase LNG 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. The fixed fee component is the amount payable to us regardless of a cancellation or suspension of LNG cargo deliveries by the customers. The variable fee component is the amount generally payable to us only upon delivery of LNG plus all future adjustments to the fixed fee for inflation. The SPAs and contracted volumes to be made available under the SPAs are not tied to a specific Train; however, the term of each SPA generally commences upon the date of first commercial delivery of a specified Train.

We intend to primarily use LNG sourced from our Sabine Pass or Corpus Christi terminals to provide contracted volumes to our customers. However, we supplement this LNG with volumes procured from third parties. LNG revenues recognized from LNG that was procured from third parties was $414 million, $268 million and $745 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Revenues from the sale of LNG are recognized at a point in time when the LNG is delivered to the customer, either at the Sabine Pass or Corpus Christi LNG terminal or at the customer's LNG receiving terminal, based on the terms of the contract, which is the point legal title, physical possession and the risks and rewards of ownership transfer to the customer. Each individual molecule of LNG is viewed as a separate performance obligation. The stated contract price (including both fixed and variable fees) per MMBtu in each LNG sales arrangement is representative of the stand-alone selling price for LNG at the time the contract was negotiated. We have concluded that the variable fees meet the exception for allocating variable consideration to specific parts of the contract. As such, the variable consideration for these contracts is allocated to each distinct molecule of LNG and recognized when that distinct molecule of LNG is delivered to the customer. Because of the use of the exception, variable consideration related to the sale of LNG is also not included in the transaction price.

When we sell LNG on a DAT basis, we consider all transportation costs, including vessel chartering, loading/unloading and canal fees, as fulfillment costs and not as separate services provided to the customer within the arrangement, regardless of whether or not such activities occur prior to or after the customer obtains control of the LNG. We expense fulfillment costs as incurred unless otherwise dictated by GAAP.

Fees received pursuant to SPAs are recognized as LNG revenues only 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.

Regasification Revenues

The Sabine Pass LNG terminal has operational regasification capacity of approximately 4 Bcf/d. Approximately 2 Bcf/d of the regasification capacity at the Sabine Pass LNG terminal has been reserved under two long-term TUAs with unaffiliated third-party customers, under which they are required to pay fixed monthly fees regardless of their use of the LNG terminal. Each of the customers has reserved approximately 1 Bcf/d of regasification capacity. The customers are each obligated to make monthly capacity payments to SPLNG aggregating approximately $125 million annually for 20 years that commenced in 2009, which is representative of fixed consideration in the contract. A portion of this fee is adjusted annually for inflation which is considered variable consideration. The remaining capacity of the Sabine Pass LNG terminal has been reserved by SPL, for which the associated revenues are eliminated in consolidation.

Because SPLNG is continuously available to provide regasification service on a daily basis with the same pattern of transfer, we have concluded that SPLNG provides a single performance obligation to its customers on a continuous basis over time. We have determined that an output method of recognition based on elapsed time best reflects the benefits of this service to the customer and accordingly, LNG regasification capacity reservation fees are recognized as regasification revenues on a straight-line basis over the term of the respective TUAs.

In 2012, SPL entered into a partial TUA assignment agreement with Total Gas & Power North America, Inc. (“Total”), whereby upon substantial completion of Train 5 of the SPL Project, SPL gained access to substantially all 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 Train 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 and we continue to recognize the payments received from Total as revenue. During the years ended December 31, 2020, 2019 and 2018, SPL recorded $129 million, $104 million and $30 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Contract Assets and Liabilities

The following table shows our contract assets, net, which are classified as other non-current assets, net on our Consolidated Balance Sheets (in millions):

	December 31,	
	2020	2019
Contract assets, net	$ 80	$ 18

Contract assets represent our right to consideration for transferring goods or services to the customer under the terms of a sales contract when the associated consideration is not yet due. Changes in contract assets during the year ended December 31, 2020 were primarily attributable to revenue recognized due to the delivery of LNG under certain SPAs for which the associated consideration was not yet due.

The following table reflects the changes in our contract liabilities, which we classify as deferred revenue on our Consolidated Balance Sheets (in millions):

	Year Ended December 31, 2020
Deferred revenues, beginning of period	$ 161
Cash received but not yet recognized	138
Revenue recognized from prior period deferral	(161)
Deferred revenues, end of period	$ 138

We record deferred revenue when we receive consideration, or such consideration is unconditionally due from a customer, prior to transferring goods or services to the customer under the terms of a sales contract. Changes in deferred revenue during the years ended December 31, 2020 and 2019 are primarily attributable to differences between the timing of revenue recognition and the receipt of advance payments related to delivery of LNG under certain SPAs.

Transaction Price Allocated to Future Performance Obligations

Because many of our sales contracts have long-term durations, we are contractually entitled to significant future consideration which we have not yet recognized as revenue. The following table discloses the aggregate amount of the transaction price that is allocated to performance obligations that have not yet been satisfied as of December 31, 2020 and 2019:

	December 31, 2020		December 31, 2019	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues	$ 102.3	10	$ 106.4	11
Regasification revenues	2.1	5	2.4	5
Total revenues	$ 104.4		$ 108.8	

(1) The weighted average recognition timing represents an estimate of the number of years during which we shall have recognized half of the unsatisfied transaction price.

We have elected the following exemptions which omit certain potential future sources of revenue from the table above:

(1) We omit from the table above all performance obligations that are part of a contract that has an original expected duration of one year or less.

(2) The table above excludes substantially all variable consideration under our SPAs and TUAs. We omit from the table above all variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation when that performance obligation qualifies as a series. The amount of revenue from variable fees that is not included in the transaction price will vary based on the future prices of Henry Hub throughout the contract terms, to the extent customers elect to take delivery of their LNG, and adjustments to the consumer price index. Certain of our contracts contain additional variable consideration based on the outcome of contingent events and the movement of various indexes. We have not included such variable consideration in the transaction price to the extent the consideration is considered constrained due to the uncertainty of ultimate pricing and receipt. Approximately 40% and 52% of our LNG revenues from contracts included in the table above during the years ended December 31, 2020 and 2019, respectively, were related to variable consideration received from customers. During each of the years ended December 31, 2020 and 2019, approximately 3% of our regasification revenues were related to variable consideration received from customers.

We may enter into contracts to sell LNG that are conditioned upon one or both of the parties achieving certain milestones such as reaching FID on a certain liquefaction Train, obtaining financing or achieving substantial completion of a Train and any related facilities. These contracts are considered completed contracts for revenue recognition purposes and are included in the transaction price above when the conditions are considered probable of being met.

NOTE 14—RELATED PARTY TRANSACTIONS

Natural Gas Supply Agreements

SPL and CCL are party to natural gas supply agreements with related parties in the ordinary course of business, to obtain feed gas for the operation of the Liquefaction Projects.

SPL Natural Gas Supply Agreement

The term of the SPL agreement is for five years, which can commence no earlier than November 1, 2021 and no later than November 1, 2022, following the achievement of contractually-defined conditions precedent. As of December 31, 2020, the notional amount for this agreement was 91 TBtu and had a fair value of zero.

CCL Natural Gas Supply Agreement

The term of the CCL agreement extends through March 2022. Under this agreement, CCL recorded $13 million and $3 million in accrued liabilities, as of December 31, 2020 and 2019, respectively.

The Liquefaction Supply Derivatives related to this agreement are recorded on our Consolidated Balance Sheets as follows (in millions, except notional amount):

	December 31,	
	2020	2019
Derivative assets	$ 3	$ 3
Non-current derivative assets	1	2
Notional amount, net (in TBtu)	60	120

We recorded the following amounts on our Consolidated Statements of Operations during the years ended December 31, 2020, 2019 and 2018 related to this agreement (in millions):

	Year Ended December 31,		
	2020	2019	2018
Cost of sales (a)	$ 114	$ 85	$ —
(a) Included in costs of sales:			
Liquefaction Supply Derivative loss	$ (1)	$ (1)	$ —

Natural Gas Transportation and Storage Agreements

SPL is party to various natural gas transportation and storage agreements and CTPL is party to an operational balancing agreement with a related party in the ordinary course of business for the operation of the SPL Project, with initial primary terms of up to 10 years with extension rights. We recorded operating and maintenance expense of $13 million in the year ended December 31, 2020 and accrued liabilities of $4 million as of December 31, 2020 with this related party.

Operation and Maintenance Service Agreements

Cheniere LNG O&M Services, LLC ("O&M Services"), our wholly owned subsidiary, provides the development, construction, operation and maintenance services to Midship Pipeline pursuant to agreements in which O&M Services receives an agreed upon fee and reimbursement of costs incurred. O&M Services recorded $9 million, $12 million and $12 million in the years ended December 31, 2020, 2019 and 2018, respectively, of other revenues and $2 million and $3 million of accounts receivable as of December 31, 2020 and 2019, respectively, for services provided to Midship Pipeline under these agreements.

NOTE 15—INCOME TAXES

The jurisdictional components of income before income taxes and non-controlling interest on our Consolidated Statements of Operations for the years ended December 31, 2020, 2019 and 2018 are as follows (in millions):

	Year Ended December 31,		
	2020	2019	2018
U.S.	$ 720	$ 289	$ 997
International	(176)	426	230
Total income before income taxes and non-controlling interest	$ 544	$ 715	$ 1,227

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

	Year Ended December 31,		
	2020	2019	2018
Current:			
Federal	$ —	$ —	$ —
State	—	—	2
Foreign	—	4	30
Total current	—	4	32
Deferred:			
Federal	41	(475)	—
State	2	(46)	—
Foreign	—	—	(5)
Total deferred	43	(521)	(5)
Total income tax provision (benefit)	$ 43	$ (517)	$ 27

Our income tax rates do not bear a customary relationship to statutory income tax rates. A reconciliation of the federal statutory income tax rate of 21% to our effective income tax rate is as follows:

	Year Ended December 31,		
	2020	2019	2018
U.S. federal statutory tax rate	21.0 %	21.0 %	21.0 %
Non-controlling interest	(22.6)%	(17.2)%	(11.4)%
State tax rate	— %	(5.4)%	(0.4)%
Executive compensation	1.4 %	1.3 %	0.5 %
Nondeductible interest expense	8.0 %	5.0 %	2.6 %
Foreign earnings taxed in the U.S.	1.2 %	6.7 %	1.4 %
Foreign rate differential	(3.7)%	(11.4)%	(1.1)%
Tax credits	(4.5)%	(5.2)%	(0.6)%
Internal restructuring	7.0 %	— %	— %
Other	1.0 %	1.4 %	— %
Valuation allowance	(0.9)%	(68.5)%	(9.8)%
Effective tax rate	7.9 %	(72.3)%	2.2 %

Significant components of our deferred tax assets and liabilities at December 31, 2020 and 2019 are as follows (in millions):

	December 31, 2020	December 31, 2019
Deferred tax assets		
Net operating loss carryforwards and credits		
Federal	$ 3,084	$ 2,860
Foreign	3	5
State	257	249
Federal and state tax credits	95	64
Disallowed business interest expense carryforward	—	154
Other	290	143
Less: valuation allowance	(190)	(196)
Total deferred tax assets	3,539	3,279
Deferred tax liabilities		
Investment in partnerships	(765)	(554)
Property, plant and equipment	(2,089)	(2,110)
Other	(196)	(86)
Total deferred tax liabilities	(3,050)	(2,750)
Net deferred tax assets	$ 489	$ 529

Business interest expense carryforward

On March 27, 2020, the Coronavirus Aid, Relief and Economic Security (CARES) Act ("the CARES Act") was signed into law which provided numerous tax changes in response to the COVID-19 pandemic. In general, the CARES Act was favorable to us because it increased the interest deductibility limit from 30% to 50% of adjusted taxable income in 2019 and 2020.

On September 14, 2020, the U.S Department of Treasury issued final and proposed regulations providing guidance on the business interest expense limitation under Section 163(j) of the Internal Revenue Code. In general, the regulations were favorable to us because they allow depreciation capitalized to inventory to be added back to adjusted taxable income from 2018 through 2021, for purposes of computing the allowable interest expense deduction. As permitted under the regulations, we intend to adopt them retroactively beginning with the tax year ended December 31, 2018.

The favorable changes brought about by the CARES Act and the final and proposed interest expense regulations allow us to fully deduct our current year business interest expense and all of our previously disallowed business interest expense carryforward.

Internal Restructuring

On March 31, 2020 we executed an internal restructuring which simplified our legal entity structure, causing foreign income to flow directly to our U.S. tax return. As a result of the internal restructuring, a one-time $38 million deferred tax expense was recorded discretely during the first quarter of 2020.

Valuation Allowance

For the period ended December 31, 2020, we have provided a valuation allowance of approximately $190 million on certain state NOLs and federal capital loss carryforwards, for which we believe are more likely than not to expire before realization of the benefit. Our valuation allowance decreased by $6 million for the year ended December 31, 2020.

For the period ended December 31, 2019, we weighed all of the positive and negative evidence, and determined that sufficient positive evidence existed to support releasing the valuation allowance against substantially all of our federal deferred tax assets and a portion of our state deferred tax assets. The positive evidence supporting such conclusion included successful completion and subsequent operations of Trains 1 and 2 of the CCL Project and Train 5 of the SPL Project, transitioning from a three-year cumulative loss position in 2018 to a three-year cumulative income position in 2019, commencing commercial delivery on 13 of our long-term customer SPAs and forecasts of sustained future profitability.

NOL and tax credit carryforwards

At December 31, 2020, we had federal and state NOL carryforwards of approximately $15.0 billion and $3.2 billion, respectively. Approximately $10.6 billion of these NOLs have an indefinite carryforward period. All other NOLs will expire between 2026 and 2040.

At December 31, 2020, we had federal and state tax credit carryforwards of $93 million and $2 million, respectively. The federal tax credit carryforwards include investment tax credit carryforwards of $52 million related to capital equipment placed in service at our Liquefaction Projects. We account for our federal investment tax credits under the flow-through method. The federal tax credit carryforwards also include $37 million of foreign tax credits related to tax years 2014 through 2020. The federal and state tax credit carryforwards will expire between 2024 and 2039.

We experienced an ownership change within the provisions of U.S. 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 over the carryover period. We 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.

Income Tax Audits

We are subject to tax in the U.S. and various state and foreign jurisdictions and we remain subject to periodic audits and reviews by taxing authorities. Federal and state tax returns for the years after 2016 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.

Unrecognized Tax Benefits

At December 31, 2020, we had unrecognized tax benefits of $62 million. If recognized, $53 million of unrecognized tax benefits would affect our effective tax rate in future periods. Currently, we do not recognize any accrued liabilities, interest and penalties associated with the unrecognized tax benefits provided in our Consolidated Statements of Operations or our Consolidated Balance Sheets because any settlement of uncertain tax positions would result in an adjustment to our NOL carryforward. We recognize interest and penalties related to income tax matters as part of income tax expense.

A reconciliation of the beginning and ending amounts of our unrecognized tax benefits for the years ended December 31, 2020 and 2019, is as follows (in millions):

	Year Ended December 31,	
	2020	2019
Balance at beginning of the year	$ 61	$ 61
Additions based on tax positions related to current year	1	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	—	—
Settlements	—	—
U.S. tax reform rate change	—	—
Balance at end of the year	$ 62	$ 61

NOTE 16—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 2011 Incentive Plan, as amended (the “2011 Plan”) and the 2020 Incentive Plan, which was approved by our shareholders in May 2020. The 2011 Plan and the 2020 Incentive Plan provide for the issuance of

35.0 million shares and 8.0 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").

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

	Year Ended December 31,		
	2020	2019	2018
Share-based compensation costs, pre-tax:			
Equity awards	$ 114	$ 131	$ 89
Liability awards	2	9	48
Total share-based compensation	116	140	137
Capitalized share-based compensation	(6)	(9)	(24)
Total share-based compensation expense	$ 110	$ 131	$ 113
Tax benefit associated with share-based compensation expense	$ 23	$ 14	$ 6

The total unrecognized compensation cost at December 31, 2020 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	$ 1	0.3
Restricted Stock Unit and Performance Stock Unit Awards	$ 111	1.3
Phantom Units Awards	$ —	0.2

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, 2020.

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, 2020	0.0	$ 67.79
Granted	0.1	41.78
Vested	0.0	—
Forfeited	0.0	—
Non-vested at December 31, 2020	0.1	$ 41.78

The fair value of restricted stock share awards vested for the years ended December 31, 2020, 2019 and 2018 were $3 million, $3 million and $53 million, respectively.

Restricted Stock Unit and Performance Stock Unit Awards

Restricted stock units are stock awards that vest over a service period of three years and 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. Performance stock units provide for cliff vesting after a period of three years with payouts based on metrics dependent upon market and performance achieved over the defined performance period compared to pre-established performance targets. The settlement amounts of the awards are based on market and performance metrics which include cumulative distributable cash flow per share, and in certain circumstances, absolute total shareholder return ("ATSR") of our common stock. Where applicable, the compensation for performance stock units is based on fair value assigned to the market metric of ATSR using a Monte Carlo model upon grant, which remains constant through the vesting period, and a performance metric, which will vary due to changing estimates regarding the expected achievement of the performance metric of cumulative distributable cash flow per share. The number of shares that may be earned at the end of the vesting period ranges from 0% up to 300% of the target award amount. Both restricted stock units and performance stock units will be settled in Cheniere common stock (on a one-for-one basis) and are classified as equity awards.

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, 2020	4.4	$ 61.68
Granted (1)	1.8	53.88
Vested	(2.3)	58.49
Forfeited	(0.2)	58.83
Non-vested at December 31, 2020 (2)	3.7	$ 60.00

(1) This number includes 0.2 million incremental shares of our common stock that were issued based on performance results from previously-granted performance stock unit awards.

(2) This number excludes 1.0 million performance stock units, which represent the incremental 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 and fair value of units vested:

	Year Ended December 31,		
	2020	2019	2018
Units issued (in millions)	1.8	1.9	2.6
Weighted average grant date fair value per unit	$ 53.88	$ 67.47	$ 59.50
Fair value of units vested (in millions)	$ 137	$ 45	$ 22

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. We did not issue any phantom units to our employees and non-employee directors during the years ended December 31, 2020, 2019 and 2018. Phantom units are not eligible to receive quarterly distributions. These awards vest based on service conditions (two, three or four-year service periods).

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

	Units
Non-vested at January 1, 2020	0.1
Granted	—
Vested	(0.1)
Forfeited	0.0
Non-vested at December 31, 2020	0.0

The value of phantom units vested during the years ended December 31, 2020, 2019 and 2018 was $4 million, $11 million and $91 million, respectively.

NOTE 17—EMPLOYEE BENEFIT PLAN

We have a defined contribution plan (“401(k) Plan”) which allows eligible employees to contribute up to 75% 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 $15 million for each of the years ended December 31, 2020 and 2019 and $9 million for the year ended December 31, 2018. We have made no discretionary contributions to the 401(k) Plan to date.

NOTE 18—NET INCOME (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, 2020, 2019 and 2018 (in millions, except per share data):

	Year Ended December 31,		
	2020	2019	2018
Weighted average common shares outstanding:			
Basic	252.4	256.2	245.6
Dilutive unvested stock	—	1.9	2.4
Diluted	252.4	258.1	248.0
Basic net income (loss) per share attributable to common stockholders	$ (0.34)	$ 2.53	$ 1.92
Diluted net income (loss) per share attributable to common stockholders	$ (0.34)	$ 2.51	$ 1.90

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

	Year Ended December 31,		
	2020	2019	2018
Unvested stock (1)	3.4	2.3	0.8
Convertible notes			
2021 Cheniere Convertible Unsecured Notes (2)	—	13.7	13.0
2025 CCH HoldCo II Convertible Senior Notes (3)	—	25.5	—
2045 Cheniere Convertible Senior Notes	4.5	4.5	4.5
Total potentially dilutive common shares	7.9	46.0	18.3

(1) Does not include 0.5 million shares, 0.5 million shares and 0.4 million shares for the years ended December 31, 2020, 2019 and 2018, respectively, of unvested stock because the performance conditions had not yet been satisfied as of the respective dates.

(2) Since we have the intent and ability to settle the remaining outstanding principal amount of the 2021 Cheniere Convertible Unsecured Notes in cash and the excess conversion premium (the "conversion spread") in either cash or shares, the treasury stock method was applied for calculating any potential dilutive effect of the conversion spread on net income per share for the year ended December 31, 2020. However, since the average market price of our common stock did not exceed the conversion price of our 2021 Cheniere Convertible Unsecured Notes, the conversion spread was excluded from the computation of diluted net income per share for the year ended December 31, 2020.

(3) Since we redeemed the remaining principal amount of the 2025 CCH HoldCo II Convertible Senior Notes and the related premium in cash, as described in Note 11—Debt, the 2025 CCH HoldCo II Convertible Senior Notes were not included in the computation of net income per share for the year ended December 31, 2020. There were no shares related to the conversion of the 2025 CCH HoldCo II Convertible Senior Notes included in the computation of diluted net income per share for the year ended December 31, 2018, because the substantive non-market based contingencies underlying the eligible conversion date were not met as of December 31, 2018.

NOTE 19—SHARE REPURCHASE PROGRAM

On June 3, 2019, we announced that our Board of Directors ("Board") authorized a 3-year, $1.0 billion share repurchase program. The following table presents information with respect to repurchases of common stock during the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
Aggregate common stock repurchased	2,875,376	4,000,424
Weighted average price paid per share	$ 53.88	$ 62.27
Total amount paid (in millions)	$ 155	$ 249

As of December 31, 2020, we had up to $596 million of the share repurchase program available. Under the share repurchase program, repurchases can be made from time to time using a variety of methods, which may include open market purchases, privately negotiated transactions or otherwise, all in accordance with the rules of the SEC and other applicable legal requirements. The timing and amount of any shares of our common stock that are repurchased under the share repurchase program will be determined by our management based on market conditions and other factors. The share repurchase program does not obligate us to acquire any particular amount of common stock, and may be modified, suspended or discontinued at any time or from time to time at our discretion.

NOTE 20—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, 2020, are not recognized as liabilities but require disclosures in our Consolidated Financial Statements.

LNG Terminal Commitments and Contingencies

Obligations under EPC Contracts

SPL has a lump sum turnkey contract with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for the engineering, procurement and construction of Train 6 of the SPL Project. The EPC contract price for Train 6 of the SPL Project is approximately $2.5 billion, reflecting amounts incurred under change orders through December 31, 2020, and including estimated costs for the third marine berth that is currently under construction. As of December 31, 2020, we have incurred $1.9 billion under this contract.

CCL has a lump sum turnkey contract with Bechtel for the engineering, procurement and construction of Train 3 of the CCL Project. The EPC contract price for Train 3 of the CCL Project is approximately $2.4 billion, reflecting amounts incurred under change orders through December 31, 2020. As of December 31, 2020, we have incurred $2.4 billion under this contract.

SPL and CCL have the right to terminate its respective EPC contracts 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.

Obligations under SPAs

SPL and CCL have third-party SPAs which obligate SPL and CCL, respectively, 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 applicable specified Trains of the SPL Project or the CCL Project. In addition, our integrated marketing function has third-party SPAs which obligate us to deliver contracted volumes of LNG to the customers' vessels or to the customers at their LNG receiving terminals.

Obligations under LNG TUAs

SPLNG has third-party TUAs with Total 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, CCL and CCL Stage III have physical natural gas supply contracts to secure natural gas feedstock for the SPL Project, the CCL Project and potential future development of Corpus Christi Stage 3, respectively. The remaining terms of these contracts range up to 15 years, some of which commence upon the satisfaction of certain events or states of affairs. As of December 31, 2020, SPL, CCL and CCL Stage III have secured up to approximately 4,950 TBtu, 2,938 TBtu and 2,361 TBtu, respectively, of natural gas feedstock through natural gas supply contracts, a portion of which are considered purchase obligations if the certain events or states of affairs are satisfied.

Additionally, SPL and CCL have natural gas transportation and storage service agreements for the SPL Project and the CCL Project, respectively. The initial terms of the natural gas transportation agreements range up to 20 years for the SPL Project and the CCL Project, with renewal options for certain contracts, and commence upon the occurrence of conditions precedent. The initial term of the natural gas storage service agreements for the SPL Project ranges up to 10 years and the initial term of the natural gas storage service agreements for the CCL Project ranges up to 5 years.

As of December 31, 2020, the obligations of SPL, CCL and CCL Stage III 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)
2021	$ 4,477
2022	2,567
2023	1,861
2024	1,367
2025	1,140
Thereafter	4,005
Total	$ 15,417

(1) Pricing of natural gas supply contracts are variable based on market commodity basis prices adjusted for basis spread. Amounts included are based on estimated forward prices and basis spreads as of December 31, 2020. Some of our contracts may not have been negotiated as part of arranging financing for the underlying assets providing the natural gas supply, transportation and storage services.

Restricted Net Assets

At December 31, 2020, our restricted net assets of consolidated subsidiaries were approximately $3.0 billion.

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.

Environmental and Regulatory Matters

Our LNG terminals and pipelines 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. Failure to comply with such laws could result in legal proceedings, which may include substantial penalties. We believe that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our results of operations, financial condition or cash flows.

Legal Proceedings

We are, and 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. While the results of these litigation matters and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

NOTE 21—CUSTOMER CONCENTRATION

The following table shows customers with revenues of 10% or greater of total revenues from external customers and customers with accounts receivable, net and contract assets, net balances of 10% or greater of total accounts receivable, net and contract assets, net from external customers:

	Percentage of Total Revenues from External Customers			Percentage of Accounts Receivable, Net and Contract Assets, Net from External Customers	
	Year Ended December 31,			December 31,	
	2020	2019	2018	2020	2019
Customer A	14%	16%	18%	14%	13%
Customer B	12%	10%	14%	12%	*
Customer C	10%	11%	19%	*	13%
Customer D	10%	11%	13%	*	*

* Less than 10%

The following table shows revenues from external customers attributable to the country in which the revenues were derived (in millions). 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.

	Revenues from External Customers		
	Year Ended December 31,		
	2020	2019	2018
Ireland	$ 1,130	$ 989	$ 1,098
Spain	1,034	598	—
India	1,021	1,160	1,048
South Korea	942	1,207	1,517
United States	687	2,807	1,911
United Kingdom	678	559	155
Singapore	646	533	417
Other countries	3,220	1,877	1,841
Total	$ 9,358	$ 9,730	$ 7,987

NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2020	2019	2018
Cash paid during the period for interest on debt, net of amounts capitalized	$ 1,395	$ 1,126	$ 707
Cash paid for income taxes	2	24	14
Non-cash investing and financing activities:			
Acquisition of non-controlling interest in Cheniere Holdings	—	—	702
Acquisition of assets under capital lease (1)	—	—	60

(1) See Note 12—Leases for our supplemental cash flow information related to our leases in 2019 following the adoption of ASC 842.

The balance in property, plant and equipment, net funded with accounts payable and accrued liabilities was $282 million, $473 million and $420 million as of December 31, 2020, 2019 and 2018, respectively.

NOTE 23—SUBSEQUENT EVENTS

In February 2021, SPL entered into a note purchase agreement for the sale of approximately $147 million aggregate principal amount of 2.95% Senior Secured Notes due 2037 (the "2.95% SPL 2037 Senior Secured Notes") on a private placement basis. The 2.95% SPL 2037 Senior Secured Notes are expected to be issued in December 2021, and the net proceeds are expected to be used to refinance a portion of SPL's outstanding Senior Secured Notes due 2022. The 2.95% SPL 2037 Senior Secured Notes will be fully amortizing, with a weighted average life of over 10 years.

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2020:				
Revenues	$ 2,709	$ 2,402	$ 1,460	$ 2,787
Income from operations	1,346	937	72	276
Net income (loss)	603	404	(508)	2
Net income (loss) attributable to common stockholders	375	197	(463)	(194)
Net income (loss) per share attributable to common stockholders—basic (1)	1.48	0.78	(1.84)	(0.77)
Net income (loss) per share attributable to common stockholders—diluted (1)	1.43	0.78	(1.84)	(0.77)
Year Ended December 31, 2019:				
Revenues	$ 2,261	$ 2,292	$ 2,170	$ 3,007
Income from operations	606	432	307	1,016
Net income (loss)	337	2	(260)	1,153
Net income (loss) attributable to common stockholders	141	(114)	(318)	939
Net income (loss) per share attributable to common stockholders—basic (1)	0.55	(0.44)	(1.25)	3.70
Net income (loss) per share attributable to common stockholders—diluted (1)	0.54	(0.44)	(1.25)	3.34

(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, 2020, 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 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, 2020.

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	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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	Cheniere Partners	8-K	10.2	8/9/2012
3.1	Restated Certificate of Incorporation of the Company	Cheniere	10-Q	3.1	8/10/2004
3.2	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere	8-K	3.1	2/8/2005
3.3	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere (SEC File No. 333-160017)	S-8	4.3	6/16/2009

3.4	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere	8-K	3.1	6/7/2012
3.5	Certificate of Amendment of Restated Certificate of Incorporation of the Company	Cheniere	8-K	3.1	2/5/2013
3.6	Bylaws of the Company, as amended and restated December 9, 2015	Cheniere	8-K	3.1	12/15/2015
3.7	Amendment No. 1 to the Amended and Restated Bylaws of the Company, dated September 15, 2016	Cheniere	8-K	3.1	9/19/2016
4.1	Specimen Common Stock Certificate of the Company	Cheniere (SEC File No. 333-10905)	S-1	4.1	8/27/1996
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	Cheniere Partners	8-K	4.1	2/4/2013
4.3	First Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1.1	4/16/2013
4.4	Second Supplemental Indenture, dated as of April 16, 2013, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1.2	4/16/2013
4.5	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.4 above)	Cheniere Partners	8-K	4.1.2	4/16/2013
4.6	Third Supplemental Indenture, dated as of November 25, 2013, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1	11/25/2013
4.7	Form of 6.25% Senior Secured Note due 2022 (Included as Exhibit A-1 to Exhibit 4.6 above)	Cheniere Partners	8-K	4.1	11/25/2013
4.8	Fourth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1	5/22/2014
4.9	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.8 above)	Cheniere Partners	8-K	4.1	5/22/2014
4.10	Fifth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.2	5/22/2014
4.11	Form of 5.625% Senior Secured Note due 2023 (Included as Exhibit A-1 to Exhibit 4.10 above)	Cheniere Partners	8-K	4.2	5/22/2014
4.12	Sixth Supplemental Indenture, dated as of March 3, 2015, between SPL and The Bank of New York Mellon, as Trustee	Cheniere Partners	8-K	4.1	3/3/2015
4.13	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.12 above)	Cheniere Partners	8-K	4.1	3/3/2015
4.14	Seventh Supplemental Indenture, dated as of June 14, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	6/14/2016
4.15	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.14 above)	Cheniere Partners	8-K	4.1	6/14/2016
4.16	Eighth Supplemental Indenture, dated as of September 19, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	9/23/2016
4.17	Ninth Supplemental Indenture, dated as of September 23, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.2	9/23/2016
4.18	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.17 above)	Cheniere Partners	8-K	4.2	9/23/2016
4.19	Tenth Supplemental Indenture, dated as of March 6, 2017, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	3/6/2017
4.20	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.19 above)	Cheniere Partners	8-K	4.1	3/6/2017
4.21	Eleventh Supplemental Indenture, dated as of May 8, 2020, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	SPL	8-K	4.1	5/8/2020
4.22	Form of 4.500% Senior Secured Note due 2030 (Included as Exhibit A-1 to Exhibit 4.21 above)	SPL	8-K	4.1	5/8/2020

4.23	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	Cheniere Partners	8-K	4.1	2/27/2017
4.24	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.23 above)	Cheniere Partners	8-K	4.1	2/27/2017
4.25	Indenture, dated as of November 28, 2014, by and between the Company, as Issuer, and The Bank of New York Mellon, as Trustee	Cheniere	8-K	4.1	12/2/2014
4.26	Form of 4.875% Unsecured PIK Convertible Note due 2021 (Included as Exhibit A to Exhibit 4.25 above)	Cheniere	8-K	4.1	12/2/2014
4.27	Indenture, dated as of March 9, 2015, between the Company, the Guarantors and The Bank of New York Mellon, as Trustee	Cheniere	8-K	4.1	3/13/2015
4.28	First Supplemental Indenture, dated as of March 9, 2015, between the Company, as Issuer, and The Bank of New York Mellon, as Trustee	Cheniere	8-K	4.2	3/13/2015
4.29	Form of 4.25% Convertible Senior Note due 2045 (Included as Exhibit A to Exhibit 4.28 above)	Cheniere	8-K	4.2	3/13/2015
4.30	Indenture, dated as of September 22, 2020, between the Company as issuer, and the Bank of New York Mellon, as trustee	Cheniere	8-K	4.1	9/22/2020
4.31	First Supplemental Indenture, dated as of September 22, 2020, between the Company, as issuer, and the Bank of New York Mellon, as trustee	Cheniere	8-K	4.2	9/22/2020
4.32	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	Cheniere	8-K	4.1	5/18/2016
4.33	Form of 7.000% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.32 above)	Cheniere	8-K	4.1	5/18/2016
4.34	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	Cheniere	8-K	4.1	12/9/2016
4.35	Form of 5.875% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.34 above)	Cheniere	8-K	4.1	12/9/2016
4.36	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	CCH	8-K	4.1	5/19/2017
4.37	Form of 5.125% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.36 above)	CCH	8-K	4.1	5/19/2017
4.38	Third Supplemental Indenture, dated as of September 6, 2019, among CCH, as issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as Guarantors, and The Bank of New York Mellon, as Trustee	CCH	8-K	4.1	9/12/2019
4.39	Fourth Supplemental Indenture, dated as of November 13, 2019, among CCH, as issuer, CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	11/13/2019
4.40	Indenture, dated as of August 20, 2020, among CCH, as issuer, and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	8/21/2020
4.41	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	Cheniere Partners	8-K	4.1	9/18/2017
4.42	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	Cheniere Partners	8-K	4.2	9/18/2017
4.43	Form of 5.250% Senior Note due 2025 (Included as Exhibit A-1 to Exhibit 4.42 above)	Cheniere Partners	8-K	4.2	9/18/2017

4.44	Second Supplemental Indenture, dated as of September 11, 2018, among Cheniere Partners, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	9/12/2018
4.45	Form of 5.625% Senior Note due 2026 (Included as Exhibit A-1 to Exhibit 4.44 above)	Cheniere Partners	8-K	4.1	9/12/2018
4.46	Third Supplemental Indenture, dated as of September 12, 2019, among Cheniere Partners, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere Partners	8-K	4.1	9/12/2019
4.47	Fourth Supplemental Indenture, dated as of November 5, 2020, between Cheniere Partners, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere	10-Q	4.4	11/6/2020
4.48	Indenture, dated as of September 27, 2019, among CCH, as issuer, and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	9/30/2019
4.49	Indenture, dated as of October 17, 2019, among CCH, as issuer, and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and The Bank of New York Mellon, as trustee	CCH	8-K	4.1	10/18/2019
4.50	Description of the Registrant’s Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	Cheniere	10-K	4.45	2/25/2020
10.1	LNG Terminal Use Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and SPLNG	Cheniere	10-Q	10.1	11/15/2004
10.2	Amendment of LNG Terminal Use Agreement, dated January 24, 2005, by and between Total LNG USA, Inc. and SPLNG	Cheniere	10-K	10.40	3/10/2005
10.3	Amendment of LNG Terminal Use Agreement, dated June 15, 2010, by and between Total Gas & Power North America, Inc. and SPLNG	Cheniere	10-Q	10.2	8/6/2010
10.4	Omnibus Agreement, dated September 2, 2004, by and between Total LNG USA, Inc. and SPLNG	Cheniere	10-Q	10.2	11/15/2004
10.5	Parent Guarantee, dated as of November 5, 2004, by Total S.A. in favor of SPLNG	Cheniere	10-Q	10.3	11/15/2004
10.6	Letter Agreement, dated September 11, 2012, between Total Gas & Power North America, Inc. and SPLNG	Cheniere Partners	10-Q	10.1	11/2/2012
10.7	LNG Terminal Use Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and SPLNG	Cheniere	10-Q	10.4	11/15/2004
10.8	Amendment to LNG Terminal Use Agreement, dated December 1, 2005, by and between Chevron U.S.A. Inc. and SPLNG	SPLNG	S-4	10.28	11/22/2006
10.9	Amendment of LNG Terminal Use Agreement, dated June 16, 2010, by and between Chevron U.S.A. Inc. and SPLNG	Cheniere	10-Q	10.3	8/6/2010
10.10	Omnibus Agreement, dated November 8, 2004, between Chevron U.S.A. Inc. and SPLNG	Cheniere	10-Q	10.5	11/15/2004
10.11	Guaranty Agreement, dated as of December 15, 2004, from ChevronTexaco Corporation to SPLNG	SPLNG	S-4	10.12	11/22/2006
10.12	Second Amended and Restated LNG Terminal Use Agreement, dated as of July 31, 2012, between SPL and SPLNG	SPLNG	8-K	10.1	8/6/2012
10.13	Letter Agreement, dated May 28, 2013, by and between SPL and SPLNG	SPLNG	10-Q	10.1	8/2/2013
10.14	Guarantee Agreement, dated as of July 31, 2012, by Cheniere Partners in favor of SPLNG	SPLNG	8-K	10.2	8/6/2012
10.15†	Cheniere Energy, Inc. 2011 Incentive Plan (as amended through April 13, 2017)	Cheniere	10-Q	10.1	8/8/2017
10.16†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2011 Incentive Plan (US - New Hire)	Cheniere	8-K	10.13	8/10/2012
10.17†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2011 Incentive Plan (UK - New Hire)	Cheniere	8-K	10.14	8/10/2012
10.18†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grades 18-20)	Cheniere	10-K	10.37	2/24/2017
10.19†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grades 18-20)	Cheniere	10-Q	10.2	5/4/2017

10.20†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 17)	Cheniere	10-K	10.38	2/24/2017
10.21†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 17)	Cheniere	10-Q	10.3	5/4/2017
10.22†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Key Executive Severance Plan)	Cheniere	10-K	10.39	2/24/2017
10.23†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Severance Pay Plan)	Cheniere	10-K	10.40	2/24/2017
10.24†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 16 and Below)	Cheniere	10-Q	10.4	5/4/2017
10.25†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Singapore) (Grade 16 and Below)	Cheniere	10-Q	10.5	5/4/2017
10.26†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grades 18-20)	Cheniere	10-K	10.41	2/24/2017
10.27†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grades 18-20)	Cheniere	10-Q	10.7	5/4/2017
10.28†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 17)	Cheniere	10-K	10.42	2/24/2017
10.29†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 17)	Cheniere	10-Q	10.8	5/4/2017
10.30†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Key Executive Severance Plan)	Cheniere	10-K	10.43	2/24/2017
10.31†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grade 16 and Below — Severance Pay Plan)	Cheniere	10-K	10.44	2/24/2017
10.32†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (UK) (Grade 16 and Below)	Cheniere	10-Q	10.9	5/4/2017
10.33†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (2019 Grades 18-20)	Cheniere	10-K	10.35	2/26/2019
10.34†	Cheniere Energy, Inc. 2014-2018 Long-Term Cash Incentive Program	Cheniere	10-Q	10.9	4/30/2015
10.35†	Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (US - Executive)	Cheniere	10-Q	10.10	4/30/2015
10.36†	Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (US - Non-Executive)	Cheniere	10-Q	10.11	4/30/2015
10.37†	Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (UK - Executive)	Cheniere	10-Q	10.12	4/30/2015
10.38†	Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (UK - Non-Executive)	Cheniere	10-Q	10.13	4/30/2015
10.39†	Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (US - Consultant)	Cheniere	10-Q	10.14	4/30/2015
10.40†	Form of Phantom Unit Award Agreement under the Cheniere Energy, Inc. 2015 Long-Term Cash Incentive Plan (UK - Consultant)	Cheniere	10-Q	10.15	4/30/2015
10.41†	Cheniere Energy, Inc. 2020 Incentive Plan	Cheniere (SEC No. 333-238261)	S-8	4.9	5/14/2020

10.42†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2020 Incentive Plan (Director)	Cheniere	8-K	10.4	5/20/2020
10.43†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan (Grades 18-20 Executive Officer)	Cheniere	8-K	10.5	5/20/2020
10.44†	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan (Grades 18-20)	Cheniere	8-K	10.6	5/20/2020
10.45†*	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan				
10.46†*	Amended and Restated Cheniere Energy, Inc. Key Executive Severance Pay Plan (Effective November 4, 2020) and Summary Plan Description				
10.47†	Employment Agreement between the Company and Jack A. Fusco, dated May 12, 2016	Cheniere	8-K	10.1	5/12/2016
10.48†	Employment Agreement Amendment between the Company and Jack Fusco, dated August 15, 2019	Cheniere	8-K	10.1	8/15/2019
10.49†	Cheniere Energy, Inc. Amended and Restated Retirement Policy, dated effective August 15, 2019	Cheniere	10-K	10.49	2/25/2020
10.50†	Form of Indemnification Agreement for officers of the Company	Cheniere	8-K	10.2	5/20/2020
10.51†	Form of Indemnification Agreement for directors of the Company	Cheniere	8-K	10.1	5/20/2020
10.52†	Letter Agreement between the Company and Douglas Shanda, dated November 1, 2019	Cheniere	8-K	10.1	11/1/2019
10.53†	Letter Agreement, dated August 5, 2020, between Cheniere Energy, Inc. and Michael J. Wortley	Cheniere	8-K	10.1	8/6/2020
10.54	Third Amended and Restated Common Terms Agreement, among SPL, as borrower, the Secured Debt Holder Group Representatives party thereto, the Secured Hedge Representatives party thereto, the Secured Gas Hedge Representatives party thereto and Société Générale, as the Common Security Trustee and the Intercreditor Agent	Cheniere	8-K	10.2	3/23/2020
10.55	Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, among SPL, as borrower, certain subsidiaries of SPL, The Bank of Nova Scotia, as Senior Facility Agent, Société Générale, as the Common Security Trustee, the issuing banks and lenders from time to time party thereto and other participants	SPL	8-K	10.1	3/23/2020
10.56	Third Amended and Restated Accounts Agreement, among SPL, certain subsidiaries of SPL, Société Générale, as the Common Security Trustee, and Citibank, N.A. as the Accounts Bank	SPL	8-K	10.3	3/23/2020
10.57	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	Cheniere	8-K	10.1	12/2/2014
10.58	Amended and Restated Term Loan Facility Agreement, dated May 22, 2018, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, the lenders party thereto from time to time and Société Générale as the Term Loan Facility Agent	Cheniere	8-K	10.1	5/24/2018
10.59	Amended and Restated Common Terms Agreement, dated May 22, 2018, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, Société Générale, as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, and Société Générale as Intercreditor Agent, and any other facility lenders party thereto from time to time	Cheniere	8-K	10.2	5/24/2018

10.60	First Amendment to the Amended and Restated Common Terms Agreement, dated as of November 28, 2018, by and among CCH, CCL, CCP and Corpus Christi Pipeline GP, LLC, Société Générale as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, each other Facility Agent on behalf of its respective Facility Lenders, and Société Générale as Intercreditor Agent	Cheniere	10-K	10.6	2/26/2019
10.61	Second Amendment to the Amended and Restated Common Terms Agreement, dated as of August 30, 2019, by and among CCH, CCL, CCP and Corpus Christi Pipeline GP, LLC Société Générale as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, each other Facility Agent on behalf of its respective Facility Lenders, and Société Générale as the Intercreditor Agent	Cheniere	10-Q	10.4	11/1/2019
10.62*	Third Amendment to the Amended and Restated Common Terms Agreement, dated as of November 8, 2019, by and among CCH, CCL, CCP and Corpus Christi Pipeline GP, LLC, Société Générale as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, each other Facility Agent on behalf of its respective Facility Lenders, and Société Générale as the Intercreditor Agent				
10.63*	Fourth Amendment to the Amended and Restated Common Terms Agreement, dated as of November 26, 2019, by and among CCH, CCL, CCP and Corpus Christi Pipeline GP, LLC, Société Générale as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, each other Facility Agent on behalf of its respective Facility Lenders, and Société Générale as the Intercreditor Agent				
10.64*	Fifth Amendment to the Amended and Restated Common Terms Agreement, dated as of November 16, 2020, by and among CCH, CCL, CCP and Corpus Christi Pipeline GP, LLC, Société Générale as Term Loan Facility Agent, The Bank of Nova Scotia as Working Capital Facility Agent, each other Facility Agent on behalf of its respective Facility Lenders, and Société Générale as the Intercreditor Agent				
10.65	Amended and Restated Common Security and Account Agreement, dated May 22, 2018, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, the Senior Creditor Group Representatives, Société Générale as the Intercreditor Agent, Société Générale as Security Trustee and Mizuho Bank, Ltd as the Account Bank	Cheniere	8-K	10.3	5/24/2018
10.66	First Amendment to the Amended and Restated Common Security and Account Agreement, dated as of November 28, 2018, by and among CCH, CCL, CCP and Corpus Christi Pipeline GP, LLC, the Senior Creditor Group Representatives, Société Générale as Intercreditor Agent for the Facility Lenders and any Hedging Banks, Société Générale as Security Trustee, and Mizuho Bank, Ltd. as Account Bank	Cheniere	10-K	10.62	2/26/2019
10.67	Second Amendment to Common Security and Account Agreement, dated as of August 30, 2019, by and among the Company, CCL, CCP, Corpus Christi Pipeline GP, LLC, the Senior Creditor Group Representatives, Société Générale as Intercreditor Agent for the Facility Lenders and any Hedging Banks, Société Générale as Security Trustee, and Mizuho Bank, Ltd; as Account Bank	Cheniere	10-Q	10.5	11/1/2019
10.68*	Third Amendment to Common Security and Account Agreement, dated as of November 16, 2020, by and among CCH, CCL, CCP, Corpus Christi Pipeline GP, LLC, the Senior Creditor Group Representatives, Société Générale as Intercreditor Agent for the Facility Lenders and any Hedging Banks, Société Générale as Security Trustee, and Mizuho Bank, Ltd; as Account Bank				
10.69	Amended and Restated Pledge Agreement, dated May 22, 2018, among CCH HoldCo I and Société Générale as Security Trustee	Cheniere	8-K	10.4	5/24/2018

10.70	Amended and Restated Equity Contribution Agreement, dated May 22, 2018, among CCH and the Company	Cheniere	8-K	10.5	5/24/2018
10.71	Amended and Restated Working Capital Facility Agreement, dated June 29, 2018, among CCH, CCP, Corpus Christi Pipeline GP, LLC, CCL, the lenders party thereto from time to time, the issuing banks party thereto from time to time, the Bank of Nova Scotia as Working Capital Facility Agent, and Société Générale as Security Trustee	Cheniere	8-K	10.1	7/2/2018
10.72	The Amended and Restated Revolving Credit Agreement, dated as of December 13, 2018, among the Company, the Lenders and Issuing Banks party thereto, Goldman Sachs Bank USA, Morgan Stanley Senior Funding, Inc. and SG Americas Securities, LLC, as Coordinating Lead Arrangers, and Société Générale, as Administrative Agent	Cheniere	8-K	10.1	12/17/2018
10.73	Amendment to Amended and Restated Revolving Credit Agreement, dated as of September 27, 2019, among the Company, Société Générale as administrative agent, and the Requisite Lenders party thereto	Cheniere	10-Q	10.7	11/1/2019
10.74	Credit Agreement, dated June 18, 2020, among the Company, the Lenders party thereto, Société Générale, as Administrative Agent, and the other agents and arrangers party thereto from time to time	Cheniere	8-K	10.1	6/19/2020
10.75	Amendment No. 2 to the Amended and Restated Revolving Credit Agreement, dated as of June 18, 2020, among the Company, Société Générale as administrative agent, and the Requisite Lenders party thereto	Cheniere	10-Q	10.11	8/6/2020
10.76	Credit and Guaranty Agreement, dated as of May 29, 2019, among the Cheniere Partners, as Borrower, certain subsidiaries of the Cheniere Partners, as Subsidiary Guarantors, the lenders from time to time party thereto, MUFG Bank, Ltd., as Administrative Agent and Sole Coordinating Lead Arranger, and certain arrangers and other participants	Cheniere	8-K	10.1	6/3/2019
10.77	Amended and Restated Senior Working Capital Revolving Credit and Letter of Credit Reimbursement Agreement, dated September 4, 2015, as amended by (a) Third Omnibus Amendment, dated as of May 23, 2018; (b) Fourth Omnibus Amendment, dated as of September 17, 2018; and (c) Fifth Omnibus Amendment, Consent and Waiver, dated as of May 29, 2019, 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	Cheniere	10-Q	10.2	8/8/2019
10.78	Registration Rights Agreement, dated as of September 22, 2020, between the Company, as issuer, and Credit Suisse Securities (USA) LLC, for itself and as representative of the purchasers	Cheniere	8-K	10.1	9/22/2020
10.79	Registration Rights Agreement, dated as of May 8, 2020, between SPL and Morgan Stanley & Co. LLC	SPL	8-K	10.1	5/8/2020
10.80	Registration Rights Agreement, dated as of November 13, 2019, among CCH and CCL, CCP and Corpus Christi Pipeline GP, LLC, as guarantors, and BofA Securities, Inc., for itself and as representative of the purchasers	CCH	8-K	10.1	11/13/2019
10.81	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil, Gas and Chemicals, Inc. (Portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment.)	Cheniere	8-K	10.1	11/9/2018

10.82	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: the Change Order CO-00001 Modifications to Insurance Language Change Order, dated June 3, 2019	Cheniere	10-Q	10.6	8/8/2019
10.83	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00002 Fuel Provisional Sum Closure, dated July 8, 2019, (ii) the Change Order CO-00003 Currency Provisional Sum Closure, dated July 8, 2019, (iii) the Change Order CO-00004 Foreign Trade Zone, dated July 2, 2019, (iv) the Change Order CO-00005 NGPL Gate Access Security Coordination Provisional Sum, dated July 17, 2019, (v) the Change Order CO-00006 Alternate to Adams Valves, dated August 14, 2019, (vi) the Change Order CO-00007 E-1503 to HRU Permanent Drain Piping, dated August 14, 2019, (vii) the Change Order CO-00008 Differing Subsurface Soil Conditions - Train 6 ISBL, dated August 27, 2019, (viii) the Change Order CO-00009 LNG Berth 3, dated September 25, 2019 and (iv) the Change Order CO-00010 Cold Box Redesign and Addition of Inspection Boxes on Methane Cold Box, dated September 16, 2019	Cheniere	10-Q	10.10	11/1/2019
10.84	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between the Company and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00011 Insurance Provisional Sum Interim Adjustment, dated October 1, 2019 and (ii) the Change Order CO-00012 Replacement of Timber Piles with Pre-Stressed Concrete Piles, dated October 30, 2019	Cheniere	10-K	10.88	2/25/2020
10.85	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00013 Cost to Comply with SPL FTZ (FTZ entries, bonded transports and receipts for AG Pipe Spools Only), dated February 10, 2020, (ii) the Change Order CO-00014 Permanent Access Road to Third Berth, dated February 10, 2020, (iii) the Change Order CO-00015 Modifications to Schedule Bonus Language, dated February 10, 2020, (iv) the Change Order CO-00016 LNG Berth 3 LNTP No 3, dated January 31, 2020 and (v) the Change Order CO-00017 Construction Doc Fender Guards and LP Fuel Gas Overpressure Interlock, dated March 18, 2020	Cheniere	10-Q	10.6	4/30/2020
10.86	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00018 Electrical Studies for GTG Grid Modification, dated April 2, 2020, (ii) the Change Order CO-00019 Third Berth - Change in 5kV Electrical Tie-In, dated April 30, 2020, (iii) the Change Order CO-00020 LNG Berth 3 LNTP No. 4, dated May 4, 2020, (iv) the Change Order CO-00021 Train 6 P1601 A/B/ Flange Changes, dated May 27, 2020 and (v) the Change Order CO-00022 Train 6 H2S Skid Modifications to Level Transmitters & GTG Pressure Range Change on PT-573 A/B, dated June 4, 2020	Cheniere	10-Q	10.9	8/6/2020

10.87	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00023 Third Berth Vapor Fence Provisional Sum Scope Removal and Closeout, dated June 22, 2020, (ii) the Change Order CO-00024 Train 6 Thermowell Upgrades, dated June 22, 2020, (iii) the Change Order CO-00025 Third Berth Bubble Curtain, dated June 22, 2020, (iv) the Change Order CO-00026 Third Berth Fuel Provisional Sum Closure Change Order, dated July 14, 2020, (v) the Change Order CO-00027 Third Berth Currency Provisional Sum Closure Change Order, dated July 20, 2020, (vi) the Change Order CO-00028 Train 6 Hot Oil WHRU PSV Bypass, dated August 11, 2020 and (vii) the Change Order CO-00029 Change in Law IMO 2020 Regulatory Change – Low Sulphur Emissions on Marine Vessels, dated August 25, 2020	Cheniere	10-Q	10.2	11/6/2020
10.88*	Change order to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Sabine Pass LNG Stage 4 Liquefaction Facility, dated November 7, 2018, by and between the SPL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00030 Third Berth Soil Preparation Provisional Sum Interim Adjustment Change Order, dated September 16, 2020, (ii) the Change Order CO-00031 Provisional Sum Consolidation (PAB, Taxes & Insurance), dated October 2, 2020, (iii) the Change Order CO-00032 COVID-19 Impacts, dated October 2, 2020, (iv) the Change Order CO-00033 Third Berth - Jetty Building (00A-4041) - Clean Agent System, dated November 2, 2020 and (v) the Change Order CO-00034 Vanessa Spare Valves, dated November 18, 2020				
10.89	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.)	Cheniere	10-K/A	10.23	4/27/2018
10.90	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00001 Stage 2 EPC Agreement Revised Table A-2, dated May 18, 2018, (ii) the Change Order CO-00002 Stage 2 EPC Agreement Amended and Restated Attachment C, dated May 18, 2018, (iii) the Change Order CO-00003 Fuel Provisional Sum Adjustment, dated May 24, 2018, (iv) the Change Order CO-00004 Currency Provisional Sum Adjustment, dated May 29, 2018, (v) the Change Order CO-00005 JT Valve Modifications, dated July 10, 2018 and (vi) the Change Order CO-00006 Tank B Soil Conditions, International Building Code, and East Jetty Marine Facility Schedule Acceleration, dated September 5, 2018 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.)	Cheniere	10-Q	10.3	11/8/2018
10.91	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00007 Tell-Tale Signs, Additional Tie-Ins, and System Inspection Isometrics, dated October 15, 2018, (ii) the Change Order CO-00008 Insurance Provisional Sum Interim Adjustment, dated November 19, 2018 and (iii) the Change Order CO-00009 Traffic and Logistics Impacts Due to Enforcement of Electronic Logging Devices, dated November 28, 2018 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment.)	Cheniere	10-K	10.117	2/26/2019

10.92	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-000010 OSHA Handrail Requirement Changes Impact, dated January 25, 2019, (ii) the Change Order CO-00011 Differing Soil Conditions - Train 3, dated March 7, 2019 and (iii) the Change Order CO-00012 Tank B Logo Deletion, dated March 25, 2019 (Portions of this exhibit have been omitted.)	Cheniere	10-Q	10.2	5/9/2019
10.93	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-000013 Section 232 Steel and Aluminum Tariffs & Anti-dumping (ADA) and Countervailing Duties (CVD), dated May 2, 2019, (ii) the Change Order CO-00014 Tank B Jump-over Tie-In Interface - Long Lead Items, dated May 2, 2019 and (iii) the Change Order CO-00015 Section 232 Steel and Aluminum Tariffs & Anti-dumping (ADA) and Countervailing Duties (CVD) Q1_2019, dated June 4, 2019 (Portions of this exhibit have been omitted.)	Cheniere	10-Q	10.4	8/8/2019
10.94	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-000016 Tank B Jump-over Tie-In (Part 1) and Deletion of East Jetty Shroud, dated August 5, 2019, (ii) the Change Order CO-00017 H2S Removal Skid PSVs Modifications and Revision to Chemical Cleaning Milestones, dated August 5, 2019 and (iii) the Change Order CO-00018 Cold Box Redesign Major Permanent Plant Materials and Ethylene Cold Box's E-1504 Partial Mockup, dated September 6, 2019 (Portions of this exhibit have been omitted.)	Cheniere	10-Q	10.9	11/1/2019
10.95	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00019 Aircraft Warning Lights, dated September 23, 2019, (ii) the Change Order CO-00020 Section 232 Steel and Aluminum Tariffs & Anti-dumping (ADA) and Countervailing Duties (CVD) Q2_2019, dated October 8, 2019, (iii) the Change Order CO-00021 Spare Transition Joints for Potential Future Cold Box Modifications, dated October 8, 2019, (iv) the Change Order CO-00022 Modification of the Train 3 Methane Cold Box, dated December 6, 2019 and (v) the Change Order Co-00023 Section 232 Steel & Aluminum Tariffs & Anti-dumping (ADA) and Countervailing Duties (CVD) Q3_2019, dated December 10, 2019 (Portions of this exhibit have been omitted.)	Cheniere	10-K	10.95	2/25/2020

10.96	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00024 East Jetty Cooldown Line & Simultaneous Ship Loading, dated January 6, 2020, (ii) the Change Order CO-00025 East Jetty Manual Gas Sampler, dated January 7, 2020, (iii) the Change Order CO-00026 Study for Adding Valve Actuator for E-W Jetty Flow Segregation, dated January 8, 2020, (iv) the Change Order CO-00027 Tank B Isolation of Proposed Fourth In-Tank LNG Pump - Long Lead Items, dated January 8, 2020, (v) the Change Order CO-00028 Tank B Rundown Line (Part I), dated January 31, 2020, (vi) the Change Order CO-00029 9% Nickel and Cryogenic Rebar Provisional Sum Closeout, dated February 18, 2020 and (vii) the Change Order CO-00030 Additional Valve for Isolation in CCL Stage 2 to CCL Stage 3 from Tank B, dated February 18, 2020 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.7	4/30/2020
10.97	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00031 Tank B Isolation of Proposed 4th In-Tank LNG Pump (Post Start-Up of Tank B) - EPC, dated April 1, 2020, (ii) the Change Order CO-00032 Train 3 Thermowell Upgrades, dated April 3, 2020, (iii) the Change Order CO-00033 Tank B Rundown Line (Part 2) Development Costs, dated April 29, 2020 and (iv) the Change Order CO-00034 Train 3 UPS Modification of MV Motors, dated May 21, 2020 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.10	8/6/2020
10.98	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00035 Spill Conveyance from Flare KO Drum Area, dated July 6, 2020, (ii) the Change Order CO-00036 Tie-Ins for Heavy Hydrocarbon Removal Modifications (E&P) Rev 1, dated August 5, 2020, (iii) the Change Order CO-00037 Train 3 PV-16002 Valve Trim Change - Rev 1, dated August 14, 2020, (iv) the Change Order CO-00038 Hot Oil Overpressure Relief, dated August 14, 2020, (v) the Change Order CO-00039 Supply of Nitrogen for Commissioning Units 16, 17 and Feed Gas, dated August 20, 2020 and (vi) the Change Order CO-00040 COVID-19 Impacts, dated September 15, 2020 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.3	11/6/2020
10.99*	Change orders to the Amended and Restated Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Stage 2 Liquefaction Facility, dated as of December 12, 2017, between CCL and Bechtel Oil, Gas and Chemicals, Inc.: (i) the Change Order CO-00041 Additional O&M Support (COVID-19), dated October 2, 2020 and (ii) the Change Order CO-00042 Replacement of Owner Spare Parts, dated December 31, 2020 (Portions of this exhibit have been omitted)				
10.100	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)	Cheniere Partners	8-K	10.1	11/21/2011
10.101	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)	Cheniere Partners	10-Q	10.1	5/3/2013

10.102	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)	SPL (SEC File No. 333-215882)	S-4	10.3	2/3/2017
10.103	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between SPL (Seller) and GAIL (India) Limited (Buyer)	Cheniere Partners	8-K	10.1	12/12/2011
10.104	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and GAIL (India) Limited (Buyer)	Cheniere Partners	10-K	10.18	2/22/2013
10.105	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between SPL (Seller) and BG Gulf Coast LNG, LLC (Buyer)	Cheniere Partners	8-K	10.1	1/26/2012
10.106	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between SPL (Seller) and Korea Gas Corporation (Buyer)	Cheniere Partners	8-K	10.1	1/30/2012
10.107	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and Korea Gas Corporation (Buyer)	Cheniere Partners	10-K	10.19	2/22/2013
10.108	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated August 5, 2014, between SPL (Seller) and Cheniere Marketing, LLC (Buyer)	SPL	8-K	10.1	8/11/2014
10.109	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)	SPL	10-K	10.14	2/24/2017
10.110	LNG Sale and Purchase Agreement (FOB), dated April 1, 2014, between CCL (Seller) and Endesa Generación, S.A. (Buyer)	Cheniere	8-K	10.1	4/2/2014
10.111	LNG Sale and Purchase Agreement (FOB), dated April 7, 2014, between CCL (Seller) and Endesa S.A. (Buyer)	Cheniere	8-K	10.1	4/8/2014
10.112	Assignment and Amendment Agreement, dated April 7, 2014, among Endesa Generación S.A., Endesa S.A. and CCL	Cheniere	10-Q	10.3	5/1/2014
10.113	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated July 23, 2015, between Endesa S.A. (Buyer) and CCL (Seller)	Cheniere	10-Q	10.9	10/30/2015
10.114	Amendment No. 2 of LNG Sale and Purchase Agreement (FOB), dated July 23, 2015, between Endesa S.A. (Buyer) and CCL (Seller)	Cheniere	10-Q	10.10	10/30/2015
10.115	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated March 20, 2015, between CCL (Seller) and PT Pertamina (Persero) (Buyer)	Cheniere	10-Q	10.5	4/30/2015
10.116	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	CCH	S-4	10.22	1/5/2017
10.117	Amendment No. 2 of Amended and Restated LNG Sale and Purchase Agreement, dated June 27, 2019, between CCL and PT Pertamina (Persero)	CCH	10-Q	10.1	11/1/2019
10.118	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)	Cheniere	8-K	10.1	6/2/2014
10.119	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 27, 2018, between CCL (Seller) and Gas Natural Fenosa LNG GOM, Limited (Buyer)	Cheniere	10-Q	10.6	5/4/2018
10.120	Amended and Restated Base LNG Sale and Purchase Agreement (FOB), dated as of November 28, 2014, between CCL and Cheniere Marketing International LLP	CCH	S-4	10.32	1/5/2017
10.121	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	CCH	S-4	10.33	1/5/2017

10.122	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	CCH	S-4	10.34	1/5/2017
10.123	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	Cheniere	10-Q	10.7	11/6/2007
10.124	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	Cheniere Partners	8-K	10.1	8/6/2012
10.125	Fourth Amended and Restated Agreement of Limited Partnership of Cheniere Partners, dated February 14, 2017	Cheniere Partners	8-K	3.1	2/21/2017
10.126	Amended and Restated Limited Liability Company Agreement of Cheniere GP Holding Company, LLC, dated December 13, 2013	Cheniere Holdings	8-K	10.3	12/18/2013
10.127	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	Cheniere	8-K	99.1	8/24/2015
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				
104*	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)				

(1) Exhibits are incorporated by reference to reports of Cheniere (SEC File No. 001-16383), Cheniere Partners (SEC File No. 001-33366), Cheniere Holdings (SEC File No. 001-36234), SPL (SEC File No. 333-192373), CCH (SEC File No. 333-215435) and SPLNG (SEC File No. 333-138916), as applicable, unless otherwise indicated.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

CONDENSED STATEMENTS OF OPERATIONS
(in millions)

	Year Ended December 31,		
	2020	2019	2018
General and administrative expense	$ 20	$ 17	$ 8
Other income (expense)			
Interest expense, net of capitalized interest	(155)	(141)	(128)
Interest income	—	1	—
Loss on modification or extinguishment of debt	(50)	—	—
Equity in income of subsidiaries	77	490	607
Total other income (expense)	(128)	350	479
Income (loss) before income taxes	(148)	333	471
Income tax benefit	63	315	—
Net income (loss) attributable to common stockholders	$ (85)	$ 648	$ 471

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

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CHENIERE ENERGY, INC.

CONDENSED BALANCE SHEETS
(in millions)

	December 31,	
	2020	2019
ASSETS		
Current assets		
Cash and cash equivalents	$ —	$ 55
Restricted cash	1	—
Other current assets	1	1
Total current assets	2	56
Property, plant and equipment, net	30	17
Operating lease assets, net	22	24
Debt issuance and deferred financing costs, net	15	16
Investments in subsidiaries	2,324	1,139
Deferred tax assets, net	381	315
Total assets	$ 2,774	$ 1,567
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities		
Current operating lease liabilities	$ 5	$ 5
Current debt	103	—
Other current liabilities	37	9
Total current liabilities	145	14
Long-term debt, net	2,790	1,534
Non-current operating lease liabilities	30	33
Stockholders' deficit	(191)	(14)
Total liabilities and stockholders' deficit	$ 2,774	$ 1,567

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,		
	2020	2019	2018
Net cash provided by operating activities	$ (285)	$ 74	$ 48
Cash flows from investing activities			
Property, plant and equipment, net	(13)	(2)	—
Distribution from (investment in) subsidiaries	(481)	842	568
Net cash provided by investing activities	(494)	840	568
Cash flows from financing activities			
Proceeds from issuance of debt	4,778	—	—
Repayments of debt	(3,143)	—	—
Debt issuance and deferred financing costs	(57)	—	(13)
Debt modification or extinguishment costs	(29)	—	—
Distribution and dividends to non-controlling interest	(626)	(591)	(576)
Payments related to tax withholdings for share-based compensation	(43)	(19)	(20)
Repurchase of common stock	(155)	(249)	—
Other	—	—	(7)
Net cash used in financing activities	725	(859)	(616)
Net increase in cash, cash equivalents and restricted cash	(54)	55	—
Cash, cash equivalents and restricted cash—beginning of period	55	—	—
Cash, cash equivalents and restricted cash—end of period	$ 1	$ 55	$ —

Balances per Condensed Balance Sheets:

	December 31,	
	2020	2019
Cash and cash equivalents	$ —	$ 55
Restricted cash	1	—
Total cash, cash equivalents and restricted cash	$ 1	$ 55

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 at the net amount attributable to Cheniere. 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 income from operations of the affiliates is reported on a net basis as investment in affiliates (equity in income of subsidiaries).

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.

Recent Accounting Standards

In August 2020, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2020-06, *Debt—Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging—Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*. This guidance simplifies the accounting for convertible instruments primarily by eliminating the existing cash conversion and beneficial conversion models within Subtopic 470-20, which will result in fewer embedded conversion options being accounted for separately from the debt host. The guidance also amends and simplifies the calculation of earnings per share relating to convertible instruments. This guidance is effective for annual periods beginning after December 15, 2021, including interim periods within that reporting period, with earlier adoption permitted for fiscal years beginning after December 15, 2020, including interim periods within that reporting period, using either a full or modified retrospective approach. We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures.

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*. This guidance primarily provides temporary optional expedients which simplify the accounting for contract modifications to existing debt agreements expected to arise from the market transition from LIBOR to alternative reference rates. The optional expedients were available to be used upon issuance of this guidance but we have not yet applied the guidance because we have not yet modified any of our existing contracts for reference rate reform. Once we apply an optional expedient to a modified contract and adopt this standard, the guidance will be applied to all subsequent applicable contract modifications until December 31, 2022, at which time the optional expedients are no longer available.

NOTE 2—DEBT

As of December 31, 2020 and 2019, our debt consisted of the following (in millions):

	December 31, 2020	December 31, 2019
Long-term debt:		
4.625% Senior Secured Notes due 2028 (the "2028 Cheniere Senior Secured Notes"), convertible notes, revolving credit facility ("Cheniere Revolving Credit Facility") and term loan facility ("Cheniere Term Loan Facility")	$ 3,145	$ 1,903
Unamortized premium, discount and debt issuance costs, net	(355)	(369)
Total long-term debt, net	2,790	1,534
Current debt:		
Current portion of 4.875% Convertible Unsecured Notes due 2021 ("2021 Cheniere Convertible Unsecured Notes")	104	$ —
Unamortized premium, discount and debt issuance costs, net	(1)	$ —
Total current debt	103	—
Total debt, net	$ 2,893	$ 1,534

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2020 (in millions):

Years Ending December 31,	Principal Payments
2021	$ 476
2022	—
2023	148
2024	—
2025	—
Thereafter	2,625
Total	$ 3,249

Issuances and Repayments

The following table shows the issuances and repayments of debt during the year ended December 31, 2020 (in millions):

Issuances and Long-Term Borrowings	Principal Amount Issued	
2028 Cheniere Senior Secured Notes (1)	$	2,000
Cheniere Term Loan Facility		2,323
Cheniere Revolving Credit Facility		455
Year Ended December 31, 2020 total	$	4,778

Repayments, Redemptions and Repurchases	Amount Repaid/ Redeemed/Repurchased	
2021 Cheniere Convertible Unsecured Notes (1)	$	(844)
Cheniere Term Loan Facility (1)		(2,175)
Cheniere Revolving Credit Facility		(455)
Year Ended December 31, 2020 total	$	(3,474)

(1) Proceeds of the 2028 Cheniere Senior Secured Notes, along with $200 million in available cash, were used to prepay approximately $2.1 billion of the outstanding indebtedness of the Cheniere Term Loan Facility, resulting in the recognition of debt extinguishment costs of $16 million for the year ended December 31, 2020. The borrowings under the Cheniere Term Loan Facility, which was entered in June 2020 with available commitments of $2.62 billion and subsequently increased to $2.695 billion in July 2020, were used to (1) redeem the remaining outstanding principal amount of the 2025 CCH HoldCo II Convertible Senior Notes with cash at a price of $1,080 per $1,000 principal amount, (2) repurchase $844 million in aggregate principal amount of outstanding 2021 Cheniere Convertible Unsecured Notes at individually negotiated prices from a small number of investors and (3) pay the related fees and expenses. The redemption of the 2025 CCH HoldCo II Convertible Senior Notes and the repurchase of the 2021 Cheniere Convertible Unsecured Notes resulted in the recognition of debt extinguishment costs of $149 million and a reduction in equity associated with reacquisition of the embedded conversion option of $10 million.

NOTE 3—GUARANTEES

Cheniere has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees and stand-by letters of credit. Cheniere enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. As of December 31, 2020, outstanding guarantees and other assurances aggregated approximately $542 million of varying duration, consisting of parental guarantees. No liabilities were recognized under these guarantee arrangements as of December 31, 2020.

NOTE 4—LEASES

Our leased assets consist primarily of office space and facilities, which are classified as operating leases.

The following table shows the classification and location of our right-of-use assets and lease liabilities on our Condensed Balance Sheets (in millions):

		December 31,			
	Condensed Balance Sheet Location	2020		2019	
Right-of-use assets—Operating	Operating lease assets, net	$	22	$	24
Total right-of-use assets		$	22	$	24
Current operating lease liabilities	Current operating lease liabilities	$	5	$	5
Non-current operating lease liabilities	Non-current operating lease liabilities		30		33
Total lease liabilities		$	35	$	38

The following table shows the classification and location of our lease cost on our Condensed Statements of Operations (in millions):

		Year Ended December 31,	
	Condensed Statements of Operations Location	2020	2019
Operating lease cost (1)	General and administrative expense	$ 10	$ 9

(1) Includes $4 million and $3 million of variable lease costs paid to the lessor during the years ended December 31, 2020 and 2019, respectively.

Future annual minimum lease payments for operating leases as of December 31, 2020 are as follows (in millions):

Years Ending December 31,	Operating Leases (1)
2021	$ 7
2022	8
2023	8
2024	7
2025	6
Thereafter	7
Total lease payments	43
Less: Interest	(8)
Present value of lease liabilities	$ 35

The following table shows the weighted-average remaining lease term (in years) and the weighted-average discount rate for our operating leases:

	December 31,	
	2020	2019
Weighted-average remaining lease term (in years)	5.7	6.6
Weighted-average discount rate	6.6%	5.5%

The following table includes other quantitative information for our operating leases (in millions):

	Year Ended December 31,	
	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 7	$ 7
Right-of-use assets obtained in exchange for new operating lease liabilities	5	1

NOTE 5—SHARE REPURCHASE PROGRAM

On June 3, 2019, we announced that our Board authorized a 3-year, $1.0 billion share repurchase program. The following table presents information with respect to repurchases of common stock during the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
Aggregate common stock repurchased	2,875,376	4,000,424
Weighted average price paid per share	$ 53.88	$ 62.27
Total amount paid (in millions)	$ 155	$ 249

As of December 31, 2020, we had up to $596 million of the share repurchase program available. Under the share repurchase program, repurchases can be made from time to time using a variety of methods, which may include open market purchases, privately negotiated transactions or otherwise, all in accordance with the rules of the SEC and other applicable legal requirements. The timing and amount of any shares of our common stock that are repurchased under the share repurchase program will be determined by our management based on market conditions and other factors. The share repurchase program does not obligate us to acquire any particular amount of common stock, and may be modified, suspended or discontinued at any time or from time to time at our discretion.

NOTE 6 —SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2020	2019	2018
Cash paid during the period for interest, net of amounts capitalized	$ 45	$ 36	$ 32
Non-cash investing and financing activities:			
Non-cash capital distribution (1)	79	490	607
Additional interest in Cheniere Holdings acquired	—	—	702

(1) Amounts represent equity income of affiliates.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
(in millions)

	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Deductions	Balance at end of period
Year Ended December 31, 2020					
Allowance for credit losses or doubtful accounts on receivables and contract assets	$ —	$ 7	$ —	$ —	$ 7
Deferred tax asset valuation allowance	196	(6)	—	—	190
Year Ended December 31, 2019					
Allowance for credit losses or doubtful accounts on receivables and contract assets	$ 30	$ 16	$ —	$ (46)	$ —
Deferred tax asset valuation allowance	686	(490)	—	—	196
Year Ended December 31, 2018					
Allowance for credit losses or doubtful accounts on receivables and contract assets	$ 30	$ —	$ —	$ —	$ 30
Deferred tax asset valuation allowance	806	(120)	—	—	686

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 23, 2021

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 23, 2021
/s/ Zach Davis Zach Davis	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2021
/s/ Leonard E. Travis Leonard E. Travis	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2021
/s/ G. Andrea Botta G. Andrea Botta	Chairman of the Board	February 23, 2021
/s/ Vicky A. Bailey Vicky A. Bailey	Director	February 23, 2021
/s/ Nuno Brandolini Nuno Brandolini	Director	February 23, 2021
/s/ David B. Kilpatrick David B. Kilpatrick	Director	February 23, 2021
/s/ Sean Klimczak Sean Klimczak	Director	February 23, 2021
/s/ Andrew Langham Andrew Langham	Director	February 23, 2021
/s/ Donald F. Robillard, Jr. Donald F. Robillard, Jr.	Director	February 23, 2021
/s/ Neal A. Shear Neal A. Shear	Director	February 23, 2021
/s/ Andrew Teno Andrew Teno	Director	February 23, 2021

APPENDIX

Consolidated Adjusted EBITDA and Distributable Cash Flow

The following table reconciles our actual Consolidated Adjusted EBITDA and Distributable Cash Flow to Net income (loss) attributable to common stockholders for 2020 (in billions):

		2020
Net income (loss) attributable to common stockholders	$	(0.09)
Net income attributable to non-controlling interest		0.59
Income tax provision		0.04
Interest expense, net of capitalized interest		1.53
Depreciation and amortization expense		0.93
Other expense, financing costs, and certain non-cash operating expenses		0.96
Consolidated Adjusted EBITDA	**$**	**3.96**
Distributions to Cheniere Partners non-controlling interest		(0.63)
SPL and Cheniere Partners cash retained and interest expense		(1.41)
Cheniere interest expense, income tax and other		(0.58)
Cheniere Distributable Cash Flow	**$**	**1.35**

Note: Totals may not sum due to rounding. For full year 2020, Distributable Cash Flow excludes cash payments of $103 million related to the settlement of forward starting interest rate derivatives.

We have not made any forecast of net income on a run rate basis, which would be the most directly comparable financial measure under GAAP, in part because net income includes the impact of derivative transactions, which cannot be determined at this time, and we are unable to reconcile differences between run rate Consolidated Adjusted EBITDA and Distributable Cash Flow and net income.

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 B. Kilpatrick
President, Kilpatrick Energy Group

Sean Klimczak
Senior Managing Director and
Global Head of Infrastructure,
The Blackstone Group L.P.

Andrew Langham
General Counsel, Icahn Enterprises L.P.

Donald F. Robillard, Jr.
President of Robillard Consulting, LLC,
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 the Advisory Committee,
Onyxpoint Global Management LP

Andrew Teno
Portfolio Manager, Icahn Capital

Senior Management

Jack A. Fusco
President and Chief Executive Officer

Anatol Feygin
Executive Vice President and
Chief Commercial Officer

Sean N. Markowitz
Executive Vice President, Chief Legal Officer
and Corporate Secretary

Corey Grindal
Executive Vice President, Worldwide Trading

Zach Davis
Senior Vice President and
Chief Financial Officer

David Craft
Senior Vice President, Engineering
and Construction

Scott Culberson
Senior Vice President, Gas Supply

Michael Dove
Senior Vice President, Shared Services

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

Aaron Stephenson
Senior Vice President, Operations

Len Travis
Senior Vice President and Chief Accounting Officer

Hilary Ware
Senior Vice President and
Chief Human Resources Officer

Tim Wyatt
Senior Vice President,
Corporate Development and Strategy

Eric Bensaude
Managing Director, Commercial Operations
and Portfolio Optimization

Ramzi Mroueh
Managing Director, Origination

Officers

Ari Aziz
Vice President and General Manager

Randy Bhatia
Vice President, Investor Relations

Eben Burnham-Snyder
Vice President, Public Affairs

Khary Cauthen
Vice President, Federal Government Affairs

Rina Chang
Vice President, Environmental,
Regulatory Projects and Managing Counsel

Lisa Cohen
Vice President and Treasurer

Robin Dane
Chief Risk Officer

Tony Eaton
Vice President, Project Development
and Execution

Robert Fee
Vice President, International Affairs and Climate

Matthew Healey
Vice President, Finance and Planning

Maas Hinz
Vice President and General Manager

William L. Knittle
Vice President, Supply Chain Management

Scott Mills
Vice President, Mid Office

Tom Myers
Vice President, Health, Safety
and Environmental

Julie Nelson
Vice President, State Government Affairs

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

Florian Pintgen
Vice President, Commercial Operations

Mitch Price
Vice President and Chief Security Risk Officer

Ryan Schleicher
Vice President, Origination

David Slack
Vice President, Corporate Controller

Brandon Smith
Vice President and Chief Information Officer

Robert Smith
Vice President, Regulatory Affairs

Sam White
Vice President, Commercial Structuring

Sean Bunk
Assistant General Counsel and Assistant
Corporate Secretary

Taylor Johnson
Assistant General Counsel, Commercial

Omer Chadha
Director, Tax

Contacts & Advisors

Cheniere Energy, Inc
700 Milam, Suite 1900, Houston, TX 77002
Tel: (713) 375-5000 | Fax: (713) 375-6000

Stock Exchange Listing
NYSE American: LNG

Transfer Agent
Computershare Trust Company, N.A.
P.O. Box 43078, Providence, RI 02940-3078
Tel: (800) 962-4284 | Fax: (303) 262-0600

Independent Accountants
KPMG LLP, Houston, TX

Investor Relations
Tel: (713) 375-5100
Email: investor@cheniere.com

Website
www.cheniere.com

CHENIERE

Cheniere Energy, Inc. provides clean, secure, and affordable LNG to the world.
We conduct our business safely and responsibly, delivering a reliable, competitive,
and integrated source of LNG to our customers.

HOUSTON - LONDON - SINGAPORE - BEIJING - TOKYO - WASHINGTON DC
SABINE PASS - CORPUS CHRISTI

www.cheniere.com