CHENIERE ENERGY, INC.

2022 ANNUAL REPORT

RELIABILITY

OPERATIONAL EXCELLENCE

638
CARGOES EXPORTED

>2,300
TBTU EXPORTED

~72%
VOLUMES DELIVERED TO EUROPE

SEAMLESS EXECUTION

~$1.4B
NET INCOME

~$11.6B
CONSOLIDATED ADJUSTED EBITDA[1]

~$8.7B
DISTRIBUTABLE CASH FLOW[1]

CAPITAL ALLOCATION

INVESTMENT GRADE RATED CHENIERE

>$5.4B
LONG-TERM DEBT REPAID/REDEEMED

~$1.4B
SHARES REPURCHASED

$1.45
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK

>180 MT LONG-TERM CONTRACTS SIGNED IN 2022
EXTENDING AS FAR AS 2050

FOB – DES – IPM | GLOBALLY DIVERSE COUNTERPARTIES

engie ARC RESOURCES LTD. equinor PetroChina eog resources posco Chevron ptt

CLIMATE & SUSTAINABILITY LEADERSHIP

CARGO EMISSIONS TAGS™

GMP Oil And Gas Methane Partnership 2.0

MIDSTREAM QMRV

~45 MT LIQUEFACTION PLATFORM
10+ MT UNDER CONSTRUCTION

Potential to double existing capacity

CORPUS CHRISTI LIQUEFACTION

CCL Stage 3 FID in June 2022

Midscale Trains 8 & 9 in pre-filing process with FERC

SABINE PASS LIQUEFACTION

Train 6 Substantial Completion in February 2022

Third Berth Substantial Completion in October 2022

~20 mtpa SPL Expansion Project in pre-filing process with FERC

Fellow shareholders,

2022 was an unprecedented year for energy markets around the world, defined by historic volatility and disruption, driven by a significant under-investment in energy infrastructure in key markets and exacerbated by geopolitical unrest. 2022 highlighted the criticality of a secure, flexible and affordable energy system, the longevity and value of the LNG market in general, and Cheniere specifically, as we completed our initial 9-Train platform ahead of schedule and began construction on Corpus Christi Stage 3, our next phase of growth. Throughout the year, our company achieved significant milestones in terms of development, execution, commercial, operations and financial results - all of which enabled Cheniere to answer the global call for reliable energy supply and pursue further accretive growth at both Sabine Pass and Corpus Christi.

Volatility in global gas markets developed during the second half of 2021 and persisted throughout 2022 as geopolitical conflict and other factors further constrained markets, pushing international gas prices to unprecedented levels during the year. The resulting uncertainty felt throughout the world highlighted the importance of energy security, and we continued to witness a structural shift to natural gas as a flexible, reliable, cleaner-burning energy source. Our thoughts and prayers remain with the people of Ukraine and broader Europe in these uncertain times as we focus on maintaining safe and reliable operations in order to reliably provide our much-needed LNG.

11%+
of Global Liquefaction Capacity

Cheniere's operational reliability enabled us to answer Europe's call for LNG supply when it was most needed. In fact, over 10% of Europe's[1] natural gas imports in 2022 were produced at Sabine Pass or Corpus Christi, representing approximately 72% of the volumes we produced. While 2021 showcased the power of the Cheniere platform, 2022 demonstrated its reliability during a critical time in energy markets across the globe. As the second largest LNG operator in the world, we have produced over 2,650 cargoes of LNG since inception, which have been delivered to 39 different countries and regions around the world. However, the Cheniere story is just getting started, as we position the company for the future while creating long-term value for our stakeholders.

We navigated a volatile market, solidifying Cheniere's leadership in the global LNG industry while demonstrating Cheniere's growth potential.

Heading into 2022, we foresaw market tightness in Europe driven by short-term supply and demand dynamics. However, the Russian invasion of Ukraine in 2022 amplified the market's imbalance well beyond our earlier estimates. Our fundamental outlook for the LNG industry remains largely unchanged since 2021, as we believe the demand for new capacity will be predominantly underpinned by Asia, specifically from China, India and Southeast Asian demand centers, as their economies grow and require more – and cleaner – energy for decades to come.

#1 Supplier
of LNG to Europe Representing **~10%** of EU Gas Imports[2]

Our commercial momentum during the year supports this view, as nearly 40% of the long-term aggregate volumes for which we signed long-term contracts in 2022 were with Asian counterparties. Nevertheless, the majority of our LNG volumes in 2022 landed in Europe, as the region needed to offset reduced Russian gas supply. Europe's ability to replenish its natural gas inventories ahead of winter was made possible largely thanks to the destination flexibility of our LNG, most of which is sold under long-term, free-on-board sale and purchase agreements that provide our customers the right to direct cargoes to the delivery point of their choosing. This contract structure allows market signals to influence the flow of LNG volumes, enabling LNG to reach the markets of the highest need, illustrating a primary advantage of US LNG, which Cheniere pioneered.

Despite the elevated volatility throughout the year, our business remains based upon stable long-term, take-or-pay style cash flows from creditworthy counterparties. Our diverse contract and counterparty portfolio demonstrates our ability to construct long-term, flexible LNG solutions tailored to our customers, enabled by our first mover advantages and ability to adapt to evolving market needs. In 2022 alone, we signed over 10 million tonnes per annum (mtpa) of long-term contracts representing an aggregate of over 180 million tonnes of LNG, with over 40 million tonnes extending through 2050. These contracts include free-on-board, delivered ex-ship and Integrated Production Marketing (IPM) agreements with counterparties that include North American producers, Asian and European end-use utilities, as well as global portfolio players.

39 Countries & Regions
Delivered to from Cheniere

While many of these contracts served to underpin the Corpus Christi Stage 3 project, several are tied to our future expansion. We believe the LNG market will need to nearly double its current capacity by 2040 in order to meet forecasted demand. This outlook would require an additional 180+ mtpa of new capacity, extending the global call for LNG for decades to come and reinforcing my confidence in the future growth of the Cheniere platform.

We remained focused on safety, operational excellence, and seamless execution, yielding record operating and financial results for the year.

Our development and execution accomplishments are a testament to the relentless dedication of the Cheniere team and our valued engineering, procurement and construction (EPC) partnership with Bechtel. During the year, we completed Train 6 at Sabine Pass, safely and over a year ahead of the guaranteed schedule, which enabled us to bring much needed new LNG volumes to market. We also completed the third marine berth at Sabine Pass, which further enhanced the flexibility and utilization of our facility. While 2022 represented an inflection point for Cheniere, marking the completion of our initial 9-train platform, we also unveiled our long-term ambitions to double our existing liquefaction capacity through further disciplined, accretive growth projects, leveraging our scale and significant infrastructure positions at both Sabine Pass and Corpus Christi. In February 2022, we issued a limited notice to proceed (LNTP) to Bechtel for Corpus Christi Stage 3, which was followed by a positive final investment decision (FID) and full notice to proceed (FNTP) in June. Issuing LNTP early provided cost benefits as well as construction schedule advantages – by year end, we had invested over $1.3 billion into Corpus Christi Stage 3 and look forward to reinforcing our execution track record on that project.

Top-Quartile Safety Record
0.05 Total Recordable Incident Rate (TRIR)[3]

At the beginning of 2022, I challenged the Cheniere team to maximize production as safely and responsibly as possible in order to provide much-needed LNG to the market. Our team was able to bring Train 6 at Sabine Pass to full utilization ahead of schedule by leveraging the experience gained placing our first 8 trains into service. This same expertise also enabled us to optimize our maintenance schedule in order to further exceed our production forecast for the year. Throughout the year, we maintained an average utilization rate of over 90% across our two facilities, while sustaining our safety-first culture in achieving a record low annual Total Reportable Incident Rate (TRIR) of 0.05.

The product of our market-leading reliability was the production of 638 LNG cargoes, which were delivered to customers across 32 different countries and regions around the world. Across our two facilities, we loaded over 2,300 TBtu of LNG and achieved a daily production record of over 7 TBtu of LNG produced in November. These achievements, coupled with elevated international gas prices and seamless execution, necessitated four consecutive raises to our full year 2022 Adjusted EBITDA[1] and Distributable Cash Flow[1] guidance, increasing the midpoint of each by over $5 billion, and resulted in record Net Income, Consolidated Adjusted EBITDA[1] and Distributable Cash Flow[1] metrics for the year that surpassed these guidance ranges.

These results enabled accelerated achievement of our capital allocation plan, and in September we announced our revised capital allocation plan – our '20/20 vision.'

Revised Long-Term Capital Allocation Plan

We efficiently deployed capital throughout the year, enhancing the long-term value of our company while delivering meaningful shareholder returns.

Our revised long-term capital allocation plan – our '20/20 vision' of \$20 billion of available cash through 2026 and \$20 per share of run-rate distributable cash flow – is built upon the foundation of our previous plan and is designed to achieve and maintain investment grade credit metrics through cycles, further return capital to shareholders over time, and continue to invest in accretive growth beyond Corpus Christi Stage 3. As part of the revised plan, we increased our share repurchase authorization by \$4.0 billion for an additional three years beginning in the third quarter, lowered our consolidated long-term leverage target to approximately 4.0x, and increased the dividend by 20% beginning in the third quarter, targeting a ~10% annual dividend growth rate through the middle of this decade.

In 2022, we prepaid over \$5.4 billion of long-term indebtedness, repurchased an aggregate of over 9.3 million shares of common stock for approximately \$1.4 billion, and declared dividends in aggregate of \$1.45 per share of common stock for the year. As mentioned, we made a positive FID with respect to our 10+ mtpa Corpus Christi Stage 3 project in June, and by August we began the pre-filing process with the Federal Energy Regulatory Commission (FERC) for two additional midscale trains adjacent to the Corpus Christi Stage 3 project. We have also begun development of additional liquefaction capacity across both of our sites with potential to double our existing platform to approximately 90 mtpa. In February of 2023, we initiated the pre-filing process with the FERC for the Sabine Pass Expansion Project, which is designed to include up to three large-scale liquefaction trains with expected total nominal production capacity of approximately 20 mtpa.

13

Credit Rating Upgrades Across Cheniere Complex

As a result of our accelerated deleveraging, we received 13 distinct credit rating upgrades across our corporate structure throughout 2022 and into early 2023. Most importantly, we received investment grade ratings at both of our corporate level entities, and now all of our entities at both the corporate and project levels are eligible for investment grade indices. Achieving investment grade ratings has been a longstanding goal of our company, as it positions Cheniere for the future and signifies the long-term value of the enterprise. With our accelerated progress on capital allocation, we have demonstrated the power of the Cheniere platform to execute on deleveraging, shareholder returns and disciplined, accretive growth.

We progressed our efforts to ensure the sustainability of our business while supporting the communities in which we live, work and serve.

As the title of our 2022 corporate responsibility report, *Acting Today, Securing Tomorrow,* suggests, we have positioned Cheniere for the future as we create value for our stakeholders, including through our environmental, social, governance (ESG) initiatives.

CARGO EMISSIONS TAGS™

Launched Cargo Emissions Tags for Long-Term FOB & DES Customers

Throughout the year, the Cheniere team continued to lead in accordance with our T.R.A.I.N.S. (Teamwork, Respect, Accountability, Integrity, Nimble, and Safety) values, encouraging development and promoting inclusivity, both inside and outside of the workplace. In addition to our continued investment in our people throughout the year, the Cheniere team supported our communities with over 15,000 hours of volunteering, approximately \$5.6 million of direct giving and over \$200,000 of matching and in-kind gifts. Building upon our Cheniere Thurgood Marshall College Fund (TMCF) scholarship program that we introduced in 2021, we partnered with Texan Southern University to engage directly with students attending Historically Black Colleges and Universities in our communities. These programs are part of our \$1 million commitment to promoting diversity, equity and inclusion (DEI) in the areas where we live and work. Our "One Team, One Goal" strategy for enhancing our DEI initiatives focuses on promoting a cohesive and collaborative work environment for all of our employees across our 6 global offices and 2 sites.

Throughout the year, we adhered to our fundamental approach to climate and sustainability – to remain actionable, not aspirational – leading on data-driven transparency surrounding greenhouse gas

>15,000 hours
of Employee Volunteer Time

emissions throughout the LNG value chain, consistent with our foundational climate and sustainability principles of science, transparency, operational excellence and supply chain. In April, we launched our collaboration with midstream companies, technology providers and academic institutions to quantify, measure, report and verify (QMRV) greenhouse gas emissions at natural gas gathering, processing, transmission, and storage systems specific to our supply chain. This collaboration builds upon our existing QMRV study with several of our upstream suppliers, as well as our LNG shipping study, in support of our Cargo Emissions tags, which we successfully launched in June. Our Cargo Emissions tags provide our long-term customers with estimated greenhouse gas emissions data associated with each LNG cargo we produce. In October, we announced our membership in the United Nations Environment Programme's (UNEP) Oil and Gas Methane Partnership (OGMP) 2.0, a comprehensive, measurement-based reporting framework intended to improve the accuracy and transparency of methane emissions reporting in the oil and gas sector. Joining OGMP 2.0 is consistent with our climate strategy to leverage technologies to measure emissions across our supply chain and promote transparency in reporting in order to inform actionable emissions reduction strategies.

Our company-wide commitment to ESG is further evidenced by the increased allocation of our corporate scorecard, which determines part of the annual compensation of every employee, to the achievement of specific ESG metrics and milestones, including safety. We are committed to ensuring the alignment of our vision with that of our communities, employees and the broader world.

I am incredibly proud of what our team accomplished in 2022 and the role Cheniere played in support of our customers, employees and stakeholders. I am excited to embark on this next chapter of the Cheniere story as we pursue expansions of both Sabine Pass and Corpus Christi, while continuing to enhance the value of the Cheniere platform in 2023.

+49%
Total Return for Shareholders in 2022

As always, thank you for your continued support of Cheniere.

Sincerely,

Jack A. Fusco
President and CEO

(1) A definition of these non-GAAP measures and a reconciliation to Net income (loss) attributable to common stockholders, the most comparable U.S. GAAP measure, is included in the appendix. (2) Excluding Turkey. (3) TRIR Top Quartile is based on the latest BLS data available (2017) for companies with 1,000+ employees and various NAICS codes.

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, 2022

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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 $33.4 billion as of June 30, 2022.

As of February 17, 2023, the issuer had 243,703,983 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

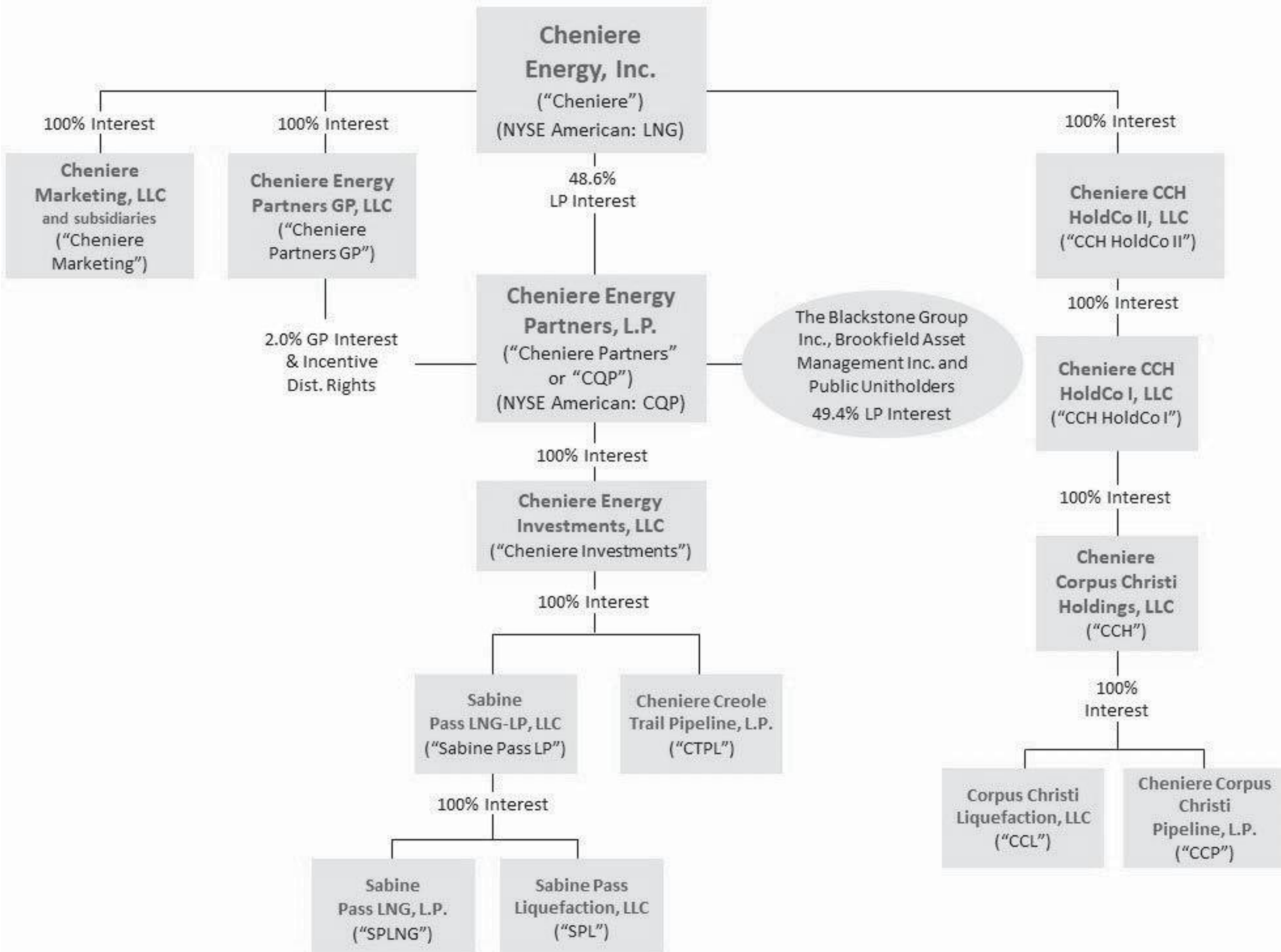
As used in this annual report, the terms listed below have the following meanings:

Common Industry and Other Terms

ASU	Accounting Standards Update
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
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FID	final investment decision
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
IPM agreements	integrated production marketing agreements in which the gas producer sells to us gas on a global LNG index price, less a fixed liquefaction fee, shipping and other costs
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; one British thermal unit measures the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit
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
SOFR	Secured Overnight Financing Rate
SPA	LNG sale and purchase agreement
TBtu	trillion British thermal units; one British thermal unit measures the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit
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, 2022, 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, CQP.

In June 2022, as part of the internal restructuring of Cheniere's subsidiaries, Cheniere contributed its equity interest in Corpus Christi Liquefaction Stage III, LLC ("CCL Stage III"), formerly a wholly owned direct subsidiary of Cheniere, to CCH, and CCL Stage III was subsequently merged with and into CCL, the surviving entity of the merger and a wholly owned subsidiary of CCH.

CAUTIONARY STATEMENT
REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical or present facts or conditions, included herein or incorporated herein by reference are “forward-looking statements.” Included among “forward-looking statements” are, among other things:

- statements that we expect to commence or complete construction of our proposed LNG terminals, liquefaction facilities, pipeline facilities or other projects, or any expansions or portions thereof, by certain dates, or at all;
- statements regarding future levels of domestic and international natural gas production, supply or consumption or future levels of LNG imports into or exports from North America and other countries worldwide or purchases of natural gas, regardless of the source of such information, or the transportation or other infrastructure or demand for and prices related to natural gas, LNG or other hydrocarbon products;
- statements regarding any financing transactions or arrangements, or our ability to enter into such transactions;
- statements relating to Cheniere’s capital deployment, including intent, ability, extent and timing of capital expenditures, debt repayment, dividends, share repurchases and execution on the capital allocation plan;
- statements regarding our future sources of liquidity and cash requirements;
- 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;
- 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, 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 are the largest producer of LNG in the United States and the second largest LNG operator globally, based on the total operational production capacity of our liquefaction facilities in operation, which totals approximately 45 mtpa as of December 31, 2022.

We own and operate a natural gas liquefaction and export facility located in Cameron Parish, Louisiana at Sabine Pass (the "Sabine Pass LNG Terminal"), one of the largest LNG production facilities in the world, through our ownership interest in and management agreements with CQP, which is a publicly traded limited partnership that we formed in 2007. As of December 31, 2022, we owned 100% of the general partner interest and a 48.6% limited partner interest in CQP. The Sabine Pass LNG Terminal has six operational Trains, with Train 6 having achieved substantial completion on February 4, 2022, for a total operational production capacity of approximately 30 mtpa of LNG (the "SPL Project"). The Sabine Pass LNG Terminal also has three marine berths, with the third berth having achieved substantial completion on October 27, 2022, two of which can accommodate vessels with nominal capacity of up to 266,000 cubic meters, and the third berth which can accommodate vessels with nominal capacity of up to 200,000 cubic meters and operational regasification facilities that include five LNG storage tanks with aggregate capacity of approximately 17 Bcfe and vaporizers with regasification capacity of approximately 4 Bcf/d. The Sabine Pass LNG Terminal also includes a 94-mile pipeline owned by CTPL, a subsidiary of CQP, that interconnects our facilities to several interstate and intrastate pipelines (the "Creole Trail Pipeline").

We also own and operate a natural gas liquefaction and export facility located near Corpus Christi, Texas (the "Corpus Christi LNG Terminal") through CCL, which has natural gas liquefaction facilities consisting of three operational Trains for a total operational production capacity of approximately 15 mtpa of LNG, 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. Additionally, we are constructing an expansion of the Corpus Christi LNG Terminal (the "Corpus Christi Stage 3 Project") for up to seven midscale Trains with an expected total operational production capacity over 10 mtpa of LNG. In June 2022, our board of directors (our "Board") made a positive FID with respect to the Corpus Christi Stage 3 Project and issued a full notice to proceed with construction to Bechtel effective June 16, 2022. In connection with the positive FID, CCL Stage III, through which we were developing and constructing the Corpus Christi Stage 3 Project, was contributed to CCH and subsequently merged with and into CCL, with CCL as the surviving entity of the merger and a wholly owned subsidiary of CCH. We also own and operate through CCP a 21.5-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 existing operational Trains, midscale Trains, storage tanks and marine berths, the "CCL Project").

Our long-term customer arrangements form the foundation of our business and provide us with significant, stable, long-term cash flows. We have contracted substantially all of our anticipated production capacity under SPAs, in which our customers are generally required to pay a fixed fee with respect to the contracted volumes irrespective of their election to cancel or suspend deliveries of LNG cargoes, and under IPM agreements, in which the gas producer sells natural gas to us on a global LNG index price, less a fixed liquefaction fee, shipping and other costs. Through our SPAs and IPM agreements, we have contracted approximately 95% of the total anticipated production from the SPL Project and the CCL Project (collectively, the

"Liquefaction Projects") through the mid-2030s, inclusive of contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project. Excluding contracts with terms less than 10 years and contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project, our SPAs and IPM agreements had approximately 17 years of weighted average remaining life as of December 31, 2022. We also market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL through our integrated marketing function. For further discussion of the contracted future cash flows under our revenue arrangements, see Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

We remain focused on safety, operational excellence and customer satisfaction. Increasing demand for 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. In September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for an expansion adjacent to the CCL Project consisting of two midscale Trains with an expected total production capacity of approximately 3 mtpa of LNG ("CCL Midscale Trains 8 and 9"). The development of CCL Midscale Trains 8 and 9 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 positive FID.

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;
- continuing to secure long-term customer contracts to support our planned expansion, including the FID of potential expansion projects beyond the Corpus Christi Stage 3 Project;
- completing our expansion construction projects safely, on-time and on-budget;
- 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;
- executing our "all of the above" capital allocation strategy, focused on strengthening our balance sheet, funding financially disciplined growth and returning capital to our stockholders; and
- strategically identifying actionable environmental solutions.

Our Business

We shipped our first LNG cargo in February 2016 and as of February 17, 2023, approximately 2,650 cumulative LNG cargoes totaling over 180 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Projects. Our LNG has been shipped to 39 countries and regions around the world.

Below is a discussion of our operations. For further discussion of our contractual obligations and cash requirements related to these operations, refer to Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Sabine Pass LNG Terminal

Liquefaction Facilities

The SPL Project, as described above under the caption General, is one of the largest LNG production facilities in the world with six Trains and three marine berths.

The following summarizes the volumes of natural gas for which we have received approvals from FERC to site, construct and operate the SPL Project and the orders we have received from the DOE authorizing the export of domestically produced LNG by vessel from the Sabine Pass LNG Terminal through December 31, 2050:

	FERC Approved Volume		**DOE Approved Volume**	
	(in Bcf/yr)	*(in mtpa)*	*(in Bcf/yr)*	*(in mtpa)*
FTA countries	1,661.94	33	1,661.94	33
Non-FTA countries	1,661.94	33	1,661.94	33

Natural Gas Supply, Transportation and Storage

SPL has secured natural gas feedstock for the Sabine Pass LNG Terminal through long-term natural gas supply agreements, including an IPM agreement. Additionally, to ensure that SPL is able to transport natural gas feedstock to the Sabine Pass LNG Terminal and manage inventory levels, it has entered into firm pipeline transportation and storage contracts with third parties.

Regasification Facilities

The Sabine Pass LNG Terminal, as described above under the caption General, has operational regasification capacity of approximately 4 Bcf/d and aggregate LNG storage capacity of approximately 17 Bcfe. SPLNG has a long-term, third party TUA for 1 Bcf/d with TotalEnergies Gas & Power North America, Inc. (“TotalEnergies”), under which TotalEnergies is required to pay fixed monthly fees, whether or not it uses the regasification capacity they have reserved. Prior to its cancellation effective December 31, 2022, SPLNG also had a TUA for 1 Bcf/d with Chevron. Approximately 2 Bcf/d of the remaining capacity has been reserved under a TUA by SPL. SPL also has a partial TUA assignment agreement with TotalEnergies, as further described in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Corpus Christi LNG Terminal

Liquefaction Facilities

The CCL Project, as described above under the caption General, includes three Trains and two marine berths and the construction of the Corpus Christi Stage 3 Project with up to seven midscale Trains. Additionally, in September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for CCL Midscale Trains 8 and 9.

The following table summarizes the project completion and construction status of the Corpus Christi Stage 3 Project as of January 31, 2023:

Overall project completion percentage	24.5%
Completion percentage of:	
Engineering	41.3%
Procurement	36.9%
Subcontract work	29.5%
Construction	2.2%
Date of expected substantial completion	2H 2025 - 1H 2027

The following summarizes the volumes of natural gas for which we have received approvals from FERC to site, construct and operate the CCL Project and the orders we have received from the DOE authorizing the export of domestically produced LNG by vessel from the Corpus Christi LNG Terminal through December 31, 2050:

	FERC Approved Volume		DOE Approved Volume	
	(in Bcf/yr)	*(in mtpa)*	*(in Bcf/yr)*	*(in mtpa)*
Trains 1 through 3 of the CCL Project:				
FTA countries	875.16	17	875.16	17
Non-FTA countries	875.16	17	875.16	17
Corpus Christi Stage 3 Project:				
FTA countries	582.14	11.45	582.14	11.45
Non-FTA countries	582.14	11.45	582.14	11.45

Pipeline Facilities

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

Natural Gas Supply, Transportation and Storage

CCL has secured natural gas feedstock for the Corpus Christi LNG Terminal through traditional long-term natural gas supply and IPM agreements. Additionally, to ensure that CCL is able to transport and manage the natural gas feedstock to the Corpus Christi LNG Terminal, it has entered into transportation precedent and other agreements to secure firm pipeline transportation and storage capacity from third parties.

Additionally, as described in Note 18—Other Non-current Assets, Net of our Notes to Consolidated Financial Statements, in June 2022, we acquired a 30% equity interest in ADCC Pipeline, LLC ("ADCC Pipeline") through our wholly owned subsidiary Cheniere ADCC Investments, LLC. ADCC Pipeline will develop, own, construct and operate an approximately 42-mile natural gas pipeline project connecting the Agua Dulce natural gas hub to the CCL Project.

Marketing

We market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL to other customers through Cheniere Marketing, our integrated marketing function. We have, and continue to develop, a portfolio of long-, medium- and short-term SPAs to transport and deliver commercial LNG cargoes to locations worldwide.

Customers

Information regarding our customer contracts can be found in Liquidity and Capital Resources in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. For additional information, see Note 21—Customer Concentration of our Notes to Consolidated Financial Statements.

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,		
	2022	2021	2020
BG Gulf Coast LNG, LLC and affiliates	*	12%	14%
Naturgy LNG GOM, Limited	*	12%	12%
Korea Gas Corporation	*	10%	10%
GAIL (India) Limited	*	*	10%

* Less than 10%

All of the above customers contribute to our LNG revenues through SPA contracts.

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 rigorous 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 the 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. On February 18, 2022, the FERC updated its 1999 Policy Statement on certification of new interstate natural gas facilities and the framework for the FERC's decision-making process, modifying the standards FERC uses to evaluate applications to include, among other things, reasonably foreseeable greenhouse gas emissions that may be attributable to the project and the project's impact on environmental justice communities. On March 24, 2022, the FERC pulled back the Policy Statement, re-issued it as a draft and it remains pending. At this time, we do not expect it to have a material adverse effect on our operations.

We are permitted to make sales of natural gas for resale in interstate commerce pursuant to a blanket marketing certificate granted by the FERC with the issuance of our Certificate of Public Convenience and Necessity 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 its final Order Granting Section 3 Authority ("Order") in April 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, in May 2012, 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. FERC issued written approval to commence site preparation work for the third berth in June 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, is required prior to making any modifications to the Creole Trail Pipeline as it is a regulated, interstate natural gas pipeline. In February 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 construction was completed in 2015. In September 2013, as part of the Application for Trains 5 and 6, 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 CCP filed an application with the FERC for authorization under Section 3 of the NGA to site, construct and operate the Corpus Christi Stage 3 Project at the existing CCL Project and pipeline locations. In November 2019, the FERC authorized the Corpus Christi Stage 3 Project. The Corpus Christi Stage 3 Project consists of the addition of seven midscale Trains and related facilities. The order is not subject to appellate court review. In 2020, the FERC authorized CCP to construct and operate a portion of the Corpus Christi Stage 3 Project (Sinton Compressor Station Unit No. 1) on an interim basis independently from the remaining Corpus Christi Stage 3 Project facilities, which received FERC approval for in-service in December 2020. In September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for CCL Midscale Trains 8 and 9.

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 DOE issued Orders granting authorization to export LNG to FTA countries in April 2020 and to non-FTA countries in March 2022. In October 2021, the FERC issued its Orders Amending Authorization under Section 3 of the NGA. In March 2022, the DOE authorized the export of an additional 152.64 Bcf/yr and 108.16 Bcf/yr of domestically produced LNG by vessel from the Sabine Pass LNG Terminal and the Corpus Christi LNG Terminal, respectively, through December 31, 2050 to non-FTA countries, that were previously authorized for FTA countries only.

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 are 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.

PHMSA performs inspections of pipeline and LNG facilities and has authority to undertake enforcement actions, including issuance of civil penalties up to approximately $258,000 per day per violation, with a maximum administrative civil penalty of approximately $2.6 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, 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 EPA administers the Clean Air Act ("CAA"), 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. The CFTC has enacted a number of regulations pursuant to the Dodd-Frank Act, including the speculative position limit rules. Given the recent enactment of the speculative position limit rules, as well as the impact of other rules and regulations under the Dodd-Frank Act, the impact of such rules and regulations on our business continues to be uncertain, but is not expected to be material.

As required by the Dodd-Frank Act, the CFTC and federal banking regulators also adopted rules requiring 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 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 trading activities, which are primarily established in and operated out of the United Kingdom ("UK"), are subject to a number of European Union ("EU") and UK laws and regulations, including but not limited to:

- the European Market Infrastructure Regulation ("EMIR"), which was designed to increase the transparency and stability of the European Economic Area ("EEA") derivatives markets;
- the Regulation on Wholesale Energy Market Integrity and Transparency ("REMIT"), which prohibits market manipulation and insider trading in EEA wholesale energy markets and imposes various transparency and other obligations on participants active in these markets;
- the Markets in Financial Instruments Directive and Regulation ("MiFID II"), which sets forth a financial services framework across the EEA, including rules for firms engaging in investment services and activities in connection with certain financial instruments, including a range of commodity derivatives; and
- the Market Abuse Regulation ("MAR"), which was implemented to create an enhanced market abuse framework, and which applies to all financial instruments listed or traded on EEA trading venues as well as other over-the-counter ("OTC") financial instruments priced on, or impacting, the trading venue contract.

Following the UK's departure from the EU ("Brexit"), the EU-wide rules that applied to the UK while it was a member of the EU (and during the transition period) have been replicated, subject to certain amendments, to create a parallel set of rules applicable only in the UK. As a result, we are subject to two sets of substantively similar rules based on the same underlying legislation: (i) one set of rules that apply in the EEA (i.e. not including the UK) (the "EEA Rules"); and (ii) one set of rules that apply only in the UK (the "UK Onshored Rules").

To the extent our trading activities have a nexus with the EEA, we comply with the EEA Rules. However, as our trading activities are primarily operated out of the UK, the main rules that impact and apply to us on a day-to-day basis are the UK Onshored Rules.

In particular, under the UK Onshored Rules, firms engaging in investment services and activities under UK MiFID II must be authorized unless an exemption applies, and we qualify for an exemption and therefore do not need to be authorized under UK MiFID II.

In addition to the UK Onshored Rules, we are also subject to a separate, UK-specific regime that is not based on prior EU/EEA legislation. This is primarily set out in the UK's Financial Services and Markets Act 2000 ("FSMA") and Financial Services and Markets Act 2000 (Regulated Activities) Order 2001 ("RAO"), which, among other things, governs the regulation of financial services and markets in the UK, and contains a definitive list of the specified kinds of activities and products that are regulated. Under these UK-specific rules, a firm engaging in regulated activities must be authorized unless an exclusion applies. We qualify under applicable exclusions and therefore are not required to be authorized under the UK FSMA/RAO regime.

On December 30, 2022, the EU enacted regulations, which among other things established a market correction mechanism against excessively high LNG prices and provided for the collection of information though new reporting obligations that would be utilized to provide for a new LNG pricing assessment/benchmark. The applicable regulations are set forth in Council Regulation (EU) 2022/2576-2581. Given the recent enactment of the applicable regulations, the impact of such regulations on our business is uncertain, but is not expected to be material.

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 and Equivalence

As referenced above, the UK withdrew from the EU. A trade deal (the "Deal") was agreed and ratified by both the UK and the EU, avoiding a "no deal" Brexit.

One area notably absent from the Deal was financial services and the issue of whether the UK's financial system will be granted "equivalence" by the EU has not yet been resolved. Moreover, the EU has not adopted a significant number of equivalence decisions concerning the UK following Brexit and is unlikely to pursue a policy of seeking a comprehensive set of equivalence decisions.

Draft legislation has been proposed that, if it becomes law, would change the UK regulatory framework by repealing the UK Onshored Rules and replacing them with new rules. However, at this time it is not possible to determine whether any such actions would have a material impact on our business.

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 can affect the cost and output of operations and may impose substantial penalties for non-compliance and substantial liabilities for pollution, as further described in the risk factor *Existing and future safety, environmental and similar laws and governmental regulations could result in increased compliance costs or additional operating costs or construction costs and restrictions* in Risks Relating to Regulations within Item 1A. Risk Factors. 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

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.

On February 28, 2022, the EPA removed a stay of formaldehyde standards in the National Emission Standards for Hazardous Air Pollutants ("NESHAP") Subpart YYYY for stationary combustion turbines located at major sources of hazardous air pollutant ("HAP") emissions. Owners and operators of lean remix gas-fired turbines and diffusion flame gas-fired turbines at major sources of HAP that were installed after January 14, 2003 were required to comply with NESHAP Subpart YYYY by March 9, 2022. 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.

We are supportive of regulations reducing greenhouse gas ("GHG") emissions over time. Since 2009, the EPA has promulgated and finalized multiple GHG emissions regulations related to reporting and reductions of GHG emissions from our facilities. The EPA has proposed additional new regulations to reduce methane emissions from both new and existing sources within the Crude Oil and Natural Gas source category that impact our assets and our supply chain.

From time to time, Congress has considered proposed legislation directed at reducing GHG emissions. On August 16, 2022, President Biden signed H.R. 5376(P.L. 117-169), the Inflation Reduction Act of 2022 ("IRA") which includes a charge on methane emissions above a certain methane intensity threshold for facilities that report their GHG emissions under the EPA's Greenhouse Gas Emissions Reporting Program ("GHGRP") Part 98 ("Subpart W") regulations. The charge starts at $900 per metric ton of methane in 2024, $1,200 per metric ton in 2025, and increasing to $1,500 per metric ton in 2026 and beyond. At this time, we do not expect it to have a material adverse effect on our operations, financial condition or results of operations.

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). The CWA regulatory programs, including the Section 404 dredge and fill permitting program and Section 401 water quality certification program carried out by the states, are frequently the subject of shifting agency interpretations and legal challenges, which at times can result in permitting delays.

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 Migratory Bird Treaty Act, the CWA and the Oil Pollution Act, prohibit certain activities that may adversely affect endangered or threatened animal, fish and plant species and/or their designated habitats, wetlands, or other natural resources. If one of our LNG terminals or pipelines 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.

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 and Competition

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 extent of energy security needs in the EU and elsewhere, the rate of fuel switching for power generation from coal, nuclear or oil to natural gas and other overarching factors such as global economic growth and the pace of any transition from fossil-based systems of energy production and consumption to renewable energy sources. 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. Market participants 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, significant amounts of money are being invested across Europe, Asia and Latin America in natural gas projects under construction, and more continues to be earmarked to planned projects globally. In Europe, there are various plans to install more than 80 mtpa of import capacity over the near-term to secure access to LNG and displace Russian gas imports. In India, there are nearly 12,000 kilometers of gas pipelines under construction to expand the gas distribution network and increase access to natural gas. And in China, billions of U.S. dollars have already been invested and hundreds of billions of U.S. dollars are expected to be further invested all along the natural gas value chain to decrease harmful emissions.

As a result of these dynamics, we expect gas and LNG to continue to play an important role in satisfying energy demand going forward. In its fourth quarter 2022 forecast, Wood Mackenzie Limited ("WoodMac") forecasts that global demand for LNG will increase by approximately 53%, from 388.5 mtpa, or 18.6 Tcf, in 2021, to 595.7 mtpa, or 28.6 Tcf, in 2030 and to 677.8 mtpa or 32.5 Tcf in 2040. In its fourth quarter 2022 forecast, WoodMac also forecasts LNG production from existing operational facilities and new facilities already under construction will be able to supply the market with approximately 537 mtpa in 2030, declining to 490 mtpa in 2040. This could result in a market need for construction of an additional approximately 59 mtpa of LNG production by 2030 and about 187 mtpa by 2040. As a cleaner burning fuel with 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 Project are competitive with new proposed projects globally and we are well-positioned to capture a portion of this incremental market need.

We have limited exposure to oil price movements as we have contracted a significant portion of our LNG production capacity under long-term sale and purchase agreements indexed to Henry Hub. These agreements contain fixed fees that are required to be paid even if the customers elect to cancel or suspend delivery of LNG cargoes. Through our SPAs and IPM agreements, we have contracted approximately 95% of the total anticipated production from the Liquefaction Projects through the mid-2030s, inclusive of contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project. Excluding contracts with terms less than 10 years and contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project, our SPAs and IPM agreements had approximately 17 years of weighted average remaining life as of December 31, 2022.

Competition

Despite the long term nature of our SPAs, when SPL, CCL or our integrated marketing function need to replace or amend any existing SPA or enter into new SPAs, they will compete with each other and other natural gas liquefaction projects throughout the world on the basis of price per contracted volume of LNG at that time. Revenues associated with any incremental volumes, including those sold by our integrated marketing function, 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 LNG markets than us.

Corporate Responsibility

As described in Market Factors and Competition, 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. Our vision is to provide clean, secure and affordable energy to the world. This vision underpins our focus on responding to the world's shared energy challenges—expanding the global supply of clean and affordable energy, improving air quality, reducing emissions and supporting the transition to a lower-carbon future. Our approach to corporate responsibility is guided by our Climate and Sustainability Principles: Transparency, Science, Supply Chain and Operational Excellence. In 2022, we published *Acting Now, Securing Tomorrow*, our third Corporate Responsibility ("CR") report, which outlines our focus on sustainability and our performance on key environmental, social and governance ("ESG") metrics. Our CR report is available at www.cheniere.com/our-responsibility/reporting-center. Information on our website, including the CR report, is not incorporated by reference into this Annual Report on Form 10-K. For further discussion on social and governance matters, see Human Capital Resources.

Our climate strategy is to measure and mitigate emissions – to better position our LNG supplies to remain competitive in a lower carbon future, providing energy, economic and environmental security to our customers across the world. To maximize the environmental benefits of our LNG, we believe it is important to develop future climate goals and strategies based on an accurate and holistic assessment of the emissions profile of our LNG, accounting for all steps in the supply chain.

Consequently, we are collaborating with natural gas midstream companies, methane detection technology providers and/or leading academic institutions on life-cycle assessment ("LCA") models, quantification, monitoring, reporting and verification ("QMRV") of GHG research and development projects, co-founding and sponsoring multidisciplinary research and education initiatives led by the University of Texas at Austin in collaboration with Colorado State University and the Colorado School of Mines.

In addition, we commenced providing Cargo Emissions Tags ("CE Tags") to our long-term customers in June 2022. We also joined the Oil and Gas Methane Partnership ("OGMP") 2.0, the United Nations Environment Programme's ("UNEP") flagship oil and gas methane emissions reporting and mitigation initiative in October 2022.

Our total incremental expenditures related to the climate initiatives, including capital expenditures, were not material to our Consolidated Financial Statements during the years ended December 31, 2022, 2021 and 2020. However, as the transition to a lower-carbon economy continues to evolve, as described in Market Factors and Competition, we expect the scope and extent of our future initiatives to evolve accordingly. While we have not incurred material direct capital expenditures related to climate change, we aspire to conduct our business in a safe and responsible manner and are proactive in our management of environmental impacts, risks and opportunities. We face certain business and operational risks associated with physical impacts from climate change, such as potential increases in severe weather events or changes in weather patterns, in addition to transition risks. Please see Item 1A. Risk Factors for additional discussion.

Subsidiaries

Substantially all of our assets are 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, we invest in the core human capital priorities — attracting, engaging and developing diverse talent and building an inclusive and equitable workplace — because they underpin our current and future success and ability to generate long-term value.

As of December 31, 2022, we had 1,551 full-time employees with 1,459 located in the U.S. and 92 located outside of the U.S. (primarily in the UK).

Our strength comes from the collective expertise of our diverse workforce and through our core values of teamwork, respect, accountability, integrity, nimble and safety ("TRAINS"). Our employees help drive our success, build our reputation, establish our legacy and deliver on our commitments to our customers. Through fulfilling career opportunities, training, development and a competitive compensation program, we aim to keep our employees engaged. Our voluntary turnover was 5.1% for 2022.

Our Chief Human Resources Officer oversees human capital management. This includes our approach to talent attraction and retention, rewards and remuneration, employee relations, employee engagement and training and development. Our Chief Compliance and Ethics Officer oversees the diversity, equity and inclusion ("DEI") program. Both officers communicate progress on our programs to our Board quarterly.

Talent Attraction, Engagement and Retention

Our recruitment strategy is focused on attracting diverse and highly skilled talent. We offer competitive compensation and benefits, and work to develop and attract a strong talent pipeline through a range of internship, apprenticeship and vocational programs. We invest in opportunities to help local students and underserved communities gain specialized skills and create local jobs through sponsorship of apprenticeships and internships. On an annual basis, we participate in workforce availability studies in the geographic areas where we operate to ensure representation of the local workforce. 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.

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. Employees are encouraged to share ideas and concerns through multiple feedback channels including engagement surveys, townhalls and hotlines which can be reached anonymously. Insights from these channels are used to develop both company-wide and business unit level talent development plans and training programs.

Compensation and Benefits

We provide robust compensation and benefits programs to our employees. In addition to salaries, all employees are eligible for annual bonuses and stock awards. Benefit plans, which vary by country, include 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. We link our annual incentive program to financial and non-financial performance metrics, including but not limited to, ESG and DEI performance criteria.

Diversity, Equity and Inclusion

We are committed to providing a diverse and inclusive 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. Our Code of Business Conduct and Ethics, our TRAINS values and 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. We are committed to providing fair and equitable employee programs including compensation and benefits. We provide executives and senior management with DEI training and Unconscious Bias training to all employees. In addition, we advanced our "Values in Action" which supports employees in identifying and implementing actions and behaviors that align with our TRAINS values.

Through our targeted recruitment efforts, we attract a variety of candidates with a diversity of backgrounds, skills, experience and expertise. Since 2018, we have had a 26% increase in racially or ethnically diverse employees and a 42% increase in racially or ethnically diverse management. In the past five years, the percentage of female employees has decreased slightly from 27% to 26% and we have had a 3% increase in women in management positions. In 2021, we announced our multiyear commitment to the Thurgood Marshall College Fund of $500,000 in scholarships to students attending selected historically black colleges and universities. We also committed to other scholarships and community efforts furthering our commitment to DEI.

We encourage our employees to leverage their unique backgrounds through involvement in various employee resource groups and employee networks. Groups such as WILS (Women Inspiring Leadership Success), EPN (Emerging Professional Network), Cultural Champions Teams and our newest employee resource group focused on military veterans 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 receive mid-year and annual performance reviews, as well as frequent informal discussions to help meet their career goals. We also conduct annual talent reviews and succession planning sessions to ensure future organizational talent trends are met. To ensure safe, reliable and efficient operations in a highly regulated environment, we offer online and site-specific learning opportunities. We also provide employees, leaders and executives with targeted development programming to solidify internal talent pipelines and succession plans.

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 Chief Executive Officer, 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, 2022, we had two employee recordable injuries and zero contractor recordable injuries. Our total recordable incident rate (employees and contractors combined) was 0.05, placing us in the top quartile of industry benchmarks based on Bureau of Labor safety statistics.

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, nutrition, emotional health and vaccinations, as well as subsidies for fitness devices and gym memberships. We also offer mammography screenings, rooms for nursing mothers and biometric screenings on site.

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 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.

The risk factors in this report are grouped into the following categories:

- Risks Relating to Our Financial Matters;
- Risks Relating to Our Operations and Industry; and
- Risks Relating to Regulations.

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, 2022, we had $1.4 billion of cash and cash equivalents, $1.1 billion of restricted cash and cash equivalents, a total of $7.5 billion of available commitments under our credit facilities and $25.1 billion of total debt outstanding on a consolidated basis (before unamortized premium, discount and debt issuance costs). SPL, CQP, CCH and Cheniere operate with independent capital structures as further detailed in Note 11—Debt of our Notes to Consolidated Financial Statements. We incur, and will incur, significant interest expense relating to financing the assets at the Sabine Pass LNG Terminal and the Corpus Christi LNG Terminal, and we anticipate drawing on current committed facilities and/or incurring additional debt to finance the construction of the Corpus Christi Stage 3 Project and CCL Midscale Trains 8 and 9. 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.

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, 2022, we had SPAs with terms of 10 or more years with a total of 28 different third party customers.

While substantially all of our long-term third party customer arrangements are executed with a creditworthy parent company or secured by a parent company guarantee or other form of collateral, we are nonetheless exposed to credit risk in the event of a customer default that requires us to seek recourse.

Additionally, our long-term SPAs entitle the customer to terminate their contractual obligations upon the occurrence of certain events which include, but are not limited to: (1) if we fail to make available specified scheduled cargo quantities; (2) delays in the commencement of commercial operations; and (3) under the majority of our SPAs, upon the occurrence of certain events of force majeure.

Although we have not had a history of material customer default or termination events, the occurrence of such events are largely outside of our control and may expose us to unrecoverable losses. We may not be able to replace these customer arrangements on desirable terms, or at all, if they are terminated. As a result, our business, contracts, financial condition, operating results, cash flow, liquidity and prospects could be materially and adversely affected.

Our subsidiaries may be restricted under the terms of their indebtedness from making distributions under certain circumstances, which may limit CQP's 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 CQP 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, appropriate reserves have been established for debt service using cash or letters of credit 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 unless, among other requirements, appropriate reserves have been established for debt service using cash or letters of credit and it achieves a historical debt service coverage ratio and fixed projected debt service coverage ratio of at least 1.25:1.00. Prior to completion of the Corpus Christi Stage 3 Project, CCH is also required to confirm that it has sufficient funds, including senior debt commitments, equity funding and projected contracted cash flows from the fixed price component of its third party SPAs, to meet remaining expenditures required for the Corpus Christi Stage 3 Project in order to achieve completion by a specified date certain.

Our subsidiaries' inability to pay distributions to CQP or us or to incur additional indebtedness as a result of the foregoing restrictions in the agreements governing their indebtedness may inhibit CQP's 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.

Our efforts to manage commodity and financial risks through derivative instruments, including our IPM agreements, could adversely affect our earnings reported under GAAP and affect our liquidity.

We use derivative instruments to manage commodity, currency and financial market risks. The extent of our derivative position at any given time depends on our assessments of the markets for these commodities and related exposures. We currently account for our derivatives at fair value, with immediate recognition of changes in the fair value in earnings, other than certain derivatives for which we have elected to apply accrual accounting, as described in Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. Such valuations are primarily valued based on estimated forward commodity prices and are more susceptible to variability particularly when markets are volatile. As described in Results of Operations in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, our net income (loss) for the years ended December 31, 2022 and 2021 includes $5.7 billion and $4.3 billion, respectively, of losses resulting from changes in the fair values of our derivatives, of which substantially all of such losses were related to commodity derivative instruments indexed to international LNG prices, mainly our IPM agreements.

These transactions and other derivative transactions have and may continue to result in substantial volatility in results of operations reported under GAAP, particularly in periods of significant commodity, currency or financial market variability. For certain of these instruments, in the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments involves management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

In addition, our liquidity may be adversely impacted by the cash margin requirements of the commodities exchanges or the failure of a counterparty to perform in accordance with a contract. As of December 31, 2022 and 2021, we had collateral posted with counterparties by us of $134 million and $765 million, respectively, which are included in margin deposits in our Consolidated Balance Sheets.

Restrictions in agreements governing us and our subsidiaries' indebtedness may prevent us and our subsidiaries from engaging in certain beneficial transactions, which could materially and adversely affect us.

In addition to restrictions on the ability of us, CQP, 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.

Any restrictions on the ability to engage in beneficial transactions could materially and adversely affect us.

Our ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Dividends are authorized and determined by our Board in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution;
- Our results of operations and anticipated future results of operations;
- Our financial condition, especially in relation to the anticipated future capital needs of any expansion of our Liquefaction Facilities;
- The level of distributions paid by comparable companies;
- Our operating expenses; and
- Other factors our Board deems relevant.

We expect to continue to pay quarterly dividends to our stockholders; however, our Board may reduce our dividend or cease declaring dividends at any time, including if it determines that our current or forecasted future cash flows provided by our operating activities, after deducting capital expenditures, investments and other commitments, are not sufficient to pay our desired levels of dividends to our stockholders or to pay dividends to our stockholders at all.

Additionally as of December 31, 2022, $3.6 billion of repurchase authority remained under our share repurchase program our Board had authorized. Our share repurchase program does not obligate us to acquire a specific number of shares during any period, and our decision to commence, discontinue or resume repurchases in any period will depend on the same factors that our Board may consider when declaring dividends, among others.

Any downward revision in the amount of dividends we pay to stockholders or the number of shares we purchase under our share repurchase program could have an adverse effect on the market price of our common stock.

Risks Relating to Our Operations and Industry

Catastrophic weather events or other disasters could result in an interruption of our operations, a delay in the construction of our Liquefaction Projects, damage to our Liquefaction Projects and increased insurance costs, all of which could adversely affect us.

Weather events such as major hurricanes and winter storms have caused interruptions or temporary suspension in construction or operations at our facilities or caused minor damage to our facilities. Our risk of loss related to weather events or other disasters is limited by contractual provisions in our SPAs, which can provide under certain circumstances relief from operational events, and partially mitigated by insurance we maintain. Aggregate direct and indirect losses associated with the aforementioned weather events, net of insurance reimbursements, have not historically been material to our Consolidated Financial Statements, and we believe our insurance coverages maintained, existence of certain protective clauses within our SPAs and other risk management strategies mitigate our exposure to material losses. However, future adverse weather events and collateral effects, or other disasters such as explosions, fires, floods or severe droughts, could cause damage to, or interruption of operations at our terminals or related infrastructure, which could impact our operating results, increase insurance premiums or deductibles paid and delay or increase costs associated with the construction and development of the Liquefaction Projects or our other facilities. Our LNG terminal infrastructure and LNG facilities located in or near Corpus Christi, Texas and Sabine Pass, Louisiana are designed in accordance with requirements of 49 Code of Federal Regulations Part 193, *Liquefied Natural Gas Facilities: Federal Safety Standards*, and all applicable industry codes and standards.

Disruptions to the third party supply of natural gas to our pipelines and facilities 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 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, failure to replace contracted firm pipeline transportation capacity on economic terms, or any other reason, our ability to receive natural gas volumes to produce LNG or to continue shipping natural gas from producing regions or to end markets could be adversely impacted. Such disruptions to our third party supply of natural gas may also be caused by weather events or other disasters described in the risk factor *Catastrophic weather events or other disasters could result in an interruption of our operations, a delay in the construction of our Liquefaction Projects, damage to our Liquefaction Projects and increased insurance costs, all of which could adversely affect us.* While certain contractual provisions in our SPAs can limit the potential impact of disruptions, and historical indirect losses incurred by us as a result of disruptions to our third party supply of natural gas have not been material, any significant disruption to our natural gas supply where we may not be protected could result in a substantial reduction in our revenues under our long-term SPAs or other customer arrangements, 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. The supply of natural gas to our Liquefaction Projects to meet our LNG production requirements timely and at sufficient quantities is critical to our operations and the fulfillment of our customer contracts. However, we may not be able to purchase or receive physical delivery of natural gas as a result of various factors, including non-delivery or untimely delivery by our suppliers, depletion of natural gas reserves within regional basins and disruptions to pipeline operations as described in the risk factor *Disruptions to the third party supply of natural gas to our pipelines and facilities could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.* Our risk is in part mitigated by the diversification of our natural gas supply and transport across suppliers and pipelines, and regionally across basins, and additionally, we have provisions within our supplier contracts that provide certain protections against non-performance. Further, provisions within our SPAs provide certain protection against force majeure events. While historically we have not incurred significant or prolonged disruptions to our natural gas supply that have resulted in a material adverse impact to our operations, due to the criticality of natural gas supply to our production of LNG, our failure to purchase or receive physical delivery of sufficient quantities of natural gas under circumstances where we may not be protected could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Our ability to complete development and/or construction of additional Trains, including CCL Midscale Trains 8 and 9, 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 continuously pursue liquefaction expansion opportunities and other projects along the LNG value chain. As described further in Items 1. and 2. Business and Properties, we are currently developing CCL Midscale Trains 8 and 9, which are an additional two midscale Trains with an expected total production capacity of approximately 3 mtpa of LNG. The commercial development of an LNG facility takes a number of years and requires a substantial capital investment that is dependent on sufficient funding and commercial interest, among other factors.

We will require significant additional funding to be able to commence construction of CCL Midscale Trains 8 and 9, and any additional expansion projects, 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 or construction of CCL Midscale Trains 8 and 9 or any additional expansion projects, and we may not be able to complete our business plan, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Cost overruns and delays in the completion of our expansion projects, including the Corpus Christi Stage 3 Project and CCL Midscale Trains 8 and 9, 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.

Our investment decision on the Corpus Christi Stage 3 Project and any potential future expansion of LNG facilities, including CCL Midscale Trains 8 and 9, relies on cost estimates developed initially through front end engineering and design studies. However, due to the size and duration of construction of an LNG facility, the actual construction costs may be significantly higher than our current estimates as a result of many factors, including but not limited to changes in scope, the ability of Bechtel and our other contractors to execute successfully under their agreements, 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 or comply with existing or future environmental or other regulations. 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. Additionally, our SPAs generally provide 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 impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Significant increases in the cost of a liquefaction project beyond the amounts that we estimate could impact the commercial viability of the project as well as 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), thereby negatively impacting our business and limiting our growth prospects. While historically we have not experienced cost overruns or construction delays that have had a significant adverse impact on our operations, factors giving rise to such events in the future may be outside of our control and could have a material adverse effect on our current or future business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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 as discussed throughout our risk factors, 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. Although losses incurred as a result of self insured risk have not been material historically, 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.

We are dependent on our EPC partners and other contractors for the successful completion of the Corpus Christi Stage 3 Project and any potential expansion projects, including CCL Midscale Trains 8 and 9.

Timely and cost-effective completion of the Corpus Christi Stage 3 Project and any potential expansion projects, including CCL Midscale Trains 8 and 9, in compliance with agreed specifications is central to our business strategy and is highly dependent on the performance of our EPC partners, including Bechtel, and our other contractors under their agreements. The ability of our EPC partners 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 Corpus Christi Stage 3 Project and any potential expansion projects, including CCL Midscale Trains 8 and 9, 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 EPC partners 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 Corpus Christi Stage 3 Project and any potential expansion projects, including CCL Midscale Trains 8 and 9, or result in a contractor's unwillingness to perform further work. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement, we would be required to engage a substitute contractor. This would likely result in significant project delays and increased costs, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

There may be impediments to the transport of LNG, such as shortages of LNG vessels worldwide or operational impacts on LNG shipping, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We sell a significant amount of our LNG under delivered at terminal ("DAT") terms requiring delivery to international destinations. To fulfill our transportation requirements, including those under long term SPAs, we depend on the ability to secure chartered vessels often through long term lease arrangements. The construction and delivery of LNG vessels require significant capital and long construction lead times, and we may execute charters several years before the lease arrangements commence.

Although we actively manage our vessel requirements in response to the market and our customer contracts, 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;
- acts of war or piracy;
- 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.

While our chartered vessels are operated by the ship owners and we are exposed to risks outside of our own control, we are generally protected through provisions in our charter agreements from transportation disruptions on the part of the ship owner, including disruptions due to offhire and downtime periods or shipping delays. However, other events outside of our control where we may not be protected may have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Additionally, while our vessel charters allow us to secure fixed rates under long term contracts (in certain cases subject to inflation) and we generally structure our SPAs to recover any increase in such costs, our profitability, particularly relating to our short term or spot LNG sales outside of our SPAs, is largely dependent on the strength of international LNG markets. While historical downturns have not had a material adverse impact to our operations or results, any prolonged weakening of such markets could result in depressed or negative margins. See the risk factor *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 flow, liquidity and prospects* for additional discussion.

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 flow, 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:

- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient LNG tanker capacity;
- weather conditions, including temperature volatility resulting from climate change, and extreme weather events may lead to unexpected distortion in the balance of international LNG supply and demand;
- 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 provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported LNG, natural gas or alternative energy sources, which may reduce the demand for imported LNG and/or natural gas;
- political conditions in customer 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 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 flow, liquidity and prospects.

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

Operations of the 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.

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 LNG from 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 facilities in the United States.

As described in Market Factors and Competition, it is expected that global demand for natural gas and LNG will continue to increase as nations seek more abundant, reliable and environmentally cleaner fuel alternatives to alternative fossil fuel energy sources such as oil and coal. However, as a result of transitions globally from fossil-based systems of energy production and consumption to renewable energy sources, LNG may face increased competition from alternative, cleaner sources of energy as such alternative sources emerge. Additionally, 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 described in Market Factors and Competition, we have contracted through our SPAs and IPM agreements approximately 95% of the total anticipated production from the Liquefaction Projects through the mid-2030s, inclusive of contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project. However, as a result of the factors described above and other factors, the LNG we produce may not remain a long term competitive source of energy internationally, particularly when our existing long term contracts begin to expire. Any significant impediment to the ability to continue to secure long term commercial contracts or deliver LNG from the United States could have a material adverse effect on our customers and 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.

A cyber attack involving our business, operational control systems or related infrastructure, or that of third party pipelines which supply the Liquefaction Facilities, could negatively impact our operations, result in data security breaches, impede the processing of transactions or delay financial or compliance reporting. These impacts could materially and adversely affect our business, contracts, financial condition, operating results, cash flow and liquidity.

The pipeline and LNG industries are increasingly dependent on business and operational control technologies to conduct daily operations. We rely on control systems, technologies and networks to run our business and to control and manage our trading, marketing, pipeline, liquefaction and shipping operations. Cyber attacks on businesses have escalated in recent years, including as a result of geopolitical tensions, and use of the internet, cloud services, mobile communication systems and other public networks exposes our business and that of other third parties with whom we do business to potential cyber attacks, including third party pipelines which supply natural gas to our Liquefaction Facilities. For example, in 2021 Colonial Pipeline suffered a ransomware attack that led to the complete shutdown of its pipeline system for six days. Should a multiple of the third party pipelines which supply our Liquefaction Facilities suffer similar concurrent attacks, the Liquefaction Facilities may not be able to obtain sufficient natural gas to operate at full capacity, or at all. A cyber attack involving our business or operational control systems or related infrastructure, or that of third party pipelines with which we do business, could negatively impact our operations, result in data security breaches, impede the processing of transactions, or delay financial or compliance reporting. These impacts could materially and adversely affect our business, contracts, financial condition, operating results, cash flow and liquidity.

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. We 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, remoteness of our site locations 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.

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

Our facilities at the Sabine Pass LNG Terminal and Corpus Christi LNG Terminal are critical infrastructure and continued to operate during the COVID-19 pandemic through our implementation of workplace controls and pandemic risk reduction measures. While the COVID-19 pandemic, including the Delta and Omicron variants, has had no adverse impact on our on-going operations, the risk of future variants is unknown. While we believe we can continue to mitigate any significant adverse impact to our employees and operations at our critical facilities related to the virus in its current form, the outbreak of a more potent variant or another infectious disease in the future at one or more of our facilities could adversely affect our operations.

Risks Relating to Regulations

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, CCL Midscale Trains 8 and 9 and other facilities, as well as 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.

To date, 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 the Corpus Christi Stage 3 Project, 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 the Corpus Christi Stage 3 Project. In September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for CCL Midscale Trains 8 and 9. To date, the DOE has also issued orders under Section 4 of the NGA authorizing SPL, CCL and the Corpus Christi Stage 3 Project to export domestically produced LNG. Additionally, we hold certificates under Section 7(c) of the NGA that grant us land use rights relating to the situation of our pipelines on land owned by third parties. If we were to lose these rights or be required to relocate our pipelines, our business could be materially and adversely affected.

Authorizations obtained from the FERC, DOE and other federal and state regulatory agencies contain ongoing conditions that we must comply with. We are currently in compliance with such conditions; however, failure to comply or our inability to obtain and maintain existing or newly imposed approvals and permits, filings, which may arise due to factors outside of our control such as a U.S. government disruption or shutdown, political opposition or local community resistance to the siting of LNG facilities due to safety, environmental or security concerns, could impede the operation and construction of our infrastructure. In addition, certain of these governmental permits, approvals and authorizations are or may be subject to rehearing requests, appeals and other challenges. 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. Any impediment 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. If we fail to comply with such regulation, we could be subject to substantial penalties and fines.

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 potential shipper 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 $1.4 million per day for each violation.

Although the FERC has not imposed fines or penalties on us to date, we are exposed to substantial penalties and fines if we fail to comply with such regulations.

Existing and future safety, 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, docks and pipelines, including FERC, PHMSA, EPA and the United States Coast Guard, to issue regulatory enforcement actions, 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, difficulty obtaining and maintaining permits from regulatory agencies 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.

The EPA has finalized or proposed multiple GHG regulations that impact our assets and supply chain. Further, the IRA includes a charge on methane emissions above certain emissions thresholds employing empirical emissions data that will apply to our facilities beginning in calendar year 2024. In addition, other international, federal and state initiatives may be considered in the future to address GHG emissions through treaty commitments, direct regulation, market-based regulations such as a GHG emissions tax or cap-and-trade programs or clean energy or performance-based 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.

Revised, reinterpreted or additional guidance, laws and regulations at local, state, federal or international levels 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. It is not possible at this time to predict how future regulations or legislation may address GHG emissions and impact our business.

On February 28, 2022, the EPA removed a stay of formaldehyde standards in the NESHAP Subpart YYYY for stationary combustion turbines located at major sources of HAP emissions. Owners and operators of lean remix gas-fired turbines and diffusion flame gas-fired turbines at major sources of HAP that were installed after January 14, 2003 were required to comply with NESHAP Subpart YYYY by March 9, 2022 and demonstrate initial compliance with those requirements by September 5, 2022. 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.

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.

Total expenditures related to environmental and similar laws and governmental regulations, including capital expenditures, were immaterial to our Consolidated Financial Statements for the years ended December 31, 2022 and 2021. 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.

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

The PHMSA requires pipeline operators to develop management programs to safely operate and maintain their pipelines and to comprehensively evaluate certain areas along their pipelines and take additional measures where necessary to protect pipeline segments located in "high or moderate 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 safety and compliance;
- 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 utilize pipeline integrity management programs that are intended to maintain pipeline integrity. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Although no fines or penalties have been imposed on us to date, 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, which for certain violations can aggregate up to as high as $2.6 million.

Additions or changes in tax laws and regulations could potentially affect our financial results or liquidity.

We are subject to various types of tax arising from normal business operations in the jurisdictions in which we operate and transact. Any changes to local, domestic or international tax laws and regulations, or their interpretation and application, including those with retroactive effect, could affect our tax obligations, profitability and cash flows in the future. In addition, tax rates in the various jurisdictions in which we operate may change significantly due to political or economic factors beyond our control. We continuously monitor and assess proposed tax legislation that could negatively impact our business.

The Inflation Reduction Act, enacted on August 16, 2022, includes the implementation of a new 15% corporate alternative minimum tax (the "CAMT") effective in 2023. The CAMT may lead to volatility in our cash tax payment obligations, particularly in periods of significant commodity, currency or financial market variability resulting from potential changes in the fair value of our derivative instruments. CAMT is a novel and new approach for calculating corporate tax liability. Many unanswered questions remain on how the operative rules for CAMT will be implemented and interpreted.

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 (the "2018 SPL tank incident"). 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. In July 2021, PHMSA issued a Notice of Probable Violation ("NOPV") and Proposed Civil Penalty to SPL alleging violations of federal pipeline safety regulations relating to the 2018 SPL tank incident and proposing civil penalties totaling $2,214,900. On September 16, 2021, PHMSA issued an Amended NOPV that reduced the proposed penalty to $1,458,200. On October 12, 2021, SPL responded to the Amended NOPV, electing not to contest the alleged violations in the Amended NOPV and electing to pay the proposed reduced penalty. PHMSA notified SPL in a letter dated November 9, 2021 that the case was considered "closed." SPL continues to coordinate with PHMSA and FERC to address the matters relating to the 2018 SPL tank incident, including repair approach and related analysis. One tank has been placed back into operational service. We do not expect that the Consent Order and related analysis, repair and remediation or resolution of the NOPV 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 Dividend Policy

Our common stock has traded on the NYSE American under the symbol "LNG" since March 24, 2003. As of February 17, 2023, we had 244 million shares of common stock outstanding held by 83 record owners.

We intend to continue to declare and pay quarterly dividends, with the goal of increasing the dividend over time. The declaration of dividends is subject to the discretion of our Board, and will depend on our financial condition and other factors deemed relevant by the Board. See the risk *Our ability to declare and pay dividends and repurchase shares is subject to certain considerations* under Risks Relating to Our Financial Matters in Item 1A. Risk Factors.

Purchase of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes stock repurchases for the three months ended December 31, 2022:

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, 2022	1,161,014	$170.57	1,161,005	$4,159,601,537
November 1 - 30, 2022	2,723,122	$165.73	2,723,122	$3,708,244,552
December 1 - 31, 2022	490,753	$169.95	490,554	$3,624,866,341
Total	4,374,889	$167.49	4,374,681	

(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 September 12, 2022, our Board authorized an increase in the existing share repurchase program by $4.0 billion for an additional three years, beginning on October 1, 2022. For additional information, see Note 19—Stock Repurchase Programs of our Notes to Consolidated Financial Statements.

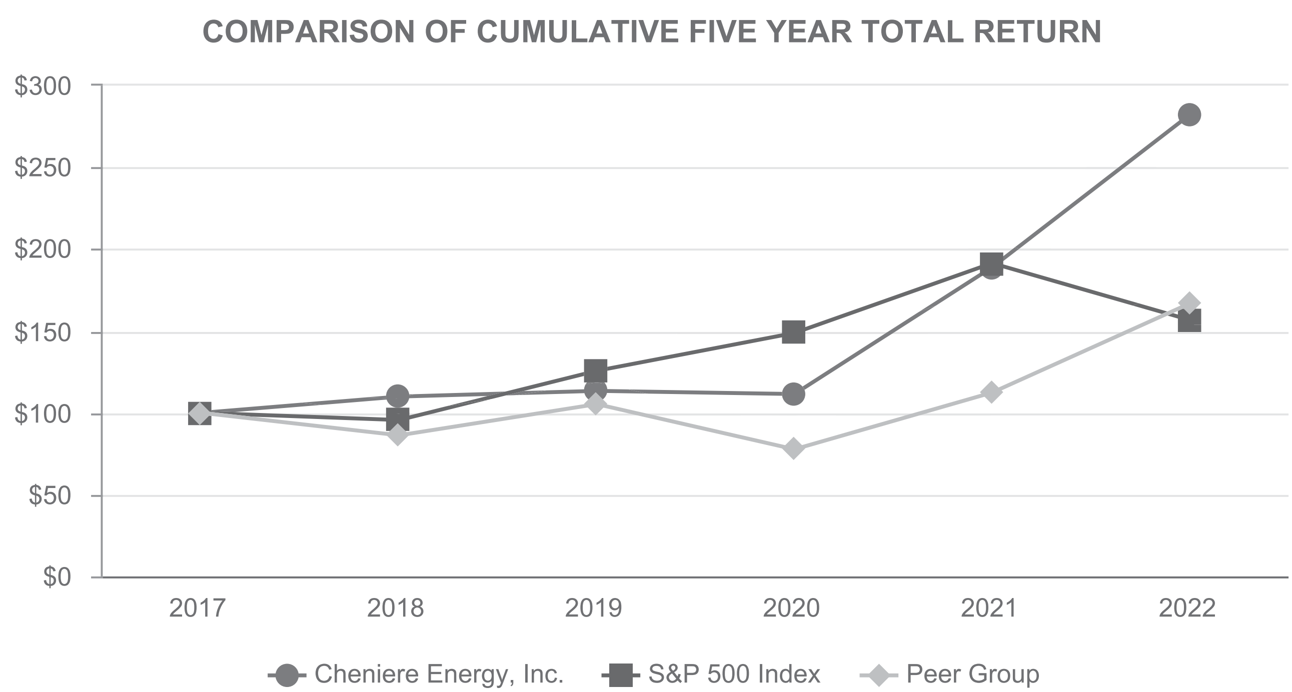
Total Stockholder Return

The following is a customized peer group consisting of 17 companies (the "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.

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 following graph compares the five-year total return on our common stock, the S&P 500 Index and our Peer Group. The graph was constructed on the assumption that $100 was invested in our common stock, the S&P 500 Index and our Peer Group on December 31, 2017 and that any dividends were fully reinvested.

Company / Index	2017	2018	2019	2020	2021	2022
Cheniere Energy, Inc.	$ 100.00	$ 109.94	$ 113.43	$ 111.50	$ 188.96	$ 282.18
S&P 500 Index	100.00	95.61	125.70	148.82	191.49	156.78
Peer Group	100.00	86.27	105.33	77.72	112.39	166.84



ITEM 6. [Reserved]

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. Discussion of 2020 items and variance drivers between the year ended December 31, 2021 as compared to December 31, 2020 are not included herein and can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our annual report on Form 10-K for the fiscal year ended December 31, 2021.

Our discussion and analysis includes the following subjects:

Overview

We are an 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 operate two natural gas liquefaction and export facilities at Sabine Pass, Louisiana and near Corpus Christi, Texas (respectively, the "Sabine Pass LNG Terminal" and "Corpus Christi LNG Terminal") with a total of nine operational natural gas liquefaction Trains. In addition to natural gas liquefaction facilities at the Sabine Pass LNG Terminal (the "SPL Project"), the Sabine Pass LNG Terminal also has operational regasification facilities and pipelines that interconnect our facilities to several interstate and intrastate natural gas pipelines. The Corpus Christi LNG Terminal includes existing natural gas liquefaction facilities, an expansion project underway for up to seven midscale Trains (the "Corpus Christi Stage 3 Project") and pipelines that interconnect our facilities to several interstate and intrastate natural gas pipelines (the "CCL Project", and together with the SPL Project, the "Liquefaction Projects"). For further discussion of our business, see Items 1. and 2. Business and Properties.

Our long-term customer arrangements form the foundation of our business and provide us with significant, stable, long-term cash flows. Through our SPAs and IPM agreements, we have contracted approximately 95% of the total anticipated production from the Liquefaction Projects through the mid-2030s, inclusive of contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project. Excluding contracts with terms less than 10 years and contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project, our SPAs and IPM agreements had approximately 17 years of weighted average remaining life as of December 31, 2022. The majority of our contracts are fixed-priced, long-term SPAs consisting of a fixed fee per MMBtu of LNG plus a variable fee per MMBtu of LNG, with the variable fees generally structured to cover the cost of natural gas purchases and transportation and liquefaction fuel to produce LNG, thus limiting our exposure to fluctuations in U.S. natural gas prices. During 2022, we continued to grow our portfolio of SPA and IPM agreements, and we believe that continued global demand for natural gas and LNG, as further described in Market Factors and Competition in Items 1. and 2. Business and Properties, will provide a foundation for additional growth in our portfolio of customer contracts in the future. The continued strength and stability of our long-term cash flows served as the foundation of our revised comprehensive, long-term capital allocation plan announced in 2022, which includes an increased share repurchase authorization, lowered consolidated long-term leverage target, increased dividends and continued investment in accretive organic growth.

Overview of Significant Events

Our significant events since January 1, 2022 and through the filing date of this Form 10-K include the following:

Strategic

- In February 2023, certain subsidiaries of Cheniere Partners initiated the pre-filing review process with the FERC under the National Environmental Policy Act for an expansion adjacent to the SPL Project consisting of up to three Trains with an expected total production capacity of approximately 20 mtpa of LNG.
- On January 2, 2023, Corey Grindal, formerly Executive Vice President, Worldwide Trading, was promoted to Executive Vice President and Chief Operating Officer of the Company.
- On October 3, 2022, our Board appointed Mr. Brian E. Edwards to serve as a member of our Board. Mr. Edwards was appointed to the Audit Committee and the Compensation Committee of our Board.
- In September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for an expansion adjacent to the CCL Project consisting of two midscale Trains with an expected total production capacity of approximately 3 mtpa of LNG ("CCL Midscale Trains 8 and 9").
- On June 15, 2022, our Board made a positive FID with respect to the Corpus Christi Stage 3 Project following the execution of an EPC contract with Bechtel for the Corpus Christi Stage 3 Project for a contract price of approximately $5.5 billion, subject to adjustment only by change order, and issuance of a limited notice to proceed to commence early engineering, procurement and site works in March 2022. CCL Stage III issued a full notice to proceed with construction to Bechtel effective June 16, 2022. In connection with the positive FID, CCL Stage III was contributed to CCH and subsequently merged with and into CCL, with CCL the surviving company of the merger and a wholly owned subsidiary of CCH. In connection with the merger, contracts held by CCL Stage III were transferred to CCL.
- In June 2022, Chevron U.S.A. Inc. ("Chevron") entered into an agreement with SPLNG providing for the early termination of the TUA and an associated terminal marine services agreement ("TMSA") between the parties and their affiliates (the "Termination Agreement"), effective July 6, 2022, for a lump sum fee of $765 million.
- We entered into, or amended, the following agreements:
    - We entered into new or amended long-term SPAs aggregating approximately 140 million tonnes of LNG to be delivered between 2026 and 2050, inclusive of long-term SPAs with Engie SA, Equinor ASA, Chevron, POSCO International Corporation, PetroChina International Company Limited and PTT Global LNG Company Limited, approximately 50 million tonnes of which is subject to Cheniere making a final investment decision to construct additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the seven-train Corpus Christi Stage 3 Project or us unilaterally waiving that requirement.
    - In May 2022, CCL Stage III entered into an IPM agreement with ARC Resources U.S. Corp, a subsidiary of ARC Resources, Ltd., to purchase 140,000 MMBtu per day of natural gas at a price based on Platts Japan Korea Marker ("JKM"), for a term of approximately 15 years commencing with commercial operations of Train 7 of the Corpus Christi Stage 3 Project. The LNG associated with this gas supply, approximately 0.85 mtpa, will be marketed by Cheniere Marketing.
    - In February 2022, CCL Stage III amended the IPM agreement previously entered into with EOG Resources, Inc. ("EOG"), increasing the volume and term of natural gas supply from 140,000 MMBtu per day for 10 years, to 420,000 MMBtu per day for 15 years, with pricing continuing to be based on JKM. Under the amended IPM agreement, supply is targeted to commence upon completion of Trains 1, 4 and 5 of the Corpus Christi Stage 3 Project. In addition, the previously executed gas supply agreement, under which EOG sells 300,000 MMBtu per day to CCL Stage III at a price indexed to Henry Hub, was extended by 5 years, resulting in a 15 year term that is expected to commence upon start-up of the amended IPM agreement. The LNG associated with this gas supply, approximately 2.55 mtpa, will be owned and marketed by Cheniere Marketing.

Operational

- As of February 17, 2023, approximately 2,650 cumulative LNG cargoes totaling over 180 million tonnes of LNG have been produced, loaded and exported from the Liquefaction Projects.
- On October 27, 2022, substantial completion of the third berth at the Sabine Pass Terminal was achieved.
- On February 4, 2022, substantial completion of Train 6 of the SPL Project was achieved (the "Train 6 Completion").

Financial

- We completed the following debt transactions:
    - In December and November 2022, SPL issued an aggregate principal amount of $70 million of 6.293% Senior Secured Notes due 2037 (the "6.293% SPL Senior Notes") and $430 million of 5.900% Senior Secured Amortizing Notes due 2037 (the "5.900% SPL Senior Notes"), respectively, with a weighted average life of approximately 9.6 years and 9.5 years, respectively. The proceeds from the 6.293% SPL Senior Notes and the 5.900% SPL Senior Notes, together with cash on hand, were used to redeem the remaining outstanding amount of SPL's $1.5 billion aggregate principal amount of Senior Secured Notes due 2023 (the "2023 SPL Senior Notes"), subsequent to the $300 million redemption in October 2022.
    - In December 2022, we repurchased $752 million in aggregate principal amount outstanding of CCH's 7.000% Senior Secured Notes due 2024 (the "2024 CCH Senior Notes") pursuant to a tender offer, with cash on hand. In January 2023, the remaining outstanding principal amount of $498 million of the 2024 CCH Senior Notes was redeemed with cash on hand.
    - In June 2022, CCH amended and restated its term loan credit facility (the "CCH Credit Facility") and its working capital facility (the "CCH Working Capital Facility") to, among other things, (1) increase the commitments to approximately $4.0 billion and $1.5 billion for the CCH Credit Facility and the CCH Working Capital Facility, respectively, which are intended to fund a portion of the cost of developing, constructing and operating the Corpus Christi Stage 3 Project, (2) extend the maturity of the CCH Credit Facility to the earlier of June 15, 2029 or two years after the substantial completion of the last Train of the Corpus Christi Stage 3 Project and extend the maturity of the CCH Working Capital Facility to June 15, 2027, (3) update the indexed interest rate to SOFR and (4) make certain other changes to the terms and conditions of each existing facility.
- In November 2022 and January 2023, Cheniere achieved its first and second issuer investment grade credit ratings from S&P Global Ratings ("S&P") and Fitch Ratings ("Fitch"), respectively, the former of which resulted in the reduction of applicable margin and letter of credit fee rates on Cheniere's revolving credit facility from 1.625% to 1.5% on LIBOR loans and the reduction of commitment fee rates from 0.25% to 0.225% and the release of previously required collateral resulting from the facility's unsecured status.
- In September 2022, Moody's Corporation ("Moody's") upgraded its issuer credit ratings of Cheniere, CQP and SPL from Ba3, Ba2 and Baa3, respectively, to Ba1, Ba1 and Baa2, respectively, with a stable outlook. Additionally in September 2022, Fitch upgraded its issuer credit ratings of CQP and SPL from BB+ and BBB-, respectively, to BBB- and BBB, respectively, both investment grade credit ratings, with a stable outlook. In November 2022, CQP achieved its second issuer investment grade credit rating from S&P, as a result of an upgrade from BB+ to BBB, with a stable outlook, which resulted in the release of previous required collateral on CQP's revolving credit facility, resulting from the facility's unsecured status. In February 2023, S&P also upgraded its issuer credit ratings of SPL from BBB to BBB+ with stable outlook.
- In September 2022, our Board approved a revised comprehensive, long-term capital allocation plan which included:
    - increasing the share repurchase authorization by $4.0 billion for an additional 3 years, beginning on October 1, 2022;
    - lowering our consolidated long-term leverage target to approximately 4x;
    - increasing our dividend by 20% commencing with a declared distribution of $0.395 per common share in September 2022 (paid in November 2022), and targeting an approximate 10% annual dividend growth rate through Corpus Christi Stage 3 Project construction; and
    - continuing to invest in accretive organic growth.

- We accomplished the following pursuant to our capital allocation priorities:
  - During the year ended December 31, 2022, we prepaid $5.4 billion of consolidated long-term indebtedness pursuant to our capital allocation plan.
  - During the year ended December 31, 2022, we repurchased approximately 9.3 million shares of our common stock as part of our share repurchase program for approximately $1.4 billion. The shares repurchased during the year ended December 31, 2022 include approximately 2.7 million shares of our common stock beneficially owned by Icahn Capital LP and certain affiliates of Icahn Capital LP (the "Icahn Group") that we repurchased for approximately $350 million.
  - We paid aggregate dividends of $1.385 per share of common stock during the year ended December 31, 2022.

Market Environment

The LNG market in 2022 saw unprecedented price volatility across all natural gas and LNG benchmarks. Gas market fundamentals across the globe were tight and exacerbated by the Russia / Ukraine war risks, and later by the drastic reduction in Russian natural gas flows to the EU. Concerns over low natural gas and LNG inventories and low additional LNG supply availability early in the year were intensified by the war dynamics in Europe and by further constraints on natural gas and LNG supplies caused by the outage at the Freeport LNG facility in June and the explosion on the Nordstream 1 and Nordstream 2 Pipelines in September. Several EU policy initiatives were passed to ensure underground gas storage in the region was filled before winter. Europe had to compete for LNG cargoes resulting in unprecedented price spikes. These conditions were worsened by high coal prices, low nuclear generation output and low hydro levels in Europe, which limited optionality for power generators and deepened the energy crisis in Europe.

Despite the generally tight supply conditions, according to Kpler, global LNG demand grew by approximately 5% from 2021, adding an additional 19.5 million tonnes to the overall market. LNG imports into Europe and Turkey increased by 45.9 million tonnes, or 61% year-over-year in 2022. This growth was primarily accompanied by a pronounced slowdown in economic activity in China, which contributed to a 7% decrease in Asia's LNG demand of 19.1 million tonnes from 2021. These sizeable EU LNG requirements resulting from the war fallout and the increase in global demand, especially demand for increased imports to Europe and Turkey, exposed the vulnerability of the LNG industry in terms of supply constraints and under-investments. This was manifested in the price levels and the magnitude of the price spreads between the benchmarks. As an example, the Dutch Title Transfer Facility ("TTF") monthly settlement prices averaged $40.9/MMBtu in 2022, approximately 184% higher than the $14.4/MMBtu average in 2021, and the TTF monthly settlement prices averaged $42.3/MMBtu in the fourth quarter of 2022, approximately 46% higher than the $28.9/MMBtu average in the fourth quarter of 2021. Similarly, the 2022 average settlement price for the JKM increased 128% year-over-year to an average of $34.2/MMBtu in 2022, and the fourth quarter of 2022 average settlement price for the JKM increased 38% year-over-year to an average of $38.5/MMBtu. This extreme price increase triggered a strong supply response from the U.S., which played a significant role in balancing the global LNG market. Despite the outage at Freeport LNG, the U.S. exported approximately 77 million tonnes of LNG in 2022, a gain of approximately 9% from 2021, as the market continued to pull on supplies from our facilities and those of our competitors. Exports from our Liquefaction Projects reached 44 million tonnes in aggregate, representing over 85% of the gain in the U.S. total for the year.

Despite the global impacts of the Russia / Ukraine war, we do not believe we have significant exposure to adverse direct or indirect impacts of the war, as we do not conduct business in Russia and refrain from business dealings with Russian entities. Additionally, we are not aware of any specific adverse direct or indirect effects of the war on our supply chain. Consequently, we believe we are well positioned to help meet the increased demand of our international LNG customers to overcome their supply shortages.

Results of Operations

Consolidated results of operations

(in millions, except per share data)	Year Ended December 31, 2022	2021	Variance
Revenues			
LNG revenues	$ 31,804	$ 15,395	$ 16,409
Regasification revenues	1,068	269	799
Other revenues	556	200	356
Total revenues	33,428	15,864	17,564
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	25,632	13,773	11,859
Operating and maintenance expense	1,681	1,444	237
Selling, general and administrative expense	416	325	91
Depreciation and amortization expense	1,119	1,011	108
Development expense	16	7	9
Other	5	5	—
Total operating costs and expenses	28,869	16,565	12,304
Income (loss) from operations	4,559	(701)	5,260
Other income (expense)			
Interest expense, net of capitalized interest	(1,406)	(1,438)	32
Loss on modification or extinguishment of debt	(66)	(116)	50
Interest rate derivative gain (loss), net	2	(1)	3
Other income (expense), net	5	(22)	27
Total other expense	(1,465)	(1,577)	112
Income (loss) before income taxes and non-controlling interest	3,094	(2,278)	5,372
Less: income tax provision (benefit)	459	(713)	1,172
Net income (loss)	2,635	(1,565)	4,200
Less: net income attributable to non-controlling interest	1,207	778	429
Net income (loss) attributable to common stockholders	$ 1,428	$ (2,343)	$ 3,771
Net income (loss) per share attributable to common stockholders—basic	$ 5.69	$ (9.25)	$ 14.94
Net income (loss) per share attributable to common stockholders—diluted	$ 5.64	$ (9.25)	$ 14.89

Volumes loaded and recognized from the Liquefaction Projects

(in TBtu)	Year Ended December 31, 2022 Operational	Commissioning	Total
Volumes loaded during the current period	2,295	13	2,308
Volumes loaded during the prior period but recognized during the current period	49	1	50
Less: volumes loaded during the current period and in transit at the end of the period	(56)	—	(56)
Total volumes recognized in the current period	2,288	14	2,302

Components of LNG revenues and corresponding LNG volumes delivered

	Year Ended December 31,		
	2022	2021	Variance
LNG revenues *(in millions)*:			
LNG from the Liquefaction Projects sold under third party long-term agreements (1)	$ 20,702	$ 11,990	$ 8,712
LNG from the Liquefaction Projects sold by our integrated marketing function under short-term agreements	10,169	4,361	5,808
LNG procured from third parties	760	499	261
Net derivative losses	(328)	(1,776)	1,448
Other revenues	501	321	180
Total LNG revenues	$ 31,804	$ 15,395	$ 16,409
Volumes delivered as LNG revenues *(in TBtu)*:			
LNG from the Liquefaction Projects sold under third party long-term agreements (1)	1,926	1,608	318
LNG from the Liquefaction Projects sold by our integrated marketing function under short-term agreements	362	344	18
LNG procured from third parties	29	45	(16)
Total volumes delivered as LNG revenues	2,317	1,997	320

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

Net income (loss) attributable to common stockholders. The favorable variance of $3.8 billion for the year ended December 31, 2022 as compared to the same period of 2021 was primarily attributable to:

- increased LNG revenues, net of cost of sales and excluding the effect of derivative losses (as further described below), of $5.1 billion, of which approximately 80% was attributable to higher margins on sales indexed to or derived from (1) international gas prices, as a result of increases in the associated indices and (2) Henry Hub, with variable consideration on our long-term SPAs generally priced at 115% of Henry Hub, and approximately 20% was attributable to increased volume delivered between the comparable periods, in part due to the Train 6 Completion and, to a lesser extent, the substantial completion and commencement of operations of Train 3 of the CCL Project on March 26, 2021 (the "Train 3 Completion"); and
- additional income resulting from the lump sum fee from Chevron of $765 million related to the Termination Agreement, as discussed in Overview of Significant Events;

These favorable variance drivers were partially offset by:

- increased derivative losses from changes in fair value and settlements of $544 million (before tax and the impact of non-controlling interest) between the years, including derivative losses from changes in fair value of $4.3 billion in the year ended December 31, 2021 to $5.7 billion in the year ended December 31, 2022, primarily related to our IPM agreements where we procure natural gas at a price indexed to international gas prices; and
- a $1.2 billion unfavorable change in income tax provision (benefit).

The following is an additional detailed discussion of the significant variance drivers of the change in net income (loss) attributable to common stockholders by line item:

Revenues. $17.6 billion increase between comparable periods primarily attributable to:

- $12.2 billion increase due to higher pricing per MMBtu, from both increased Henry Hub pricing, for which the majority of our long-term contracts are indexed, and from international gas pricing;
- $2.6 billion increase due to higher volumes of LNG delivered between the periods, which increased 320 TBtu or 16%, due to Train 6 Completion and, to a lesser extent, the Train 3 Completion, which have a total production capacity aggregating approximately 10 mtpa;
- $1.4 billion decrease in derivative losses from change in fair value and settlements, primarily due to shifts in forward commodity curves related to arrangements designed to economically hedge commodity markets in which we have contractual arrangements to sell physical LNG;

- $799 million increase in regasification revenues, due to the acceleration of regasification revenues from the Termination Agreement with Chevron, as described above in Overview of Significant Events; and
- $356 million increase in other revenues, primarily due to an increase in sublease income from LNG vessel subcharters as a result of higher rates and an increase in the total number of days subchartered due to the availability of and demand for vessel charter capacity between the periods.

Operating costs and expenses. $12.3 billion increase between comparable periods primarily attributable to:

- $9.9 billion increase in cost of sales excluding the effect of derivative losses described below, primarily as a result of $8.9 billion in increased cost of natural gas feedstock largely due to higher U.S. natural gas prices and, to a lesser extent, from increased volume of natural gas liquified and delivered as LNG, as discussed above under the caption *Revenues;*
- $2.0 billion increase in derivative losses from changes in fair value and settlements included in cost of sales, from $4.2 billion in the year ended December 31, 2021 to $6.2 billion in the year ended December 31, 2022, primarily due to non-cash unfavorable changes in fair value of our commodity derivatives that are attributed to positions indexed to international gas prices; and
- $237 million increase in operating and maintenance expense primarily due to increased natural gas transportation and storage capacity demand charges following the Train 6 Completion and the Train 3 Completion as well as third party service and maintenance contract costs.

Other expense (income). $112 million decrease in total other expense between comparable periods primarily attributable to:

- $50 million decrease in loss on modification or extinguishment of debt, primarily due to a reduction in premiums paid for the early redemption or repayment of debt principal, as further described under *Financing Cash Flows* in Sources and Uses of Cash within Liquidity and Capital Resources, partially offset by a $31 million loss associated with a premium paid to Chevron to terminate a revenue sharing agreement between the parties;
- $32 million decrease in interest expense, net of capitalized interest, as a result of repayment of debt in accordance with our capital allocation plan and lower interest costs due to refinancing higher cost debt, which was partially offset by a lower portion of total interest costs eligible for capitalization following substantial completion of Train 3 of the CCL Project and Train 6 of the SPL Project in 2021 and 2022, respectively; and
- $27 million favorable variance in other expense (income), net primarily due to higher interest income earned on cash and cash equivalents from higher interest rates in 2022, partially offset by increased other-than-temporary impairment losses related to our investment in Midship Holdings.

Income tax provision (benefit). $1.2 billion increase between comparable periods primarily attributable to an increase in pretax income.

The effective tax rate was 14.8% and 31.3% for the years ended December 31, 2022 and 2021, respectively. The 2022 effective tax rate was less than the statutory tax rate primarily due to income allocated to non-controlling interest not taxable to Cheniere, partially offset by an increase in the valuation allowance on our Louisiana net operating loss ("NOL") carryforwards. The 2021 effective tax rate represents a tax benefit on pre-tax losses and was higher than the statutory tax rate primarily due to income allocated to non-controlling interest not taxable to Cheniere and a decrease in the valuation allowance on our Louisiana NOL carryforwards. Our valuation allowance on Louisiana NOLs decreased in 2021 primarily as a result of a change in tax law allowing for indefinite carryover of NOLs and our valuation allowance on Louisiana NOLs increased in 2022 due to a reduction in our forecasted Louisiana taxable income as a result of receiving favorable guidance from the Louisiana Department of Revenue on a state apportionment tax matter. See further discussion in Note 15—Income Taxes of our Notes to Consolidated Financial Statements.

Our effective tax rate is subject to variation 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. $429 million increase between comparable periods primarily attributable to $0.9 billion increase in CQP's consolidated net income between the comparable periods.

Significant factors affecting our results of operations

In addition to sources and uses of liquidity as discussed in Liquidity and Capital Resources, below are additional significant factors that affect our results of operations.

Gains and losses on derivative instruments

Derivative instruments, which in addition to managing exposure to commodity-related marketing and price risks are utilized to manage exposure to changing interest rates and foreign exchange volatility, are reported at fair value on our Consolidated Financial Statements. For commodity derivative instruments related to our IPM agreements, including those entered into during the year ended December 31, 2022 as described further in Overview of Significant Events, the underlying LNG sales being economically hedged are accounted for under the accrual method of accounting, whereby revenues expected to be derived from the future LNG sales are recognized only upon delivery 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, and given the significant volumes, long-term duration and volatility in price basis for certain of our derivative contracts, use of derivative instruments may result in continued volatility of our results of operations based on changes in market pricing, counterparty credit risk and other relevant factors that may be outside of our control, notwithstanding the operational intent to mitigate risk exposure over time.

Commissioning cargoes

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 December 31, 2022 and 2021, we realized offsets to LNG terminal costs of $204 million and $319 million, corresponding to 15 TBtu and 42 TBtu, respectively, that were related to the sale of commissioning cargoes from the Liquefaction Projects.

Customer agreements at SPL

During the year ended December 31, 2022, in fulfillment of a prior commitment to collateralize financing for Train 6 of the SPL Project, Cheniere provided to SPL certain SPAs aggregating approximately 21 million tonnes of LNG to be delivered between 2023 and 2035 and an IPM agreement to purchase 140,000 MMBtu per day of natural gas for a term of approximately 15 years beginning in early 2023. Additionally, during the year ended December 31, 2022, SPL executed an SPA with a counterparty aggregating approximately 1.0 mtpa of LNG to be delivered between 2026 and 2042. As a result, net income attributable to non-controlling interest will be impacted in future periods as volumes are delivered under the aforementioned contracts and by gains and losses from changes in the fair value of the IPM agreement, which is accounted for as a derivative.

Liquidity and Capital Resources

The following information describes our ability to generate and obtain adequate amounts of cash to meet our requirements in the short term and the long term. In the short term, we expect to meet our cash requirements using operating cash flows and available liquidity, consisting of cash and cash equivalents, restricted cash and cash equivalents and available commitments under our credit facilities. In the long term, we expect to meet our cash requirements using operating cash flows and other future potential sources of liquidity, which may include debt and equity offerings by us or our subsidiaries. The table below provides a summary of our available liquidity (in millions). Future material sources of liquidity are discussed below.

	December 31, 2022
Cash and cash equivalents (1)	$ 1,353
Restricted cash and cash equivalents designated for the following purposes:	
SPL Project	92
CCL Project	738
Cash held by our subsidiaries that is restricted to Cheniere	304
Total restricted cash and cash equivalents	1,134
Available commitments under our credit facilities (2):	
SPL's working capital revolving credit and letter of credit reimbursement agreement (the "SPL Working Capital Facility")	872
CQP's credit facilities	750
CCH Credit Facility	3,260
CCH Working Capital Facility	1,322
Cheniere's revolving credit facility (the "Cheniere Revolving Credit Facility")	1,250
Total available commitments under our credit facilities	7,454
Total available liquidity	$ 9,941

(1) Amounts presented include balances held by our consolidated variable interest entity, CQP, as discussed in Note 9—Non-controlling Interest and Variable Interest Entity of our Notes to Consolidated Financial Statements. As of December 31, 2022, assets of CQP, which are included in our Consolidated Balance Sheets, included $0.9 billion of cash and cash equivalents.

(2) Available commitments represent total commitments less loans outstanding and letters of credit issued under each of our credit facilities as of December 31, 2022. See Note 11—Debt of our Notes to Consolidated Financial Statements for additional information on our credit facilities and other debt instruments.

Our liquidity position subsequent to December 31, 2022 will be driven by future sources of liquidity and future cash requirements as further discussed below under the caption *Future Sources and Uses of Liquidity*.

Although our sources and uses of cash are presented below from a consolidated standpoint, SPL, CQP, CCH and Cheniere operate with independent capital structures. Certain restrictions under debt and equity instruments executed by our subsidiaries limit each entity's ability to distribute cash, including the following:

- SPL and CCH are required to deposit all cash received into restricted cash and cash equivalents accounts under certain of their debt agreements. The usage or withdrawal of such cash is restricted to the payment of liabilities related to the Liquefaction Projects and other restricted payments. In addition, SPL and CCH's operating expenses are managed by our subsidiaries under affiliate agreements, which may require SPL and CCH to advance cash to the respective affiliates, however the cash remains restricted to Cheniere for operation and construction of the Liquefaction Projects;
- CQP is required under its partnership agreement to distribute to unitholders all available cash on hand at the end of a quarter less the amount of any reserves established by its general partner. Beginning with the distribution paid in the second quarter of 2022, quarterly distributions by CQP are comprised of a base amount plus a variable amount equal to the remaining available cash per unit, which takes into consideration, among other things, amounts reserved for annual debt repayment and capital allocation goals, anticipated capital expenditures to be funded with cash, and cash reserves to provide for the proper conduct of CQP's business.

- Our 48.6% limited partner interest, 100% general partner interest and incentive distribution rights in CQP limit our right to receive cash held by CQP to the amounts specified by the provisions of CQP's partnership agreement; and
- SPL, CQP and CCH are restricted by affirmative and negative covenants included in certain of their debt agreements in their ability to make certain payments, including distributions, unless specific requirements are satisfied.

Notwithstanding the restrictions noted above, we believe that sufficient flexibility exists within the Cheniere complex to enable each independent capital structure to meet its currently anticipated cash requirements. The sources of liquidity at SPL, CQP and CCH primarily fund the cash requirements of the respective entity, and any remaining liquidity not subject to restriction, as supplemented by liquidity provided by Cheniere Marketing, is available to enable Cheniere to meet its cash requirements.

Future Sources and Uses of Liquidity

Future Sources of Liquidity under Executed Contracts

Because many of our sales contracts have long-term durations, we are contractually entitled to significant future consideration under our SPAs and TUAs which has not yet been recognized as revenue. This future consideration is in most cases not yet legally due to us and was not reflected on our Consolidated Balance Sheets as of December 31, 2022. In addition, a significant portion of this future consideration is subject to variability as discussed more specifically below. We anticipate that this consideration will be available to meet liquidity needs in the future. The following table summarizes our estimate of future material sources of liquidity to be received from executed contracts as of December 31, 2022 (in billions):

	Estimated Revenues Under Executed Contracts by Period (1)			
	2023	2024 - 2027	Thereafter	Total
LNG revenues (fixed fees) (2)	$ 6.1	$ 26.1	$ 79.8	$ 112.0
LNG revenues (variable fees) (2) (3)	10.5	46.2	144.5	201.2
Regasification revenues	0.1	0.5	0.2	0.8
Financial derivatives (4)	(0.1)	—	—	(0.1)
Other revenues (5)	0.2	0.2	0.1	0.5
Total	$ 16.8	$ 73.0	$ 224.6	$ 314.4

(1) Agreements in force as of December 31, 2022 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2022. The timing of revenue recognition under GAAP may not align with cash receipts, although we do not consider the timing difference to be material. The estimates above reflect management's assumptions and currently known market conditions and other factors as of December 31, 2022. Estimates are not guarantees of future performance and actual results may differ materially as a result of a variety of factors described in this annual report on Form 10-K.

(2) LNG revenues exclude revenues from contracts with original expected durations of one year or less. Fixed fees are fees that are due to us regardless of whether a customer exercises their contractual right to not take delivery of an LNG cargo under the contract. Variable fees are receivable only in connection with LNG cargoes that are delivered.

(3) LNG revenues (variable fees) reflect the assumption that customers elect to take delivery of all cargoes made available under the contract. LNG revenues (variable fees) are based on estimated forward prices and basis spreads as of December 31, 2022. The pricing structure of our SPA arrangements with our customers incorporates a variable fee per MMBtu of LNG generally equal to 115% of Henry Hub, which is paid upon delivery, thus limiting our net exposure to future increases in natural gas prices. 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 to the extent the consideration is considered constrained due to the uncertainty of ultimate pricing and receipt.

(4) Financial derivatives include certain LNG Trading Derivatives that are recorded as LNG revenues based on the nature and intent of the derivative instrument. Pricing of financial derivatives is based on estimated forward prices and basis spreads as of December 31, 2022.

(5) Other revenues include payments to be received from certain LNG vessel subcharters.

LNG Revenues

Through our SPAs and IPM agreements, we have contracted substantially all of the total anticipated production capacity from the Liquefaction Projects. The majority of the contracted capacity is comprised of fixed-price, long-term SPAs that SPL and CCL have executed with third parties to sell LNG from the SPL Project and the CCL Project, including the Corpus Christi Stage 3 Project. Substantially all of our contracted capacity is from contracts with terms exceeding 10 years. Excluding contracts with terms less than 10 years and contracts executed to support additional liquefaction capacity at the Corpus Christi LNG Terminal beyond the Corpus Christi Stage 3 Project, our SPAs had approximately 17 years of weighted average remaining life as of December 31, 2022. Under the SPAs, the customers purchase LNG on either a FOB or delivered at terminal ("DAT") 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 generally equal to 115% of Henry Hub. Certain 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. The variable fees under our SPAs were generally sized with the intention to cover the costs of gas purchases and variable transportation and liquefaction fuel to produce the LNG to be sold under each such SPA. In aggregate, the annual fixed fee portion to be paid by the third-party SPA customers is approximately $3.4 billion for the SPL Project and $2.7 billion for the CCL Project, including the Corpus Christi Stage 3 Project. Our long-term SPA customers consist of creditworthy counterparties, with an average credit rating of A-, A3 and A- by S&P, Moody's and Fitch, respectively. A discussion of revenues under our SPAs can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements.

We market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPL through our integrated marketing function, Cheniere Marketing. Cheniere Marketing has a portfolio of long-, medium- and short-term SPAs to deliver 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, 2022, Cheniere Marketing has sold or has options to sell approximately 6,529 TBtu of LNG to be delivered to third party customers between 2023 and 2043, including 6,393 TBtu from long-term executed contracts that are included in the Future Sources of Liquidity under Executed Contracts table above. 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 DAT basis (delivered to the customer at their specified LNG receiving terminal).

Regasification Revenues

SPLNG has a long-term, third party TUA with TotalEnergies Gas & Power North America, Inc. ("TotalEnergies") under which TotalEnergies is required to pay fixed monthly fees, whether or not it uses the approximately 1 Bcf/d of the regasification capacity it has reserved at the Sabine Pass LNG Terminal. TotalEnergies 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 TotalEnergies' obligations under its TUA up to $2.5 billion, subject to certain exceptions.

SPLNG has also entered into a TUA with SPL to reserve approximately 2 Bcf/d of the regasification capacity at the Sabine Pass LNG Terminal. 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 TotalEnergies, whereby SPL gained access to substantially all of TotalEnergies' capacity and other services provided under TotalEnergies' TUA with SPLNG that started in 2019. Notwithstanding any arrangements between TotalEnergies and SPL, payments required to be made by TotalEnergies to SPLNG will continue to be made by TotalEnergies to SPLNG in accordance with its TUA. Payments made by SPL to TotalEnergies under this partial TUA assignment agreement are included in other purchase obligations in the Future Cash Requirements for Operations and Capital Expenditures under Executed Contracts table below. Full discussion of the partial TUA assignment and SPLNG's revenues under the TUA agreements can be found in Note 13—Revenues of our Notes to Consolidated Financial Statements.

Financial Derivatives

Cheniere Marketing has entered into financial derivatives to minimize future cash flow variability associated with Cheniere Marketing's LNG agreements. Full discussion of financial derivatives can be found in Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements.

Additional Future Sources of Liquidity

Available Commitments under Credit Facilities

As of December 31, 2022, we had $7.5 billion in available commitments under our credit facilities, subject to compliance with the applicable covenants, to potentially meet liquidity needs. Our credit facilities mature between 2024 and 2029.

Uncontracted Liquefaction Supply

We expect a portion of total production capacity from the Liquefaction Projects that has not yet been contracted under executed agreements as of December 31, 2022 to be available for Cheniere Marketing to market to additional LNG customers. Debottlenecking opportunities and other optimization projects have led to increased run-rate production levels which has increased the production capacity available for Cheniere Marketing to the extent it has not already been contracted to other customers.

Financially Disciplined Growth

Our significant land positions at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal provide potential development and investment opportunities for further liquefaction capacity expansion at strategically advantaged locations with proximity to pipeline infrastructure and resources. In September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for CCL Midscale Trains 8 and 9. 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 positive FID.

Future Cash Requirements for Operations and Capital Expenditures under Executed Contracts

We are committed to make future cash payments for operations and capital expenditures pursuant to certain of our contracts. The following table summarizes our estimate of material cash requirements for operations and capital expenditures under executed contracts as of December 31, 2022 (in billions):

	Estimated Payments Due Under Executed Contracts by Period (1)			
	2023	2024 - 2027	Thereafter	Total
Purchase obligations (2):				
Natural gas supply agreements (3)	$ 10.5	$ 26.2	$ 29.2	$ 65.9
Natural gas transportation and storage service agreements (4)	0.5	2.1	5.4	8.0
Capital expenditures	1.0	3.1	—	4.1
Other purchase obligations (5)	0.2	0.6	0.6	1.4
Leases (6)	0.8	3.0	3.3	7.1
Total	$ 13.0	$ 35.0	$ 38.5	$ 86.5

(1) Agreements in force as of December 31, 2022 that have terms dependent on project milestone dates are based on the estimated dates as of December 31, 2022. The estimates above reflect management's assumptions and currently known market conditions and other factors as of December 31, 2022. Estimates are not guarantees of future performance and actual results may differ materially as a result of a variety of factors described in this annual report on Form 10-K.

(2) 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 contracts for which we have an early termination option if the option is not currently expected to be exercised. We include contracts with unsatisfied conditions precedent if the conditions are currently expected to be met.

(3) Pricing of natural gas supply agreements is based on estimated forward prices and basis spreads as of December 31, 2022. Pricing of IPM agreements is based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Includes $0.4 billion under natural gas supply agreements with unsatisfied conditions precedent.

(4) Includes $1.4 billion of purchase obligations to related parties under the natural gas transportation and storage service agreements. Also includes $1.2 billion under natural gas transportation and storage service agreements with unsatisfied conditions precedent.

(5) Other purchase obligations include payments under SPL's partial TUA assignment agreement with TotalEnergies, as discussed in *Regasification Revenues* above.

(6) Leases include payments under (1) operating leases, (2) finance leases, (3) short-term leases and (4) vessel time charters that were executed as of December 31, 2022 but will commence in the future. Certain of our leases also contain variable payments, such as inflation, which are not included above unless the contract terms require the payment of a fixed amount that is unavoidable. Payments during renewal options that are exercisable at our sole discretion are included only to the extent that the option is believed to be reasonably certain to be exercised.

Natural Gas Supply, Transportation and Storage Service Agreements

We have secured natural gas feedstock for the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal through long-term natural gas supply and IPM agreements. Under our IPM agreements, we pay for natural gas feedstock based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. While IPM agreements are not revenue contracts for accounting purposes, the payment structure for the purchase of natural gas under the IPM agreements generates a take-or-pay style fixed liquefaction fee, assuming that LNG produced from the natural gas feedstock is subsequently sold at a price approximating the global LNG market price paid for the natural gas feedstock purchase.

As of December 31, 2022, we have secured approximately 86% of the natural gas supply required to support the total forecasted production capacity of the Liquefaction Projects during 2023. Natural gas supply secured decreases as a percentage of forecasted production capacity beyond 2023. Natural gas supply is generally secured on an indexed pricing basis plus a fixed fee, with title transfer occurring upon receipt of the commodity. As further described in the *LNG Revenues* section above, the pricing structure of our SPA arrangements with our customers incorporates a variable fee per MMBtu of LNG generally equal to 115% of Henry Hub, which is paid upon delivery, thus limiting our net exposure to future increases in natural gas prices. Inclusive of amounts under contracts with unsatisfied conditions precedent as of December 31, 2022, we have secured up to 14,094 TBtu of natural gas feedstock through agreements with remaining terms that range up to 15 years. A discussion of our natural gas supply and IPM agreements can be found in Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements.

To ensure that we are able to transport natural gas feedstock to the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal, we have entered into transportation precedent and other agreements to secure firm pipeline transportation capacity from pipeline companies. We have also entered into firm storage services agreements with third parties to assist in managing variability in natural gas needs for the Liquefaction Projects.

Capital Expenditures

We enter into lump sum turnkey contracts with third party contractors for the EPC of our Liquefaction Projects. The future capital expenditures included in the table above primarily consist of fixed costs under the Bechtel EPC contract for the Corpus Christi Stage 3 Project, in which Bechtel charges a lump sum and generally bares project cost, schedule and performance risks unless certain specified events occurred, in which case Bechtel causes us to enter into a change order, or we agree with Bechtel to a change order. Additionally, we expect to incur ongoing capital expenditures to maintain our facilities and other assets, as well as to optimize our existing assets and purchase new assets that are intended to grow our productive capacity. See *Financially Disciplined Growth* section for further discussion.

Corpus Christi Stage 3 Project

The following table summarizes the project completion and construction status of the Corpus Christi Stage 3 Project as of January 31, 2023:

Overall project completion percentage	24.5%
Completion percentage of:	
Engineering	41.3%
Procurement	36.9%
Subcontract work	29.5%
Construction	2.2%
Date of expected substantial completion	2H 2025 - 1H 2027

Leases

Our obligations under our lease arrangements primarily consist of LNG vessel time charters with terms of up to 15 years to ensure delivery of cargoes sold on a DAT basis. We have also entered into leases for the use of tug vessels, office space and facilities and land sites. A discussion of our lease obligations can be found in Note 12—Leases of our Notes to Consolidated Financial Statements.

Additional Future Cash Requirements for Operations and Capital Expenditures

Corporate Activities

We are required to maintain corporate and general and administrative functions to serve our business activities. During the year ended December 31, 2022, selling, general and administrative expense was $0.4 billion, a portion of which was related to leases for office space, which is included in the table of cash requirements for operations and capital expenditures under executed contracts above. Our full-time employee headcount was 1,551 as of December 31, 2022.

Financially Disciplined Growth

The FID of any expansion projects will result in additional cash requirements to fund the construction and operations of such projects in excess of our current contractual obligations under executed contracts discussed above. However, in connection with reaching FID, we may be required to secure financing to meet the cash needs that such project will initially require, in support of commercializing the project.

Beyond the Corpus Christi Stage 3 Project, our significant land positions at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal provide potential development and investment opportunities for further liquefaction capacity expansion at strategically advantaged locations with proximity to pipeline infrastructure and resources. We expect that any potential future expansion at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal would increase cash requirements to support expanded operations, although expansion could be designed to leverage shared infrastructure to reduce the incremental costs of any potential expansion.

Future Cash Requirements for Financing under Executed Contracts

We are committed to make future cash payments for financing pursuant to certain of our contracts. The following table summarizes our estimate of material cash requirements for financing under executed contracts as of December 31, 2022 (in billions):

	Estimated Payments Due Under Executed Contracts by Period (1)			
	2023	**2024 - 2027**	**Thereafter**	**Total**
Debt (2)	$ 0.5	$ 10.1	$ 14.5	$ 25.1
Interest payments (2)	1.2	3.8	2.0	7.0
Total	$ 1.7	$ 13.9	$ 16.5	$ 32.1

(1) The estimates above reflect management's assumptions and currently known market conditions and other factors as of December 31, 2022. Estimates are not guarantees of future performance and actual results may differ materially as a result of a variety of factors described in this annual report on Form 10-K.

(2) Debt and interest payments are based on the total debt balance, scheduled contractual maturities and fixed or estimated forward interest rates in effect at December 31, 2022, excluding debt and interest payments on the 2024 CCH Senior Notes which are based on the redemption payment made January 5, 2023. In December 2022, we issued a notice of redemption for the remaining aggregate principal amount outstanding of the 2024 CCH Senior Notes. Other than debt and interest payments on the 2024 CCH Senior Notes, debt and interest payments do not contemplate repurchases, repayments and retirements that we expect to make prior to contractual maturity. See further discussion in Note 11—Debt of our Notes to Consolidated Financial Statements.

Debt

As of December 31, 2022, our debt complex was comprised of senior notes with an aggregate outstanding principal balance of $25.1 billion and credit facilities with no outstanding balances. As of December 31, 2022, each of our issuers was in compliance with all covenants related to their respective debt agreements. Further discussion of our debt obligations, including the restrictions imposed by these arrangements, can be found in Note 11—Debt of our Notes to Consolidated Financial Statements.

Interest

As of December 31, 2022, our senior notes had a weighted average contractual interest rate of 4.76%. We have various credit facilities indexed to LIBOR, which is expected to be phased out in 2023. To date, we have amended certain of our credit facilities to incorporate a replacement rate or a fallback replacement rate indexed to SOFR as a result of the expected LIBOR transition. We intend to continue working with our lenders to pursue amendments to our remaining debt agreements that are currently indexed to LIBOR. Undrawn commitments under our credit facilities are subject to commitment fees ranging from 0.10% to 0.638%, subject to change based on the applicable entity's credit rating. Issued letters of credit under our credit facilities are subject to letter of credit fees ranging from 1.25% to 1.625%. We had $506 million aggregate amount of issued letters of credit under our credit facilities as of December 31, 2022.

Additional Future Cash Requirements for Financing

CQP Distribution

CQP is required by its partnership agreement to, within 45 days after the end of each quarter, distribute to unitholders all available cash at the end of a quarter less the amount of any reserves established by its general partner. We own a 48.6% limited partner interest in CQP in the form of 239.9 million common units, with the remaining non-controlling limited partner interest held by Blackstone Inc., Brookfield Asset Management Inc. and the public. During the year ended December 31, 2022, CQP paid $947 million in distributions to its non-controlling interest.

Revised Capital Allocation Plan

As described in Overview of Significant Events, in September 2022, our Board approved a revised comprehensive long-term capital allocation plan. Pursuant to the revised capital allocation plan, on September 12, 2022 our Board authorized an increase in the existing share repurchase program by $4.0 billion for an additional three years, beginning on October 1, 2022. As of December 31, 2022, we had up to $3.6 billion available under the share repurchase program. The timing and amount of any shares of our common stock that are repurchased under the share repurchase program will be determined by management based on market conditions and other factors. During the year ended December 31, 2022, we repurchased a total of 9.3 million shares of our common stock for $1.4 billion at a weighted average price per share of $146.88. A discussion of our share repurchase program can be found in Item 5. Market for Registrant's Common Equity, Related Stockholders Matters and Issuer Purchase of Equity Securities.

A further aspect of our revised capital allocation plan is to lower our long-term leverage target through debt paydown to approximately 4x, which may involve the repayment, redemption or repurchase, on the open market or otherwise, of our indebtedness, including senior notes of SPL, CQP, CCH and Cheniere. The timing and amount of any paydown of our indebtedness will be determined by management based on market conditions and other factors. During the year ended December 31, 2022, we used $5.6 billion of available cash to reduce our outstanding indebtedness, of which $5.4 billion was the redemption or prepayment of indebtedness pursuant to our capital allocation plan.

The revised capital allocation plan also includes a targeted annual dividend growth rate of approximately 10% through Corpus Christi Stage 3 Project construction. On September 12, 2022, we declared a quarterly dividend of $0.395 per common share, which represented a 20% increase from the previous quarterly dividend. On January 27, 2023, we declared a quarterly dividend of $0.395 per share of common stock that is payable on February 27, 2023 to stockholders of record as of February 7, 2023.

Financially Disciplined Growth

To the extent that liquefaction capacity at the Corpus Christi LNG Terminal and the Sabine Pass LNG Terminal is expanded beyond the Liquefaction Projects and the Corpus Christi Stage 3 Project, such as CCL Midscale Trains 8 and 9, we expect that additional financing would be used to fund construction of the expansion.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash, cash equivalents and restricted cash and cash equivalents (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,	
	2022	2021
Net cash provided by operating activities	$ 10,523	$ 2,469
Net cash used in investing activities	(1,844)	(912)
Net cash used in financing activities	(8,014)	(1,817)
Effect of exchange rate changes on cash, cash equivalents and restricted cash and cash equivalents	5	—
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	$ 670	$ (260)

Operating Cash Flows

Our operating cash net inflows during the years ended December 31, 2022 and 2021 were $10.5 billion and $2.5 billion, respectively. The $8.1 billion increase was primarily related to increased cash receipts from the sale of LNG cargoes due to higher revenue per MMBtu and, to a lesser extent, higher volume of LNG delivered. Additionally, a portion of the increase was related to the receipt of the lump sum Termination Fee from Chevron related to the Termination Agreement, as further described in Overview of Significant Events, of which $796 million of cash inflows were allocable to the termination of the TUA, while an offsetting $31 million was recognized as a loss on extinguishment of debt allocable to a premium paid to Chevron to terminate a revenue sharing arrangement with them that was accounted for as debt, as discussed below under *Financing Cash Flows*. Partially offsetting these operating cash inflows were higher operating cash outflows primarily due to higher natural gas feedstock costs and lower contribution from certain portfolio optimization activities.

On August 16, 2022, President Biden signed H.R. 5376 (P.L. 117-169), commonly referred to as the Inflation Reduction Act, into law, which includes the implementation of a new 15% corporate alternative minimum tax (the "CAMT") effective in 2023 on the adjusted financial statement income of certain large corporations, among other provisions. We have elected to account for the effects of CAMT on deferred tax assets, carryforwards, and tax credits in the period they arise.

Investing Cash Flows

Our investing cash net outflows in both years primarily were for the construction costs for the Liquefaction Projects. The $932 million increase in 2022 compared to 2021 was primarily due to spend during the year ended December 31, 2022 related to construction work performed by Bechtel for the Corpus Christi Stage 3 Project, partially offset by a decrease in spend due to the completion of Train 6 of the SPL Project in February 2022, which was under construction throughout 2021. We expect our capital expenditures to increase in future periods as construction work progresses on the Corpus Christi Stage 3 Project following our issuance of full notice to proceed to Bechtel in June 2022.

Financing Cash Flows

The following table summarizes our financing activities (in millions):

	Year Ended December 31,	
	2022	2021
Proceeds from issuances of debt	$ 1,575	$ 5,911
Redemptions and repayments of debt	(6,771)	(6,810)
Distributions to non-controlling interest	(947)	(649)
Repurchase of common stock	(1,373)	(9)
Dividends to stockholders	(349)	(85)
Other, net	(149)	(175)
Net cash used in financing activities	$ (8,014)	$ (1,817)

During the years ended December 31, 2022 and 2021, we had total debt issuances of $1.6 billion and $5.9 billion, respectively. The proceeds from the borrowings during the year ended December 31, 2022, together with cash on hand, were used to pay down $6.8 billion of outstanding indebtedness, which included $965 million of debt repurchases on the open market, and the remaining associated with redemptions of our outstanding notes or paydown of our credit facilities. The proceeds from the borrowings during year ended December 31, 2021, together with cash on hand, were used to redeem or repurchase $6.8 billion of outstanding indebtedness, entirely associated with redemptions of our outstanding notes or paydown of our credit facilities.

Debt Issuances and Related Financing Costs

The following table shows the proceeds from issuances of debt, including intra-year borrowings (in millions):

	Year Ended December 31,	
	2022	2021
Proceeds from issuances of debt		
SPL:		
5.900% Senior Secured Amortizing Notes due 2037	$ 430	$ —
2037 SPL Private Placement Senior Secured Notes	70	482
SPL Working Capital Facility	60	—
CQP:		
4.000% Senior Notes due 2031	—	1,500
3.25% Senior Notes due 2032	—	1,200
CCH:		
2.742% Senior Notes due 2029	—	750
CCH Credit Facility	440	—
CCH Working Capital Facility	—	400
Cheniere:		
Cheniere Revolving Credit Facility	575	1,359
Cheniere's term loan facility (the "Cheniere Term Loan Facility")	—	220
Total proceeds from issuances of debt	$ 1,575	$ 5,911

During the years ended December 31, 2022 and 2021, we paid debt issuance costs and other financing costs of $51 million and $53 million, respectively, included in other, net in the *Financing Cash Flows* table above, related to the debt issuances above and amendment of credit facilities during the respective periods.

Debt Redemptions, Repayments and Repurchases and Related Modification or Extinguishment Costs

The following table shows the redemptions, repayments and repurchases of debt, including intra-year repayments (in millions):

	Year Ended December 31,	
	2022	2021
Redemption, repayments and repurchases of debt		
SPL:		
2022 SPL Senior Notes	$ —	$ (1,000)
2023 SPL Senior Notes	(1,500)	—
SPL Working Capital Facility	(60)	—
CQP:		
5.250% Senior Notes due 2025	—	(1,500)
5.625% Senior Notes due 2026	—	(1,100)
CCH:		
CCH Credit Facility	(2,169)	(898)
CCH Working Capital Facility	(250)	(290)
2024 CCH Senior Notes	(752)	—
5.625% Senior Notes due 2025	(9)	
5.125% Senior Notes due 2027	(230)	—
3.700% Senior Notes due 2029	(138)	—
3.751% weighted average Senior Notes rate due 2039	(88)	—
Cheniere:		
4.875% Cheniere Convertible Senior Notes due 2021	—	(295)
4.25% Convertible Senior Notes due 2045	(500)	—
Cheniere Revolving Credit Facility	(575)	(1,359)
4.625% Senior Secured Notes due 2028	(500)	—
Cheniere Term Loan Facility	—	(368)
Total redemptions, repayments and repurchases of debt	$ (6,771)	$ (6,810)

During the years ended December 31, 2022 and 2021, we paid debt modification or extinguishment costs of $3 million and $82 million, respectively, included in other, net in the *Financing Cash Flows* table above, related to these redemptions and repayments. In addition, during the year ended December 31, 2022, we paid $31 million associated with a premium paid to terminate a revenue sharing arrangement under the Termination Agreement with Chevron.

Non-Controlling Interest Distributions

We own a 48.6% limited partner interest in CQP with the remaining non-controlling limited partner interest held by Blackstone Inc., Brookfield Asset Management Inc. and the public. CQP paid distributions of $947 million and $649 million during the years ended December 31, 2022 and 2021, respectively, to non-controlling interests.

Repurchase of Common Stock

The following table presents information with respect to repurchases of common stock (in millions, except per share data):

	Year Ended December 31,	
	2022	2021
Aggregate common stock repurchased	9.35	0.10
Weighted average price paid per share	$ 146.88	$ 87.32
Total amount paid	$ 1,373	$ 9

As of December 31, 2022, we had approximately $3.6 billion remaining under our share repurchase program.

Cash Dividends to Stockholders

During the year ended December 31, 2022, we paid aggregate dividends of $1.385 per share of common stock, for a total of $349 million paid to common stockholders. We paid dividends of $0.33 per share of common stock, for a total of $85 million during the year ended December 31, 2021.

On January 27, 2023, we declared a quarterly dividend of $0.395 per share of common stock that is payable on February 27, 2023 to stockholders of record as of February 7, 2023.

Summary of Critical Accounting Estimates

The preparation of our 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 Level 3 Physical Liquefaction Supply Derivatives

All derivative instruments are recorded at fair value, other than certain derivatives for which we have elected to apply accrual accounting, as described in Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. We record changes in the fair value of our derivative positions through earnings, based on the value for which the derivative instrument could be exchanged between willing parties. Valuation of our physical liquefaction supply derivative contracts is often developed through the use of internal models which includes significant unobservable inputs representing Level 3 fair value measurements as further described in Note 2—Summary of Significant Accounting Policies of our Notes to Consolidated Financial Statements. 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 and adjustments for transportation prices, and associated events deriving fair value including, but not limited to, evaluation of whether the respective market exists from the perspective of market participants as infrastructure is developed.

Additionally, the valuation of certain physical liquefaction supply derivatives requires significant judgment in estimating underlying forward commodity curves due to periods of unobservability or limited liquidity. Such valuations are more susceptible to variability particularly when markets are volatile. Provided below are the changes in fair value from valuation of instruments valued through the use of internal models which incorporate significant unobservable inputs for the years ended December 31, 2022 and 2021 (in millions), which entirely consisted of physical liquefaction supply derivatives. The changes in fair value shown are limited to instruments still held at the end of each respective period.

	Year Ended December 31,	
	2022	2021
Unfavorable changes in fair value relating to instruments still held at the end of the period	$ (6,493)	$ (4,305)

The unfavorable changes in fair value on instruments held at the end of both years is primarily attributed to significant appreciation in estimated forward international LNG commodity curves on our IPM agreements during the years ended December 31, 2022 and 2021.

The estimated fair value of level 3 derivatives recognized in our Consolidated Balance Sheets as of December 31, 2022 and 2021 amounted to a liability of $9.9 billion and $4.0 billion, respectively, consisting entirely of physical liquefaction supply derivatives.

The ultimate fair value of our derivative instruments is uncertain, and we believe that it is reasonably possible that a material change in the estimated fair value could occur in the near future, particularly as it relates to commodity prices given the level of volatility in the current year. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for further analysis of the sensitivity of the fair value of our derivatives to hypothetical changes in underlying prices.

Recent Accounting Standards

For a summary 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 and the CCL Project, and associated economic hedges (collectively, "Liquefaction Supply Derivatives"). We have also entered into physical and financial derivatives to hedge the exposure to the commodity markets in which we have contractual arrangements to purchase or sell physical LNG (collectively, "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, 2022		December 31, 2021	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
Liquefaction Supply Derivatives	$ (10,019)	$ 2,249	$ (4,038)	$ 903
LNG Trading Derivatives	(46)	15	(400)	38

See Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements for additional details about our commodity derivative instruments.

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, 2022		December 31, 2021	
	Fair Value	Change in Fair Value	Fair Value	Change in Fair Value
FX Derivatives	$ (28)	$ 3	$ 12	$ 2

See Note 7—Derivative Instruments of our Notes to Consolidated Financial Statements for additional details about our foreign currency 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, 2022, 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, 2022, 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)		Executive Vice President and Chief Financial Officer (Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cheniere Energy, Inc. and subsidiaries (the Company) as of December 31, 2022 and 2021, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2022, 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, 2022, 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 22, 2023 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

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

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

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 $(9,924) million, as of December 31, 2022. 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 using internal models that 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.

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 related to 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 model. For a selection of level 3 liquefaction supply derivatives, we involved valuation professionals with specialized skills and knowledge who assisted in:

- evaluating the future prices of energy units for observable periods by comparing to market data, including quoted or published forward prices
- developing independent fair value estimates and comparing the independently developed estimates to the Company's fair value estimates.

In addition, we evaluated the Company's assumptions for future prices of energy units for unobservable periods and liquidity by comparing them 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 22, 2023

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, 2022, 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, 2022, 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, 2022 and 2021, the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2022, and the related notes and financial statement schedules I to II (collectively, the consolidated financial statements), and our report dated February 22, 2023 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 22, 2023

CHENIERE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Year Ended December 31, 2022	2021	2020
Revenues			
LNG revenues	$ 31,804	$ 15,395	$ 8,924
Regasification revenues	1,068	269	269
Other revenues	556	200	165
Total revenues	33,428	15,864	9,358
Operating costs and expenses			
Cost of sales (excluding items shown separately below)	25,632	13,773	4,161
Operating and maintenance expense	1,681	1,444	1,320
Selling, general and administrative expense	416	325	302
Depreciation and amortization expense	1,119	1,011	932
Development expense	16	7	6
Other	5	5	6
Total operating costs and expenses	28,869	16,565	6,727
Income (loss) from operations	4,559	(701)	2,631
Other income (expense)			
Interest expense, net of capitalized interest	(1,406)	(1,438)	(1,525)
Loss on modification or extinguishment of debt	(66)	(116)	(217)
Interest rate derivative gain (loss), net	2	(1)	(233)
Other income (expense), net	5	(22)	(112)
Total other expense	(1,465)	(1,577)	(2,087)
Income (loss) before income taxes and non-controlling interest	3,094	(2,278)	544
Less: income tax provision (benefit)	459	(713)	43
Net income (loss)	2,635	(1,565)	501
Less: net income attributable to non-controlling interest	1,207	778	586
Net income (loss) attributable to common stockholders	$ 1,428	$ (2,343)	$ (85)
Net income (loss) per share attributable to common stockholders—basic	$ 5.69	$ (9.25)	$ (0.34)
Net income (loss) per share attributable to common stockholders—diluted	$ 5.64	$ (9.25)	$ (0.34)
Weighted average number of common shares outstanding—basic	251.1	253.4	252.4
Weighted average number of common shares outstanding—diluted	253.4	253.4	252.4

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,	
	2022	2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,353	$ 1,404
Restricted cash and cash equivalents	1,134	413
Trade and other receivables, net of current expected credit losses	1,944	1,506
Inventory	826	706
Current derivative assets	120	55
Margin deposits	134	765
Other current assets	97	207
Total current assets	5,608	5,056
Property, plant and equipment, net of accumulated depreciation	31,528	30,288
Operating lease assets	2,625	2,102
Derivative assets	35	69
Goodwill	77	77
Deferred tax assets	864	1,204
Other non-current assets, net	529	462
Total assets	$ 41,266	$ 39,258
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities		
Accounts payable	$ 124	$ 155
Accrued liabilities	2,679	2,299
Current debt, net of discount and debt issuance costs	813	366
Deferred revenue	234	155
Current operating lease liabilities	616	535
Current derivative liabilities	2,301	1,089
Other current liabilities	28	94
Total current liabilities	6,795	4,693
Long-term debt, net of premium, discount and debt issuance costs	24,055	29,449
Operating lease liabilities	1,971	1,541
Finance lease liabilities	494	57
Derivative liabilities	7,947	3,501
Other non-current liabilities	175	50
Commitments and contingencies (see Note 20)		
Stockholders' deficit		
Preferred stock: $0.0001 par value, 5.0 million shares authorized, none issued	—	—
Common stock: $0.003 par value, 480.0 million shares authorized; 276.7 million shares and 275.2 million shares issued at December 31, 2022 and 2021, respectively	1	1
Treasury stock: 31.2 million shares and 21.6 million shares at December 31, 2022 and 2021, respectively, at cost	(2,342)	(928)
Additional paid-in-capital	4,314	4,377
Accumulated deficit	(4,942)	(6,021)
Total Cheniere stockholders' deficit	(2,969)	(2,571)
Non-controlling interest	2,798	2,538
Total stockholders' deficit	(171)	(33)
Total liabilities and stockholders' deficit	$ 41,266	$ 39,258

(1) Amounts presented include balances held by our consolidated variable interest entity ("VIE"), CQP, as further discussed in Note 9—Non-controlling Interest and Variable Interest Entity. As of December 31, 2022, total assets and liabilities of CQP were $18.9 billion and $21.7 billion, respectively, including $0.9 billion of cash and cash equivalents and $0.1 billion of restricted cash and cash equivalents.

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

CHENIERE ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)
(in millions)

	Total Stockholders' Deficit							
	Common Stock		Treasury Stock					
	Shares	Par Value Amount	Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Non-controlling Interest	Total Equity (Deficit)
Balance at December 31, 2019	253.6	$ 1	17.1	$ (674)	$ 4,167	$ (3,508)	$ 2,449	$ 2,435
Vesting of share-based compensation awards	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 attributable to common stockholders	—	—	—	—	—	(85)	—	(85)
Balance at December 31, 2020	252.3	1	20.8	(872)	4,273	(3,593)	2,409	2,218
Vesting of share-based compensation awards	2.1	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	105	—	—	105
Issued shares withheld from employees related to share-based compensation, at cost	(0.7)	—	0.7	(47)	(1)	—	—	(48)
Shares repurchased, at cost	(0.1)	—	0.1	(9)	—	—	—	(9)
Net income attributable to non-controlling interest	—	—	—	—	—	—	778	778
Distributions to non-controlling interest	—	—	—	—	—	—	(649)	(649)
Dividends declared ($0.33 per common share)	—	—	—	—	—	(85)	—	(85)
Net loss attributable to common stockholders	—	—	—	—	—	(2,343)	—	(2,343)
Balance at December 31, 2021	253.6	1	21.6	(928)	4,377	(6,021)	2,538	(33)
Vesting of share-based compensation awards	1.5	—	—	—	—	—	—	—
Share-based compensation	—	—	—	—	112	—	—	112
Issued shares withheld from employees related to share-based compensation, at cost	(0.3)	—	0.3	(41)	(22)	—	—	(63)
Shares repurchased, at cost	(9.3)	—	9.3	(1,373)	—	—	—	(1,373)
Adoption of ASU 2020-06, net of tax (see Note 2)	—	—	—	—	(153)	4	—	(149)
Net income attributable to non-controlling interest	—	—	—	—	—	—	1,207	1,207
Distributions to non-controlling interest	—	—	—	—	—	—	(947)	(947)
Dividends declared ($1.385 per common share)	—	—	—	—	—	(353)	—	(353)
Net income attributable to common stockholders	—	—	—	—	—	1,428	—	1,428
Balance at December 31, 2022	245.5	$ 1	31.2	$ (2,342)	$ 4,314	$ (4,942)	$ 2,798	$ (171)

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,		
	2022	2021	2020
Cash flows from operating activities			
Net income (loss)	$ 2,635	$ (1,565)	$ 501
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized foreign currency exchange gain, net	(5)	—	—
Depreciation and amortization expense	1,119	1,011	932
Share-based compensation expense	205	140	110
Non-cash interest expense	26	19	51
Amortization of debt issuance costs, premium and discount	57	72	114
Reduction of right-of-use assets	607	393	291
Loss on modification or extinguishment of debt	66	116	217
Total losses on derivative instruments, net	6,531	5,989	211
Net cash used for settlement of derivative instruments	(904)	(1,579)	74
Loss on equity method investments	55	24	126
Deferred taxes	440	(715)	40
Repayment of paid-in-kind interest related to repurchase of convertible notes	(13)	(190)	(911)
Other, net	11	9	8
Changes in operating assets and liabilities:			
Trade and other receivables, net of current expected credit losses	(502)	(799)	(154)
Inventory	(123)	(409)	21
Margin deposits	631	(741)	(13)
Other current assets	67	(101)	(14)
Accounts payable and accrued liabilities	250	1,144	54
Total deferred revenue	124	55	(23)
Total operating lease liabilities	(622)	(418)	(277)
Other, net	(132)	14	(93)
Net cash provided by operating activities	10,523	2,469	1,265
Cash flows from investing activities			
Property, plant and equipment	(1,830)	(966)	(1,839)
Proceeds from sale of fixed assets	1	68	—
Investment in equity method investment	(15)	—	(100)
Other, net	—	(14)	(8)
Net cash used in investing activities	(1,844)	(912)	(1,947)
Cash flows from financing activities			
Proceeds from issuances of debt	1,575	5,911	7,823
Redemptions and repayments of debt	(6,771)	(6,810)	(6,940)
Debt issuance and other financing costs	(51)	(53)	(125)
Debt modification or extinguishment costs	(28)	(82)	(172)
Distributions to non-controlling interest	(947)	(649)	(626)
Payments related to tax withholdings for share-based compensation	(63)	(48)	(43)
Repurchase of common stock	(1,373)	(9)	(155)
Dividends to stockholders	(349)	(85)	—
Payments of finance lease liabilities	(7)	—	—
Other, net	—	8	3
Net cash used in financing activities	(8,014)	(1,817)	(235)
Effect of exchange rate changes on cash, cash equivalents and restricted cash and cash equivalents	5	—	—
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	670	(260)	(917)
Cash, cash equivalents and restricted cash and cash equivalents—beginning of period	1,817	2,077	2,994
Cash, cash equivalents and restricted cash and cash equivalents—end of period	$ 2,487	$ 1,817	$ 2,077

Balances per Consolidated Balance Sheets:

	December 31, 2022	December 31, 2021
Cash and cash equivalents	$ 1,353	$ 1,404
Restricted cash and cash equivalents	1,134	413
Total cash, cash equivalents and restricted cash and cash equivalents	$ 2,487	$ 1,817

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

NOTE 1—ORGANIZATION AND NATURE OF OPERATIONS

We operate two natural gas liquefaction and export facilities located in Cameron Parish, Louisiana at Sabine Pass and near Corpus Christi, Texas (respectively, the "Sabine Pass LNG Terminal" and "Corpus Christi LNG Terminal").

CQP owns the Sabine Pass LNG Terminal, which has natural gas liquefaction facilities consisting of six operational Trains, with Train 6 having achieved substantial completion on February 4, 2022, for a total operational production capacity of approximately 30 mtpa of LNG (the "SPL Project"). The Sabine Pass LNG Terminal also has operational regasification facilities that include five LNG storage tanks, vaporizers and three marine berths, with the third berth having achieved substantial completion on October 27, 2022. The Sabine Pass LNG Terminal also includes a 94-mile pipeline owned by CTPL, a subsidiary of CQP, that interconnects our facilities with a number of large interstate and intrastate pipelines. As of December 31, 2022, we owned 100% of the general partner interest and a 48.6% limited partner interest in CQP.

The Corpus Christi LNG Terminal currently has three operational Trains for a total operational production capacity of approximately 15 mtpa of LNG, three LNG storage tanks and two marine berths. Additionally, we are constructing an expansion of the Corpus Christi LNG Terminal (the "Corpus Christi Stage 3 Project") for up to seven midscale Trains with an expected total operational production capacity of over 10 mtpa of LNG. CCL Stage III, CCL and CCP received approval from FERC in November 2019 to site, construct and operate the Corpus Christi Stage 3 Project. In March 2022, CCL Stage III issued limited notice to proceed to Bechtel Energy Inc. ("Bechtel") to commence early engineering, procurement and site works. In June 2022, our board of directors (our "Board") made a positive FID with respect to the investment in the construction and operation of the Corpus Christi Stage 3 Project and issued a full notice to proceed with construction to Bechtel effective June 16, 2022. In connection with the positive FID, CCL Stage III, through which we were developing and constructing the Corpus Christi Stage 3 Project, was contributed to CCH and subsequently merged with and into CCL, the surviving entity of the merger and a wholly owned subsidiary of CCH. Through our subsidiary CCP, we also own a 21.5-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 existing operational Trains, midscale Trains, storage tanks and marine berths, the "CCL Project").

We have increased available liquefaction capacity at the SPL Project and the CCL Project (collectively, the "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. In September 2022, certain of our subsidiaries entered the pre-filing review process with the FERC under the National Environmental Policy Act for an expansion adjacent to the CCL Project consisting of two midscale Trains with an expected total production capacity of approximately 3 mtpa of LNG. 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 positive 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 subsidiaries and affiliates in which we hold a controlling interest, reflecting ownership of a majority of the voting interest, as of the financial statement date. Additionally, we consolidate a VIE under certain criteria discussed further below. All intercompany accounts and transactions have been eliminated in consolidation.

VIEs

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 VIE. Generally, an entity is a VIE if either (1) the entity does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, (2) the entity's investors lack any characteristics of a controlling financial interest or (3) the entity was established with non-substantive voting rights.

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.

Non-controlling Interests

When we consolidate an entity, we include 100% of the assets, liabilities, revenues and expenses of the subsidiary in our Consolidated Financial Statements. For those entities that we consolidate in which our ownership is less than 100%, we record a non-controlling interest as a component of equity on our Consolidated Balance Sheets, which represents the third party ownership in the net assets of the respective consolidated subsidiary. Additionally, 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 Statements of Operations. Changes in our ownership interests in an entity 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.

Equity Method Investments

Investments in non-controlled entities in 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 Statements of Operations or, if the investment is deemed operationally integral to our operations, reported within operating income on our Consolidated Statements of Operations in the respective line item depending on the nature of the investment. 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. See Note 8—Other Non-Current Assets, Net for additional details about our equity method investments.

Use of Estimates

The preparation of our 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 of derivatives and other instruments, useful lives of property, plant and equipment, certain valuations including leases, asset retirement obligations ("AROs") and recoverability of deferred tax assets, each 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, and liability-classified share-based compensation awards, as disclosed in Note 16—Share-Based Compensation.

The carrying amount of cash and cash equivalents, restricted cash and cash equivalents, trade and other receivables, net of current expected credit losses, contract assets, margin deposits, accounts payable and accrued liabilities 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.

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. See Note 13—Revenues for further discussion of our revenue streams and accounting policies related to revenue recognition.

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 and Cash Equivalents

Restricted cash and cash equivalents consist 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.

Current Expected Credit Losses

Trade and other receivables and contract assets are reported net of any current expected credit losses. 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, 2022 and 2021, we had current expected credit losses of zero and $5 million, respectively, on our trade and other receivables and $5 million and $4 million, respectively, on our non-current contract assets.

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. Inventory is charged to expense when sold, or, for certain qualifying costs, capitalized to property, plant and equipment when issued, primarily using the weighted average method.

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.

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.

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 over assigned useful lives. Refer to Note 6—Property, Plant and Equipment, Net of Accumulated Depreciation for additional discussion of our useful lives by asset category. 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 on disposal are recorded in other operating costs and expenses.

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

We did not record any material impairments related to property, plant and equipment during the years ended December 31, 2022, 2021 and 2020.

Interest Capitalization

We capitalize interest costs during the construction period of our LNG terminals and related assets as construction-in-process. Upon placing the underlying asset in service, these costs are transferred out of construction-in-process into the respective in-service asset category and depreciated over the estimated useful life of the corresponding assets, except for capitalized interest associated with land, which is not depreciated.

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 classified in our Consolidated Balance Sheets as other assets and other liabilities. Upon identification of a triggering event, we 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 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, under which we account for the instrument under the accrual method of accounting, whereby revenues and expenses are recognized only upon delivery, receipt or realization of the underlying transaction. When we have the contractual right and intent to net settle, derivative assets and liabilities are reported on a net basis.

For those derivative instruments measured at fair value, changes in the fair value of the 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, 2022, 2021 and 2020. See Note 7—Derivative Instruments for additional details about our derivative instruments.

Leases

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 in which we are the lessee, 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 minimum lease payments over the lease term. In determining the present value of minimum 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.

Certain of our leases also contain variable payments that are included in the right-of-use asset and lease liability only when the contract terms require the payment of a fixed amount that is unavoidable.

When we determine the arrangement is, or contains, a lease in which we are the lessor or sublessor, we assess classification of the lease as either an operating lease, sales-type lease or direct financing lease. All of our arrangements have been assessed as operating leases and consist of sublessor arrangements in which we have not been relieved of our primary obligation under the original lease. Our sublessor arrangements are not recognized on our Consolidated Balance Sheet and we recognize income from these arrangements on a straight-line basis over the sublease term.

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 derivative instruments and accounts receivable related to our long-term SPAs and regasification contracts, each discussed further below. Additionally, we maintain cash balances at financial institutions, which may at times be in excess of federally insured levels. We have not incurred credit losses related to these cash 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 margin deposits. Our 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.

We have contracted our anticipated production capacity under SPAs and under IPM agreements. Substantially all of our contracted capacity is from contracts with terms exceeding 10 years. As of December 31, 2022, we had SPAs with terms of 10 or more years with a total of 28 different third party customers. Excluding contracts with terms less than 10 years, our SPAs and IPM agreements had approximately 17 years of weighted average remaining life as of December 31, 2022. We market and sell LNG produced by the Liquefaction Projects that is not contracted by CCL or SPLs through our integrated marketing function. We are dependent on the respective customers' creditworthiness and their willingness to perform under their respective agreements.

See Note 21—Customer Concentration for additional details about our customer concentration.

Our arrangements with our customers incorporate certain provisions to mitigate our exposure to credit losses and include, under certain circumstances, customer collateral, netting of exposures through the use of industry standard commercial agreements and, as described above, margin deposits with certain counterparties in the over-the-counter derivative market, with such margin deposits primarily facilitated by independent system operators and by clearing brokers. Payments on margin deposits, either by us or by the counterparty depending on the position, are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us (or to the counterparty) on or near the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions.

Goodwill

Goodwill is the excess of acquisition cost of a business over the estimated fair value of net assets acquired. Goodwill is not amortized; however, we test goodwill for impairment at least annually as of October 1st, or more frequently if events or circumstances indicate goodwill is more likely than not impaired. Factors that could indicate a more likely than not impairment include, but may not be limited to, significant negative industry or economic trends, cost increases, disruptions to our business, regulatory or political environment changes or other unanticipated events. When evaluating goodwill for impairment, we may either perform 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. If it is concluded that it is more-likely-than not that an impairment exists, a quantitative test is required which compares the estimated fair value of a reporting unit to its carrying value and measures any goodwill impairment as the amount by which the carrying amount of the reporting unit exceeds its fair value. Significant judgments and assumptions are inherent in our estimate of future cash flows used to determine the estimate of the reporting unit's fair value. We may elect not to perform the qualitative assessment and instead perform a quantitative impairment test.

We completed our annual assessment of goodwill impairment in the current year by performing a qualitative assessment; which indicated it was not more likely than not that there was an impairment and therefore no quantitative test was required.

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, printing costs and in certain cases, commitment fees. If debt issuance costs are incurred in connection with a line of credit arrangement or on undrawn funds, the debt issuance costs 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 loss on modification or extinguishment of debt on our Consolidated Statements of Operations.

We classify debt on our Consolidated Balance Sheets based on contractual maturity, with the following exceptions:

- We classify term debt that is contractually due within one year as long-term debt if management has the intent and ability to refinance the current portion of such debt with future cash proceeds from an executed long-term debt agreement.
- We evaluate the classification of long-term debt extinguished after the balance sheet date but before the financial statements are issued based on facts and circumstances existing as of the balance sheet date.

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 (immediately vested), restricted stock shares, restricted stock units, performance stock units and phantom units. The awards and our related accounting policies are more fully described in Note 16—Share-based Compensation.

Foreign Currency

The functional currency of all of our subsidiaries is the U.S. dollar. Certain of our subsidiaries transact in currencies outside of the U.S. dollar, which gives rise to the recognition of transaction gains and losses based on the change in exchange rates between the U.S. dollar and the currency in which the foreign currency transaction is denominated. During the years ended December 31, 2022, 2021 and 2020, we recognized net transaction gains (losses) totaling $60 million, $33 million and $(0.5) million, respectively, substantially all of which was attributable to net gains (losses) totaling $61 million, $33 million and $(0.3) million, respectively, relating to commercial transactions within Cheniere Marketing. The transaction gains and losses on such commercial transactions primarily consisted of those on Euro denominated receivables and related foreign currency hedges arising from the sale of cargoes, which are presented within LNG revenues in our Consolidated Statements of Operations with the underlying activities. The remaining transaction gains and losses are presented primarily within other income (expense), net in our Consolidated Statements of Operations.

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 some or all of our deferred tax assets will not be realized. We evaluate the realizability of our deferred tax assets as of each reporting date, weighing all positive and negative evidence. The assessment requires significant judgment and is performed in each of our applicable jurisdictions. In making such determination, we consider various factors such as historical profitability, future projections of sustained profitability underpinned by fixed-price long-term SPAs and reversal of existing deferred tax liabilities.

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.

On August 16, 2022, President Biden signed H.R. 5376 (P.L. 117-169), commonly referred to as the Inflation Reduction Act, into law, which includes the implementation of a new 15% corporate alternative minimum tax (the "CAMT") effective in 2023 on the adjusted financial statement income of certain large corporations, among other provisions. We have elected to account for the effects of CAMT on deferred tax assets, carryforwards, and tax credits in the period they arise.

Net Income (Loss) Per Share

Basic net income or loss per share attributable to common stockholders excludes dilution and is computed by dividing net income or loss attributable to common stockholders during the period by the weighted average number of common shares outstanding during the period. Diluted net income or loss per share 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, which is increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued. However, if the effect of any additional securities are anti-dilutive (i.e., resulting in a higher net income per share or lower net loss per share), they are excluded from the dilutive net income or loss computation. 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.

Refer to Note 18—Net Income (Loss) per Share Attributable to Common Stockholders for additional details of the computation for the years ended December 31, 2022, 2021 and 2020.

Business Segment

We have determined that we operate as a single operating and reportable segment. Substantially all of our long-lived assets are located in the United States. 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.

Recent Accounting Standards

ASU 2020-06

In August 2020, the FASB issued 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 adopted this guidance on January 1, 2022 using the modified retrospective approach. The adoption of ASU 2020-06 primarily resulted in the reclassification of the previously bifurcated equity component associated with the 4.25% Convertible Senior Notes due 2045 (the "2045 Cheniere Convertible Senior Notes") to debt as a result of the elimination of the cash conversion model. As of January 1, 2022, the reclassification resulted in: (1) a \$194 million reduction of the equity component recorded in additional paid-in capital, before offsetting tax effect of \$41 million, (2) a \$189 million increase in the carrying value of our 2045 Cheniere Convertible Senior Notes and (3) a \$5 million decrease in accumulated deficit, before offsetting tax effect of \$1 million. In December 2021, we issued a notice of redemption for all \$625 million aggregate principal amount outstanding of our 2045 Cheniere Convertible Senior Notes, which were redeemed on January 5, 2022. See Note 11—Debt for further discussion of the 2045 Cheniere Convertible Senior Notes.

The adoption of ASU 2020-06 also impacted the calculation of the dilutive effect of our 2045 Cheniere Convertible Senior Notes on our net loss per share for the year ended December 31, 2022, as further discussed in Note 18—Net Income (Loss) per Share Attributable to Common Stockholders.

ASU 2020-04

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 contracts expected to arise from the market transition from LIBOR to alternative reference rates. The temporary optional expedients under the standard became effective March 12, 2020 and will be available until December 31, 2024 following a subsequent amendment to the standard.

We have various credit facilities indexed to LIBOR, as further described in Note 11—Debt. To date, we have amended certain of our credit facilities to incorporate a replacement rate or a fallback replacement rate indexed to SOFR as a result of the expected LIBOR transition. We elected to apply the optional expedients as applicable to certain modified facilities; however, the impact of applying the optional expedients was not material, and we do not expect the transition to SOFR or other replacement rate indexes to have a material impact on our future cash flows. We will apply the optional expedients to qualifying contract modifications in the future; however, we do not expect the impact of such application to be material.

NOTE 3—RESTRICTED CASH AND CASH EQUIVALENTS

Restricted cash and cash equivalents consisted of the following (in millions):

	December 31,	
	2022	2021
Restricted cash and cash equivalents		
SPL Project	$ 92	$ 98
CCL Project	738	44
Cash held by our subsidiaries that is restricted to Cheniere	304	271
Total restricted cash and cash equivalents	$ 1,134	$ 413

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 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—TRADE AND OTHER RECEIVABLES, NET OF CURRENT EXPECTED CREDIT LOSSES

Trade and other receivables, net of current expected credit losses consisted of the following (in millions):

	December 31,	
	2022	2021
Trade receivables		
SPL and CCL	$ 922	$ 802
Cheniere Marketing	917	640
Other receivables	105	64
Total trade and other receivables, net of current expected credit losses	$ 1,944	$ 1,506

NOTE 5—INVENTORY

Inventory consisted of the following (in millions):

	December 31,	
	2022	2021
LNG in-transit	$ 356	$ 312
LNG	212	153
Materials	194	174
Natural gas	60	64
Other	4	3
Total inventory	$ 826	$ 706

NOTE 6—PROPERTY, PLANT AND EQUIPMENT, NET OF ACCUMULATED DEPRECIATION

Property, plant and equipment, net of accumulated depreciation consisted of the following (in millions):

	December 31,	
	2022	2021
LNG terminal		
Terminal and interconnecting pipeline facilities	$ 33,815	$ 30,660
Site and related costs	451	441
Construction-in-process	1,685	2,995
Accumulated depreciation	(4,985)	(3,912)
Total LNG terminal, net of accumulated depreciation	30,966	30,184
Fixed assets and other		
Computer and office equipment	33	25
Furniture and fixtures	20	20
Computer software	121	120
Leasehold improvements	48	45
Land	1	1
Other	19	19
Accumulated depreciation	(191)	(176)
Total fixed assets and other, net of accumulated depreciation	51	54
Assets under finance leases		
Marine assets	533	60
Accumulated depreciation	(22)	(10)
Total assets under finance lease, net of accumulated depreciation	511	50
Property, plant and equipment, net of accumulated depreciation	$ 31,528	$ 30,288

The following table shows depreciation expense and offsets to LNG terminal costs (in millions):

	Year Ended December 31,		
	2022	2021	2020
Depreciation expense	$ 1,113	$ 1,006	$ 926
Offsets to LNG terminal costs (1)	204	319	19

(1) We recognize 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 6 and 50 years, as follows:

Components	Useful life (years)
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	6-50
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.

Assets under Finance Lease

Our assets under finance lease consists of certain tug vessels and LNG vessel time charters that meet the classification of a finance lease. These assets are depreciated on a straight-line method over the respective lease term. See Note 12—Leases for additional details of our finance leases.

NOTE 7—DERIVATIVE INSTRUMENTS

We have entered into the following derivative instruments:

- 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 term loan credit facility (the "CCH Credit Facility"), which expired in May 2022, and to hedge against changes in interest rates that could impact anticipated future issuances of debt by CCH (the "Interest Rate Forward Start Derivatives" and, collectively with the CCH Interest Rate Derivatives, the "Interest Rate Derivatives"), which were settled in August 2020;
- commodity derivatives consisting of natural gas and power supply contracts, including those under our IPM agreements, for the development, commissioning and operation of the Liquefaction Projects and associated economic hedges (collectively, "Liquefaction Supply Derivatives");
- LNG derivatives in which we have contractual net settlement and economic hedges on the exposure to the commodity markets in which we have contractual arrangements to purchase or sell physical LNG (collectively, "LNG Trading Derivatives"); and
- foreign currency exchange ("FX") contracts to hedge exposure to currency risk associated with cash flows denominated in currencies other than United States dollar ("FX Derivatives"), associated with both LNG Trading Derivatives and operations in countries outside of the United States.

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, in which case such changes are capitalized.

The following table shows the fair value of our derivative instruments that are required to be measured at fair value on a recurring basis (in millions):

	Fair Value Measurements as of							
	December 31, 2022				December 31, 2021			
	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
Interest Rate Derivatives liability	$ —	$ —	$ —	$ —	$ —	$ (40)	$ —	$ (40)
Liquefaction Supply Derivatives asset (liability)	(66)	(29)	(9,924)	(10,019)	7	(9)	(4,036)	(4,038)
LNG Trading Derivatives asset (liability)	1	(47)	—	(46)	(22)	(378)	—	(400)
FX Derivatives asset (liability)	—	(28)	—	(28)	—	12	—	12

We valued 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 Liquefaction Supply Derivatives and LNG Trading Derivatives are 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, but not limited to, evaluation of whether the respective market exists from the perspective of market participants as infrastructure is developed.

We include a significant portion of our 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 and volatility.

The Level 3 fair value measurements of our natural gas positions within our 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 Liquefaction Supply Derivatives as of December 31, 2022:

	Net Fair Value Liability (in millions)	Valuation Approach	Significant Unobservable Input	Range of Significant Unobservable Inputs / Weighted Average (1)
Liquefaction Supply Derivatives	$(9,924)	Market approach incorporating present value techniques	Henry Hub basis spread	$(1.775) - $0.660 / $(0.154)
		Option pricing model	International LNG pricing spread, relative to Henry Hub (2)	73% - 532% / 163%

(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 Liquefaction Supply Derivatives.

The following table shows the changes in the fair value of our Level 3 Liquefaction Supply Derivatives and LNG Trading Derivatives (in millions):

	Year Ended December 31,		
	2022	2021 (1)	2020
Balance, beginning of period	$ (4,036)	$ 241	$ 138
Realized and change in fair value gains (losses) included in net income (2):			
Included in cost of sales, existing deals (3)	(5,120)	(2,509)	156
Included in cost of sales, new deals (4)	(1,373)	(1,796)	—
Purchases and settlements:			
Purchases (5)	—	(1)	5
Settlements (6)	605	29	(65)
Transfers in and/or out of level 3			
Transfers into level 3 (7)	—	—	7
Balance, end of period	$ (9,924)	$ (4,036)	$ 241
Favorable (unfavorable) changes in fair value relating to instruments still held at the end of the period	$ (6,493)	$ (4,305)	$ 156

(1) Includes amounts recorded related to natural gas supply contracts that CCL had with a related party. The agreement ceased to be considered a related party agreement during 2021, as discussed in Note 14—Related Party Transactions.

(2) Does not include the realized value associated with derivative instruments that settle through physical delivery, as settlement is equal to contractually fixed price from trade date multiplied by contractual volume. See settlements line item in this table.

(3) Impact to earnings on deals that existed at the beginning of the period and continue to exist at the end of the period.

(4) Impact to earnings on deals that were entered into during the reporting period and continue to exist at the end of the period.

(5) Includes any day one gain (loss) recognized during the reporting period on deals that were entered into during the reporting period which continue to exist at the end of the period, in addition to any derivative contracts acquired from entities at a value other than zero on acquisition date, such as derivatives assigned or novated during the reporting period and continuing to exist at the end of the period.

(6) Roll-off in the current period of amounts recognized in our Consolidated Balance Sheets at the end of the previous period due to settlement of the underlying instruments in the current period.

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

All existing counterparty derivative contracts provide for the unconditional right of set-off in the event of default. We have elected to report derivative assets and liabilities arising from those derivative contracts with the same counterparty and the unconditional contractual right of set-off on a net basis. 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 depending on the position of the derivative. 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 previously entered into the following Interest Rate Derivatives to protect against volatility of future cash flows and hedge a portion of the variable interest payments on the CCH Credit Facility, which expired in May 2022:

	Notional Amounts			
	December 31, 2022	December 31, 2021	Weighted Average Fixed Interest Rate Paid	Variable Interest Rate Received
CCH Interest Rate Derivatives	$—	$4.5 billion	2.30%	One-month LIBOR

The following table shows the effect and location of our Interest Rate Derivatives on our Consolidated Statements of Operations (in millions):

		Gain (Loss) Recognized in Consolidated Statements of Operations		
	Consolidated Statements of Operations Location	Year Ended December 31,		
		2022	2021	2020
CCH Interest Rate Derivatives	Interest rate derivative gain (loss), net	$ 2	$ (1)	$ (138)
CCH Interest Rate Forward Start Derivatives	Interest rate derivative gain (loss), net	—	—	(95)

Commodity Derivatives

SPL and CCL hold Liquefaction Supply Derivatives which are primarily indexed to the natural gas market and international LNG indices. The terms of the Liquefaction Supply Derivatives range up to approximately 15 years, some of which commence upon the satisfaction of certain events or states of affairs.

Cheniere Marketing has historically entered into, and may from time to time enter into LNG transactions that provide for contractual net settlement. Such transactions are accounted for as LNG Trading Derivatives along with financial commodity contracts in the form of swaps or futures. The terms of LNG Trading Derivatives range up to approximately two years.

The following table shows the notional amounts of our Liquefaction Supply Derivatives and LNG Trading Derivatives (collectively, "Commodity Derivatives"):

	December 31, 2022		December 31, 2021	
	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives	Liquefaction Supply Derivatives	LNG Trading Derivatives
Notional amount, net (in TBtu)	14,504	50	11,238	33

(1) Excludes notional amounts associated with extension options that were uncertain to be taken as of December 31, 2022.

The following table shows the effect and location of our Commodity Derivatives recorded on our Consolidated Statements of Operations (in millions):

	Consolidated Statements of Operations Location (1)	Gain (Loss) Recognized in Consolidated Statements of Operations Year Ended December 31, 2022	2021	2020
LNG Trading Derivatives	LNG revenues	$ (387)	$ (1,812)	$ (26)
LNG Trading Derivatives	Cost of sales	(2)	91	(42)
Liquefaction Supply Derivatives (2)	LNG revenues	2	3	(1)
Liquefaction Supply Derivatives (2)	Cost of sales (3)	(6,203)	(4,303)	94

(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 value associated with derivative instruments that settle through physical delivery.

(3) Includes amounts recorded related to natural gas supply contracts that CCL had with a related party. The agreement ceased to be considered a related party agreement during 2021, as discussed in Note 14—Related Party Transactions.

FX Derivatives

Cheniere Marketing holds 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 that are denominated in a currency other than the United States dollar. The terms of FX Derivatives range up to approximately one year.

The total notional amount of our FX Derivatives was $619 million and $762 million as of December 31, 2022 and 2021, respectively.

The following table shows the effect and location of our FX Derivatives recorded on our Consolidated Statements of Operations (in millions):

	Consolidated Statements of Operations Location	Gain Recognized in Consolidated Statements of Operations Year Ended December 31, 2022	2021	2020
FX Derivatives	LNG revenues	$ 57	$ 33	$ (3)

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, 2022				
Consolidated Balance Sheets Location	CCH Interest Rate Derivatives	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives (2)	FX Derivatives	Total
Current derivative assets	$ —	$ 36	$ 84	$ —	$ 120
Derivative assets	—	35	—	—	35
Total derivative assets	—	71	84	—	155
Current derivative liabilities	—	(2,143)	(130)	(28)	(2,301)
Derivative liabilities	—	(7,947)	—	—	(7,947)
Total derivative liabilities	—	(10,090)	(130)	(28)	(10,248)
Derivative liability, net	$ —	$ (10,019)	$ (46)	$ (28)	$ (10,093)

	December 31, 2021				
Consolidated Balance Sheets Location	CCH Interest Rate Derivatives	Liquefaction Supply Derivatives (1)	LNG Trading Derivatives (2)	FX Derivatives	Total
Current derivative assets	$ —	$ 38	$ 2	$ 15	$ 55
Derivative assets	—	69	—	—	69
Total derivative assets	—	107	2	15	124
Current derivative liabilities	(40)	(644)	(402)	(3)	(1,089)
Derivative liabilities	—	(3,501)	—	—	(3,501)
Total derivative liabilities	(40)	(4,145)	(402)	(3)	(4,590)
Derivative asset (liability), net	$ (40)	$ (4,038)	$ (400)	$ 12	$ (4,466)

(1) Does not include collateral posted with counterparties by us of $111 million and $20 million as of December 31, 2022 and 2021, respectively, which are included in margin deposits in our Consolidated Balance Sheets.

(2) Does not include collateral posted with counterparties by us of $23 million and $745 million, as of December 31, 2022 and 2021, respectively, which are included in margin deposits in our Consolidated Balance Sheets.

Consolidated Balance Sheets Presentation

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

	Liquefaction Supply Derivatives	LNG Trading Derivatives	FX Derivatives
As of December 31, 2022			
Gross assets	$ 76	$ 87	$ —
Offsetting amounts	(5)	(3)	—
Net assets	$ 71	$ 84	$ —
Gross liabilities	$ (10,436)	$ (132)	$ (29)
Offsetting amounts	346	2	1
Net liabilities	$ (10,090)	$ (130)	$ (28)
As of December 31, 2021			
Gross assets	$ 155	$ 10	$ 48
Offsetting amounts	(48)	(8)	(33)
Net assets	$ 107	$ 2	$ 15
Gross liabilities	$ (4,382)	$ (551)	$ (10)
Offsetting amounts	237	149	7
Net liabilities	$ (4,145)	$ (402)	$ (3)

NOTE 8—OTHER NON-CURRENT ASSETS, NET

Other non-current assets, net consisted of the following (in millions):

	December 31, 2022	December 31, 2021
Contract assets, net of current expected credit losses	$ 171	$ 135
Advances made to municipalities for water system enhancements	78	81
Equity method investments	16	56
Advances and other asset conveyances to third parties to support LNG terminals	92	80
Debt issuance costs and debt discount, net of accumulated amortization	60	34
Advances made under EPC and non-EPC contracts	—	5
Advance tax-related payments and receivables	20	17
Other	92	54
Total other non-current assets, net	$ 529	$ 462

Equity Method Investments

Interest in Midship Holdings, LLC

As of December 31, 2022, our equity method investment balance consists of our 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 years ended December 31, 2022, 2021 and 2020, we recognized other-than-temporary impairment losses of $67 million, $37 million and $129 million, respectively, related to our investment in Midship Holdings. Impairment losses during the year ended December 31, 2022 were primarily the result of increased forecast construction-related and operating costs, resulting in an other-than-temporary reduction in the fair value of our equity interests. Impairment losses during the years ended December 31, 2021 and 2020 were precipitated primarily due to declining market conditions in the energy industry and customer credit risk, resulting in an other-than-temporary reduction in the fair value of our equity interests. The fair values of our equity interests were primarily measured using an income approach, which utilized level 3 fair value inputs such as projected earnings and discount rates. Impairment losses associated with our equity method investment is presented in other expense, net.

Our investment in Midship Holdings, net of impairment losses, was $16 million and $56 million as of December 31, 2022 and 2021, respectively.

Interest in ADCC Pipeline, LLC

In June 2022, we acquired a 30% equity interest in ADCC Pipeline, LLC and its wholly owned subsidiary (collectively, "ADCC Pipeline") through our wholly owned subsidiary Cheniere ADCC Investments, LLC. ADCC Pipeline will develop, construct and operate an approximately 42-mile natural gas pipeline project (the "ADCC Pipeline Project") connecting the Agua Dulce natural gas hub to the CCL Project. We currently have a future commitment of up to approximately $93 million to fund our equity interest, which commitment is subject to a condition precedent that has not yet been satisfied. Upon funding of such commitment, the investment will be recognized in our Consolidated Balance Sheets as an equity method investment.

NOTE 9—NON-CONTROLLING INTEREST AND VARIABLE INTEREST ENTITY

We own a 48.6% limited partner interest in CQP in the form of 239.9 million common units, with the remaining non-controlling limited partner interest held by Blackstone Inc., Brookfield Asset Management Inc. and the public. We also own 100% of the general partner interest and the incentive distribution rights in CQP.

CQP 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 CQP. In 2012, CQP, Cheniere and Blackstone CQP Holdco LP ("Blackstone CQP Holdco") entered into a unit purchase agreement whereby CQP 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 CQP is less than 20% of outstanding common units and subordinated units.

As a holder of common units of CQP, we are not obligated to fund losses of CQP. However, our capital account, which would be considered in allocating the net assets of CQP were it to be liquidated, continues to share in losses of CQP. 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 CQP 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 CQP in our Consolidated Financial Statements.

The following table presents the summarized assets and liabilities (in millions) of CQP, which are included in our Consolidated Balance Sheets. The assets in the table below may only be used to settle obligations of CQP. 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 CQP only and exclude intercompany balances between CQP and Cheniere that eliminate in the Consolidated Financial Statements of Cheniere.

	December 31,	
	2022	2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 904	$ 876
Restricted cash and cash equivalents	92	98
Trade and other receivables, net of current expected credit losses	627	580
Other current assets	269	285
Total current assets	1,892	1,839
Property, plant and equipment, net of accumulated depreciation	16,725	16,830
Other non-current assets, net	288	316
Total assets	$ 18,905	$ 18,985
LIABILITIES		
Current liabilities		
Accrued liabilities	$ 1,384	$ 1,077
Other current liabilities	960	200
Total current liabilities	2,344	1,277
Long-term debt, net of premium, discount and debt issuance costs	16,198	17,177
Other non-current liabilities	3,122	100
Total liabilities	$ 21,664	$ 18,554

NOTE 10—ACCRUED LIABILITIES

Accrued liabilities consisted of the following (in millions):

	December 31,	
	2022	2021
Natural gas purchases	$ 1,621	$ 1,323
Derivative settlements	7	329
Interest costs and related debt fees	383	214
LNG terminals and related pipeline costs	240	144
Compensation and benefits	245	180
LNG inventory	88	34
Other accrued liabilities	95	75
Total accrued liabilities	$ 2,679	$ 2,299

NOTE 11—DEBT

Debt consisted of the following (in millions):

	December 31, 2022	December 31, 2021
SPL:		
Senior Secured Notes:		
5.625% due 2023	$ —	$ 1,500
5.75% due 2024	2,000	2,000
5.625% due 2025	2,000	2,000
5.875% due 2026	1,500	1,500
5.00% due 2027	1,500	1,500
4.200% due 2028	1,350	1,350
4.500% due 2030	2,000	2,000
4.746% weighted average rate due 2037	1,782	1,282
Total SPL Senior Secured Notes	12,132	13,132
Working capital revolving credit and letter of credit reimbursement agreement (the "SPL Working Capital Facility")	—	—
Total debt - SPL	12,132	13,132
CQP:		
Senior Notes:		
4.500% due 2029	1,500	1,500
4.000% due 2031	1,500	1,500
3.25% due 2032	1,200	1,200
Total CQP Senior Notes	4,200	4,200
Credit facilities (the "CQP Credit Facilities")	—	—
Total debt - CQP	4,200	4,200
CCH:		
Senior Secured Notes:		
7.000% due 2024 (the "2024 CCH Senior Notes") (1)	498	1,250
5.875% due 2025	1,491	1,500
5.125% due 2027 (2)	1,271	1,500
3.700% due 2029 (2)	1,361	1,500
3.751% weighted average rate due 2039 (2)	2,633	2,721
Total CCH Senior Secured Notes	7,254	8,471
CCH Credit Facility	—	1,728
Working capital facility (the "CCH Working Capital Facility") (3)	—	250
Total debt - CCH	7,254	10,449
Cheniere:		
4.625% Senior Secured Notes due 2028	1,500	2,000
2045 Cheniere Convertible Senior Notes (4)	—	625
Revolving credit facility (the "Cheniere Revolving Credit Facility")	—	—
Total debt - Cheniere	1,500	2,625
Cheniere Marketing: trade finance facilities and letter of credit facility (3)	—	—
Total debt	25,086	30,406
Current portion of long-term debt	(813)	(117)
Short-term debt	—	(250)
Unamortized premium, discount and debt issuance costs, net	(218)	(590)
Total long-term debt, net of premium, discount and debt issuance costs	$ 24,055	$ 29,449

(1) In January 2023, we redeemed the remaining outstanding principal balance of the 2024 CCH Senior Notes with cash that was on hand at December 31, 2022. Therefore, the outstanding principal balance redeemed was classified as current portion of long-term debt as of December 31, 2022, net of discount and debt issuance costs of $3 million.

(2) Subsequent to December 31, 2022 and through February 16, 2023, we executed bond repurchases totaling $322 million, inclusive of CCH's Senior Secured Notes due 2027, 2029 and 2039 on the open market. These bonds

were repurchased with cash that was on hand at December 31, 2022; therefore, the amounts repurchased are classified as current portion of long-term debt as of December 31, 2022, net of discount and debt issuance costs of $4 million.

(3) These debt instruments are classified as short-term debt.

(4) The redemption of these notes was financed with borrowings under the Cheniere Revolving Credit Facility, which is a long-term debt instrument. Therefore, the 2045 Cheniere Convertible Senior Notes were classified as long-term debt as of December 31, 2021. See *Convertible Notes* section below for further discussion of the redemption.

Senior Notes

SPL Senior Secured Notes

The SPL Senior Secured Notes are senior secured obligations of SPL, ranking equally in right of payment with SPL's other existing and future senior debt and secured by the same collateral and senior in right of payment to any of its future subordinated debt. Subject to permitted liens, the SPL Senior Secured 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, at any time, redeem all or part of the SPL Senior Secured Notes at specified prices set forth in the respective indentures governing the SPL Senior Secured Notes, plus accrued and unpaid interest, if any, to the date of redemption. The series of SPL Senior Secured Notes due in 2037 are fully amortizing according to a fixed sculpted amortization schedule, as set forth in the respective indentures.

CQP Senior Notes

The CQP Senior Notes are jointly and severally guaranteed by each of CQP's 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 senior obligations of CQP, ranking equally in right of payment with CQP's other existing and future unsubordinated debt and senior to any of its future subordinated debt. In the event that the aggregate amount of CQP's 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 by a first-priority lien (subject to permitted encumbrances) on substantially all the existing and future tangible and intangible assets and rights of CQP and the CQP Guarantors and equity interests in the CQP Guarantors. The liens securing the CQP Senior Notes, if applicable, will be shared equally and ratably (subject to permitted liens) with the holders of any other senior secured obligations. CQP may, at any time, redeem all or part of the CQP Senior Notes at specified prices set forth in the respective indentures governing the CQP Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption.

CCH Senior Secured Notes

The CCH Senior Secured 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 CCH Senior Secured Notes are senior secured obligations of CCH, ranking senior in right of payment to any and all of CCH's future indebtedness that is subordinated to the CCH Senior Secured 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 Secured Notes. The CCH Senior Secured Notes are secured by a first-priority security interest in substantially all of CCH's and the CCH Guarantors' assets. CCH may, at any time, redeem all or part of the CCH Senior Secured Notes at specified prices set forth in the respective indentures governing the CCH Senior Secured Notes, plus accrued and unpaid interest, if any, to the date of redemption.

Cheniere Senior Secured Notes

The 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 Cheniere Senior Secured Notes and equally in right of payment with all of our other existing and future unsubordinated indebtedness. The Cheniere Senior Secured Notes became unsecured in June 2021 concurrent with the repayment of all outstanding obligations under the Cheniere Term Loan Facility and may, in certain instances become secured in the future in connection with the incurrence of additional secured indebtedness by us. When required, the Cheniere Senior Secured Notes will 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), which liens rank *pari passu* with the liens securing the Cheniere Revolving Credit Facility. As of December 31, 2022, the Cheniere Senior Secured Notes are not guaranteed by any of our subsidiaries. In the future, the Cheniere Senior Secured Notes will be guaranteed by our subsidiaries who guarantee our other material indebtedness. We may, at any time, redeem all or part of the Cheniere Senior Secured Notes at specified prices set forth in the indenture governing the Cheniere Senior Secured Notes, plus accrued and unpaid interest, if any, to the date of redemption.

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2022 (in millions):

Years Ending December 31,	Principal Payments
2023	$ 498
2024	2,000
2025	3,542
2026	1,608
2027	2,966
Thereafter	14,472
Total	$ 25,086

Credit Facilities

Below is a summary of our committed credit facilities outstanding as of December 31, 2022 (in millions):

	SPL Working Capital Facility (1)	CQP Credit Facilities (2)	CCH Credit Facility (3) (4)	CCH Working Capital Facility (4) (5)	Cheniere Revolving Credit Facility (6)
Total facility size	$ 1,200	$ 750	$ 3,260	$ 1,500	$ 1,250
Less:					
Outstanding balance	—	—	—	—	—
Letters of credit issued	328	—	—	178	—
Available commitment	$ 872	$ 750	$ 3,260	$ 1,322	$ 1,250
Priority ranking	Senior secured	Unsecured	Senior secured	Senior secured	Unsecured
Interest rate on available balance (7)	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%	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.5% or base rate plus 0.5%	SOFR plus credit spread adjustment of 0.1%, plus margin of 1.0% - 1.5% or base rate plus 0.0% - 0.5%	LIBOR plus 1.125% - 2.250% or base rate plus 0.125% - 1.250% (8)
Commitment fees on undrawn balance (7)	0.10% - 0.30%	0.375% - 0.638%	0.525%	0.10% - 0.20%	0.125% - 0.375%
Maturity date	March 19, 2025	May 29, 2024	(9)	June 15, 2027	October 28, 2026

(1) The obligations of SPL under the 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 Secured Notes. The SPL Working Capital Facility contains customary conditions precedent for extensions.

(2) The obligations under the CQP Credit Facilities are unconditionally guaranteed by the CQP Guarantors.

(3) 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 Cheniere CCH Holdco I of its limited liability company interests in CCH.

(4) In June 2022, CCH amended and restated the CCH Credit Facility and the CCH Working Capital Facility resulting in $20 million of debt extinguishment and modification costs to, among other things, (1) provide incremental commitments of $3.7 billion and $300 million for the CCH Credit Facility and the CCH Working Capital Facility, respectively, in connection with the FID with respect to the Corpus Christi Stage 3 Project, (2) extend the maturity, (3) update the indexed interest rate to SOFR and (4) make certain other changes to the terms and conditions of each existing facility.

(5) 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 Secured Notes and the CCH Credit Facility.

(6) The Cheniere Revolving Credit Facility contains a financial covenant requiring us to maintain a non-consolidated leverage ratio not to exceed 5.50:1.00 as of the end of any fiscal quarter if (i) as of the last day of such fiscal quarter the aggregate principal amount of outstanding loans plus drawn and unreimbursed letters of credit is greater than 35% of the aggregate commitments under the Cheniere Revolving Credit Facility (a "Covenant Trigger Event") or (ii) a Covenant Trigger Event had occurred and been continuing as of the last day of the immediately preceding fiscal quarter and as of the last day of such ending fiscal quarter such Covenant Trigger Event had not ceased for a period of at least thirty consecutive days.

(7) The margin on the interest rate and the commitment fees are subject to change based on the applicable entity's credit rating.

(8) This facility was amended in 2021 to establish a SOFR-indexed replacement rate for LIBOR.

(9) The CCH Credit Facility matures the earlier of June 15, 2029 or two years after the substantial completion of the last Train of the Corpus Christi Stage 3 Project.

Convertible Notes

On December 6, 2021, we issued a notice of redemption for all $625 million aggregate principal amount outstanding of the 2045 Cheniere Convertible Senior Notes. The notice of redemption allowed holders to elect to convert their notes at any time prior to a specified deadline on December 31, 2021, with settlement of such converted notes in cash, as elected by us, on January 5, 2022. The impact of holders electing conversion was immaterial to the Consolidated Financial Statements. The 2045 Cheniere Convertible Senior Notes not converted were redeemed on January 5, 2022 with borrowings under the Cheniere Revolving Credit Facility. We recognized $16 million of debt extinguishment costs related to the early redemption of these convertible notes.

Losses on Extinguishment of Debt Related to Termination of Agreement with Chevron

Our loss on modification or extinguishment of debt for the year ended December 31, 2022 includes a loss on extinguishment of prospective payment obligations of $31 million associated with a premium paid to Chevron U.S.A. Inc. ("Chevron") to terminate a revenue sharing arrangement under the terminal marine services agreement with them. See Note 13—Revenue for further discussion of the termination of agreements with Chevron.

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. SPL, CQP and CCH are restricted from making distributions under agreements governing their respective indebtedness generally until, among other requirements, appropriate reserves have been established for debt service using cash or letters of credit and a historical debt service coverage ratio and projected debt service coverage ratio of at least 1.25:1.00 is satisfied. At December 31, 2022, our restricted net liabilities of consolidated subsidiaries were approximately $0.4 billion.

As of December 31, 2022, 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,		
	2022	2021	2020
Interest cost on convertible notes:			
Interest per contractual rate	$ —	$ 36	$ 152
Amortization of debt discount and debt issuance costs	—	10	53
Total interest cost related to convertible notes	—	46	205
Interest cost on debt and finance leases excluding convertible notes	1,485	1,558	1,568
Total interest cost	1,485	1,604	1,773
Capitalized interest	(79)	(166)	(248)
Total interest expense, net of capitalized interest	$ 1,406	$ 1,438	$ 1,525

Fair Value Disclosures

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

	December 31, 2022		December 31, 2021	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Senior notes — Level 2 (1)	$ 21,763	$ 20,539	$ 24,550	$ 26,725
Senior notes — Level 3 (2)	3,323	2,961	3,253	3,693
2045 Cheniere Convertible Senior Notes — Level 1 (3)	—	—	625	526

(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 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.

The estimated fair value of our credit facilities approximates the principal amount outstanding 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.

NOTE 12—LEASES

Our leased assets consist primarily of LNG vessel time charters ("vessel charters") and additionally include tug vessels, office space and facilities and land sites. All of our leases are classified as operating leases except for certain of our vessel charters and tug vessels, which are classified as finance leases.

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

	Consolidated Balance Sheets Location	December 31, 2022	December 31, 2021
Right-of-use assets—Operating	Operating lease assets	$ 2,625	$ 2,102
Right-of-use assets—Financing	Property, plant and equipment, net of accumulated depreciation	511	50
Total right-of-use assets		$ 3,136	$ 2,152
Current operating lease liabilities	Current operating lease liabilities	$ 616	$ 535
Current finance lease liabilities	Other current liabilities	28	2
Non-current operating lease liabilities	Operating lease liabilities	1,971	1,541
Non-current finance lease liabilities	Finance lease liabilities	494	57
Total lease liabilities		$ 3,109	$ 2,135

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

	Consolidated Statements of Operations Location	Year Ended December 31, 2022	2021	2020
Operating lease cost (a)	Operating costs and expenses (1)	$ 828	$ 621	$ 432
Finance lease cost:				
Amortization of right-of-use assets	Depreciation and amortization expense	12	3	2
Interest on lease liabilities	Interest expense, net of capitalized interest	14	9	7
Total lease cost		$ 854	$ 633	$ 441
(a) Included in operating lease cost:				
Short-term lease costs		$ 122	$ 139	$ 93
Variable lease costs		18	21	16

(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.

Future annual minimum lease payments for operating and finance leases as of December 31, 2022 are as follows (in millions):

Years Ending December 31,	Operating Leases	Finance Leases
2023	$ 690	$ 63
2024	644	66
2025	505	71
2026	372	75
2027	275	77
Thereafter	492	427
Total lease payments (1)	2,978	779
Less: Interest	(391)	(257)
Present value of lease liabilities	$ 2,587	$ 522

(1) Does not include approximately $3.3 billion of legally binding minimum payments primarily for vessel charters contracted for as of December 31, 2022, which will commence in future periods with fixed minimum lease terms of up to 15 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, 2022		December 31, 2021	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted-average remaining lease term (in years)	5.9	10.6	5.6	16.7
Weighted-average discount rate (1)	4.2%	7.8%	3.6%	16.2%

(1) The weighted average discount rate is impacted by certain finance leases that 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,		
	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 713	$ 483	$ 309
Operating cash flows from finance leases	14	10	10
Right-of-use assets obtained in exchange for operating lease liabilities	1,220	1,736	615
Right-of-use assets obtained in exchange for finance lease liabilities (1)	473	—	—

(1) Includes $88 million reclassified from operating leases to finance leases during the year ended December 31, 2022, as a result of modifications of the underlying vessel charters.

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. The following table shows the sublease income recognized in other revenues on our Consolidated Statements of Operations (in millions):

	Year Ended December 31,		
	2022	2021	2020
Fixed income	$ 371	$ 72	$ 68
Variable income	79	37	27
Total sublease income	$ 450	$ 109	$ 95

Future annual minimum sublease payments to be received from LNG vessel subcharters as of December 31, 2022 are as follows (in millions):

Years Ending December 31,	LNG Vessel Subcharters
2023	$ 165
2024	18
2025	—
2026	—
2027	—
Thereafter	—
Total lease payments	183

NOTE 13—REVENUES

The following table represents a disaggregation of revenue earned (in millions):

	Year Ended December 31,		
	2022	2021	2020
Revenues from contracts with customers			
LNG revenues (1)	$ 32,132	$ 17,171	$ 8,954
Regasification revenues	1,068	269	269
Other revenues	107	91	70
Total revenues from contracts with customers	33,307	17,531	9,293
Net derivative loss (2)	(328)	(1,776)	(30)
Other (3)	449	109	95
Total revenues	$ 33,428	$ 15,864	$ 9,358

(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 during the year ended December 31, 2021 had the cargoes been lifted pursuant to the delivery schedules with the customers. We did not have revenues associated with LNG cargoes for which customers notified us that they would not take delivery during the years ended December 31, 2022 and 2021. 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 LNG Terminal or our 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 generally equal to 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 LNG Terminal or our Corpus Christi LNG Terminal 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 $760 million, $499 million and $414 million for the years ended December 31, 2022, 2021 and 2020, 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 LNG Terminal or our 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.

Sales of natural gas where, in the delivery of the natural gas to the end customer, we have concluded that we acted as a principal are presented within revenues in our Consolidated Statements of Operations, and where we have concluded that we acted as an agent are netted within cost of sales in our Consolidated Statements of Operations.

Regasification Revenues

The Sabine Pass LNG Terminal has operational regasification capacity of approximately 4 Bcf/d. Approximately 1 Bcf/d of the regasification capacity at the Sabine Pass LNG Terminal has been reserved under a long-term TUA with TotalEnergies Gas & Power North America, Inc. ("TotalEnergies"), under which they are required to pay fixed monthly fees to SPLNG, regardless of their use of the LNG terminal, 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. Prior to its cancellation effective December 31, 2022, SPLNG also had a TUA for 1 Bcf/d with Chevron, as further described below. Approximately 2 Bcf/d of regasification 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 TotalEnergies, whereby upon substantial completion of Train 5 of the SPL Project, SPL gained access to substantially all of TotalEnergies' capacity and other services provided under TotalEnergies' 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 and permit SPL to more flexibly manage its LNG storage capacity. Notwithstanding any arrangements between TotalEnergies and SPL, payments required to be made by TotalEnergies to SPLNG will continue to be made by TotalEnergies to SPLNG in accordance with its TUA and we continue to recognize the payments received from TotalEnergies as revenue. During the years ended December 31, 2022, 2021 and 2020, SPL recorded $131 million, $129 million and $129 million, respectively, as operating and maintenance expense under this partial TUA assignment agreement.

Termination Agreement with Chevron

In June 2022, Chevron entered into an agreement with SPLNG providing for the early termination of the TUA and an associated terminal marine services agreement between the parties and their affiliates (the "Termination Agreement"), effective July 2022, for a lump sum fee of $765 million (the "Termination Fee"). Obligations pursuant to the TUA and associated agreement, including Chevron's obligation to pay SPLNG capacity payments totaling $125 million annually (adjusted for inflation) from 2023 through 2029, terminated on December 31, 2022, upon SPLNG's receipt of the Termination Fee in December 2022. We allocated the $765 million Termination Fee to the terminated commitments, with $796 million in cash inflows allocable to the termination of the TUA, which was recognized ratably over the July 6, 2022 to December 31, 2022 period as regasification revenues on our Consolidated Statements of Operations, and an offsetting $31 million reported, upon receipt of the Termination Fee, as a loss on extinguishment of debt on our Consolidated Statements of Operations allocable to a premium paid to Chevron to terminate a revenue sharing arrangement with them that was accounted for as debt.

Contract Assets and Liabilities

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

	December 31, 2022	December 31, 2021
Contract assets, net of current expected credit losses	$ 186	$ 140

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, 2022 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 and other non-current liabilities on our Consolidated Balance Sheets (in millions):

	Year Ended December 31, 2022
Deferred revenue, beginning of period	$ 194
Cash received but not yet recognized in revenue	320
Revenue recognized from prior period deferral	(194)
Deferred revenue, end of period	$ 320

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, 2022 and 2021 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:

	December 31, 2022		December 31, 2021	
	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)	Unsatisfied Transaction Price (in billions)	Weighted Average Recognition Timing (years) (1)
LNG revenues	$ 112.0	9	$ 107.1	9
Regasification revenues	0.8	4	1.9	4
Total revenues	$ 112.8		$ 109.0	

(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.

Additionally, we have excluded variable consideration related to contracts where there is uncertainty that one or both of the parties will achieve certain milestones. Approximately 72% and 60% of our LNG revenues from contracts included in the table above during the years ended December 31, 2022 and 2021, respectively, were related to variable consideration received from customers. During the years ended December 31, 2022 and 2021, approximately 2% and 5%, respectively, 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

Below is a summary of our related party transactions as reported on our Consolidated Statements of Operations (in millions):

	Year Ended December 31,		
	2022	2021	2020
LNG Revenues			
Natural Gas Transportation and Storage Agreements (1)	$ —	$ 1	$ —
Other revenues			
Operation and Maintenance Services Agreements (2)	7	7	9
Cost of sales			
Natural Gas Supply Agreements (a) (3)	—	162	114
Natural Gas Transportation and Storage Agreements (1)	—	1	—
Total cost of sales	—	163	114
Operating and maintenance expense			
Natural Gas Transportation and Storage Agreements (1) (4)	81	55	19
(a) Included in cost of sales:			
Liquefaction Supply Derivative gain (3)	—	13	(1)

(1) 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. This related party is partially owned by Brookfield Asset Management, Inc., who indirectly acquired a portion of CQP's limited partner interests in September 2020. We recorded accrued liabilities of $6 million and $4 million as of December 31, 2022 and 2021, respectively, with this related party.

(2) 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 $1 million and $2 million of other receivables as of December 31, 2022 and 2021, respectively, for services provided to Midship Pipeline under these agreements.

(3) Includes amounts recorded related to natural gas supply contracts that SPL and CCL had with related parties. These agreements ceased to be considered related party agreements during 2021, when the related party entity was acquired by a non-related party.

(4) CCL is party to natural gas transportation agreements with Midship Pipeline Company, LLC ("Midship Pipeline") in the ordinary course of business for the operation of the CCL Project. We recorded accrued liabilities of $1 million as of both December 31, 2022 and 2021 with this related party.

Other Agreements

Natural Gas Transportation Agreement with ADCC Pipeline

CCL is party to a natural gas transportation agreement with ADCC Pipeline in the ordinary course of business for the operation of the CCL Project, with an initial term of 20 years with extension rights, which will commence upon the completion of the ADCC Pipeline Project. We have a 30% equity interest in ADCC Pipeline, as further described in Note 8—Other Non-current Assets, Net.

Share Purchase Agreement

In June 2022, we entered into a purchase agreement to purchase approximately $350 million of our common shares beneficially owned by Icahn Capital LP and certain affiliates of Icahn Capital LP (the "Icahn Group") pursuant to which we purchased an aggregate of approximately 2.68 million shares of our common stock at a price per share of $130.52, the closing price on our common shares on the date of execution of the purchase agreement. Pursuant to the Nomination and Standstill Agreement entered into on August 21, 2015 by Cheniere and the Icahn Group, the Icahn Group's remaining director designee to our Board, Andrew Teno, resigned from our Board and all committees of our Board effective June 21, 2022. Additionally, as of such date, the Icahn Group ceased to be considered a related party.

NOTE 15—INCOME TAXES

The jurisdictional components of book income (loss) before income taxes and non-controlling interest on our Consolidated Statements of Operations are as follows (in millions):

	Year Ended December 31,		
	2022	2021	2020
U.S.	$ (1,575)	$ (2,317)	$ 720
International	4,669	39	(176)
Total income (loss) before income taxes and non-controlling interest	$ 3,094	$ (2,278)	$ 544

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

	Year Ended December 31,		
	2022	2021	2020
Current:			
Federal	$ 6	$ —	$ —
State	2	3	—
Foreign	11	5	—
Total current	19	8	—
Deferred:			
Federal	320	(633)	41
State	118	(89)	2
Foreign	2	1	—
Total deferred	440	(721)	43
Total income tax provision (benefit)	$ 459	$ (713)	$ 43

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,		
	2022	2021	2020
U.S. federal statutory tax rate	21.0 %	21.0 %	21.0 %
Non-controlling interest	(8.2)	7.2	(22.6)
State tax, net of federal benefit	0.5	(2.5)	—
Foreign-derived intangible income deduction	(1.2)	—	—
Executive compensation	0.8	(0.5)	1.4
Nondeductible interest expense	—	—	8.0
Foreign earnings taxed in the U.S.	—	—	1.2
Foreign rate differential	0.2	(0.1)	(3.7)
Tax credits	(0.6)	0.6	(4.5)
Internal restructuring	—	—	7.0
Valuation allowance	2.6	5.6	(0.9)
Other	(0.3)	—	1.0
Effective tax rate as reported	14.8 %	31.3 %	7.9 %

Significant components of our deferred tax assets and liabilities are as follows (in millions):

	December 31,	
	2022	2021
Deferred tax assets		
Net operating loss (“NOL”) carryforwards		
Federal	$ 1,968	$ 3,231
Foreign	—	2
State	177	244
Federal and state tax credits	66	108
Derivative instruments	1,345	951
Operating lease liabilities	542	438
Other	311	146
Less: valuation allowance	(143)	(63)
Total deferred tax assets	4,266	5,057
Deferred tax liabilities		
Investment in partnerships	(211)	(716)
Property, plant and equipment	(2,646)	(2,638)
Operating lease assets	(536)	(431)
Other	(9)	(68)
Total deferred tax liabilities	(3,402)	(3,853)
Net deferred tax assets	$ 864	$ 1,204

NOL and tax credit carryforwards

As of December 31, 2022, we had federal and state NOL carryforwards of approximately $9.4 billion and $2.2 billion, respectively. All of our NOLs have an indefinite carryforward period.

As of December 31, 2022, we had federal and state tax credit carryforwards of $65 million and $1 million, respectively. The federal tax credit carryforwards include investment tax credit carryforwards of $49 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 $15 million of foreign tax credits. Our federal and state tax credits will expire between 2026 and 2042.

Our NOL and tax credit carryforwards are not subject to, nor impacted by, any prior tax ownership change. We continue to monitor public trading activity in our shares to identify potential tax ownership changes that could impact our timing and ability to utilize such attributes.

Valuation Allowance

For the period ended December 31, 2022, our valuation allowance of $143 million primarily relates to state NOL carryforward deferred tax assets. We increased our valuation allowance on our Louisiana NOL carryforward deferred tax assets by $80 million primarily due to a reduction in our forecasted Louisiana taxable income as a result of receiving favorable guidance from the Louisiana Department of Revenue on a state apportionment tax matter.

Unrecognized Tax Benefits

As of December 31, 2022, we had unrecognized tax benefits of $74 million. If recognized, $65 million of unrecognized tax benefits would affect our effective tax rate in future periods. Interest and penalties related to income tax matters are recognized as part of income tax expense.

We are subject to tax in the U.S. and various state and foreign jurisdictions and we are subject to periodic audits and reviews by taxing authorities. Federal and state tax returns for the years after 2018 and United Kingdom tax returns for years after 2017 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.

A reconciliation of the beginning and ending amounts of our unrecognized tax benefits is as follows (in millions):

	Year Ended December 31,	
	2022	2021
Balance at beginning of the year	$ 65	$ 62
Additions based on tax positions related to current year	10	3
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	(1)	—
Settlements	—	—
Balance at end of the year	$ 74	$ 65

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 (the "2020 Plan"). The 2011 Plan and the 2020 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").

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 restricted stock shares, restricted stock units and performance stock units granted 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 that cash settle (which include phantom units, certain restricted stock that will settle in cash and a portion of performance stock units), compensation costs are remeasured at fair value through settlement or maturity.

We account for forfeitures as they occur.

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

	Year Ended December 31,		
	2022	2021	2020
Share-based compensation costs, pre-tax:			
Equity awards	$ 112	$ 105	$ 114
Liability awards (1)	97	40	2
Total share-based compensation	209	145	116
Capitalized share-based compensation	(4)	(5)	(6)
Total share-based compensation expense	$ 205	$ 140	$ 110
Tax benefit associated with share-based compensation expense	$ 48	$ 33	$ 23

(1) The amount of share-based compensation recognized in 2022 and 2021 associated with liability awards includes incremental expense as a result of modifications made for certain employees to settle certain awards in cash in lieu of shares, resulting in a reclassification from equity awards to liability awards. During the years ended December 31, 2022 and 2021, we recognized $56 million and $18 million, respectively, in incremental expense as a result of the modifications.

The total unrecognized compensation cost at December 31, 2022 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	$ —	0.3
Restricted Stock Unit and Performance Stock Unit Awards	172	1.4

Restricted Stock Share Awards

Restricted stock share awards are awards of common stock that are granted to the members of our Board of Directors for their service, subject to restrictions on transfer and to a risk of forfeiture if the recipient is unaffiliated with us prior to the lapse of the restrictions. These awards vest over a one-year service period. There were nominal non-vested restricted stock share awards outstanding as of December 31, 2022.

The fair value of restricted stock share awards vested for the years ended December 31, 2022, 2021 and 2020 were $2 million, $2 million and $3 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 a performance condition consisting of cumulative distributable cash flow per share, and in certain circumstances, a market condition consisting of absolute total shareholder return (“ATSR”) of our common stock. All performance stock units will settle entirely in stock, with the exception of awards granted in 2021 and 2022 to certain officers which will settle in cash up to a cap of $3 million. Additionally, certain restricted stock unit and performance stock unit awards vesting in 2023 may be settled in cash in lieu of shares, for which the officers elected such settlement at the Compensation Committee’s permission. The Compensation Committee, in its discretion, also has authorization from the Board to permit certain officers to make an election to cash settle their earned performance stock units that vest in 2024 and restricted stock units that vest in 2024 and 2025.

Where applicable, the compensation for performance stock units containing a market condition of ATSR is based on a fair value assigned to the market metric using a Monte Carlo model as of the grant date, which utilizes level 3 inputs such as projected stock volatility and projected risk free rates, and remains constant through the vesting period for the equity-settled component and is remeasured each reporting period for the cash-settled component. Compensation cost attributed to the performance metric 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. The restricted stock units, and portion of performance stock units, that will be settled in Cheniere common stock (on a one-for-one basis) are accounted for as equity awards and the remainder that will settle in cash are accounted for as liability awards.

The fair value of awards, or portion of awards, that are accounted for as liability awards was $98 million and $40 million as of December 31, 2022 and 2021, respectively, and recognized within our Consolidated Balance Sheets as accrued liabilities and other non-current liabilities.

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, 2022	3.7	$ 66.71
Granted (1)	1.7	112.91
Vested	(2.1)	69.23
Forfeited	(0.1)	85.15
Non-vested at December 31, 2022 (2)	3.2	$ 90.21

(1) This number includes 0.4 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 0.8 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,		
	2022	2021	2020
Units issued (in millions)	1.7	2.2	1.8
Weighted average grant date fair value per unit	$ 112.91	$ 70.99	$ 53.88
Fair value of units vested (in millions)	$ 140	$ 123	$ 137

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. Phantom units are not eligible to receive quarterly distributions. These awards vest based on service conditions (two, three or four-year service periods). We did not issue any phantom units to our employees and non-employee directors during the years ended December 31, 2022, 2021 and 2020. The remaining outstanding phantom units vested during the year ended December 31, 2021. The value of phantom units vested during the years ended December 31, 2022, 2021 and 2020 was zero, $1 million and $4 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 Internal Revenue Service 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 $16 million, $15 million and $15 million for of the years ended December 31, 2022, 2021 and 2020, respectively. 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 and common stock dividends declared (in millions, except per share data):

	Year Ended December 31,		
	2022	2021	2020
Net income (loss) attributable to common stockholders	$ 1,428	$ (2,343)	$ (85)
Weighted average common shares outstanding:			
Basic	251.1	253.4	252.4
Dilutive unvested stock	2.3	—	—
Diluted	253.4	253.4	252.4
Net income (loss) per share attributable to common stockholders—basic	$ 5.69	$ (9.25)	$ (0.34)
Net income (loss) per share attributable to common stockholders—diluted	$ 5.64	$ (9.25)	$ (0.34)
Dividends paid per common share	$ 1.385	$ 0.33	$ —

On January 27, 2023, we declared a quarterly dividend of $0.395 per share of common stock that is payable on February 27, 2023 to stockholders of record as of February 7, 2023.

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,		
	2022	2021	2020
Unvested stock (1)	—	1.8	3.4
2045 Cheniere Convertible Senior Notes (2)	0.3	—	4.5
Total potentially dilutive common shares	0.3	1.8	7.9

(1) Includes the impact of unvested shares containing performance conditions to the extent that the underlying performance conditions are satisfied based on actual results as of the respective dates.

(2) As described in Note 11—Debt, the 2045 Cheniere Convertible Senior Notes were redeemed or converted in cash on January 5, 2022. However, the adoption of ASU 2020-06 on January 1, 2022 required a presumption of share settlement for the purpose of calculating the impact to diluted earnings per share during the period the notes were outstanding in 2022. Such impact was anti-dilutive as a result of the reported net loss attributable to common stockholders during the 2022 period. See Note 2—Summary of Significant Accounting Policies for further discussion of our adoption of ASU 2020-06.

NOTE 19—STOCK REPURCHASE PROGRAMS

On September 7, 2021, our Board authorized a reset in the previously existing share repurchase program to $1.0 billion, inclusive of any amounts remaining under the previous authorization as of September 30, 2021, for an additional three years beginning on October 1, 2021. On September 12, 2022, our Board authorized an increase in the existing share repurchase program by $4.0 billion for an additional three years, beginning on October 1, 2022. The following table presents information with respect to repurchases of common stock (in millions, except per share data):

	Year Ended December 31,		
	2022	2021	2020
Aggregate common stock repurchased	9.35	0.10	2.88
Weighted average price paid per share	$ 146.88	$ 87.32	$ 53.88
Total amount paid	$ 1,373	$ 9	$ 155

As of December 31, 2022, we had approximately $3.6 billion remaining under our share repurchase program.

NOTE 20—COMMITMENTS AND CONTINGENCIES

Commitments

We have various future commitments under executed contracts that include unconditional purchase obligations and other commitments which do not meet the definition of a liability as of December 31, 2022 and thus are not recognized as liabilities in our Consolidated Financial Statements.

EPC Contract

CCL has a lump sum turnkey contract with Bechtel for the engineering, procurement and construction of the Corpus Christi Stage 3 Project. The total contract price of the EPC contract is approximately $5.4 billion, reflecting amounts incurred under change orders through December 31, 2022. As of December 31, 2022, we had approximately $3.9 billion remaining under this contract.

Natural Gas Supply, Transportation and Storage Service Agreements

SPL and CCL have physical natural gas supply contracts to secure natural gas feedstock for the SPL Project and the CCL Project, respectively. The remaining terms of these contracts range up to 15 years.

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 five years.

As of December 31, 2022, the obligations of SPL and CCL under natural gas supply, transportation and storage service agreements for contracts in which conditions precedent were met or are currently expected to be met were as follows (in billions):

Years Ending December 31,	Payments Due to Third Parties (1) (2)	Payments Due to Related Parties (1) (3)
2023	$ 10.9	$ 0.1
2024	8.6	0.1
2025	7.2	0.1
2026	6.2	0.1
2027	5.9	0.1
Thereafter	33.7	0.9
Total	$ 72.5	$ 1.4

(1) Pricing of natural gas supply contracts is variable based on market commodity basis prices adjusted for basis spread, and pricing of IPM agreements is variable based on global gas market prices less fixed liquefaction fees and certain costs incurred by us. Amounts included are based on estimated forward prices and basis spreads as of December 31, 2022. 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.

(2) Includes $0.4 billion under natural gas supply agreements with unsatisfied conditions precedent.

(3) Includes $1.2 billion under natural gas transportation and storage service agreements with unsatisfied conditions precedent.

Other Agreements

We have certain fixed commitments under SPL's partial TUA assignment agreement with TotalEnergies and other agreements of $1.4 billion. See Note 13—Revenues for further discussion of the partial TUA assignment.

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. We recognize legal costs in connection with legal and regulatory matters as they are incurred. 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 impact on our operating results, financial position or cash flows.

NOTE 21—CUSTOMER CONCENTRATION

The following table shows external customers with revenues of 10% or greater of total revenues from external customers and external customers with trade and other receivables, net of current expected credit losses and contract assets, net of current expected credit losses balances of 10% or greater of total trade and other receivables, net of current expected credit losses from external customers and contract assets, net of current expected credit losses from external customers, respectively:

	Percentage of Total Revenues from External Customers			Percentage of Trade and Other Receivables, Net and Contract Assets, Net from External Customers	
	Year Ended December 31,			December 31,	
	2022	2021	2020	2022	2021
Customer A	*	12%	14%	*	10%
Customer B	*	12%	12%	*	*
Customer C	*	10%	10%	*	*
Customer D	*	*	10%	*	*

* 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.

	Revenues from External Customers		
	Year Ended December 31,		
	2022	2021	2020
United States	$ 5,213	$ 1,340	$ 2,466
United Kingdom	4,642	1,246	678
Singapore	3,273	1,740	646
Ireland	2,726	1,838	1,130
Spain	2,226	1,577	1,034
South Korea	2,225	1,680	942
India	2,109	1,375	1,021
Germany	1,747	507	66
Switzerland	1,725	582	147
Other countries	7,542	3,979	1,228
Total	$ 33,428	$ 15,864	$ 9,358

NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2022	2021	2020
Cash paid during the period for interest on debt, net of amounts capitalized	$ 891	$ 1,365	$ 1,395
Cash paid for income taxes, net of refunds	30	4	2
Non-cash investing activity:			
Transfers of property, plant and equipment in exchange for other non-current assets	17	—	—

The balance in property, plant and equipment, net of accumulated depreciation funded with accounts payable and accrued liabilities was $346 million, $339 million and $282 million as of December 31, 2022, 2021 and 2020, respectively.

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, 2022, 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.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Items 10 through 13 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, 2022.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Houston, Texas, Auditor Firm ID 185.

The remaining information required by this Item 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, 2022.

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 CQP, Cheniere Pipeline Company, Grand Cheniere Pipeline, LLC and the Company	CQP	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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	CQP	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	CQP	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	CQP	8-K	4.1.2	4/16/2013
4.5	Third Supplemental Indenture, dated as of November 25, 2013, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1	11/25/2013
4.6	Fourth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1	5/22/2014
4.7	Form of 5.750% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.6 above)	CQP	8-K	4.1	5/22/2014
4.8	Fifth Supplemental Indenture, dated as of May 20, 2014, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.2	5/22/2014
4.9	Sixth Supplemental Indenture, dated as of March 3, 2015, between SPL and The Bank of New York Mellon, as Trustee	CQP	8-K	4.1	3/3/2015
4.10	Form of 5.625% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.9 above)	CQP	8-K	4.1	3/3/2015
4.11	Seventh Supplemental Indenture, dated as of June 14, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	6/14/2016
4.12	Form of 5.875% Senior Secured Note due 2026 (Included as Exhibit A-1 to Exhibit 4.11 above)	CQP	8-K	4.1	6/14/2016
4.13	Eighth Supplemental Indenture, dated as of September 19, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/23/2016
4.14	Ninth Supplemental Indenture, dated as of September 23, 2016, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.2	9/23/2016
4.15	Form of 5.00% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.14 above)	CQP	8-K	4.2	9/23/2016
4.16	Tenth Supplemental Indenture, dated as of March 6, 2017, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	3/6/2017
4.17	Form of 4.200% Senior Secured Note due 2028 (Included as Exhibit A-1 to Exhibit 4.16 above)	CQP	8-K	4.1	3/6/2017
4.18	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
4.19	Form of 4.500% Senior Secured Note due 2030 (Included as Exhibit A-1 to Exhibit 4.18 above)	SPL	8-K	4.1	5/8/2020

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.20	Twelfth Supplemental Indenture, dated as of November 29, 2022, between SPL and The Bank of New York Mellon, as Trustee under the Indenture	SPL	8-K	4.1	11/29/2022
4.21	Form of 5.900% Senior Secured Amortizing Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.20 above)	SPL	8-K	4.1	11/29/2022
4.22	Indenture, dated as of February 24, 2017, between SPL, the guarantors that may become party thereto from time to time and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	2/27/2017
4.23	Form of 5.00% Senior Secured Note due 2037 (Included as Exhibit A-1 to Exhibit 4.22 above)	CQP	8-K	4.1	2/27/2017
4.24	Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.24	2/24/2022
4.25	Form of 2.95% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.24 above)	Cheniere	10-K	4.24	2/24/2022
4.26	Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.26	2/24/2022
4.27	Form of 3.17% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.26 above)	Cheniere	10-K	4.26	2/24/2022
4.28	First Supplemental Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.28	2/24/2022
4.29	Form of 3.19% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.28 above)	Cheniere	10-K	4.28	2/24/2022
4.30	Second Supplemental Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.30	2/24/2022
4.31	Form of 3.08% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.30 above)	Cheniere	10-K	4.30	2/24/2022
4.32	Third Supplemental Indenture, dated as of December 15, 2021, between SPL and The Bank of New York Mellon, as Trustee	Cheniere	10-K	4.32	2/24/2022
4.33	Form of 3.10% Senior Secured Notes due 2037 (Included as Exhibit A-1 to Exhibit 4.32 above)	Cheniere	10-K	4.32	2/24/2022
4.34	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
4.35	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
4.36	Form of 4.625% Senior Secured Notes due 2028 (Included as Exhibit A-1 to Exhibit 4.35 above)	Cheniere	8-K	4.2	9/22/2020
4.37	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
4.38	Form of 7.000% Senior Secured Note due 2024 (Included as Exhibit A-1 to Exhibit 4.37 above)	Cheniere	8-K	4.1	5/18/2016
4.39	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
4.40	Form of 5.875% Senior Secured Note due 2025 (Included as Exhibit A-1 to Exhibit 4.39 above)	Cheniere	8-K	4.1	12/9/2016
4.41	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
4.42	Form of 5.125% Senior Secured Note due 2027 (Included as Exhibit A-1 to Exhibit 4.41 above)	CCH	8-K	4.1	5/19/2017

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.43	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
4.44	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
4.45	Form of 3.700% Note due 2029 (Included as Exhibit A-1 to Exhibit 4.44 above)	CCH	8-K	4.1	11/13/2019
4.46	Fifth Supplemental Indenture, dated as of August 24, 2021, 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	8/24/2021
4.47	Form of 2.742% Senior Secured Note due 2039 (Included as Exhibit A-1 to Exhibit 4.46 above)	CCH	8-K	4.1	8/24/2021
4.48	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
4.49	Form of 3.52% Senior Secured Note due December 31, 2039 (Included as Exhibit A-1 to Exhibit 4.48 above)	CCH	8-K	4.1	8/21/2020
4.50	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
4.51	Form of 4.80% Senior Note due December 31, 2039 (Included as Exhibit A-1 to Exhibit 4.50 above)	CCH	8-K	4.1	9/30/2019
4.52	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
4.53	Form of 3.925% Senior Note due December 31, 2039 (Included as Exhibit A to Exhibit 4.52 above)	CCH	8-K	4.1	10/18/2019
4.54	Indenture, dated as of September 18, 2017, between CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/18/2017
4.55	First Supplemental Indenture, dated as of September 18, 2017, between CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.2	9/18/2017
4.56	Second Supplemental Indenture, dated as of September 11, 2018, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/12/2018
4.57	Third Supplemental Indenture, dated as of September 12, 2019, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/12/2019
4.58	Form of 4.500% Senior Notes due 2029 (Included as Exhibit A-1 to Exhibit 4.57 above)	CQP	8-K	4.1	9/12/2019
4.59	Fourth Supplemental Indenture, dated as of November 5, 2020, between CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	Cheniere	10-Q	4.4	11/6/2020
4.60	Fifth Supplemental Indenture, dated as of March 11, 2021, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	3/11/2021
4.61	Form of 4.000% Senior Notes due 2031 (Included as Exhibit A-1 to Exhibit 4.60 above)	CQP	8-K	4.1	3/11/2021
4.62	Sixth Supplemental Indenture, dated as of September 27, 2021, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	9/27/2021

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
4.63	Form of 3.25% Senior Notes due 2032 (Included as Exhibit A-1 to Exhibit 4.62 above)	CQP	8-K	4.1	9/27/2021
4.64	Seventh Supplemental Indenture, dated as of September 27, 2021, among CQP, the guarantors party thereto and The Bank of New York Mellon, as Trustee under the Indenture	CQP	8-K	4.1	10/1/2021
4.65*	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934				
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	CQP	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 CQP 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 Unit Award Agreement under the Cheniere Energy, Inc. 2011 Incentive Plan (Grades 18-20)	Cheniere	10-K	10.37	2/24/2017
10.18†	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
10.19†	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
10.20†	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
10.21†	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
10.22†	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.23†	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
10.24†	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
10.25†	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
10.26†	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
10.27†	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
10.28†	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
10.29†	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
10.30†	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
10.31†	Cheniere Energy, Inc. 2014-2018 Long-Term Cash Incentive Program	Cheniere	10-Q	10.9	4/30/2015
10.32†	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
10.33†	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
10.34†	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
10.35†	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
10.36†	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
10.37†	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
10.38†	Cheniere Energy, Inc. 2020 Incentive Plan	Cheniere (SEC No. 333-238261)	S-8	4.9	5/14/2020
10.39†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2020 Incentive Plan (Director)	Cheniere	8-K	10.4	5/20/2020
10.40†	Form of Restricted Stock Grant under the Cheniere Energy, Inc. 2020 Incentive Plan (Director)	Cheniere	10-Q	10.1	8/5/2021
10.41†	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
10.42†	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
10.43†*	Form of Restricted Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan				
10.44†	Form of Performance Stock Unit Award Agreement under the Cheniere Energy, Inc. 2020 Incentive Plan	Cheniere	10-K	10.45	2/24/2021
10.45†	Form of Performance Stock Unit Award Agreement Under the Cheniere Energy, Inc. 2020 Incentive Plan	Cheniere	10-K	10.44	2/24/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.46†*	Form of Performance Stock Unit Award Agreement Under the Cheniere Energy, Inc. 2020 Incentive Plan				
10.47†	Amended and Restated Cheniere Energy, Inc. Key Executive Severance Pay Plan (Effective November 3, 2021) and Summary Plan Description	Cheniere	10-K	10.45	2/24/2022
10.48†	Director Deferred Compensation Plan (Effective February 10, 2022)	Cheniere	10-K	10.46	2/24/2022
10.49†	Form of Deferred Stock Unit Award Agreement Under the Director Deferred Compensation Plan	Cheniere	10-K	10.47	2/24/2022
10.50†	Employment Agreement between the Company and Jack A. Fusco, dated May 12, 2016	Cheniere	8-K	10.1	5/12/2016
10.51†	Employment Agreement Amendment between the Company and Jack Fusco, dated August 15, 2019	Cheniere	8-K	10.1	8/15/2019
10.52†	Second Employment Agreement Amendment between the Company and Jack Fusco, dated August 11, 2021	Cheniere	8-K	10.1	8/13/2021
10.53†	Cheniere Energy, Inc. Amended and Restated Retirement Policy, dated effective August 15, 2019	Cheniere	10-K	10.49	2/25/2020
10.54†	Form of Indemnification Agreement for officers of the Company	Cheniere	8-K	10.2	5/20/2020
10.55†	Form of Indemnification Agreement for directors of the Company	Cheniere	8-K	10.1	5/20/2020
10.56†	Letter Agreement between the Company and Douglas Shanda, dated November 1, 2019	Cheniere	8-K	10.1	11/1/2019
10.57†	Letter Agreement, dated August 5, 2020, between the Company and Michael J. Wortley	Cheniere	8-K	10.1	8/6/2020
10.58†	Letter Agreement, dated February 15, 2023, between the Company and Aaron Stephenson	Cheniere	8-K	10.1	2/15/2023
10.59	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
10.60	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
10.61	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
10.62	First Amendment to Third Amended and Restated Common Terms Agreement, dated as of July 26, 2021, 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	10-Q	10.2	11/4/2021
10.63	Second Amended and Restated Term Loan Facility Agreement, dated June 15, 2022, 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	6/22/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.64	Second Amended and Restated Common Terms Agreement, dated June 15, 2022, 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	10.3	6/22/2022
10.65	Second Amended and Restated Common Security and Account Agreement, dated June 15, 2022, 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	10.4	6/22/2022
10.66	Amended and Restated Pledge Agreement, dated May 22, 2018, among Cheniere CCH HoldCo I, LLC and Société Générale as Security Trustee	Cheniere	8-K	10.4	5/24/2018
10.67	Amended and Restated Equity Contribution Agreement, dated May 22, 2018, among CCH and the Company	Cheniere	8-K	10.5	5/24/2018
10.68	Second Amended and Restated Working Capital Facility Agreement, dated June 15, 2022, 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 swing line lenders 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	10.2	6/22/2022
10.69	Second Amended and Restated Revolving Credit Agreement, dated as of October 28, 2021, among the Company, the Lenders and Issuing Banks party thereto, Sumitomo Mitsui Banking Corporation, as ESG Coordinator, and Société Générale, as Administrative Agent	Cheniere	8-K	10.1	11/1/2021
10.70	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
10.71	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
10.72	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
10.73	Credit and Guaranty Agreement, dated as of May 29, 2019, among the CQP, as Borrower, certain subsidiaries of the CQP, 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
10.74	Consent and Amendment to the Credit and Guaranty Agreement, dated July 6, 2022, among CQP, as Borrower, certain subsidiaries of the Partnership, as Subsidiary Guarantors, the lenders from time to time party thereto, Natixis, Société Générale, The Bank of Nova Scotia, Wells Fargo Bank, as Issuing Banks, MUFG Bank, LTD as Administrative Agent and Sole Coordinating Lead Arranger, and certain arrangers and other participants	Cheniere	10-Q	10.5	8/4/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.75	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
10.76	Registration Rights Agreement, dated as of November 29, 2022, between SPL and Goldman Sachs & Co. LLC	SPL	8-K	10.1	11/29/2022
10.77	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
10.78	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
10.79	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
10.80	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-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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.81	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
10.82	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.: (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
10.83	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
10.84	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 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	Cheniere	10-K	10.88	2/24/2021

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.85	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-00035 Impacts from Hurricanes Laura and Delta, dated December 22, 2020, (ii) the Change Order CO-00036 Third Berth - Add N2 Connection on Liquid & Hybrid SVT Loading Arm Apex, dated December 22, 2020, (iii) the Change Order CO-00037 Third Berth Design Vessels Update, dated December 22, 2020, (iv) the Change Order CO-00038 Train 6 PV-16002 & FV-15104 Valve Trim Upgrades, dated January 21, 2021, (v) the Change Order CO-00039 Third Berth Design Update to Supply Bunkering Fuel, dated February 11, 2021, (vi) the Change Order CO-00040 LNG Benchmark 7 Elevation Change, dated February 11, 2021, (vii) the Change Order CO-00041 Costs to Comply with SPL FTZ (Excluding Pipe Spools), dated February 12, 2021 and (viii) the Change Order CO-00042 COVID-19 Impacts 1Q2021, dated March 12, 2021	Cheniere	10-Q	10.2	5/4/2021
10.86	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-00043 Third Berth SVT Loading Arm Spares, dated April 9, 2021, (ii) the Change Order CO-00044 Third Berth U/G Directional Drilling & Cathodic Protection Provisional Sum Closures, dated April 9, 2021, (iii) the Change Order CO-00045 Winter Storm Impacts, dated April 9, 2021, (iv) the Change Order CO-00046 NGPL Security Provisional Sum Interim Adjustment, dated June 15, 2021, (v) the Change Order CO-00047 80 Acres Bridge, dated June 15, 2021 and (vi) the Change Order CO-00048 AGRU Additions for Lean Solvent Overpressure, dated June 15, 2021	Cheniere	10-Q	10.4	8/5/2021
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-00049 COVID-19 Impacts 2Q2021, dated July 6, 2021, (ii) CO-00050 Third Berth Bunkering Ship Modifications — Pre-Investment for Foundations, dated July 6, 2021, (iii) CO-00051 Thermal Oxidizer Controls Change, dated September 8, 2021, (iv) CO-00052 Third Berth Spare Beacon and Additional Cable Tray, dated September 8, 2021 and (v) CO-00053 Train 6 Gearbox Assembly Replacement for Unit 1411, dated September 24, 2021	Cheniere	10-Q	10.1	11/4/2021
10.88	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-00054 80 Acres Bridge Credit, dated November 30, 2021, (ii) CO-00055 Change in Law LPDES Permit - Water Treatment Filter Washing, dated December15, 2021, (iii) CO-00056 Impacts from Hurricane Ida, dated December 15, 2021 and (iv) CO-00057 Impacts from Hurricane Nicholas, dated December 15, 2021	Cheniere	10-K	10.99	2/24/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.89	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-00058 COVID-19 Impacts 3Q2021, dated January 6, 2022, (ii) CO-00059 Spill Containment SIL 2 Interlock, dated January 11, 2022, (iii) the Change Order CO-00060 Third Berth Soil Preparation Provisional Sum Closure, dated March 15, 2022, (iv) the Change Order CO-00061 COVID-19 Impacts 4Q2021, dated March 15, 2022 and (v) the Change Order CO-00062 FERC Condition 61, dated March 15, 2022	Cheniere	10-Q	10.2	5/4/2022
10.90	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-00063 FERC Condition 78, dated May 6, 2022, (ii) the Change Order CO-00064 FERC Impact to Pipe Installation, dated June 14, 2022, (iii) the Change Order CO-00065 Spill Containment Sil 2 Interlock, dated June 15, 2022 and (iv) the Change Order CO-00066 Marine Dredging and Management Oversight Provisional Sums Closure, dated June 16, 2022	Cheniere	10-Q	10.6	8/4/2022
10.91	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-00067 Performance and Attendance Bonus (“PAB”) Provisional Sum Closure, dated August 18, 2022, (ii) the Change Order CO-00068 Performance and Attendance Bonus (“PAB”) Provisional Sum Closure (Reconciliation to CO-00067), dated August 18, 2022, and (iii) the Change Order CO-00069 COVID-19 Impacts 1Q2022 and 2Q2022, dated August 29, 2022	Cheniere	10-Q	10.1	11/3/2022
10.92*	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-00070 80-Acres Bridge, dated October 28, 2022, (ii) the Change Order CO-00071 Mooring System Low-Tension Common Alarm, dated October 31, 2022, (iii) the Change Order CO-00072 FERC Hydrocarbon Permit Conditions, dated October 31, 2022, (iv) the Change Order CO-00073 BN#2 Beacon Pile Relocation, dated October 31, 2022 and (v) the Change Order CO-00074 FERC Condition 56: ISA 84 Gas Detection, dated October 31, 2022				
10.93	Fixed Price Separated Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL Stage III and Bechtel Energy Inc. (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment)	Cheniere	10-Q	10.1	5/4/2022
10.94	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL Stage III and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00001 Maintaining Elevated Ground Flare Option, dated March 28, 2022, (ii) the Change Order CO-00002 Package 7 Pre-Investment of Trains 8 and 9 (Without Site Work), dated April 29, 2022 and (iii) the Change Order CO-00003 Modifications to Insurance Language, dated June 13, 2022 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.7	8/4/2022

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.95	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-00004 Currency Conversion, dated June 27, 2022, (ii) the Change Order CO-00005 Fuel Adjustment, dated July 15, 2022, (iii) the Change Order CO-00006 Removal of Laydown Yard Scope Option, dated August 2, 2022, (iv) the Change Order CO-00007 Removal of Air Bridges Scope Option, dated August 22, 2022, (v) the Change Order CO-00008 Acid Gas Flare K/O Drum, dated August 16, 2022, and (vi) the Change Order CO-00009 Package 7A (Without Site Work), dated August 16, 2022 (Portions of this exhibit have been omitted)	Cheniere	10-Q	10.2	11/3/2022
10.96*	Change orders to the Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Corpus Christi Liquefaction Stage 3 Project, dated March 1, 2022, by and between CCL and Bechtel Oil Gas and Chemicals, Inc.: (i) the Change Order CO-000010 Insurance Provisional Sum Interim Adjustment, dated September 13, 2022 and (ii) the Change Order CO-000011 Package 6 Descope and Transfer to Owner, dated September 14, 2022 (Portions of this exhibit have been omitted)				
10.97	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)	CQP	8-K	10.1	11/21/2011
10.98	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)	CQP	10-Q	10.1	5/3/2013
10.99	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
10.100	LNG Sale and Purchase Agreement (FOB), dated December 11, 2011, between SPL (Seller) and GAIL (India) Limited (Buyer)	CQP	8-K	10.1	12/12/2011
10.101	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and GAIL (India) Limited (Buyer)	CQP	10-K	10.18	2/22/2013
10.102	Amended and Restated LNG Sale and Purchase Agreement (FOB), dated January 25, 2012, between SPL (Seller) and BG Gulf Coast LNG, LLC (Buyer)	CQP	8-K	10.1	1/26/2012
10.103	LNG Sale and Purchase Agreement (FOB), dated January 30, 2012, between SPL (Seller) and Korea Gas Corporation (Buyer)	CQP	8-K	10.1	1/30/2012
10.104	Amendment No. 1 of LNG Sale and Purchase Agreement (FOB), dated February 18, 2013, between SPL (Seller) and Korea Gas Corporation (Buyer)	CQP	10-K	10.19	2/22/2013
10.105	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
10.106	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

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
10.107	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
10.108	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
10.109	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
10.110	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
10.111	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
10.112	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
10.113	Investors' and Registration Rights Agreement, dated as of July 31, 2012, by and among the Company, Cheniere Energy Partners GP, LLC, CQP, Cheniere Class B Units Holdings, LLC, Blackstone CQP Holdco LP and the other investors party thereto from time to time	CQP	8-K	10.1	8/6/2012
10.114	Fourth Amended and Restated Agreement of Limited Partnership of CQP, dated February 14, 2017	CQP	8-K	3.1	2/21/2017
10.115	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
10.116	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
10.117	Purchase Agreement, dated June 14, 2022, between Cheniere Energy, Inc., on the one hand, and Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Onshore LP, Icahn Offshore LP and Icahn Capital LP, on the other hand	Cheniere	8-K	10.1	6/15/2022
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				

Exhibit No.	Description	Incorporated by Reference (1)			
		Entity	Form	Exhibit	Filing Date
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), CQP (SEC File No. 001-33366), Cheniere Energy Partners LP Holdings, LLC (“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,		
	2022	2021	2020
General and administrative expense	$ (20)	$ (17)	$ (20)
Amortization of capitalized interest associated to investment in subsidiaries	(1)	(1)	—
Total operating costs and expenses	(21)	(18)	(20)
Other income (expense)			
Interest expense, net of capitalized interest	(91)	(151)	(155)
Loss on modification or extinguishment of debt	(12)	(6)	(50)
Total other income (expense)	(103)	(157)	(205)
Loss before income taxes and equity in income (loss) of subsidiaries	(124)	(175)	(225)
Less: income tax expense (benefit) (1)	565	(416)	(63)
Add: equity in income (loss) of subsidiaries, net of income taxes	2,117	(2,584)	77
Net income (loss) attributable to common stockholders	$ 1,428	$ (2,343)	$ (85)

(1) The income tax expense (benefit) reported by Cheniere includes tax expense (benefit) incurred by Cheniere as if Cheniere were a separate taxpayer rather than a member of Cheniere's consolidated income tax group, and tax expense (benefit) from Cheniere's subsidiaries who are disregarded for federal income tax purposes and whose taxable income or loss is included in the federal income tax return of Cheniere.

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,	
	2022	2021
ASSETS		
Current assets		
Cash and cash equivalents	$ —	$ 17
Other current assets	6	1
Total current assets	6	18
Capitalized interest associated to investment in subsidiaries, net of amortization	38	35
Operating lease assets	64	19
Debt issuance and deferred financing costs, net of accumulated amortization	12	16
Deferred tax assets	92	797
Total assets	$ 212	$ 885
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities		
Current operating lease liabilities	$ 7	$ 6
Other current liabilities	18	30
Total current liabilities	25	36
Long-term debt, net of debt issuance costs	1,477	2,285
Investments in subsidiaries	1,552	1,110
Operating lease liabilities	69	24
Other non-current liabilities	58	1
Stockholders' deficit	(2,969)	(2,571)
Total liabilities and stockholders' deficit	$ 212	$ 885

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,		
	2022	2021	2020
Net cash used in operating activities	$ (28)	$ (232)	$ (285)
Cash flows from investing activities			
Capitalized interest associated to investment in subsidiaries	(4)	(6)	(13)
Payments to acquire debt instruments of subsidiaries	(1,223)	—	—
Distribution from (investment in) subsidiaries	4,970	1,498	(481)
Net cash provided by (used in) investing activities	3,743	1,492	(494)
Cash flows from financing activities			
Proceeds from issuance of debt	575	1,579	4,778
Redemptions and repayments of debt	(1,575)	(2,022)	(3,143)
Debt issuance and other financing costs	—	(9)	(57)
Debt modification or extinguishment costs	—	(1)	(29)
Dividends to stockholders	(349)	(85)	—
Distributions to non-controlling interest	(947)	(649)	(626)
Payments related to tax withholdings for share-based compensation	(63)	(48)	(43)
Repurchase of common stock	(1,373)	(9)	(155)
Net cash provided by (used in) financing activities	(3,732)	(1,244)	725
Net increase (decrease) in cash and cash equivalents	(17)	16	(54)
Cash and cash equivalents—beginning of period	17	1	55
Cash and cash equivalents—end of period	$ —	$ 17	$ 1

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—BASIS OF PRESENTATION

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 the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the affiliates are recorded on the Condensed Balance Sheets. The net income or loss from operations of the affiliates is reported in equity or loss in income of subsidiaries, excluding income or loss from non-controlling interests.

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

NOTE 2—DEBT

Our debt consisted of the following (in millions):

	December 31,	
	2022	2021
4.625% Senior Secured Notes due 2028	$ 1,500	$ 2,000
4.25% Convertible Senior Notes due 2045	—	625
Revolving credit facility the "Cheniere Revolving Credit Facility")	—	—
Cheniere Term Loan Facility	—	—
Total debt	1,500	2,625
Unamortized debt issuance costs, net	(23)	(340)
Total long-term debt, net of discount and debt issuance costs	$ 1,477	$ 2,285

Below is a schedule of future principal payments that we are obligated to make on our outstanding debt at December 31, 2022 (in millions):

Years Ending December 31,	Principal Payments
2023	$ —
2024	—
2025	—
2026	—
2027	—
Thereafter	1,500
Total	$ 1,500

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, 2022, outstanding guarantees and other assurances aggregated to up to $472 million of varying duration, consisting of parental guarantees. No liabilities were recognized under these guarantee arrangements as of December 31, 2022.

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	2022	2021
Right-of-use assets—Operating	Operating lease assets	$ 64	$ 19
Total right-of-use assets		$ 64	$ 19
Current operating lease liabilities	Current operating lease liabilities	$ 7	$ 6
Non-current operating lease liabilities	Operating lease liabilities	69	24
Total lease liabilities		$ 76	$ 30

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	2022	2021	2020
Operating lease cost (1)	General and administrative expense	$ 12	$ 9	$ 10

(1) Includes $4 million of variable lease costs paid to the lessor during each of the years ended December 31, 2022, 2021 and 2020.

Future annual minimum lease payments (reimbursements) for operating leases as of December 31, 2022 are as follows (in millions):

Years Ending December 31,	Operating Leases
2023 (1)	$ (11)
2024	6
2025	8
2026	13
2027	8
Thereafter	105
Total lease payments	129
Less: Interest	(53)
Present value of lease liabilities	$ 76

(1) Includes an expected reimbursement from our lessor of $18 million for construction of leasehold improvements.

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

	December 31,	
	2022	2021
Weighted-average remaining lease term (in years)	13.4	4.8
Weighted-average discount rate	5.6%	6.6%

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

	Year Ended December 31,		
	2022	2021	2020
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 8	$ 7	$ 7
Right-of-use assets obtained in exchange for new operating lease liabilities	48	—	5

NOTE 5—STOCK REPURCHASE PROGRAMS AND DIVIDENDS

On September 7, 2021, our Board authorized a reset in the previously existing share repurchase program to $1.0 billion, inclusive of any amounts remaining under the previous authorization as of September 30, 2021, for an additional three years beginning on October 1, 2021. On September 12, 2022, our Board authorized an increase in the existing share repurchase program by $4.0 billion for an additional three years, beginning on October 1, 2022. The following table presents information with respect to repurchases of common stock (in millions, except per share data):

	Year Ended December 31,		
	2022	2021	2020
Aggregate common stock repurchased	9.35	0.10	2.88
Weighted average price paid per share	$ 146.88	$ 87.32	$ 53.88
Total amount paid (in millions)	$ 1,373	$ 9	$ 155

As of December 31, 2022, we had up to $3.6 billion of the share repurchase program available.

Dividends

On January 27, 2023, we declared a quarterly dividend of $0.395 per share of common stock that is payable on February 27, 2023 to stockholders of record as of February 7, 2023.

NOTE 6 —SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides supplemental disclosure of cash flow information, excluding any contributions to the parent that were immediately contributed to the subsidiaries (in millions):

	Year Ended December 31,		
	2022	2021	2020
Cash paid during the period for interest, net of amounts capitalized	$ 109	$ 130	$ 45
Cash paid for income taxes, net of refunds	11	—	—
Non-cash investing activities:			
Contribution of purchased bonds to subsidiaries (1)	1,223	—	—

(1) Includes total cash paid by us for bond repurchases of our subsidiary, net of discount, premium and commission fees, of $1,193 million and associated interest of $30 million.

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, 2022					
Current expected credit losses on receivables and contract assets	$ 9	$ (4)	$ —	$ —	$ 5
Deferred tax asset valuation allowance	63	80	—	—	143
Year Ended December 31, 2021					
Current expected credit losses on receivables and contract assets	$ 7	$ 2	$ —	$ —	$ 9
Deferred tax asset valuation allowance	190	(127)	—	—	63
Year Ended December 31, 2020					
Current expected credit losses on receivables and contract assets	$ —	$ 7	$ —	$ —	$ 7
Deferred tax asset valuation allowance	196	(6)	—	—	190

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 22, 2023

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 22, 2023
/s/ Zach Davis Zach Davis	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2023
/s/ David Slack David Slack	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 22, 2023
/s/ G. Andrea Botta G. Andrea Botta	Chairman of the Board	February 22, 2023
/s/ Vicky A. Bailey Vicky A. Bailey	Director	February 22, 2023
/s/ Patricia K. Collawn Patricia K. Collawn	Director	February 22, 2023
/s/ Brian E. Edwards Brian E. Edwards	Director	February 22, 2023
/s/ Lorraine Mitchelmore Lorraine Mitchelmore	Director	February 22, 2023
/s/ Scott Peak Scott Peak	Director	February 22, 2023
/s/ Donald F. Robillard, Jr. Donald F. Robillard, Jr.	Director	February 22, 2023
/s/ Neal A. Shear Neal A. Shear	Director	February 22, 2023

APPENDIX

Consolidated Adjusted EBITDA and Distributable Cash Flow

Note: Totals may not sum due to rounding.

The following table reconciles our actual Consolidated Adjusted EBITDA and Distributable Cash Flow to Net Loss attributable to common stockholders for 2022 (in billions):

		2022
Net income attributable to common stockholders	$	1.43
Net income attributable to non-controlling interest		1.21
Income tax provision		0.46
Interest expense, net of capitalized interest		1.41
Depreciation and amortization expense		1.12
Other expense, financing costs, and certain non-cash operating expenses		5.95
Consolidated Adjusted EBITDA	**$**	**11.56**
Interest expense (net of capitalized interest and amortization) and realized interest rate derivatives		(1.36)
Maintenance capital expenditures, income tax and other expense		(0.15)
Consolidated Distributable Cash Flow	**$**	**10.05**
Cheniere Partners' distributable cash flow attributable to non-controlling interest		(1.33)
Cheniere Distributable Cash Flow	**$**	**8.72**

The following tables reconcile our Consolidated Adjusted EBITDA and Distributable Cash Flow to Net income (loss) attributable to common stockholders for the forecast amounts for full year 2022 (in billions):

<u>As of November 2021:</u>

	2022		
Net income attributable to common stockholders	$ 1.4	-	$ 1.8
Net income attributable to non-controlling interest	1.0	-	1.2
Income tax provision	0.7	-	0.8
Interest expense, net of capitalized interest	1.5	-	1.5
Depreciation and amortization expense	1.1	-	1.1
Other expense (income), financing costs, and certain non-cash operating expenses	0.1	-	(0.1)
Consolidated Adjusted EBITDA	**$ 5.8**	-	**$ 6.3**
Interest expense (net of capitalized interest and amortization) and realized interest rate derivatives	(1.4)	-	(1.4)
Maintenance capital expenditures, income tax and other expense	(0.4)	-	(0.2)
Consolidated Distributable Cash Flow	**$ 4.0**	-	**$ 4.7**
Cheniere Partners' distributable cash flow attributable to non-controlling interest	(0.9)	-	(1.1)
Cheniere Distributable Cash Flow	**$ 3.1**	-	**$ 3.6**

Note: Totals may not sum due to rounding.

As of February 2022:

	2022		
Net income (loss) attributable to common stockholders	$ (0.2)	-	$ 0.2
Net income attributable to non-controlling interest	1.1	-	1.2
Income tax provision	1.1	-	1.2
Interest expense, net of capitalized interest	1.5	-	1.5
Depreciation and amortization expense	1.1	-	1.1
Other expense (income), financing costs, and certain non-cash operating expenses	2.4	-	2.3
Consolidated Adjusted EBITDA	**$ 7.0**	-	**$ 7.5**
Interest expense (net of capitalized interest and amortization) and realized interest rate derivatives	(1.4)	-	(1.4)
Maintenance capital expenditures, income tax and other expense	(0.4)	-	(0.3)
Consolidated Distributable Cash Flow	**$ 5.2**	-	**$ 5.8**
Cheniere Partners' distributable cash flow attributable to non-controlling interest	(0.9)	-	(1.0)
Cheniere Distributable Cash Flow	**$ 4.3**	-	**$ 4.8**

Note: Totals may not sum due to rounding.

As of May 2022:

	2022		
Net income attributable to common stockholders	$ 0.6	-	$ 1.1
Net income attributable to non-controlling interest	1.0	-	1.1
Income tax provision	0.8	-	0.9
Interest expense, net of capitalized interest	1.5	-	1.5
Depreciation and amortization expense	1.1	-	1.1
Other expense (income), financing costs, and certain non-cash operating expenses	3.2	-	3.0
Consolidated Adjusted EBITDA	**$ 8.2**	-	**$ 8.7**
Interest expense (net of capitalized interest and amortization) and realized interest rate derivatives	(1.4)	-	(1.4)
Maintenance capital expenditures, income tax and other expense	(0.3)	-	(0.2)
Consolidated Distributable Cash Flow	**$ 6.5**	-	**$ 7.1**
Cheniere Partners' distributable cash flow attributable to non-controlling interest	(1.0)	-	(1.1)
Cheniere Distributable Cash Flow	**$ 5.5**	-	**$ 6.0**

Note: Totals may not sum due to rounding.

As of August 2022:

	2022		
Net income attributable to common stockholders	$ 0.8	-	$ 1.3
Net income attributable to non-controlling interest	1.2	-	1.3
Income tax provision	0.6	-	0.7
Interest expense, net of capitalized interest	1.4	-	1.4
Depreciation and amortization expense	1.1	-	1.1
Other expense (income), financing costs, and certain non-cash operating expenses	4.7	-	4.5
Consolidated Adjusted EBITDA	**$ 9.8**	-	**$ 10.3**
Interest expense (net of capitalized interest and amortization) and realized interest rate derivatives	(1.4)	-	(1.4)
Maintenance capital expenditures, income tax and other expense	(0.3)	-	(0.2)
Consolidated Distributable Cash Flow	**$ 8.1**	-	**$ 8.7**
Cheniere Partners' distributable cash flow attributable to non-controlling interest	(1.2)	-	(1.3)
Cheniere Distributable Cash Flow	**$ 6.9**	-	**$ 7.4**

Note: Totals may not sum due to rounding.

As of September 2022:

	2022		
Net income attributable to common stockholders	$ 1.8	-	$ 2.3
Net income attributable to non-controlling interest	1.2	-	1.3
Income tax provision	0.9	-	1.0
Interest expense, net of capitalized interest	1.4	-	1.4
Depreciation and amortization expense	1.1	-	1.1
Other expense (income), financing costs, and certain non-cash operating expenses	4.6	-	4.4
Consolidated Adjusted EBITDA	**$ 11.0**	-	**$ 11.5**
Interest expense (net of capitalized interest and amortization) and realized interest rate derivatives	(1.4)	-	(1.4)
Maintenance capital expenditures, income tax and other expense	(0.3)	-	(0.2)
Consolidated Distributable Cash Flow	**$ 9.3**	-	**$ 9.9**
Cheniere Partners' distributable cash flow attributable to non-controlling interest	(1.2)	-	(1.3)
Cheniere Distributable Cash Flow	**$ 8.1**	-	**$ 8.6**

Note: Totals may not sum due to rounding.

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

Patricia Collawn
Chairman, President and Chief Executive Officer,
PNM Resources, Inc.

Brian E. Edwards
Senior Vice President, Caterpillar Inc.

Matthew Runkle
Senior Managing Director – Infrastructure,
Blackstone Inc.

Lorraine Mitchelmore
Former President and Chief Executive Officer,
Enlighten Innovations Inc.

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

Senior Management

Jack A. Fusco
President and Chief Executive Officer

Zach Davis
Executive Vice President and Chief Financial Officer

Anatol Feygin
Executive Vice President and
Chief Commercial Officer

Corey Grindal
Executive Vice President and
Chief Operating Officer

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

David Craft
Senior Vice President, Engineering
and Construction

Scott Culberson
Senior Vice President, Worldwide Trading

Michael Dove
Senior Vice President, Shared Services

Maas Hinz
Senior Vice President, Operations

Julie Nelson
Senior Vice President, Policy, Government
and Public Affairs

Tim Wyatt
Senior Vice President,
Corporate Development and Strategy

Ramzi Mroueh
Managing Director, Origination

Officers

Matthew Barr
Vice President, State Government Affairs

Randy Bhatia
Vice President, Investor Relations

Nancy Bui
Vice President and Chief Human Resources Officer

Eben Burnham-Snyder
Vice President, Public Affairs

Khary Cauthen
Vice President, Federal Government Affairs

Robin Dane
Vice President and Chief Risk Officer

Stephen Dugat
Vice President and General Manager

Tony Eaton
Vice President, Project Execution

Robert Fee
Vice President, International Affairs and Climate

Matthew Healey
Vice President, Finance and Treasury

Scott Mills
Vice President, Mid Office

Tom Myers
Vice President, Health, Safety
and Environmental

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

Florian Pintgen
Vice President, Commercial Operations

Ryan Schleicher
Vice President, Origination

Nishita Singh
Vice President, Operations Support

David Slack
Vice President and Chief Accounting Officer

Brandon Smith
Vice President and Chief Information Officer

Robert Smith
Vice President, Regulatory Affairs

Viet Van
Vice President, Supply Chain Management

Patrick Ward
Vice President, Project Development
and Engineering

Michael Weller
Vice President, Environmental, Regulatory Projects
and Managing Counsel

Sam White
Vice President, Commercial Structuring

Wayne Williams
Vice President, Total Rewards and HR Services

Sean Bunk
Assistant General Counsel and
Assistant Corporate Secretary

Taylor Johnson
Deputy General Counsel

Erin O'Driscoll
Assistant General Counsel,
Employment Law and Litigation

Victoria Salem
Assistant General Counsel, Finance and Tax

Joshua Silverman
Assistant Treasurer

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 Energy, Inc. provides clean, secure, and affordable LNG to the world. Safety is the central priority of Cheniere's culture as we deliver 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