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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **December 30, 2022**

Tellurian Inc.

(Exact name of registrant as specified in its charter)

Delaware	**001-5507**	**06-0842255**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

1201 Louisiana Street, Suite 3100, Houston, TX	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(832) 962-4000**

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock, par value $0.01 per share	**TELL**	**NYSE American LLC**
8.25% Senior Notes due 2028	**TELZ**	**NYSE American LLC**

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§ 230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§ 240.12b-2 of this chapter).

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. ☐

Item 8.01 Other Events.

In connection with a Registration Statement on Form S-3ASR to be filed by Tellurian Inc. ("**Tellurian**" or the "**Company**") on or about December 30, 2022 that will replace the Company's Registration Statement on Form S-3ASR (File No. 333-235793) scheduled to expire on January 3, 2023, the Company is filing this Current Report on Form 8-K (this "**8-K**") to retrospectively revise the consolidated financial statements of the Company that were included in its Annual Report on Form 10-K for the fiscal year ended December 31, 2021 (the "**2021 10-K**"), as filed with the Securities and Exchange Commission (the "**SEC**") on February 23, 2022, in order to give effect to a change in segment reporting. This 8-K will permit us to incorporate the retrospectively revised financial statements by reference, or otherwise, in future SEC filings.

As previously disclosed in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2022 (as filed with the SEC on August 3, 2022), beginning with the second quarter of fiscal year 2022, the Company began reporting its operating results through three reportable segments: Upstream, Midstream and Marketing & Trading. Previously, the Company had operated as a single operating and reportable segment.

In Exhibit 99.1 to this 8-K, pursuant to guidance provided by the staff of the SEC, the Company has updated, to the extent applicable, the following sections of the 2021 10-K to reflect the revised segment presentation:

- Part I, Items 1 and 2 (Our Business and Properties);
- Part II, Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations); and
- Part II, Item 8 (Financial Statements and Supplementary Data).

The information in Exhibit 99.1 of this 8-K updates the 2021 10-K solely for changes in the Company's reportable segment information and the related impact to segment disclosures. There are no changes to other disclosures presented in the 2021 10-K, including the Company's previously reported consolidated balance sheets, statements of operations, statements of stockholders' equity, and statements of cash flows included in the 2021 10-K. No items in the 2021 10-K other than those identified above are being updated by this 8-K. Information in the 2021 10-K is generally stated as of December 31, 2021, and this 8-K does not reflect any subsequent information or events other than the change in segment reporting noted above. Without limiting the foregoing, this 8-K does not purport to update Management's Discussion and Analysis of Financial Condition and Results of Operations contained in the 2021 10-K for any information, uncertainties, transactions, risks, events, or trends occurring, or known to management, other than the events described above. More current information is contained in the Company's Quarterly Reports on Form 10-Q for the quarters ended March 31, 2022, June 30, 2022, and September 30, 2022 and other filings with the SEC. Exhibit 99.1 should be read in conjunction with the 2021 10-K, the Company's Quarterly Reports on Form 10-Q for the quarters ended March 31, 2022, June 30, 2022, and September 30, 2022, and any other documents that the Company has filed with the SEC since August 3, 2022.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Description
23.1	Consent of Deloitte & Touche LLP
99.1	Tellurian Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2021, as filed with the SEC on February 23, 2022, retrospectively revised solely to reflect changes in segment reporting in the following Items: Part I, Items 1 and 2 (Our Business and Properties); Part II, Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operations); and Part II, Item 8 (Financial Statements and Supplementary Data)
101.INS	XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File – the cover page XBRL tags are embedded within the Inline XBRL document (included as Exhibit 101)

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

TELLURIAN INC.

Date: December 30, 2022	By:	/s/ L. Kian Granmayeh
	Name:	L. Kian Granmayeh
	Title:	Executive Vice President and Chief Financial Officer

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-235793 on Form S-3ASR and Registration Statement Nos. 333-220641, 333-216010, 333-189614, 333-171149, 333-162668 and 333-70567 on Form S-8 of our report dated February 23, 2022, (December 30, 2022, as to the change in segment reporting disclosed in Notes 2 and 19) relating to the financial statements of Tellurian Inc. and our report dated February 23, 2022, on the effectiveness of Tellurian Inc.'s internal control over financial reporting appearing in this Current Report on Form 8-K dated December 30, 2022.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
December 30, 2022

Exhibit 99.1

Explanatory Note

Tellurian Inc. (“Tellurian” or the “Company”) is filing this exhibit (the “Exhibit”) solely for changes in the Company’s reportable segment information and the related impact to segment disclosures as set forth in its Annual Report on Form 10-K for the fiscal year ended December 31, 2021 (the “2021 10-K”), as filed with the Securities and Exchange Commission (the “SEC”) on February 23, 2022. As previously disclosed in the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2022 (as filed with the SEC on August 3, 2022), beginning with the second quarter of fiscal year 2022, the Company began reporting its operating results through three reportable segments: Upstream, Midstream and Marketing & Trading. There are no changes to other disclosures presented in the 2021 10-K. This Exhibit speaks as of the original filing date of the 2021 10-K, does not reflect events that may have occurred subsequent to the original filing date and does not modify or update in any way the disclosures made in the 2021 10-K other than as required to reflect the retrospectively revised segment information.

Tellurian Inc.

For the Fiscal Year Ended December 31, 2021

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Cautionary Information About Forward-Looking Statements

The information in this report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical facts, that address activity, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “contemplate,” “continue,” “could,” “estimate,” “expect,” “forecast,” “initial,” “intend,” “likely,” “may,” “plan,” “possible,” “potential,” “predict,” “project,” “proposed,” “should,” “will,” “would” and similar terms, phrases, and expressions are intended to identify forward-looking statements. These forward-looking statements relate to, among other things:

- our businesses and prospects and our overall strategy;
- planned or estimated capital expenditures;
- availability of liquidity and capital resources;
- our ability to obtain financing as needed and the terms of financing transactions, including for the Driftwood Project;
- revenues and expenses;
- progress in developing our projects and the timing of that progress;
- future values of the Company’s projects or other interests, operations or rights; and
- government regulations, including our ability to obtain, and the timing of, necessary governmental permits and approvals.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Factors that could cause actual results and performance to differ materially from any future results or performance expressed or implied by the forward-looking statements include, but are not limited to, the following:

- the uncertain nature of demand for and price of natural gas and LNG;
- risks related to shortages of LNG vessels worldwide;
- technological innovation which may render our anticipated competitive advantage obsolete;
- risks related to a terrorist or military incident involving an LNG carrier;
- changes in legislation and regulations relating to the LNG industry, including environmental laws and regulations that impose significant compliance costs and liabilities;
- governmental interventions in the LNG industry, including increases in barriers to international trade;
- uncertainties regarding our ability to maintain sufficient liquidity and attract sufficient capital resources to implement our projects;
- our limited operating history;
- our ability to attract and retain key personnel;

- risks related to doing business in, and having counterparties in, foreign countries;
- our reliance on the skill and expertise of third-party service providers;
- the ability of our vendors, customers and other counterparties to meet their contractual obligations;
- risks and uncertainties inherent in management estimates of future operating results and cash flows;
- our ability to maintain compliance with our debt arrangements;
- changes in competitive factors, including the development or expansion of LNG, pipeline and other projects that are competitive with ours;
- development risks, operational hazards and regulatory approvals;
- our ability to enter into and consummate planned financing and other transactions;
- risks related to pandemics or disease outbreaks;
- risks of potential impairment charges and reductions in our reserves; and
- risks and uncertainties associated with litigation matters.

The forward-looking statements in this report speak as of the date hereof. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document, the terms listed below have the following meanings:

ASC	Accounting Standards Codification
Bcf	Billion cubic feet of natural gas
Bcfe	Billion cubic feet of natural gas equivalent volumes using a ratio of 6 Mcf to 1 barrel of liquid
Condensate	Hydrocarbons that exist in a gaseous phase at original reservoir temperature and pressure, but when produced, are in the liquid phase at surface pressure and temperature
DD&A	Depreciation, depletion, and amortization
DES	Delivered ex-ship
DOE/FE	U.S. Department of Energy, Office of Fossil Energy
EPC	Engineering, procurement, and construction
FASB	Financial Accounting Standards Board
FEED	Front-End Engineering and Design
FERC	U.S. Federal Energy Regulatory Commission
FID	Final investment decision as it pertains to the Driftwood Project
FTA countries	Countries with which the U.S. has a free trade agreement providing for national treatment for trade in natural gas
GAAP	Generally accepted accounting principles in the U.S.
ICE	Intercontinental Exchange
JKM	Platts Japan Korea Marker index price for LNG
LIBOR	London Inter-bank Offered Rate
LNG	Liquefied natural gas
LSTK	Lump Sum Turnkey
Mcf	Thousand cubic feet of natural gas
MMBtu	Million British thermal unit
MMcf	Million cubic feet of natural gas
MMcf/d	MMcf per day
MMcfe	Million cubic feet of natural gas equivalent volumes using a ratio of 6 Mcf to 1 barrel of liquid
Mtpa	Million tonnes per annum
NGA	Natural Gas Act of 1938, as amended
Non-FTA countries	Countries with which the U.S. does not have a free trade agreement providing for national treatment for trade in natural gas and with which trade is permitted
NYMEX	New York Mercantile Exchange
NYSE American	NYSE American LLC
Oil	Crude oil and condensate
PUD	Proved undeveloped reserves
SEC	U.S. Securities and Exchange Commission
SPA	Sale and purchase agreement
Train	An industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
TTF	Platts Dutch Title Transfer Facility Index price for LNG
U.K.	United Kingdom
U.S.	United States
USACE	U.S. Army Corps of Engineers

With respect to the information relating to our ownership in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

ITEM 1 AND 2. OUR BUSINESS AND PROPERTIES

Overview

Tellurian Inc. (“Tellurian,” “we,” “us,” “our,” or the “Company”), a Delaware corporation, is a Houston-based company that intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide (the “Business”). We are developing a portfolio of natural gas, LNG marketing, and infrastructure assets that includes an LNG terminal facility (the “Driftwood terminal”), an associated pipeline (the “Driftwood pipeline”), other related pipelines, and upstream natural gas assets. The Driftwood terminal and the Driftwood pipeline are collectively referred to as the “Driftwood Project”. Our existing natural gas assets consist of 11,060 net acres and interests in 78 producing wells located in the Haynesville Shale trend of northern Louisiana. Our Business may be developed in phases.

As part of our execution strategy, which includes increasing our asset base, we will consider various commercial arrangements with third parties across the natural gas value chain. We are also pursuing activities such as direct sales of LNG to global counterparties, trading of LNG, the acquisition of additional upstream acreage and drilling of new wells on our existing or newly acquired upstream acreage. As discussed in “Overview of Significant Events – LNG Sale and Purchase Agreements” below, in 2021 we entered into four LNG SPAs with three unrelated purchasers, completing the planned sales for plants one and two of the Driftwood terminal (“Phase 1”). We are currently focused on securing financing for the construction of Phase 1.

We manage and report our operations in three reportable segments. The Upstream segment is organized and operates to produce and gather natural gas. The Midstream segment is organized to develop, construct and operate LNG terminals and pipelines. The Marketing & Trading segment is organized and operates to purchase and sell natural gas, market the Driftwood terminal’s LNG production capacity and trade LNG.

We continue to evaluate the scope and other aspects of our Business in light of the evolving economic environment, needs of potential counterparties and other factors. How we execute our Business will be based on a variety of factors, including the results of our continuing analysis, changing business conditions and market feedback.

Overview of Significant Events

LNG Sale and Purchase Agreements

Driftwood LNG LLC (“Driftwood LNG”), a wholly owned subsidiary of the Company, entered into the following SPAs with three purchasers for the purchase of a total of 9.0 Mtpa of LNG:

- An SPA with Gunvor Singapore Pte Ltd (“Gunvor”) in May 2021 for the purchase of 3.0 Mtpa of LNG;
- An SPA with Vitol Inc. (“Vitol”) in June 2021 for the purchase of 3.0 Mtpa of LNG; and
- Two SPAs with Shell NA LNG LLC (“Shell”) in July 2021 for the purchase of 3.0 Mtpa of LNG.

The price for LNG sold under the SPAs with Gunvor and Vitol will be a blended average based on the JKM index price and the TTF futures contract price, in each case minus a transportation netback. The price for LNG sold under each SPA with Shell will be based on the JKM index price or the TTF futures contract price, in each case minus a transportation netback. Each SPA has a ten-year term from the date of first commercial delivery from the Driftwood terminal.

Initiated Owner Construction Activities

During the year ended December 31, 2021 we initiated owner construction activities necessary to proceed under our LSTK EPC agreements with Bechtel Oil, Gas and Chemicals, Inc. (“Bechtel”).

Driftwood Land Lease Agreement

On July 1, 2021, we entered into a long-term ground lease agreement with the Lake Charles Harbor and Terminal District to secure property essential for the construction of the Driftwood terminal.

Environmental, Social, Governance Practices

During the year ended December 2021, the Company began a partnership with the National Forest Foundation on a five-year plan for reforestation and other forest management projects totaling $25 million across the United States. One of the first identified projects is to re-plant 300,000 trees in the Kisatchie National Forest, located near Alexandria, Louisiana, where nearly 40,000 acres of native trees were lost due to extreme weather events during the past few years.

Upstream Drilling Activities

During the year ended December 31, 2021, we completed the drilling of and put in production four new Haynesville operated natural gas wells. We also participated in the drilling of six Haynesville non-operated natural gas wells. Our 2021 drilling activities increased our proved developed reserves by approximately 51 Bcfe as of December 31, 2021.

Repayment of Borrowing Obligations

During the year ended December 31, 2021, we repaid all borrowing obligations that were outstanding at the end of December 31, 2020. For further information regarding the repayment of our borrowing obligations, see *Note 10 - Borrowings*, of our Notes to the Consolidated Financial Statements.

Equity Offering

On August 6, 2021, we sold 35.0 million shares of our common stock in an underwritten public offering at a price of $3.00 per share. Net proceeds from this offering, after deducting fees and expenses, were approximately $100.8 million. The underwriters were granted an option to purchase up to an additional 5.3 million shares of common stock within 30 days. On August 31, 2021, the underwriters exercised this option, which generated net proceeds, after deducting fees, of approximately $15.1 million.

8.25% Senior Notes due 2028

On November 10, 2021, we sold $50.0 million aggregate principal amount of 8.25% Senior Notes due November 30, 2028 (the “Senior Notes”) in a registered public offering. Net proceeds from the sale of the Senior Notes were approximately $47.5 million after deducting fees. The underwriter was granted an option to purchase up to an additional $7.5 million of the Senior Notes within 30 days. On December 7, 2021, the underwriter exercised the option and purchased an additional $6.5 million of the Senior Notes, which generated net proceeds of approximately $6.2 million after deducting fees.

At-the-Market Debt Offering Program

On December 17, 2021, we entered into an at-the-market debt offering program under which the Company may offer and sell, from time to time on the NYSE American, up to an aggregate principal amount of $200.0 million of additional Senior Notes. During the year ended December 31, 2021, we did not sell any additional Senior Notes under the at-the-market debt offering program.

Natural Gas Properties

Reserves

Our natural gas assets consist of 11,060 net acres and interests in 78 producing wells located in the Haynesville Shale trend of north Louisiana. For the year ended December 31, 2021, our average net production was approximately 39.2 MMcf/d. All of our proved reserves were associated with those properties as of December 31, 2021. Proved reserves are the estimated quantities of natural gas and condensate which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., costs as of the date the estimate is made). Proved reserves are categorized as either developed or undeveloped.

Our reserves as of December 31, 2021 were estimated by Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm, and are set forth in the following table. Per SEC rules, NSAI based its estimates on the 12-month unweighted arithmetic average of the first-day-of-the-month price of natural gas for each month from January through December 2021. Prices include consideration of changes in existing prices provided for under contractual arrangements, but not on escalations or reductions based upon future conditions. The price used for the reserve estimates as of December 31, 2021 was $3.60 per MMBtu of natural gas, adjusted for energy content, transportation fees and market differentials.

The following table shows our proved reserves as of December 31, 2021:

	Gas (MMcf)
Proved reserves (as of December 31, 2021):	
Developed	73,927
Undeveloped	249,409
Total	323,336

As of December 31, 2021, the standardized measure of discounted future net cash flow from our proved reserves (the "standardized measure") was approximately $364.2 million.

During the year ended December 31, 2021, we did not have any material capital expenditures related to the development of our undeveloped reserves and thus did not convert any meaningful quantities from proved undeveloped to proved developed reserves. As of December 31, 2021, we do not expect to have any proved undeveloped reserves that will remain undeveloped for more than five years from the date that they were initially booked.

Refer to Supplemental Disclosures About Natural Gas Producing Activities, starting on page 47, for additional details.

Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used

Our December 31, 2021 reserve report was prepared by NSAI in accordance with guidelines established by the SEC. Reserve definitions comply with the definitions provided by Regulation S-X of the SEC. NSAI prepared the reserve report based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information we provided to them. This information was reviewed by knowledgeable members of our Company for accuracy and completeness prior to submission to NSAI. A letter that identifies the professional qualifications of the individual at NSAI who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2021, has been filed as an addendum to Exhibit 99.1 to this report and is incorporated by reference herein.

Internally, a Senior Vice President is responsible for overseeing our reserves process. Our Senior Vice President has over 20 years of experience in the oil and natural gas industry, with the majority of that time in reservoir engineering and asset management. She is a graduate of Virginia Polytechnic Institute and State University with dual degrees in Chemical Engineering and French, and a graduate of the University of Houston with a Masters of Business Administration degree. During her career, she has had multiple responsibilities in technical and leadership roles, including reservoir engineering and reserves management, production engineering, planning, and asset management for multiple U.S. onshore and international projects. She is also a licensed Professional Engineer in the State of Texas.

Production

For the years ended December 31, 2021, 2020 and 2019, we produced 14,302 MMcf, 16,893 MMcf and 13,901 MMcf of natural gas at an average sales price of $3.52, $1.74 and $2.07 per Mcf, respectively. Natural gas and condensate production and operating costs for the periods ended December 31, 2021, 2020 and 2019 were $0.48, $0.28 and $0.25 per Mcfe, respectively.

Drilling Activity

The table below shows the number of net productive and dry development wells drilled during the past three years. The information in the table below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found, or economic value. A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development, or extension well that is not a dry well. Completion refers to installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.

	For the Year Ended December 31,		
	2021	2020	2019
Development wells:			
Productive	6.9	—	3.1
Dry	—	—	—

We had no exploratory wells drilled during any of the periods presented.

Wells and Acreage

As of December 31, 2021, we owned working interests in 65 gross (28 net) productive natural gas wells. We have 4,419 gross (4,100 net) developed leasehold acres that are held by production. Additionally, we hold 7,448 gross (6,960 net) undeveloped leasehold acres. As of December 31, 2021, there were seven gross (3.33 net) in process wells.

Of the total gross and net undeveloped acreage, 1,995 gross and 1,901 net acres are not held by production, of which no acres are set to expire in 2022.

Volume Commitments

We are not currently subject to any material volume commitments.

Gathering, Processing and Transportation

As part of our acquisitions of natural gas properties, we also acquired certain gathering systems that deliver the natural gas we produce into third-party gathering systems. We believe that these systems and other available midstream facilities and services in the Haynesville Shale trend are adequate for our current operations and near-term growth.

Government Regulations

Our operations are and will be subject to extensive federal, state and local statutes, rules, regulations, and laws that include, but are not limited to, the NGA, the Energy Policy Act of 2005 ("EPAct 2005"), the Oil Pollution Act, the National Environmental Policy Act ("NEPA"), the Clean Air Act (the "CAA"), the Clean Water Act (the "CWA"), the Resource Conservation and Recovery Act ("RCRA"), the Pipeline Safety Improvement Act of 2002 (the "PSIA"), and the Coastal Zone Management Act (the "CZMA"). These statutes cover areas related to the authorization, construction and operation of LNG facilities, natural gas pipelines and natural gas producing properties, including discharges and releases to the air, land and water, and the handling, generation, storage and disposal of hazardous materials and solid and hazardous wastes due to the development, construction and operation of the facilities. These laws are administered and enforced by governmental agencies including but not limited to FERC, the U.S. Environmental Protection Agency (the "EPA"), DOE/FE, the U.S. Department of Transportation ("DOT"), the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), the Louisiana Department of Environmental Quality and the Louisiana Department of Natural Resources. Additionally, numerous other governmental and regulatory permits and approvals will be required to build and operate our Business, including, with respect to the construction and operation of the Driftwood Project, consultations and approvals by the Advisory Council on Historic Preservation, USACE, U.S. Department of Commerce, National Marine Fisheries Service, U.S. Department of the Interior, U.S. Fish and Wildlife Service, and U.S. Department of Homeland Security. For example, throughout the life of our liquefaction project, we will be subject to regular reporting requirements to FERC, PHMSA and other federal and state regulatory agencies regarding the operation and maintenance of our facilities.

Failure to comply with applicable federal, state, and local laws, rules, and regulations could result in substantial administrative, civil and/or criminal penalties and/or failure to secure and retain necessary authorizations.

We have received regulatory permits and approvals in connection with the Driftwood terminal and Driftwood pipeline, including the following:

Agency	**Permit / Consultation**	**Approval Date**
FERC	Section 3 and Section 7 Application - NGA	April 18, 2019
DOE	Section 3 Application - NGA	FTA countries: February 28, 2017 (3968); amended December 6, 2018 (3968-A); amended December 18, 2020 (4641) Non-FTA countries: May 2, 2019 (4373); amended December 10, 2020 (4373-A); amended December 18, 2020 (4641)
USACE	Section 404	May 3, 2019
	Section 10 (*Rivers and Harbors Act*)	May 3, 2019
United States Coast Guard	Letter of Intent and Preliminary Water Suitability Assessment	June 21, 2016
	Follow-On Water Suitability Assessment and Letter of Recommendation	April 25, 2017
United States Fish and Wildlife Service	Section 7 of *Endangered Species Act* Consultation	September 19, 2017; February 7, 2019
National Oceanic and Atmospheric Administration / National Marine Fisheries Service	Section 7 of the *Endangered Species Act* Consultation	February 14, 2018
	Magnuson-Stevens Fishery Management and Conservation Act Essential Fish Habitat Consultation	October 3, 2017
	Marine Mammal Protection Act Consultation	October 3, 2017
State		
Louisiana Department of Natural Resources-Coastal Management Division	Coastal Use Permit and Coastal Zone Consistency Permit, Joint Permit with USACE Coastal Use Permit Extension	May 29, 2018 May 21, 2020
Louisiana Department of Environmental Quality - Air Quality Division	Air Permit for LNG Terminal Gillis Compressor Station	July 10, 2018; June 2, 2021 (extension) October 2, 2017; April 8, 2021 (extension)
Louisiana State Historic Preservation Office	Section 106 Consultation	Concurrence received on June 29, 2016
		Concurrence received on November 22, 2016
		Concurrence received on April 13, 2017
		Concurrence received on March 1, 2019

Federal Energy Regulatory Commission

The design, construction and operation of liquefaction facilities and pipelines, the export of LNG and the transportation of natural gas are highly regulated activities. In order to site, construct and operate the Driftwood Project, we obtained authorizations from FERC under Section 3 and Section 7 of the NGA as well as several other material governmental and regulatory approvals and permits as detailed in the table above. In order to gain regulatory certainty with respect to certain potential commercial transactions, on November 13, 2020, Driftwood Holdings LP (“Driftwood Holdings”), a wholly owned subsidiary of the Company, and Driftwood LNG (jointly, “Driftwood”) filed a Petition with FERC requesting, among other things, a prospective limited waiver of FERC’s buy/sell prohibition as well as any other prospective waivers necessary to enable Driftwood to purchase natural gas from potentially affiliated upstream suppliers that may be resold to a different affiliate under a long-term contract for export as LNG in foreign commerce. On

January 19, 2021, FERC issued an order granting a prospective limited waiver of the prohibition on buy/sell arrangements for future proposed transactions in which Driftwood enters into: (1) an agreement to purchase natural gas from a potentially affiliated supplier; and (2) an agreement to sell LNG to affiliates in foreign commerce.

EPAct 2005 amended Section 3 of the NGA to establish or clarify FERC's exclusive authority to approve or deny an application for the siting, construction, expansion or operation of LNG terminals, although except as specifically provided in EPAct 2005, nothing in the statute is intended to affect otherwise applicable law related to any other federal agency's authorities or responsibilities related to LNG terminals.

In 2002, FERC concluded that it would apply light-handed regulation to the rates, terms and conditions agreed to by parties for LNG terminalling services, such that LNG terminal owners would not be required to provide open-access service at non-discriminatory rates or maintain a tariff or rate schedule on file with FERC, as distinguished from the requirements applied to FERC-regulated interstate natural gas pipelines. Although EPAct 2005 codified FERC's policy, those provisions expired on January 1, 2015. Nonetheless, we see no indication that FERC intends to modify its longstanding policy of light-handed regulation of LNG terminal operations.

A certificate of public convenience and necessity from FERC is required for the construction and operation of facilities used in interstate natural gas transportation, including pipeline facilities, in addition to other required governmental and regulatory approvals. In this regard, in April 2019, we obtained a certificate of public convenience and necessity to construct and operate the Driftwood pipeline. On June 17, 2021, Driftwood Pipeline LLC, a wholly owned subsidiary of the Company, filed an application pursuant to Section 7(c) of the NGA in FERC Docket No. CP21-465-000 requesting that FERC grant a certificate of public convenience and necessity and related approvals to construct, own and operate dual 42-inch diameter natural gas pipelines, an approximately 211,200 horsepower compressor station and appurtenant facilities to be located in Beauregard and Calcasieu Parishes, Louisiana, which would provide a maximum seasonal capacity of 5.7 Bcf of natural gas per day. The application is currently pending.

FERC's jurisdiction under the NGA generally extends to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate consumption for domestic, commercial, industrial or any other use and to natural gas companies engaged in such transportation or sale. FERC's jurisdiction does not extend to the production, gathering, local distribution or export of natural gas.

Specifically, FERC's authority to regulate interstate natural gas pipelines includes:

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

In addition, FERC has the authority to approve, and if necessary set, "just and reasonable rates" for the transportation or sale of natural gas in interstate commerce. Relatedly, under the NGA, our proposed pipelines will not be permitted to unduly discriminate or grant undue preference as to rates or the terms and conditions of service to any shipper, including our own affiliates.

EPAct 2005 amended the NGA to make it unlawful for any entity, including otherwise non-jurisdictional producers, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction. EPAct 2005 also gives FERC authority to impose civil penalties for violations of the NGA or Natural Gas Policy Act of up to $1 million per violation.

Transportation of the natural gas we produce, and the prices we pay for such transportation, will be significantly affected by the foregoing laws and regulations.

U.S. Department of Energy, Office of Fossil Energy Export License

Under the NGA, exports of natural gas to FTA countries are "deemed to be consistent with the public interest," and authorization to export LNG to FTA countries shall be granted by the DOE/FE "without modification or delay." FTA countries currently capable of importing LNG include but are not limited to Canada, Chile, Colombia, Jordan, Mexico, Singapore, South Korea and the Dominican Republic. Exports of natural gas to Non-FTA countries are authorized unless the DOE/FE "finds that the proposed exportation" "will not be consistent with the public interest." We have authorization from the DOE/FE to export LNG in a volume up to the equivalent of 1,415.3 Bcf per year of natural gas to FTA countries for a term of 30 years and to Non-FTA countries for a term through December 31, 2050.

Pipeline and Hazardous Materials Safety Administration

The Natural Gas Pipeline Safety Act of 1968 (the "NGPSA") authorizes DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases, as well as the transportation and storage of LNG. Amendments to the NGPSA include the Pipeline Safety Act of 1979, which addresses liquids pipelines, and the PSIA, which governs the areas of testing, education, training, and communication.

PHMSA administers pipeline safety regulations for jurisdictional gas gathering, transmission, and distribution systems under minimum federal safety standards. PHMSA also establishes and enforces safety regulations for onshore LNG facilities, which are defined as pipeline facilities used for the transportation or storage of LNG subject to such safety standards. Those regulations address requirements for siting, design, construction, equipment, operations, personnel qualification and training, fire protection, and security of LNG facilities. The Driftwood terminal will be subject to such PHMSA regulations.

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

On December 27, 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) of 2020 was signed into law as part of the Consolidated Appropriations Act of 2021. The legislation reauthorizes the PHMSA pipeline safety program through fiscal year 2023 and provides for advances to improve pipeline safety. The legislation includes a directive to PHMSA to update its current regulations for large-scale LNG facilities.

On January 11, 2021, PHMSA published a final rule in the Federal Register amending the Federal Pipeline Safety Regulations to reduce regulatory burdens and offer greater flexibility with respect to the construction, maintenance, and operation of gas transmission, distribution, and gathering pipeline systems, including updates to corrosion control requirements and test requirements for pressure vessels. Mandatory compliance with this rule started October 1, 2021. This rule is subject to review for possible modification pursuant to executive orders signed by President Biden on or shortly after January 20, 2021.

On November 15, 2021, PHMSA published a final rule in the Federal Register revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas gathering pipelines. The rule extends reporting requirements to all gas gathering operators and applies a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. This rule goes into effect on May 16, 2022.

The Driftwood pipeline and other related pipelines will be subject to regulation under PHMSA, which will involve capital and operating costs for compliance-related equipment and operations. We have no reason to believe that these compliance costs will be material to our financial performance, but the significance of such costs will depend on future events and our ability to achieve and maintain compliance throughout the life of the Driftwood Project or related pipelines.

Natural Gas Pipeline Safety Act of 1968

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

Other Governmental Permits, Approvals and Authorizations

The construction and operation of the Driftwood terminal and Driftwood pipeline are subject to federal permits, orders, approvals and consultations required by other federal and state agencies, including DOT, the Advisory Council on Historic Preservation, USACE, U.S. Department of Commerce, National Marine Fisheries Service, U.S. Department of the Interior, U.S. Fish and Wildlife Service, the EPA and the U.S. Department of Homeland Security. The necessary permits required for construction have been obtained and will be maintained for the Driftwood terminal and Driftwood pipeline. Similarly, additional permits, orders, approvals and consultations will be required for other related pipelines.

Three significant permits that apply to the Driftwood terminal and Driftwood pipeline are the USACE Section 404 of the CWA/Section 10 of the Rivers and Harbors Act Permit, the CAA Title V Operating Permit and the Prevention of Significant Deterioration Permit, of which the latter two permits are issued by the Louisiana Department of Environmental Quality. Each of the Driftwood terminal and Driftwood pipeline has received its permit from USACE, including a review and approval by USACE of the findings and conditions set forth in an Environmental Impact Statement and Record of Decision issued for the Driftwood terminal and Driftwood pipeline pursuant to the requirements of NEPA. The Louisiana Department of Environmental Quality has issued the Prevention of Significant Deterioration permit, which is required to commence construction of the Driftwood terminal as well as the Title V Operating Permit. These material approvals may be required for other related pipelines.

Environmental Regulation

Our operations are and will be subject to various federal, state and local laws and regulations relating to the protection of the environment and natural resources, the handling, generation, storage and disposal of hazardous materials and solid and hazardous wastes and other matters. These environmental laws and regulations, which can restrict or prohibit impacts to the environment or the types, quantities and concentration of substances that can be released into the environment, will require significant expenditures for compliance, can affect the cost and output of operations, may impose substantial administrative, civil and/or criminal penalties for non-compliance and can result in substantial liabilities. The statutes, regulations and permit requirements imposed under environmental laws are modified frequently, sometimes retroactively. Such changes are difficult to predict or prepare for, and may impose material costs for new permits, capital investment or operational limitations or changes.

The Biden Administration has issued a number of executive orders that direct federal agencies to take actions that may change regulations and guidance applicable to our business.

Executive Order 14008, “Tackling the Climate Crisis at Home and Abroad,” 86 FR 7619 (January 27, 2021), establishes a policy “promoting the flow of capital toward climate-aligned investments and away from high-carbon investments.” It also requires the heads of agencies to identify any fossil fuel subsidies provided by their respective agencies, and to seek to eliminate fossil fuel subsidies from the budget request for fiscal year 2022 and thereafter.

Executive Order 13990, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” 86 FR 7037 (January 20, 2021) directs agencies to review regulations and policies adopted by the Trump Administration and to “confront the climate crisis.” It specifically directs the EPA to consider suspending, revising or rescinding certain regulations, including restrictions on emissions from the oil and gas sector. In addition, Executive Order 13990 establishes a federal inter-agency working group to recommend methods for agencies to incorporate the “social cost of carbon” into their decision making. Finally, Executive Order 13990 directs the White House Council on Environmental Quality to rescind draft guidance restricting the review of climate change issues in reviews under NEPA and to update regulations to strengthen climate change reviews. On March 8, 2021, 12 states filed a lawsuit in the U.S. District Court for the Eastern District of Missouri challenging President Biden’s authority to establish interim values for the social cost of greenhouse gases under Executive Order 13990; the case is currently pending appeal before the U.S. Circuit Court of Appeals for the 8th Circuit.

NEPA. NEPA and comparable state laws and regulations require that government agencies review the environmental impacts of proposed projects. On July 16, 2020, the White House Council on Environmental Quality (the “CEQ”) published a final rule to “modernize and clarify” the prior NEPA implementation regulations and to streamline environmental reviews required by NEPA (the “Revised NEPA Regulations”). The Revised NEPA Regulations set a presumptive time limit for completion of NEPA reviews and limit the scope of NEPA reviews to those effects that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action or alternatives. While these changes are not likely to require amendments to the USACE permits and NEPA-related findings that were completed prior to the effective date of the final NEPA rule, the changes in the NEPA regulations may impact new permits, permit modifications and other elements of the Driftwood Project and related pipelines that are under development. The Revised NEPA Regulations are currently subject to legal challenges. On October 7, 2021, the CEQ published a notice of proposed rulemaking to announce a set of proposed changes to generally restore prior regulatory provisions. Therefore, the impact on the Driftwood Project and related pipelines of the previously Revised NEPA Regulations and new NEPA regulations and guidance is not determinable at this time.

Clean Air Act. The CAA and comparable state laws and regulations restrict the emission of air pollutants from many sources and impose various monitoring and reporting requirements, among other requirements. The Driftwood Project and related pipelines include facilities and operations that are subject to the federal CAA and comparable state and local laws, including requirements to obtain pre-construction permits and operating permits. We may be required to incur capital expenditures for air pollution control equipment in connection with maintaining or obtaining permits and approvals pursuant to the CAA and comparable state laws and regulations.

In August 2020, the EPA issued two final rules that revised the new source performance standards under the CAA (the “2020 CAA Revisions”) to require reductions in emissions, including methane emissions, from new and modified sources in the oil and natural gas sector. On June 30, 2021, President Biden signed into law a joint Congressional resolution disapproving many of the 2020 CAA Revisions pursuant to the Congressional Review Act making the disapproved portions of the 2020 CAA Revisions no longer effective. In November 2021, the EPA published a proposed rule that would update and expand existing requirements for the oil and gas industry, as well as creating significant new requirements and standards for new, modified and existing oil and gas facilities. The proposed new requirements would include, for example, new standards and emission limitations applicable to storage vessels, well liquids unloading, pneumatic controllers, and flaring of natural gas at both new and existing facilities. The proposed rules for new and modified facilities are expected to be finalized by the end of 2022, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become applicable and effective. The comment period for that proposed rule was extended until January 31, 2022. Therefore, the impact of the revised oil and gas new source performance standards on the Driftwood Project and other related pipelines and Tellurian’s compliance obligations are not determinable at this time.

Greenhouse Gases. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because emissions of GHGs are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings provide the basis for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. In June 2010, the EPA began regulating GHG emissions from stationary sources, including LNG terminals. In June 2019, the EPA issued the final Affordable Clean Energy rule, which, among other things, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The Affordable Clean Energy rule was subject to legal challenges and, in January 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the rule and remanded the rule to the EPA for revision or replacement.

The Biden Administration has communicated its intention to address climate change and has issued Executive Orders with respect to certain governmental actions related to climate change. In the future, the EPA may promulgate additional regulations for sources of GHG emissions that could affect the oil and gas sector, and Congress or states may enact new GHG legislation, either of which could impose emission limits on the Driftwood Project or related pipelines or require the Driftwood Project or related pipelines to implement additional pollution control technologies, pay fees related to GHG emissions or implement mitigation measures. The scope and effects of any new laws or regulations are difficult to predict, and the impact of such laws or regulations on the Driftwood Project or related pipelines cannot be predicted at this time.

Coastal Zone Management Act. Certain aspects of the Driftwood terminal are subject to the requirements of the CZMA. The CZMA is administered by the states (in Louisiana, by the Department of Natural Resources). This program is implemented to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas. Certain facilities that are part of the Driftwood Project obtained permits for construction and operation in coastal areas pursuant to the requirements of the CZMA.

Clean Water Act. The Driftwood Project and related pipelines are subject to the CWA and analogous state and local laws. The CWA and analogous state and local laws regulate discharges of pollutants to waters of the United States or waters of the state, including discharges of wastewater and storm water runoff and discharges of dredged or fill material into waters of the United States, as well as spill prevention, control and countermeasure requirements. Permits must be obtained prior to discharging pollutants into state and federal waters or dredging or filling wetland and coastal areas. The CWA is administered by the EPA, the USACE and by the states. Additionally, the siting and construction of the Driftwood terminal and Driftwood pipeline will impact jurisdictional wetlands, which would require appropriate federal, state and/or local permits and approval prior to impacting such wetlands. The authorizing agency may impose significant direct or indirect mitigation costs to compensate for regulated impacts to wetlands. Although the CWA permits required for construction and operation of the Driftwood terminal and Driftwood pipeline have been obtained, other CWA permits may be required in connection with our projects that are under development and our future projects. The approval timeframe may also be longer than expected and could potentially affect project schedules.

In April 2020, the EPA and the USACE finalized a rule revising and narrowing the definition of “waters of the United States” and replacing prior rules defining the same issued in 1986 and 2015 (the “2020 Rule”). On August 30, 2021, the U.S. District Court for the District of Arizona vacated and remanded the 2020 Rule and in June 2021, the EPA and the Department of the Army announced their intention to initiate a new rulemaking process to restore the pre-2015 definition of “waters of the United States” informed by decisions of the Supreme Court of the United States. The proposed rule was published on December 7, 2021 and the comment period closed on February 7, 2022. In addition, in January 2022, the Supreme Court of the United States granted certiorari in a case, Sackett v. EPA, that could further impact this rulemaking process and the ultimate rule. Changes in the definition of “waters of the United States” are not likely to affect the permits already obtained for the Driftwood terminal and Driftwood pipeline, but further regulatory changes or any judicial decisions could affect other elements of the Driftwood terminal and Driftwood pipeline or other related pipelines in ways that cannot be predicted at this time.

Federal laws including the CWA require certain owners or operators of facilities that store or otherwise handle oil and produced water to prepare and implement spill prevention, control, countermeasure and response plans addressing the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 (“OPA”) subjects owners and operators of facilities to strict and joint and several liability for all containment and cleanup costs and certain other damages arising from oil spills, including the government’s response costs. Spills subject to the OPA may result in varying civil and criminal penalties and liabilities. The Driftwood Project incorporates appropriate equipment and operational measures to reduce the potential for spills of oil and establish protocols for responding to spills, but oil spills remain an operational risk that could adversely affect our operations and result in additional costs or fines or penalties.

Resource Conservation and Recovery Act. The federal RCRA and comparable state requirements govern the generation, handling and disposal of solid and hazardous wastes and require corrective action for releases into the environment. In the event such wastes are generated or used in connection with our facilities, we will be subject to regulatory requirements affecting the handling, transportation, treatment, storage and disposal of such wastes and could be required to perform corrective action measures to clean up releases of such wastes. The EPA and certain environmental groups entered into an agreement pursuant to which the EPA was required to propose, no later than March 2019, a rulemaking for revision of certain regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. In April 2019, the EPA determined that revision of the regulations is not necessary. Information comprising the EPA’s review and the decision is contained in a document entitled “Management of Exploration, Development and Production Wastes: Factors Informing a Decision on the Need for Regulatory Action.” The EPA indicated that it would continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development and production wastes continue to be managed in a manner that is protective of human health and the environment. Environmental groups, however, expressed dissatisfaction with the EPA's decision and will likely continue to press the issue at the federal and state levels. A loss of the exclusion from RCRA coverage for drilling fluids, produced waters and related wastes in the future could result in a significant increase in our costs to manage and dispose of waste associated with our production operations.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"). CERCLA, often referred to as Superfund, and comparable state statutes, impose liability that is generally joint and several and that is retroactive for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, for the release of a "hazardous substance" (or under state law, other specified substances) into the environment. So-called potentially responsible parties ("PRPs") include the current and certain past owners and operators of a facility where there has been a release or threat of release of a hazardous substance and persons who disposed of or arranged for the disposal of, or transported hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties and/or from conditions at disposal facilities where materials were sent. Our operations involve the use or handling of materials that include or may be classified as hazardous substances under CERCLA or regulated under similar state statutes. We may also be the owner or operator of sites on which hazardous substances have been released and may be responsible for the investigation, management and disposal of soils or dredge spoils containing hazardous substances in connection with our operations.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at some of our properties by previous owners and operators. Materials from these operations remain on some of the properties and in certain instances may require remediation. In some instances, we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. Accordingly, we could incur material costs for remediation required under CERCLA or similar state statutes in the future.

Hydraulic Fracturing. Hydraulic fracturing is commonly used to stimulate the production of crude oil and/or natural gas from dense subsurface rock formations. We plan to use hydraulic fracturing extensively in our natural gas development operations. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations which are held open by the grains of sand, enabling the natural gas to more easily flow to the wellbore. The process is generally subject to regulation by state oil and natural gas commissions but is also subject to new and changing regulatory programs at the federal, state and local levels.

In February 2014, the EPA issued permitting guidance under the Safe Drinking Water Act (the "SDWA") for the underground injection of liquids from hydraulically fractured wells and other wells where diesel is used. Depending upon how it is implemented, this guidance may create duplicative requirements in certain areas, further slow the permitting process in certain areas, increase the costs of operations, and result in expanded regulation of hydraulic fracturing activities related to the Driftwood Project.

In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act ("TSCA") pursuant to which it will collect extensive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. If the EPA regulates hydraulic fracturing fluid under TSCA in the future, such regulation may increase the cost of our natural gas development operations and the feedstock for the Driftwood terminal.

In June 2016, the EPA finalized pretreatment standards for indirect discharges of wastewater from the oil and natural gas extraction industry. The regulation prohibits sending wastewater pollutants from onshore unconventional oil and natural gas extraction facilities to publicly-owned treatment works. Certain activities of our Business are subject to the pretreatment standards, which means that we are required to use disposal methods that may require additional permits or cost more to implement than disposal at publicly-owned treatment works.

In December 2016, the EPA released a report titled "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States." The report concluded that activities involved in hydraulic fracturing can have impacts on drinking water under certain circumstances. In addition, the U.S. Department of Energy has investigated practices that the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. These and similar studies, depending on their degree of development and nature of results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. If the EPA proposes additional regulations of hydraulic fracturing in the future, they could impose additional emission limits and pollution control technology requirements, which could limit our operations and revenues and potentially increase our costs of gas production or acquisition.

Endangered Species Act ("ESA"). Our operations may be restricted by requirements under the ESA. The ESA prohibits the harassment, harming or killing of certain protected species and destruction of protected habitats. Under the NEPA review process conducted by FERC, we have been and will be required to consult with federal agencies to determine limitations on and mitigation measures applicable to activities that have the potential to result in harm to threatened or endangered species of plants, animals, fish and their designated habitats. Although we have conducted studies and engaged in consultations with agencies in order to avoid harming protected species, inadvertent or incidental harm may occur in connection with the construction or operation of our properties, including of the Driftwood Project or related pipelines, which could result in fines or penalties. In addition, if threatened or endangered species are found on any part of our properties, including the sites of the Driftwood Project, related pipelines, or pipeline rights of way, then we may be required to implement avoidance or mitigation measures that could limit our operations or impose additional costs.

Regulation of Natural Gas Operations

Our natural gas operations are subject to a number of additional laws, rules and regulations that require, among other things, permits for the drilling of wells, drilling bonds and reports concerning operations. States, parishes and municipalities in which we operate may regulate, among other things:

- the location of new wells;
- the method of drilling, completing and operating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- notice to surface owners and other third parties; and
- produced water and waste disposal.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states, including Louisiana, allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells and generally prohibit the venting or flaring of natural gas and require that oil and natural gas be produced in a prorated, equitable system. These laws and regulations may limit the amount of oil and natural gas that we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, most states generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within their jurisdictions. Many local authorities also impose an ad valorem tax on the minerals in place. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

Anti-Corruption, Trade Control, and Tax Evasion Laws

We are subject to anti-corruption laws in various jurisdictions, such as the U.S. Foreign Corrupt Practices Act of 1977, as amended (the "FCPA"), the U.K. Bribery Act of 2010 and other anti-corruption laws. The FCPA and these other laws generally prohibit our employees, directors, officers and agents from authorizing, offering, or providing improper payments or anything else of value to government officials or other covered persons to obtain or retain business or gain an improper business advantage. We face the risk that one of our employees or agents will offer, authorize, or provide something of value that could subject us to liability under the FCPA and other anti-corruption laws. In addition, we cannot predict the nature, scope or effect of future regulatory requirements to which our international operations might be subject or the manner in which existing laws might be administered or interpreted.

We are also subject to other laws and regulations governing our international operations, including regulations administered by the U.S. Department of Commerce's Bureau of Industry and Security, the U.S. Department of Treasury's Office of Foreign Assets Control, and various non-U.S. government entities, including applicable export control regulations, economic sanctions on countries and persons, customs requirements, currency exchange regulations, and transfer pricing regulations (collectively, "Trade Control laws").

We are also subject to new U.K. corporate criminal offenses for failure to prevent the facilitation of tax evasion pursuant to the Criminal Finances Act 2017, which imposes criminal liability on a company where it has failed to prevent the criminal facilitation of tax evasion by a person associated with the company.

We have instituted policies, procedures and ongoing training of employees designed to ensure that we and our employees and agents comply with the FCPA, other anti-corruption laws, Trade Control laws and the Criminal Finances Act 2017. However, there is no assurance that our efforts have been and will be completely effective in ensuring our compliance with all applicable anti-corruption laws, including the FCPA or other legal requirements. If we are not in compliance with the FCPA, other anti-corruption laws, the Trade Control laws or the Criminal Finances Act 2017, we may be subject to criminal and civil penalties, disgorgement and other sanctions and remedial measures, and legal expenses, which could have a material adverse impact on our business, financial condition, results of operations and liquidity. Likewise, any investigation of any potential violations of the FCPA, other anti-corruption laws the Trade Control laws or the Criminal Finances Act 2017 by the U.S. or foreign authorities could have a material adverse impact on our reputation, business, financial condition and results of operations. U.S. or foreign authorities may also seek to hold us liable for successor liability for anti-corruption violations committed by companies we acquire or in which we invest (for example, by way of acquiring equity interests, participating as a joint venture partner, or acquiring assets).

Competition

We are subject to a high degree of competition in all aspects of our business. See "Item 1A — Risk Factors — Risks Relating to Our Business in General — *Competition is intense in the energy industry and some of Tellurian's competitors have greater financial, technological and other resources.*"

Production & Transportation. The natural gas and oil business is highly competitive in the exploration for and acquisition of reserves, the acquisition of natural gas and oil leases, equipment and personnel required to develop and produce reserves, and the gathering, transportation and marketing of natural gas and oil. Our competitors include national oil companies, major integrated natural gas and oil companies, other independent natural gas and oil companies, and participants in other industries supplying energy and fuel to industrial, commercial, and individual consumers, such as operators of pipelines and other midstream facilities. Many of our competitors have longer operating histories, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we currently possess.

Liquefaction. The Driftwood terminal will compete with liquefaction facilities worldwide to supply low-cost liquefaction to the market. There are a number of liquefaction facilities worldwide that we compete with for customers. Many of the companies with which we compete have greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than we do.

LNG Marketing. Tellurian competes with a variety of companies in the global LNG market, including (i) integrated energy companies that market LNG from their own liquefaction facilities, (ii) trading houses and aggregators with LNG supply portfolios, and (iii) liquefaction plant operators that market equity volumes. Many of the companies with which we compete have greater name recognition, larger staffs, greater access to the LNG market and substantially greater financial, technical, and marketing resources than we do.

Title to Properties

With respect to our natural gas producing properties, we believe that we hold good and defensible leasehold title to substantially all of our properties in accordance with standards generally accepted in the industry. A preliminary title examination is conducted at the time the properties are acquired. Our natural gas properties are subject to royalty, overriding royalty, and other outstanding interests. We believe that we hold good title to our other properties, subject to customary burdens, liens, or encumbrances that we do not expect to materially interfere with our use of the properties.

Major Customers

We do not have any major customers.

Facilities

Certain subsidiaries of Tellurian have entered into operating leases for office space in Houston, Texas, and Washington, D.C. The tenors of the leases are five and eight years for Houston and Washington, D.C., respectively.

Employees and Human Capital

As of December 31, 2021, Tellurian had 107 full-time employees worldwide. None of them are subject to collective bargaining arrangements. The Company's workforce is primarily located in Houston, Texas, and we have offices in Louisiana, Washington DC, London and Singapore. Many of our employees are originally from, or have extensive experience working in, countries other than the United States. This reflects our overall strategy of building a natural gas business that is global in scope.

We plan to build, among other things, an LNG liquefaction facility that we believe is one of the largest energy infrastructure projects currently under development in the United States. Given the inherent challenges involved in the construction of a project of this type, in particular by a company that has limited current operations, our human resources strategy focuses on the recruitment and retention of employees who have already established relevant expertise in the industry. The execution of this strategy has resulted in us assembling what we believe to be a premier management team in the global natural gas and LNG industry. A related aspect of our human resources strategy is that the compensation structure for many of our employees is weighted towards incentive compensation that is designed to reward progress toward the development of our business, including in particular the financing and construction of the Driftwood Project.

Jurisdiction and Year of Formation

The Company is a Delaware corporation originally formed in 1967 and formerly known as Magellan Petroleum Corporation.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available free of charge from the SEC's website at www.sec.gov or from our website at www.tellurianinc.com. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact Tellurian Inc., Investor Relations, 1201 Louisiana Street, Suite 3100, Houston, Texas 77002.

PART II

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 development activities, current financial condition and outlook for the future organized as follows:

- Our Business
- Overview of Significant Events
- Liquidity and Capital Resources
- Capital Development Activities
- Results of Operations
- Commitments and Contingencies
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

Our Business

Tellurian Inc. ("Tellurian," "we," "us," "our," or the "Company"), a Delaware corporation, is a Houston-based company that intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide (the "Business"). We are developing a portfolio of natural gas, LNG marketing, and infrastructure assets that includes an LNG terminal facility (the "Driftwood terminal"), an associated pipeline (the "Driftwood pipeline"), other related pipelines, and upstream natural gas assets. The Driftwood terminal and the Driftwood pipeline are collectively referred to as the "Driftwood Project". Our existing natural gas assets consist of 11,060 net acres and interests in 78 producing wells located in the Haynesville Shale trend of northern Louisiana. Our Business may be developed in phases.

As part of our execution strategy, which includes increasing our asset base, we will consider various commercial arrangements with third parties across the natural gas value chain. We are also pursuing activities such as direct sales of LNG to global counterparties, trading of LNG, the acquisition of additional upstream acreage and drilling of new wells on our existing or newly acquired upstream acreage. As discussed in "Overview of Significant Events – LNG Sale and Purchase Agreements" below, we entered into four LNG SPAs with three unrelated purchasers, completing the planned sales for plants one and two of the Driftwood terminal ("Phase 1"). We are currently focused on securing financing for the construction of Phase 1.

We manage and report our operations in three reportable segments. The Upstream segment is organized and operates to produce and gather natural gas. The Midstream segment is organized to develop, construct and operate LNG terminals and pipelines. The Marketing & Trading segment is organized and operates to purchase and sell natural gas, market the Driftwood terminal's LNG production capacity and trade LNG.

We continue to evaluate the scope and other aspects of our Business in light of the evolving economic environment, needs of potential counterparties and other factors. How we execute our Business will be based on a variety of factors, including the results of our continuing analysis, changing business conditions and market feedback.

Overview of Significant Events

LNG Sale and Purchase Agreements

Driftwood LNG LLC ("Driftwood LNG"), a wholly owned subsidiary of the Company, entered into the following SPAs with three purchasers for the purchase of a total of 9.0 Mtpa of LNG:

- An SPA with Gunvor Singapore Pte Ltd ("Gunvor") in May 2021 for the purchase of 3.0 Mtpa of LNG;
- An SPA with Vitol Inc. ("Vitol") in June 2021 for the purchase of 3.0 Mtpa of LNG; and
- Two SPAs with Shell NA LNG LLC ("Shell") in July 2021 for the purchase of 3.0 Mtpa of LNG.

The price for LNG sold under the SPAs with Gunvor and Vitol will be a blended average based on the JKM index price and the TTF futures contract price, in each case minus a transportation netback. The price for LNG sold under each SPA with Shell will be based on the JKM index price or the TTF futures contract price, in each case minus a transportation netback. Each SPA has a ten-year term from the date of first commercial delivery from the Driftwood terminal.

Initiated Owner Construction Activities

During the year ended, December 31, 2021 we initiated owner construction activities necessary to proceed under our LSTK EPC agreements with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel").

Driftwood Land Lease Agreement

On July 1, 2021, we entered into a long-term ground lease agreement with the Lake Charles Harbor and Terminal District to secure property essential for the construction of the Driftwood terminal.

Environmental, Social, Governance Practices

During the year ended December 2021, the Company began a partnership with the National Forest Foundation on a five-year plan for reforestation and other forest management projects totaling $25 million across the United States. One of the first identified projects is to re-plant 300,000 trees in the Kisatchie National Forest, located near Alexandria, Louisiana, where nearly 40,000 acres of native trees were lost due to extreme weather events during the past few years.

Upstream Drilling Activities

During the year ended December 31, 2021, we completed the drilling of and put in production four new Haynesville operated natural gas wells. We also participated in the drilling of six Haynesville non-operated natural gas wells. Our 2021 drilling activities increased our proved developed reserves by approximately 51 Bcfe as of December 31, 2021.

Repayment of Borrowing Obligations

During the year ended December 31, 2021, we repaid all borrowing obligations that were outstanding at the end of December 31, 2020. For further information regarding the repayment of our borrowing obligations, see Note 10 - Borrowings, of our Notes to the Consolidated Financial Statements.

Equity Offering

On August 6, 2021, we sold 35.0 million shares of our common stock in an underwritten public offering at a price of $3.00 per share. Net proceeds from this offering, after deducting fees and expenses, were approximately $100.8 million. The underwriters were granted an option to purchase up to an additional 5.3 million shares of common stock within 30 days. On August 31, 2021, the underwriters exercised this option, which generated net proceeds, after deducting fees, of approximately $15.1 million.

8.25% Senior Notes due 2028

On November 10, 2021, we sold $50.0 million aggregate principal amount of 8.25% Senior Notes due November 30, 2028 (the “Senior Notes”) in a registered public offering. Net proceeds from the sale of the Senior Notes were approximately $47.5 million after deducting fees. The underwriter was granted an option to purchase up to an additional $7.5 million of the Senior Notes within 30 days. On December 7, 2021, the underwriter exercised the option and purchased an additional $6.5 million of the Senior Notes, which generated net proceeds of approximately $6.2 million after deducting fees.

At-the-Market Debt Offering Program

On December 17, 2021, we entered into an at-the-market debt offering program under which the Company may offer and sell, from time to time on the NYSE American, up to an aggregate principal amount of $200.0 million of additional Senior Notes. During the year ended December 31, 2021, we did not sell any additional Senior Notes under the at-the-market debt offering program.

Liquidity and Capital Resources

Capital Resources

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We are currently funding our operations, development activities and general working capital needs through our cash on hand. Our current capital resources consist of approximately $305.5 million of cash and cash equivalents as of December 31, 2021 on a consolidated basis. We currently maintain at-the-market debt and equity offering programs pursuant to which we sell our Senior Notes and common stock from time to time. As of the date of this filing, we have remaining availability to raise aggregate gross sales proceeds of approximately $581.9 million under these programs.

As of December 31, 2021, we had total indebtedness of approximately $56.5 million, of which no amounts are scheduled to be repaid within the next twelve months. We also had contractual obligations associated with our finance and operating leases totaling $216.9 million, of which $7.1 million is scheduled to be paid within the next twelve months.

The Company has sufficient cash on hand and available liquidity to satisfy its obligations and fund its working capital needs for at least twelve months following the date of issuance of the consolidated financial statements. The Company has the ability to generate additional proceeds from various other potential financing transactions. We are currently focused on securing financing for the construction of plants one and two of the Driftwood terminal.

Sources and Uses of Cash

The following table summarizes the sources and uses of our cash and cash equivalents and costs and expenses for the periods presented (in thousands):

	Year Ended December 31, 2021	Year Ended December 31, 2020
Cash used in operating activities	$ (61,560)	$ (69,965)
Cash used in investing activities	(57,865)	(1,307)
Cash provided by financing activities	344,962	84,527
Net increase in cash, cash equivalents and restricted cash	225,537	13,255
Cash, cash equivalents and restricted cash, beginning of the period	81,737	68,482
Cash, cash equivalents and restricted cash, end of the period	$ 307,274	$ 81,737
Net working capital	$ 238,920	$ (34,403)

Cash used in operating activities for the year ended December 31, 2021 decreased by approximately $8.4 million compared to the same period in 2020 due to an overall decline in disbursements in the normal course of business.

Cash used in investing activities for the year ended December 31, 2021 increased by approximately $56.6 million compared to the same period in 2020. This increase is predominantly driven by increased spending on natural gas development activities, settlement of outstanding liabilities associated with engineering services for the Driftwood terminal and property and equipment purchases.

Cash provided by financing activities for the year ended December 31, 2021 increased by approximately $260.4 million compared to the same period in 2020. This increase primarily relates to the following:

- Increase of approximately $315.4 million in net proceeds from equity issuances and warrant exercises.
- Increase of approximately $6.3 million in net borrowings as compared to the prior period.
- These increases were partially offset by cash outflows used in principal repayments of our borrowing obligations compared to the prior period.

See Note 10, *Borrowings* and Note 12, *Stockholders' Equity*, of our Notes to the Consolidated Financial Statements for additional information about our financing activities.

Capital Development Activities

The activities we have proposed will require significant amounts of capital and are subject to risks and delays in completion. We received all major regulatory approvals for the construction of Phase 1 and, as a result, our business success will depend to a significant extent upon our ability to obtain the funding necessary to construct assets on a commercially viable basis and to finance the costs of staffing, operating and expanding our company during that process. We have initiated certain owner construction activities necessary to proceed under our LSTK EPC agreements and have increased our upstream development activities.

We currently estimate the total cost of the Driftwood Project as well as related pipelines and upstream natural gas assets to be approximately $25.0 billion including owners' costs, transaction costs and contingencies but excluding interest costs incurred during construction and other financing costs. We have entered into four LSTK EPC agreements currently totaling $15.5 billion, or $561 per tonne, with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for construction of the Driftwood terminal. The proposed Driftwood terminal will have a liquefaction capacity of up to approximately 27.6 Mtpa and will be situated on approximately 1,200 acres in Calcasieu Parish, Louisiana. The proposed Driftwood terminal will include up to 20 liquefaction Trains, three full containment LNG storage tanks and three marine berths. Our strategy involves acquiring additional natural gas properties, including properties in the Haynesville shale trend. We intend to pursue potential acquisitions of such assets, or public or private companies that own such assets. We would expect to use stock, cash on hand, or cash raised in financing transactions to complete an acquisition of this type.

We anticipate funding our more immediate liquidity requirements relative to the commencement of construction of the Driftwood terminal, natural gas development costs, and general and administrative costs through the use of cash on hand, proceeds from operations, and proceeds from completed and future issuances of securities by us. Investments in the construction of the Driftwood terminal and natural gas development may be significant in 2022, but the size of those investments will depend on, among other things, commodity prices, Driftwood Project financing developments and other liquidity considerations, and our continuing analysis of strategic risks and opportunities. Consistent with our overall financing strategy, the Company has considered, and in some cases discussed with investors, various potential financing transactions, including issuances of debt, equity and equity-linked securities or similar transactions, to support its short-term and long-term capital requirements. The Company will continue to evaluate its cash needs and business outlook, and it may execute one or more transactions of this type in the future.

Results of Operations

The following table summarizes costs and expenses for the periods presented (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Natural gas sales	$ 51,499	$ 30,441	$ 28,774
LNG sales	19,776	6,993	—
Total revenue	71,275	37,434	$ 28,774
Operating expenses	11,693	10,230	7,071
LNG cost of sales	24,745	6,993	—
Total cost of sales	36,438	17,223	7,071
Development expenses	50,186	27,492	59,629
Depreciation, depletion and amortization	11,481	17,228	20,446
General and administrative expenses	85,903	47,349	87,487
Impairment charge and loss on transfer of assets	—	81,065	—
Severance and reorganization charges	—	6,359	—
Related party charges	—	7,357	—
Loss from operations	(112,733)	(166,639)	(145,859)
Interest expense, net	(9,378)	(43,445)	(16,355)
Gain on extinguishment of debt, net	1,422	—	—
Other income (loss), net	5,951	(612)	10,447
Income tax benefit (provision)	—	—	—
Net loss	$ (114,738)	$ (210,696)	$ (151,767)

The most significant changes affecting our results of operations for the year ended December 31, 2021 compared to 2020, on a consolidated basis and by segment, are the following:

Upstream

- Increase of approximately $21.1 million and approximately $1.5 million in Natural gas sales and Operating expenses, respectively, attributable to increased realized natural gas prices, partially offset by decreased production volumes, as compared to 2020.

- Absence of proved natural gas Impairment charges of approximately $81.1 million that were incurred during 2020.

- Decrease of approximately $5.7 million in DD&A expenses due to utilizing a lower net book value in the calculation of DD&A as a result of the Impairment charge that we recognized in the prior year.

Marketing & Trading

- Increase of approximately $12.8 million and approximately $17.8 million in LNG sales and LNG cost of sales, respectively, as a result of increased prices of an LNG cargo sold during the second quarter of 2021, as compared to an LNG cargo sold in the third quarter of 2020.

Midstream

- An increase of approximately $22.7 million in Development expenses primarily attributable to an $18.1 million increase in compensation expenses and a $4.6 million increase in professional services, engineering services and other development expenses associated with the Driftwood Project.

Consolidated

- Absence of Severance and reorganization charges, and Related party charges of approximately \$6.4 million and \$7.4 million, respectively, that were incurred during 2020.

- Decrease of approximately \$34.1 million in Interest expense due to the decline in interest charges as a result of the repayment of our borrowing obligations that were outstanding at the end of 2020. For further information regarding the repayment of our borrowing obligations, see Note 10, Borrowings, of our Notes to the Consolidated Financial Statements.

- Increase of approximately \$38.6 million in General and administrative expenses primarily attributable to a \$32.2 million increase in compensation expenses and a \$6.4 million increase in professional services.

- Increase of approximately \$6.6 million in Other income (loss), net primarily attributable to an approximately \$8.7 million unrealized gain on natural gas financial instruments due to changes in the fair value of the Company's derivative instruments during the current period. The increase was partially offset by an approximately \$2.5 million realized loss on the settlements of unvested warrants during the prior period.

As a result of the foregoing, our consolidated Net loss was approximately \$114.7 million for the year ended December 31, 2021, compared to a Net loss of approximately \$210.7 million in 2020.

The most significant changes affecting our results of operations for the year ended December 31, 2020 compared to 2019, on a consolidated basis and by segment, are the following:

Upstream

- Increase of approximately \$1.7 million and approximately \$3.2 million in Natural gas sales and Operating expenses, respectively, attributable to increased production volumes, partially offset by decreased realized natural gas prices, as compared to the same period in 2019.

- Approximately \$81.1 million related to an Impairment charge of our proved natural gas properties primarily due to depressed natural gas prices caused by the combined impact of increased natural gas production and falling demand brought about by economic conditions at the time. For further information regarding this impairment charge, see Note 4, Property, Plant and Equipment, of our Notes to the Consolidated Financial Statements.

- Decrease of approximately \$3.2 million in DD&A expenses due to utilizing a lower net book value in the calculation of DD&A as a result of the Impairment charge recognized in the current period.

Marketing & Trading

- Increase of approximately \$7.0 million in LNG sales and LNG cost of sales, primarily attributable to the sale of an LNG cargo during the third quarter of 2020.

Midstream

- Decrease in Development expenses of approximately \$32.1 million due to an overall decline in business activities during the current period.

Consolidated

- Increase of approximately \$27.1 million in Interest expense, net, primarily attributable to incurring interest charges on both the 2019 Term Loan and 2020 Unsecured Note during the current period compared to only incurring charges on a portion of the 2019 Term Loan during the prior period.

- Approximately $7.4 million in Related party charges incurred during the current period compared to none in the prior period. For further information regarding these Related party charges, see Note 8, *Related Party Transactions*, of our Notes to the Consolidated Financial Statements.

- Approximately $6.4 million in Severance and reorganization charges incurred during the current period compared to none in the prior period. For further information regarding the Severance and reorganization charges, see Note 13, *Severance and Reorganization*, of our Notes to the Consolidated Financial Statements.

- Decrease in General and administrative expenses of approximately $40.1 million due to an overall decline in business activities during the current period.

- Decrease of approximately $11.1 million in Other income (loss), net primarily attributable to the recognition of a realized gain of approximately $4.2 million on the sale of a wholly-owned subsidiary to a third party and gains on financial instruments not designated as hedges of approximately $7.1 million in the prior period.

As a result of the foregoing, our consolidated net loss was approximately $210.7 million for the year ended December 31, 2020, compared to a net loss of approximately $151.8 million in 2019.

Commitments and Contingencies

The information set forth in Note 11, *Commitments and Contingencies*, to the accompanying Consolidated Financial Statements included in Part II, Item 8 of this Form 10-K is incorporated herein by reference.

Summary of Critical Accounting Estimates

Our accounting policies are more fully described in Note 2, Summary of Significant Accounting Policies, of our Notes to Consolidated Financial Statements included in this report. As disclosed in Note 2, the preparation of financial statements requires the use of judgments and estimates. We base our estimates on historical experience and on various other assumptions we believe to be reasonable according to current facts and circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from these estimates. We considered the following to be our most critical accounting estimates that involve significant judgment:

Valuation of Long-Lived Assets

When there are indicators that our proved natural gas properties carrying value may not be recoverable, we compare expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows, based on our estimates of (and assumptions regarding) future natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the income approach in accordance with GAAP. Estimates of undiscounted future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation. In addition, such assumptions and estimates are reasonably likely to change in the future.

Proved reserves are the estimated quantities of natural gas and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, because we use the units-of-production method to deplete our natural gas properties, the quantity of reserves could significantly impact our DD&A expense. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Finally, these reserves are the basis for our supplemental natural gas disclosures. See Item 1 and 2 — Our Business and Properties for additional information on our estimate of proved reserves.

Share-Based Compensation

Share-based compensation transactions are measured based on the grant-date estimated fair value. For awards containing only service conditions or performance conditions deemed probable of occurring, the fair value is recognized as expense over the requisite service period using the straight-line method. We recognize compensation cost for awards with performance conditions if and when we conclude that it is probable that the performance condition will be achieved. For awards where the performance or market condition is not considered probable, compensation cost is not recognized until the performance or market condition becomes probable. We reassess the probability of vesting at each reporting period for awards with performance conditions and adjust compensation cost based on our probability assessment. We recognize forfeitures as they occur.

Recent Accounting Standards

We do not believe that any recently issued, but not yet effective, accounting standards, if currently adopted, would have a material effect on our Consolidated Financial Statements or related disclosures.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS
TELLURIAN INC.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Company's Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Tellurian Inc.'s internal control over financial reporting was effective as of December 31, 2021.

Deloitte & Touche LLP, an independent registered public accounting firm, audited the effectiveness of Tellurian Inc.'s internal control over financial reporting as of December 31, 2021, as stated in their report on page 24.

/s/ Octávio M.C. Simões	/s/ L. Kian Granmayeh	/s/ Khaled A. Sharafeldin
Octávio M.C. Simões	L. Kian Granmayeh	Khaled A. Sharafeldin
President and Chief Executive Officer *(as Principal Executive Officer)*	*Chief Financial Officer* *(as Principal Financial Officer)*	*Chief Accounting Officer* *(as Principal Accounting Officer)*

Houston, Texas

February 23, 2022

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Tellurian Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Tellurian Inc. and subsidiaries (the "Company") as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity and cash flows, for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

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, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2022, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 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 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 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 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 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 financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the 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.

Proved Natural Gas Properties and Depletion – Natural Gas Reserves – Refer to Note 2 and 4 to the financial statements

Critical Audit Matter Description

The Company's proved natural gas properties are depleted using the units-of-production method based upon natural gas reserves. The development of the Company's natural gas reserve quantities requires management to make significant estimates and assumptions. The Company engages an independent reservoir engineer, management's specialist, to estimate natural gas quantities using generally accepted methods, calculation procedures and engineering data. Changes in assumptions or engineering data could have a significant impact on the amount of depletion. Proved natural gas properties were $47.7 million as of December 31, 2021, and depletion expense was $11.0 million for the year then ended.

Given the significant judgments made by management and management's specialist, performing audit procedures to evaluate the Company's natural gas reserve quantities, including management's estimates and assumptions related to natural gas prices requires a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to natural gas reserves included the following, among others:

- We tested the effectiveness of controls related to the Company's estimation of natural gas properties reserve quantities, including controls relating to the natural gas prices.

- We evaluated the reasonableness of natural gas prices by comparing such amounts to:

  - Third party industry sources.

  - Historical realized natural gas prices.

  - Historical realized natural gas price differentials.

- We evaluated the Company's estimates around production volumes by evaluating wells' past production performance to ensure it was appropriately reflected in production forecasts used in generating proved reserves.

- We evaluated the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm, including the methodologies and calculation procedures used to estimate natural gas reserves and performing analytical procedures on the reserve quantities.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 23, 2022 (December 30, 2022, as to the change in segment reporting disclosed in Notes 2 and 19)

We have served as the Company's auditor since 2016.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Tellurian Inc.

Opinions on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Tellurian Inc. and subsidiaries (the "Company") as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Company and our report dated February 23, 2022, expressed an unqualified opinion on those 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 included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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/ DELOITTE & TOUCHE LLP

Houston, Texas
February 23, 2022

TELLURIAN INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share amounts)

	December 31, 2021		December 31, 2020	
ASSETS				
Current assets:				
Cash and cash equivalents	$	305,496		78,297
Accounts receivable		9,270		4,500
Prepaid expenses and other current assets		12,952		2,105
Total current assets		327,718		84,902
Property, plant and equipment, net		150,545		61,257
Deferred engineering costs		110,025		110,499
Other non-current assets		33,518		36,337
Total assets	$	621,806	$	292,995
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	2,852		23,573
Accounts payable due to related parties (Note 8)		—		910
Accrued and other liabilities		85,946		22,003
Borrowings		—		72,819
Total current liabilities		88,798		119,305
Long-term liabilities:				
Borrowings		53,687		38,275
Other non-current liabilities		61,020		26,325
Total long-term liabilities		114,707		64,600
Commitments and Contingencies (Note 11)				
Stockholders' equity:				
Preferred stock, $0.01 par value, 100,000,000 authorized: 6,123,782 and 6,123,782 shares outstanding, respectively		61		61
Common stock, $0.01 par value, 800,000,000 and 800,000,000 authorized: 500,453,575 and 354,315,739 shares outstanding, respectively		4,774		3,309
Additional paid-in capital		1,344,526		922,042
Accumulated deficit		(931,060)		(816,322)
Total stockholders' equity		418,301		109,090
Total liabilities and stockholders' equity	$	621,806	$	292,995

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

TELLURIAN INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

	Year Ended December 31,		
	2021	2020	2019
Revenues:			
Natural gas sales	$ 51,499	$ 30,441	28,774
LNG sales	19,776	6,993	—
Total revenue	71,275	37,434	28,774
Operating costs and expenses:			
Cost of sales	36,438	17,223	7,071
Development expenses	50,186	27,492	59,629
Depreciation, depletion and amortization	11,481	17,228	20,446
General and administrative expenses	85,903	47,349	87,487
Impairment charges	—	81,065	—
Severance and reorganization charges	—	6,359	—
Related party charges (Note 8)	—	7,357	—
Total operating costs and expenses	184,008	204,073	174,633
Loss from operations	(112,733)	(166,639)	(145,859)
Interest expense, net	(9,378)	(43,445)	(16,355)
Gain on extinguishment of debt, net	1,422	—	—
Other (expense) income, net	5,951	(612)	10,447
Loss before income taxes	(114,738)	(210,696)	(151,767)
Income tax benefit (provision)	—	—	—
Net loss	$ (114,738)	$ (210,696)	$ (151,767)
Net loss per common share:			
Basic and diluted	$ (0.28)	$ (0.79)	$ (0.69)
Weighted average shares outstanding:			
Basic and diluted	407,615	267,615	218,548

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

TELLURIAN INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY

(in thousands)

	Year Ended December 31, 2021	2020	2019
Total shareholders' equity, beginning balance	$ 109,090	$ 166,285	$ 297,934
Preferred stock	61	61	61
Common stock:			
Beginning balance	3,309	2,211	2,195
Common stock issuance	1,361	808	—
Share-based compensation, net(1)	43	55	15
Severance and reorganization charges	—	22	—
Shared-based payments	1	—	1
Settlement of Final Payment Fee (Note 10)	—	110	—
Borrowings principal repayment (Note 10)	—	93	—
Warrants exercised	60	10	—
Ending balance	4,774	3,309	2,211
Additional paid-in capital:			
Beginning balance	922,042	769,639	749,537
Common stock issuance	406,493	98,867	—
Share-based compensation, net(1)	7,892	8,589	15,934
Severance and reorganization charges	—	2,667	—
Share-based payments	200	561	868
Settlement of Final Payment Fee (Note 10)	—	9,036	—
Warrants issued in connection with Borrowings (Note 12)	—	17,998	3,300
Borrowings principal repayment (Note 10)	—	13,695	—
Warrants exercised	8,117	990	—
Debt extinguishment	(218)	—	—
Ending balance	1,344,526	922,042	769,639
Accumulated deficit:			
Beginning balance	(816,322)	(605,626)	(453,859)
Net loss	(114,738)	(210,696)	(151,767)
Ending balance	(931,060)	(816,322)	(605,626)
Total shareholders' equity, ending balance	$ 418,301	$ 109,090	$ 166,285

(1) Includes settlement of 2019 and 2018 bonuses that were accrued for in 2019 and 2018, respectively.

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

TELLURIAN INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2021	2020	2019
Cash flows from operating activities:			
Net loss	$ (114,738)	$ (210,696)	$ (151,767)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	11,481	17,228	20,446
Amortization of debt issuance costs, discounts and fees	3,102	28,741	10,148
Share-based compensation	5,950	2,699	4,238
Severance and reorganization charges	—	2,689	—
Share-based payments	200	562	869
Interest elected to be paid-in-kind	508	3,317	—
Impairment charge and loss on transfer of assets	—	81,065	—
Gain on sale of assets	—	—	(4,218)
Unrealized loss (gain) on financial instruments not designated as hedges	(8,693)	2,618	(3,443)
Net gain on extinguishment of debt	(1,422)	—	—
Other	1,035	3,378	(459)
Net changes in working capital (Note 18)	41,017	(1,566)	11,178
Net cash used in operating activities	(61,560)	(69,965)	(113,008)
Cash flows from investing activities:			
Acquisition and development of natural gas properties	(32,364)	(1,307)	(45,354)
Payment of engineering services	(15,208)	—	(25,997)
Proceeds from sale of assets	—	—	8,140
Purchase of property and equipment	(10,293)	—	(2,732)
Net cash used in investing activities	(57,865)	(1,307)	(65,943)
Cash flows from financing activities:			
Proceeds from common stock issuances	421,809	103,664	—
Equity issuance costs	(13,955)	(3,989)	—
Proceeds from borrowings	56,500	50,000	75,000
Borrowings issuance costs	(2,854)	(2,612)	(2,246)
Borrowings principal repayments	(119,725)	(60,100)	—
Proceeds from warrant exercise	8,177	1,000	—
Tax payments for net share settlements of equity awards (Note 18)	(3,064)	(1,659)	(6,686)
Finance lease principal payments	(1,926)	(1,777)	(2,224)
Net cash provided by financing activities	344,962	84,527	63,844
Net increase (decrease) in cash, cash equivalents and restricted cash	225,537	13,255	(115,107)
Cash, cash equivalents and restricted cash, beginning of period	81,737	68,482	183,589
Cash, cash equivalents and restricted cash, end of period	307,274	81,737	$ 68,482
Supplementary disclosure of cash flow information:			
Interest paid	$ 4,105	$ 11,025	$ 8,414

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

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — ORGANIZATION AND NATURE OF OPERATIONS

Tellurian Inc. ("Tellurian," "we," "us," "our," or the "Company"), a Delaware corporation, is a Houston-based company which intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide (the "Business").

We plan to develop, own and operate a global natural gas business and to deliver natural gas to customers worldwide. Tellurian is developing a portfolio of natural gas, LNG marketing, and infrastructure assets that includes an LNG terminal facility (the "Driftwood terminal"), an associated pipeline (the "Driftwood pipeline"), other related pipelines, and upstream natural gas assets. The Driftwood terminal and the Driftwood pipeline are collectively referred to as the "Driftwood Project."

The terms "we," "our," "us," "Tellurian" and the "Company" as used in this report refer collectively to Tellurian Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity associated with Tellurian Inc.

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 Tellurian Inc. and its wholly owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

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

Liquidity

Our Consolidated Financial Statements have been prepared in accordance with GAAP, which contemplates the realization of assets and satisfaction of liabilities in the normal course of business as well as the Company's ability to continue as a going concern. As of the date of the Consolidated Financial Statements, we have generated losses and negative cash flows from operations, and have an accumulated deficit. We have not yet established an ongoing source of revenues that is sufficient to cover our future operating costs and obligations as they become due during the twelve months following the issuance of the Consolidated Financial Statements.

The Company has sufficient cash on hand and available liquidity to satisfy its obligations and fund its working capital needs for at least twelve months following the date of issuance of the Consolidated Financial Statements. The Company has the ability to generate additional proceeds from various other potential financing transactions. We are currently focused on securing financing for the construction of plants one and two of the Driftwood terminal.

Segments

Segment information is prepared on the same basis that our Chief Executive Officer, who is our Chief Operating Decision Maker, uses to manage the segments, evaluate financial results and make key operating decisions. We identified the Upstream, Midstream and Marketing & Trading components as the Company's operating segments. These operating segments represent the Company's reportable segments. The remainder of our business is presented as "Corporate," and consists of corporate costs and intersegment eliminations.

Use of Estimates

The preparation of 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 on a regular basis. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company uses three levels of the fair value hierarchy of inputs to measure the fair value of an asset or a liability. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Level 3 inputs are inputs that are not observable in the market.

Revenue Recognition

For the sale of natural gas, we consider the delivery of each unit (MMBtu) to be a separate performance obligation that is satisfied upon delivery to the designated sales point and therefore is recognized at a point in time. These contracts are either fixed price contracts or contracts with a fixed differential to an index price, both of which are deemed fixed consideration that is allocated to each performance obligation and represents the relative standalone selling price basis.

Each LNG cargo, in its entirety, is deemed to be a single performance obligation due to each molecule of LNG being distinct and substantially the same and therefore meeting the criteria for the transfer of a series of distinct goods. Accordingly, LNG sales are recognized at a point in time when the LNG has completed discharging to the customer. These are contracts with a fixed differential to an index price, which is deemed fixed consideration that is allocated to each performance obligation and represents the relative standalone selling price basis. These LNG sales are recorded on a gross basis and reported in “LNG sales” on the Consolidated Statements of Operations.

Purchases and sales of LNG inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in “LNG sales” on the Consolidated Statements of Operations. For such LNG sales, we require payment within 10 days from delivery.

We exclude all taxes from the measurement of the transaction price.

Cash, Cash Equivalents and Restricted Cash

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. Cash and cash equivalents that are restricted as to withdrawal or use under the terms of certain contractual agreements are recorded in Non-current restricted cash on our Consolidated Balance Sheets. The carrying value of cash, cash equivalents and restricted cash approximates their fair value.

Concentration of Cash

We maintain cash balances and restricted cash at financial institutions, which may, at times, be in excess of federally insured levels. We have not incurred losses related to these balances to date.

Derivative Instruments

We use derivative instruments to hedge our exposure to cash flow variability from commodity price 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 the criteria for and we elect the normal purchases and sales exception.

We have not elected and do not apply hedge accounting for our derivative instruments; therefore, all changes in fair value of the Company’s derivative instruments are recognized within Other income, net, in the Consolidated Statements of Operations.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Settlements of derivative instruments are reported as a component of cash flows from operations in the Consolidated Statements of Cash Flows.

Property, Plant and Equipment

Natural gas development and production activities are accounted for using the successful efforts method of accounting. Costs incurred to acquire a property (whether proved or unproved) are capitalized when incurred. Costs to develop proved reserves are capitalized and we deplete our natural gas reserves using the units-of-production method.

Fixed assets are recorded at cost. We depreciate our property, plant and equipment, excluding land, using the straight-line depreciation method over the estimated useful life of the asset. Upon retirement or other disposition of property, plant and equipment, the cost and related accumulated depreciation are removed, and the resulting gains or losses are recorded in our Consolidated Statements of Operations.

Management tests property, plant and equipment for impairment whenever there are indicators that the carrying amount of property, plant and equipment might not be recoverable. The carrying values of our proved natural gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. If there is an indication that the carrying amount of our proved natural gas properties may not be recoverable, we compare the estimated expected undiscounted future cash flows from our natural gas properties to the carrying values of those properties. Proved properties that have carrying amounts in excess of estimated future undiscounted cash flows are written down to fair value.

Leases

The Company adopted Accounting Standards Update ASU 2016-02, *Leases (Topic 842*), and subsequent amendments thereto ("ASC 842") on January 1, 2019 using the optional transition approach to apply the standard at the beginning of the first quarter of 2019 with no retrospective adjustments to prior periods. We elected the transition package of practical expedients to carry-forward prior conclusions related to lease identification and classification for existing leases, combine lease and non-lease components of an arrangement for all classes of our leased assets and omit short-term leases with a term of 12 months or less from recognition on the balance sheet.

The Company determines if an arrangement is a lease at inception. Leases are recognized as either finance or operating leases 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. Refer to Note 17 - *Leases* for operating and finance right-of-use assets and lease liabilities classification within our Consolidated Balance Sheets. In the absence of a readily determinable implicitly interest rate, we discount our expected future lease payments using our incremental borrowing rate. 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.

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 over the lease term.

Accounting for LNG Development Activities

As we have been in the preliminary stage of developing the Driftwood terminal, substantially all the costs related to such activities have been expensed. These costs primarily include professional fees associated with FEED studies and complying with FERC for authorization to construct our terminal and other required permitting for the Driftwood Project.

Costs incurred in connection with a project to develop the Driftwood terminal shall generally be treated as development expenses until the project has reached the notice-to-proceed state ("NTP State") and the following criteria (the "NTP Criteria") have been met: (i) the necessary regulatory permits have been obtained, (ii) financing for the project has been secured and (iii) management has committed to commence construction.

In addition, certain costs incurred prior to achieving the NTP State will be capitalized although the NTP Criteria have not been met. Costs to be capitalized prior to achieving the NTP State include land purchase costs, land improvement costs, costs associated with preparing the facility for use and any fixed structure construction costs (fence, storage areas, drainage, etc.). Furthermore, activities directly associated with detailed engineering and/or facility designs shall be capitalized. All amounts capitalized are periodically assessed for impairment and may be impaired if indicators are present. For additional details regarding capitalized amounts, please refer to Note 5, *Deferred Engineering Costs*.

Debt

Discounts, fees and expenses incurred with the issuance of debt are amortized over the term of the debt. These amounts are presented as a reduction of our indebtedness on the accompanying Consolidated Balance Sheets. See Note 10, *Borrowings*, for additional details about our loans.

Share-Based Compensation

We have awarded share-based compensation in the form of stock, restricted stock, restricted stock units and stock options to employees, directors and outside consultants. Share-based compensation transactions are measured based on the grant-date estimated fair value. For awards containing only service conditions or performance conditions deemed probable of occurring, the fair value is recognized as expense over the requisite service period using the straight-line method. We recognize compensation cost for awards with performance conditions if and when we conclude that it is probable that the performance condition will be achieved. For awards where the performance or market condition is not considered probable, compensation cost is not recognized until the performance or market condition becomes probable. We reassess the probability of vesting at each reporting period for awards with performance conditions and adjust compensation cost based on our probability assessment. We recognize forfeitures as they occur.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, we determine deferred tax assets and liabilities on the basis of the differences between the financial statement and tax basis of assets and liabilities by using enacted tax rates in effect for the year in which the differences are expected to be realized or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

We recognize deferred tax assets to the extent that we believe that these assets are more likely than not to be realized. In making such a determination, we consider current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. If we determine that we would be able to realize our deferred tax assets in the future in excess of their net recorded amount, we will make an adjustment to the deferred tax asset valuation allowance, which would reduce the provision for income taxes.

Postemployment benefits

The Company provides cash and other termination benefits pursuant to ongoing benefit arrangements to its employees in connection with a qualifying termination of their employment. The cost of providing postemployment benefits is recognized when the obligation is probable of occurring and can be reasonably estimated.

Net Loss Per Share (EPS)

Basic net loss per share excludes dilution and is computed by dividing net loss by the weighted average number of common shares outstanding during the period. Diluted net loss per share reflects potential dilution and is computed by dividing net loss by the weighted average number of common shares outstanding during the period increased by the number of additional common shares that would have been outstanding if the potential common shares had been issued and were dilutive.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3 — PREPAID EXPENSES AND OTHER CURRENT ASSETS

The components of prepaid expenses and other current assets consist of the following (in thousands):

	December 31,	
	2021	2020
Prepaid expenses	$ 605	$ 1,156
Deposits	3,589	100
Derivative asset, net - current (Note 7)	8,693	843
Other current assets	65	6
Total prepaid expenses and other current assets	$ 12,952	$ 2,105

NOTE 4 — PROPERTY, PLANT AND EQUIPMENT

The components of property, plant and equipment consist of the following (in thousands):

	December 31,	
	2021	2020
Land and Land improvements	$ 25,399	$ 13,808
Proved properties	96,297	62,227
Wells in progress	17,653	492
Corporate and other	3,476	3,476
Total property, plant and equipment, at cost	142,825	80,003
Accumulated depreciation, depletion and amortization	(50,163)	(38,764)
Right of use asset — finance leases	57,883	20,018
Total property, plant and equipment, net	$ 150,545	$ 61,257

Depreciation, depletion and amortization expenses for the years ended December 31, 2021, 2020 and 2019 were approximately $11.5 million, $17.2 million and $20.4 million, respectively.

Land and Land improvements

We own land in Louisiana for the purpose of constructing the Driftwood terminal. During the year ended December 31, 2021, we capitalized approximately $9.4 million in land improvement costs to prepare the land for its intended use.

Proved Properties

During the year ended December 31, 2021, we completed the drilling and put in production four new Haynesville operated natural gas wells. We also participated in the drilling of six Haynesville non-operated natural gas wells.

During the year ended December 31, 2020, we recognized an Impairment charge of approximately $81.1 million primarily associated with our assets located in northern Louisiana.

NOTE 5 — DEFERRED ENGINEERING COSTS

Deferred engineering costs of approximately $110.0 million and $110.5 million at December 31, 2021 and 2020, respectively, represent detailed engineering services related to the Driftwood terminal. The balance in this account will be transferred to construction in progress upon reaching an affirmative FID by the Company's Board of Directors.

NOTE 6 — OTHER NON-CURRENT ASSETS

Other non-current assets consist of the following (in thousands):

	December 31, 2021	December 31, 2020
Land lease and purchase options	$ 6,368	$ 5,831
Permitting costs	13,408	13,092
Right of use asset — operating leases	10,166	11,884
Restricted cash	1,778	3,440
Other	1,798	2,090
Total other non-current assets	$ 33,518	$ 36,337

Land Lease and Purchase Options

We hold lease and purchase option agreements (the "Options") for certain tracts of land and associated river frontage. Upon exercise of the Options, the leases are subject to maximum terms of 50 years (inclusive of various renewals, at the option of the Company). Costs of the Options are amortized over the life of the lease once obtained or capitalized into the land if purchased.

Permitting Costs

Permitting costs primarily represent the purchase of wetland credits in connection with our permit application to the USACE in 2017 and 2018. These wetland credits will be applied to our permit in accordance with the Clean Water Act and the Rivers and Harbors Act, which require us to mitigate the impact to Louisiana wetlands caused by the construction of the Driftwood Project. In May 2019, we received the USACE permit. The permitting costs will be transferred to construction in progress upon reaching an affirmative FID by the Company's Board of Directors.

Restricted Cash

Restricted cash as of December 31, 2021 represents cash collateralization of a letter of credit associated with a finance lease. Restricted cash as of December 31, 2020 represents unused proceeds from the 2018 Term Loan as described under Note 10 - *Borrowings*.

NOTE 7 — FINANCIAL INSTRUMENTS

Natural Gas Financial Instruments

During the year ended December 31, 2021, we entered into natural gas future options to economically hedge the commodity price exposure for a portion of our natural gas production. As of December 31, 2021, there were no open natural gas financial instruments positions.

LNG Financial Futures

During the fourth quarter of 2021, we entered into LNG financial future contracts to reduce our exposure to commodity price fluctuations, and to achieve more predictable cash flows relative to two LNG cargos that we are committed to purchase from and sell to unrelated third-party LNG merchants in the normal course of business in January and April 2022. As of December 31, 2021, the Company hedged approximately 2.4 million MMBtu of LNG, which represents a portion of its expected LNG cargo transactions. The open LNG financial futures positions at December 31, 2021 had maturities extending through April 2022.

The following table summarizes the effect of the Company's financial instruments on the consolidated Statements of Operations (in thousands):

	Year ended December 31, 2021	Year ended December 31, 2020
Natural Gas Financial Instruments		
Realized (loss) gain	$ (826)	$ 5,050
Unrealized loss	—	(2,618)
LNG Financial Futures		
Realized gain	1,010	—
Unrealized gain	8,693	—

The following table presents the classification of the Company's financial derivative assets and liabilities that are required to be measured at fair value on a recurring basis on the Company's Consolidated Balance Sheets (in thousands):

	Year ended December31, 2021	Year ended December 31, 2020
Current Assets:		
Natural Gas Financial Instruments	$ —	$ 843
LNG Financial Futures	8,693	—
Non-Current Assets:		
Natural Gas Financial Instruments	—	84

The Company's natural gas and LNG financial instruments are valued using quoted prices in active exchange markets as of the balance sheet date and are classified as Level 1 within the fair value hierarchy.

NOTE 8 — RELATED PARTY TRANSACTIONS

Accounts Payable due to Related Parties

In conjunction with the dismissal of prior litigation, we agreed to reimburse the Vice Chairman of our Board of Directors, Martin Houston, for reasonable attorneys' fees and expenses he incurred during the litigation. We paid approximately $5.1 million to third parties to settle outstanding amounts incurred by Mr. Houston for reasonable attorneys' fees and expenses for the year ended December 31, 2020. As of December 31, 2021 and 2020, we had also paid Mr. Houston approximately $0.9 million and $1.4 million, respectively, for other expenses he incurred in connection with the litigation. As of December 31, 2021, all amounts owed to Mr. Houston were fully settled.

Other

A member of our Board of Directors is a partner at a law firm that has provided legal services to the Company. Fees incurred for such services were $0.1 million and $0.4 million for the years ended December 31, 2020 and 2019, respectively. There were no fees incurred for such services for the year ended December 31, 2021.

TELLURIAN INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 9 — ACCRUED AND OTHER LIABILITIES

The components of accrued and other liabilities consist of the following (in thousands):

	December 31, 2021	December 31, 2020
Project development activities	26,421	3,228
Payroll and compensation	50,243	9,454
Accrued taxes	991	1,057
Professional services (e.g., legal, audit)	2,934	1,004
Warrant liabilities	—	3,774
Lease liabilities	2,279	1,950
Other	3,078	1,536
Total accrued and other liabilities	$ 85,946	$ 22,003

NOTE 10 — BORROWINGS

The following tables summarize the Company's borrowings as of December 31, 2021, and December 31, 2020 (in thousands):

	December 31, 2021		
	Principal repayment obligation	Unamortized debt issuance costs and discounts	Carrying value
Senior Notes due 2028	$ 56,500	$ (2,813)	$ 53,687
2020 Unsecured Note	—	—	—
2019 Term Loan, due March 2022	—	—	—
2018 Term Loan, due September 2021	—	—	—
Total borrowings	$ 56,500	$ (2,813)	$ 53,687

	December 31, 2020		
	Principal repayment obligation and other fees	Unamortized debt issuance costs and discounts	Carrying value
2020 Unsecured Note	$ 16,000	$ (2,376)	$ 13,624
2019 Term Loan, due March 2022 (a)	43,217	(4,942)	38,275
2018 Term Loan, due September 2021	60,000	(805)	59,195
Total borrowings	$ 119,217	$ (8,123)	$ 111,094

(a) Includes paid-in-kind interest on the 2019 Term Loan of $3.3 million.

Senior Notes due 2028

On November 10, 2021, we sold in a registered public offering, $50.0 million aggregate principal amount of 8.25% Senior Notes due November 30, 2028 (the "Senior Notes"). Net proceeds from the Senior Notes were approximately $47.5 million after deducting fees. The underwriter was granted an option to purchase up to an additional $7.5 million of the Senior Notes within 30 days. On December 7, 2021, the underwriter exercised the option and purchased an additional $6.5 million of the Senior Notes resulting in net proceeds of approximately $6.2 million after deducting fees. The Senior Notes have quarterly interest payments due on January 31, April 30, July 31, and October 31 of each year and on the maturity date.

At-the-Market Debt Offering Program

On December 17, 2021, we entered into an at-the-market debt offering program under which the Company may offer and sell, from time to time on the NYSE American, up to an aggregate principal amount of $200.0 million of additional Senior Notes. During the year ended December 31, 2021, we did not sell any additional Senior Notes under the at-the-market debt offering program. See Note 20, *Subsequent Events*, for further information.

2020 Senior Unsecured Note

On April 29, 2020, we issued a zero coupon $56.0 million senior unsecured note (the "2020 Unsecured Note") to an unrelated third party. The 2020 Unsecured Note was repaid in installments with the final contractually required payment made on March 31, 2021.

2019 Term Loan

On May 23, 2019, Driftwood Holdings LP ("Driftwood Holdings"), a wholly owned subsidiary of the Company, entered into a senior secured term loan agreement (the "2019 Term Loan") to borrow an aggregate principal amount of $60.0 million. On July 16, 2019, the principal amount was increased by an additional $15.0 million. Upon maturity or early repayment of the 2019 Term Loan, Driftwood Holdings was obligated to pay to the lender a fee equal to 20% of the principal amount borrowed less financing costs and cash interest paid (the "Final Payment Fee"). We issued to the lender a warrant to purchase approximately 1.5 million shares of our common stock at $10.00 per share (the "Original Warrant"). On March 3, 2020, the Original Warrant was replaced with a new warrant (the "Replacement Warrant") which provided the lender with the right to purchase 9.0 million shares of our common stock at $1.00 per share.

On March 12, 2021 (the "Extinguishment Date"), we finalized a voluntary repayment of the remaining outstanding principal balance of the 2019 Term Loan. The extinguishment of the 2019 Term Loan resulted in an approximately $2.1 million gain, which was recognized within Gain on extinguishment of debt, net, on our Consolidated Statements of Operations for the year ended December 31, 2021. As a result of repaying the outstanding balance prior to its contractual maturity, an approximately $4.4 million in unamortized debt issuance costs and discount were written off and included in the computation of the gain from the extinguishment of the 2019 Term Loan for the year ended December 31, 2021.

The holder of the 2019 Term Loan held approximately 3.5 million unvested warrants that had a fair value of approximately $6.3 million as of the Extinguishment Date. Due to the extinguishment of the 2019 Term Loan, all the unvested warrants were contractually terminated, and their respective fair value was included in the computation of the gain on extinguishment of the 2019 Term Loan.

2018 Term Loan

On September 28, 2018, Tellurian Production Holdings LLC, a wholly owned subsidiary of Tellurian Inc., entered into a three-year senior secured term loan credit agreement (the "2018 Term Loan") in an aggregate principal amount of $60.0 million.

On April 23, 2021, we voluntarily repaid the remaining outstanding principal balance of the 2018 Term Loan. As a result of the voluntary repayment, we recognized an approximately $0.7 million loss, which was recognized within Gain on extinguishment of debt, net, on our Consolidated Statements of Operations for the year ended December 31, 2021.

Covenant Compliance

As of December 31, 2021, the Company was in compliance with all covenants under the indentures governing the Senior Notes.

Fair Value

The Senior Notes are traded on the NYSE American under the symbol "TELZ," and are classified as Level 1 within the fair value hierarchy. As of December 31, 2021, the closing market price of $25.02 per Senior Note was substantially the same as its carrying value.

Trade Finance Credit Line

On July 19, 2021, we entered into an uncommitted trade finance credit line for up to $30.0 million that is intended to finance the purchase of LNG cargos for ultimate resale in the normal course of business. On December 7, 2021, the uncommitted trade finance credit line was amended and increased to $150.0 million. As of the period ended December 31, 2021, no amounts were drawn under this credit line.

NOTE 11 — COMMITMENTS AND CONTINGENCIES

Contractual Obligations

In connection with our LNG trading activities, we have previously entered into agreements with unrelated third-party LNG merchants pursuant to which we are obligated to purchase one cargo of LNG per quarter through October 2022 at a price based on then-prevailing JKM prices. The volume of each cargo is expected to range from 3.3 to 3.6 million MMBtu, and each cargo will be purchased under DES terms.

NOTE 12 — STOCKHOLDERS' EQUITY

At-the-Market Equity Offering Programs

We maintain multiple at-the-market equity offering programs pursuant to which we may sell shares of our common stock from time to time on the NYSE American. For the year ended December 31, 2021, we issued approximately 95.9 million shares of our common stock under our at-the-market programs for net proceeds of approximately $292.0 million. As of December 31, 2021, we had remaining availability under the at-the-market programs to raise aggregate gross sales proceeds of up to approximately $432.8 million. See Note 20, *Subsequent Events*, for further information.

Common Stock Issuances

On August 6, 2021, we sold 35.0 million shares of our common stock in an underwritten public offering at a price of $3.00 per share. Net proceeds from this offering, after deducting fees and expenses, were approximately $100.8 million. The underwriters were granted an option to purchase up to an additional 5.3 million shares of common stock within 30 days. On August 31, 2021, the underwriters exercised this option, which generated net proceeds, after deducting fees, of approximately $15.1 million.

Common Stock Purchase Warrants

2020 Unsecured Note

In conjunction with the issuance of the 2020 Unsecured Note, we issued a warrant providing the lender with the right to purchase up to 20.0 million shares of our common stock at $1.542 per share (the "2020 Warrant"). The 2020 Warrant, which vested immediately, will expire in October 2025. The 2020 Warrant was valued using a Black-Scholes option pricing model that resulted in a relative fair value of approximately $16.1 million on the Issuance Date and is not subject to subsequent remeasurement. The 2020 Warrant has been classified as equity and is recognized within Additional paid-in capital on our Consolidated Balance Sheets. The 2020 Warrant has been excluded from the computation of diluted loss per share because including it in the computation would have been antidilutive for the periods presented.

2019 Term Loan

During the first quarter of 2021, the lender of the 2019 Term Loan exercised warrants to purchase approximately 6.0 million shares of our common stock for total proceeds of approximately $8.2 million. As discussed in Note 10, *Borrowings*, the 2019 Term Loan has been repaid in full and the lender no longer holds any warrants.

Preferred Stock

In March 2018, we entered into a preferred stock purchase agreement with BDC Oil and Gas Holdings, LLC (“Bechtel Holdings”), a Delaware limited liability company and an affiliate of Bechtel Oil, Gas and Chemicals, Inc., a Delaware corporation, pursuant to which we sold to Bechtel Holdings approximately 6.1 million shares of our Series C convertible preferred stock (the “Preferred Stock”).

The holders of the Preferred Stock do not have dividend rights but do have a liquidation preference over holders of our common stock. The holders of the Preferred Stock may convert all or any portion of their shares into shares of our common stock on a one-for-one basis. At any time after “Substantial Completion” of “Project 1,” each as defined in and pursuant to the LSTK EPC Agreement for the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, or at any time after March 21, 2028, we have the right to cause all of the Preferred Stock to be converted into shares of our common stock on a one-for-one basis. The Preferred Stock has been excluded from the computation of diluted loss per share because including it in the computation would have been antidilutive for the periods presented.

NOTE 13 — 2020 SEVERANCE AND REORGANIZATION

We implemented a cost reduction and reorganization plan during the first quarter of 2020 due to the sharp decline in oil and natural gas prices as well as the negative economic effects of the COVID-19 pandemic. We satisfied all amounts owed to former employees and incurred approximately $6.4 million of severance and reorganization charges during the year ended December 31, 2020.

Employee Retention Plan

In July 2020, the Company’s Board of Directors approved an employee retention incentive plan (the “Employee Retention Plan”) aggregating $12.0 million. The Employee Retention Plan vests in four equal installments upon the attainment of a ten-day average closing price of the Company’s common stock above $2.25, $3.25, $4.25 and $5.25 (the “Stock Performance Targets”). Subject to continued employment, the Employee Retention Plan’s awards are payable over a period of twelve months commencing with the later of (i) the first month following the month in which the applicable Stock Performance Target is attained, and (ii) June 2021. The Employee Retention Plan will expire if the Stock Performance Targets are not attained by March 31, 2022. During the year ended December 31, 2021, three of the four installments vested and we recognized approximately $7.9 million in retention charges within General and administrative expenses and Development expenses in our Consolidated Statements of Operations, of which $3.7 million will be paid during 2022.

NOTE 14 — SHARE-BASED COMPENSATION

We have granted restricted stock and restricted stock units (collectively, “Restricted Stock”), as well as unrestricted stock and stock options, to employees, directors and outside consultants under the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan, as amended (the “2016 Plan”), and the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (the “Legacy Plan”). The maximum number of shares of Tellurian common stock authorized for issuance under the 2016 Plan is 40 million shares of common stock, and no further awards can be made under the Legacy Plan.

For the years ended December 31, 2021, 2020 and 2019, Tellurian recognized approximately $6.0 million, $2.7 million and $4.2 million, respectively, of share-based compensation expense related to all share-based awards. As of December 31, 2021, unrecognized compensation expense, based on the grant date fair value, for all share-based awards totaled approximately $200.7 million.

Restricted Stock

As of December 31, 2021, we had approximately 30.8 million shares of performance-based Restricted Stock outstanding, of which approximately 19.2 million shares will vest entirely based upon an affirmative FID by the Company’s Board of Directors, as defined in the award agreements, and approximately 10.8 million shares will vest in one-third increments at FID and the first and second anniversaries of FID. The remaining shares of primarily performance-based Restricted Stock, totaling approximately 0.8 million shares, will vest based on other criteria. As of December 31, 2021, no expense had been recognized in connection with performance-based Restricted Stock.

The approximately 30.8 million shares of performance-based and time-based Restricted Stock have been excluded from the computation of diluted loss per share because including them in the computation would have been antidilutive for the periods presented.

The following table provides a summary of our Restricted Stock transactions for the year ended December 31, 2021 (shares and units in thousands):

	Shares	Weighted-Average Grant Date Fair Value
Unvested at January 1, 2021	34,961	$ 5.78
Granted [1]	1,857	2.90
Vested	(5,658)	1.31
Forfeited	(356)	5.59
Unvested at December 31, 2021	30,804	$ 6.43

(1) The weighted-average per share grant date fair values of Restricted Stock granted during the years ended December 31, 2020 and 2019 were $1.17 and $8.53, respectively.

The total grant date fair value of restricted stock vested during the years ended December 31, 2021, 2020 and 2019 were approximately $7.4 million, $11.7 million and $1.2 million, respectively.

Stock Options

Participants in the 2016 Plan have been granted non-qualified options to purchase shares of common stock. Stock options are granted at a price not less than the market price of the common stock on the date of grant. The following table provides a summary of our stock option transactions for the year ended December 31, 2021 (stock options in thousands):

	Stock Options	Weighted Average Exercise Price
Outstanding at January 1, 2021	11,355	$ 5.19
Granted [1]	—	—
Exercised	—	—
Forfeited or expired	(276)	10.32
Outstanding at December 31, 2021	11,079	5.07
Exercisable at December 31, 2021	4,413	$ 5.17

The stock options that were granted to a member of the Company's executive management team during the year ended December 31, 2020, vest and become exercisable upon the achievement of both triggers as follows (stock options in thousands):

Service Trigger [1]	Stock Price Trigger [2]	Amount
December 15, 2021 [3]	$ 3.50	3,333
December 15, 2022	$ 4.50	3,333
December 15, 2023	$ 5.50	3,334
		10,000

(1) Satisfied through continued employment or other service to the Company through the designated date.

(2) Satisfied upon the Company's common stock price closing at a price per share at or equal to the designated closing price for any ten consecutive trading days.

(3) Vested during the year ended December 31, 2021.

The stock options granted during the year ended December 31, 2020, expire on the fifth anniversary of the date of its grant. There were no stock options granted during the years ended December 31, 2019 or 2018.

The fair value of each stock option awarded in 2020 was estimated using a Monte Carlo simulation and, due to the service trigger, is being recognized as compensation expense ratably over the vesting term. Valuation assumptions used to value stock options granted during the year ended December 31, 2020 were as follows:

Expected volatility	113.6 %
Expected dividend yields	— %
Risk-free rate	0.4 %

Due to our limited history, the expected volatility is based on a blend of our historical annualized volatility and the implied volatility utilizing options quoted or traded. The expected dividend yield is based on historical yields on the date of grant. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of the grant.

There were approximately zero, zero and seven thousand stock options exercised during the years ended December 31, 2021, 2020, and 2019, respectively. Further, the approximately 11.1 million stock options outstanding have been excluded from the computation of diluted loss per share because including them in the computation would have been antidilutive for the periods presented.

NOTE 15 — INCENTIVE COMPENSATION PROGRAM

On November 18, 2021, the Company's Board of Directors approved the adoption of the Tellurian Incentive Compensation Program (the "Incentive Compensation Program" or "ICP"). The ICP allows the Company to award short-term and long-term performance and service-based incentive compensation to full-time employees of the Company. ICP awards may be earned with respect to each calendar year and are determined based on guidelines established by the Compensation Committee of the Board of Directors, as administrator of the ICP.

Short-term incentive awards

Short-term incentive ("STI") awards are payable in cash annually at the discretion of the Company's Board of Directors. Compensation expense for STI awards is recognized over the performance period when it is probable that the performance condition will be achieved. For the year ended December 31, 2021, we recognized approximately $26.2 million in compensation expenses for STI awards.

Long-term incentive awards

Long-term incentive ("LTI") awards are granted in the form of "tracking units," at the discretion of the Company's Board of Directors. Each tracking unit will have a value equal to one share of Tellurian common stock and entitles the grantee to receive, upon vesting, a cash payment equal to the closing price of our common stock on the trading day prior to the vesting date. Tracking units will vest in three equal tranches at grant date, and the first and second anniversaries of the grant date. As of December 31, 2021, no tracking units for LTI awards had been granted under the ICP.

We recognize compensation expense for awards with graded vesting schedules over the requisite service periods for each separately vesting portion of the award as if each award was in substance multiple awards. Compensation expense for the first tranche of the LTI award that vests at the grant date is recognized over the performance period when it is probable that the performance condition will be achieved. Compensation expense for the second and third tranches will be recognized on a straight-line basis over the requisite service period. Compensation expense for unvested tracking units is subsequently adjusted each reporting period to reflect the estimated payout levels based on the changes in the Company's stock price and actual forfeitures. For the year ended December 31, 2021, we recognized approximately $19.9 million in compensation expenses for LTI awards that have been earned over the 2021 performance period.

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NOTE 16 — INCOME TAXES

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

	Year Ended December 31,		
	2021	2020	2019
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Foreign	—	—	—
Total Current	—	—	—
Deferred:			
Federal	—	—	—
State	—	—	—
Foreign	—	—	—
Total Deferred	—	—	—
Total income tax benefit (provision)	$ —	$ —	$ —

The sources of loss from operations before income taxes were as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Domestic	$ (111,114)	$ (202,831)	$ (139,654)
Foreign	(3,624)	(7,865)	(12,113)
Total loss before income taxes	$ (114,738)	$ (210,696)	$ (151,767)

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

	Year Ended December 31,		
	2021	2020	2019
Income tax benefit (provision) at U.S. statutory rate	$ 24,095	$ 44,246	$ 31,871
Share-based compensation	1,352	—	—
Impairment	—	—	—
Change in U.S. tax rate	—	—	—
Change in valuation allowance due to change in U.S. tax rate	—	—	—
U.S. state tax	4,333	8,563	7,529
Change in valuation allowance	(29,648)	(49,802)	(38,953)
Other	(132)	(3,007)	(447)
Total income tax benefit (provision)	$ —	$ —	$ —

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

	December 31,	
	2021	2020
Deferred tax assets:		
Capitalized engineering costs	$ 59,366	$ 45,865
Capitalized start-up costs	15,012	16,361
Compensation and benefits	14,740	4,475
Property, plant and equipment	—	10,569
Lease liability	15,514	5,977
Net operating loss carryforwards and credits:		
Federal	80,246	68,515
State	13,406	11,449
Foreign	5,687	5,242
Other, net	1,593	3,329
Deferred tax assets	205,564	171,782
Less valuation allowance	(201,366)	(171,782)
Deferred tax assets, net of valuation allowance	4,198	—
Deferred tax liabilities		
Property and equipment	(4,198)	—
Net deferred tax assets	$ —	$ —

As of December 31, 2021, we had federal, state and international net operating loss (“NOL”) carryforwards of approximately $360.8 million, $253.7 million and $31.4 million, respectively. Approximately $270.5 million of these NOLs have an indefinite carryforward period. All other NOLs will expire between 2036 and 2037.

Due to our historical losses and other available evidence related to our ability to generate taxable income, we have established a valuation allowance to fully offset our federal, state and international deferred tax assets as of December 31, 2021 and 2020. We will continue to evaluate the realizability of our deferred tax assets in the future. The increase in the valuation allowance was approximately $29.6 million for the year ended December 31, 2021.

In addition, we experienced a Section 382 ownership change in April 2017. An analysis of the annual limitation on the utilization of our NOLs was performed in accordance with IRC Section 382. It was determined that IRC Section 382 will not materially limit the use of our NOLs over the carryover period. We will continue to monitor trading activity in our shares which could cause an additional ownership change. If the Company experiences a Section 382 ownership change, it could further affect our ability to utilize our existing NOL carryforwards.

As of December 31, 2021, the Company determined that it has no uncertain tax positions, interest or penalties as defined within ASC 740-10. The Company does not have unrecognized tax benefits. The Company does not believe that it is reasonably possible that the total unrecognized benefits will significantly increase within the next 12 months.

We are subject to tax in the U.S. and various state and foreign jurisdictions. We are not currently under audit by any taxing authority. Federal and state tax returns filed with each jurisdiction remain open to examination under the normal three-year statute of limitations.

Pursuant to ASC 740-30-25-17, the Company recognizes deferred tax liabilities associated with outside basis differences on investments in foreign subsidiaries unless the difference is considered essentially permanent in duration. As of December 31, 2021, the Company has not recorded any deferred taxes on unremitted earnings as the Company has no undistributed earnings and profits. If circumstances change in the foreseeable future and it becomes apparent that some or all of the undistributed earnings and profits will not be reinvested indefinitely, or will be remitted in the foreseeable future, a deferred tax liability will be recorded for some or all of the outside basis difference.

NOTE 17 — LEASES

Our land leases are classified as finance leases and include one or more options to extend the lease term for up to 40 years, as well as to terminate the lease within five years, at our sole discretion. We are reasonably certain that those options will be exercised, and that our termination rights will not be exercised, and we have, therefore, included those assumptions within our right of use assets and corresponding lease liabilities. Our office space leases are classified as operating leases and include one or more options to extend the lease term up to 10 years, at our sole discretion. As we are not reasonably certain that those options will be exercised, none are recognized as part of our right of use assets and lease liabilities. As none of our leases provide an implicit rate, we have determined our own discount rate.

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

Leases	Consolidated Balance Sheets Classification	December 31, 2021	December 31, 2020
Right of use asset			
Operating	Other Non-Current Assets	$ 10,166	$ 11,884
Finance	Property, plant and equipment, net	57,883	20,018
Total Leased Assets		$ 68,049	$ 31,902
Liabilities			
Current			
Operating	Accrued and other liabilities	$ 2,147	$ 1,947
Finance	Accrued and other liabilities	132	3
Non-Current			
Operating	Other non-current liabilities	9,563	11,709
Finance	Other non-current liabilities	50,103	13,506
Total leased liabilities		$ 61,945	$ 27,165

Lease costs recognized in our Consolidated Statements of Operations is summarized as follows (in thousands):

	Year Ended December 31, 2021	2020	2019
Lease Costs			
Operating lease cost	$ 2,519	$ 2,741	$ 3,616
Finance lease cost			
Amortization of lease assets	788	367	44
Interest on lease liabilities	2,904	1,694	197
Finance lease cost	$ 3,692	$ 2,061	$ 241
Total lease cost	$ 6,211	$ 4,802	$ 3,857

Other information about lease amounts recognized in our Consolidated Financial Statements is as follows:

	December 31, 2021	December 31, 2020
Lease term and discount rate		
Weighted average remaining lease term (years)		
Operating lease	4.7	5.7
Finance lease	49.4	50.2
Weighted average discount rate		
Operating lease	8.0 %	8.0 %
Finance lease	9.4 %	13.5 %

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

	Year Ended December 31, 2021	2020	2019
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 2,953	$ 2,847	$ 3,173
Operating cash flows from finance leases	$ 1,813	$ 1,056	$ —
Financing cash flows from finance leases	$ 1,926	$ 1,777	$ 2,224

The table below presents a maturity analysis of our lease liability on an undiscounted basis and reconciles those amounts to the present value of the lease liability as of December 31, 2021 (in thousands):

	Operating	Finance
2022	$ 3,006	$ 4,111
2023	3,044	4,111
2024	3,081	4,111
2025	3,119	4,111
2026	1,261	4,111
After 2026	600	182,222
Total lease payments	$ 14,111	$ 202,777
Less: discount	2,401	152,542
Present value of lease liability	$ 11,710	$ 50,235

NOTE 18 — SUPPLEMENTAL CASH FLOW INFORMATION

The following table provides information regarding the net changes in working capital (in thousands):

	Year Ended December 31, 2021	2020	2019
Accounts receivable	$ (4,770)	$ 506	$ (3,508)
Prepaid expenses and other current assets	(2,536)	6,915	1,147
Accounts payable	(5,514)	(1,069)	(699)
Accounts payable due to related parties	(910)	910	—
Accrued liabilities	55,884	(6,842)	18,167
Other, net	(1,137)	(1,986)	(3,929)
Net changes in working capital	$ 41,017	$ (1,566)	$ 11,178

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

	Year Ended December 31, 2021	2020	2019
Non-cash accruals of property, plant and equipment and other non-current assets	$ 56,305	8,370	11,759
Non-cash settlement of Final Payment Fee	—	8,539	—
Future proceeds from sale of Magellan Petroleum UK	—	—	1,384
Tradable equity securities	—	—	5,069
Non-cash settlement of withholding taxes associated with the 2019 and 2018 bonus paid and vesting of certain awards, respectively	3,064	1,659	6,686
Non-cash settlement of the 2019 and 2018 bonus paid, respectively	5,430	7,602	18,396
Asset retirement obligation additions and revisions	76	—	182

For the year ended December 31, 2020, the statement of cash flows reflects approximately $78.5 million and $2.1 million in non-cash movements related to the 2019 Term Loan and the Replacement Warrant, respectively. For the year ended December 31, 2019, the statement of cash flows reflects a non-cash movement of approximately $0.4 million associated with funds deposited in escrow in December 2018 that were cleared in March 2019 for the purchase of land.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of such amounts shown in the Consolidated Statements of Cash Flows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Cash and cash equivalents	$ 305,496	78,297	64,615
Non-current restricted cash	1,778	3,440	3,867
Total cash, cash equivalents and restricted cash in the statement of cash flows	$ 307,274	$ 81,737	$ 68,482

NOTE 19 — DISCLOSURE ABOUT SEGMENTS AND RELATED INFORMATION

During the quarter ended June 30, 2022, the Company commenced construction of the Driftwood terminal under the Phase 1 EPC Agreement with Bechtel. The Company also continued to increase its natural gas presence in the Haynesville Shale basin in northern Louisiana through the acquisition of mineral rights and natural gas drilling and marketing activities. The Company's Chief Operating Decision Maker ("CODM") determined to place additional emphasis on operating cash flows generated by our upstream and natural gas marketing business activities. Consequently, we identified the Upstream, Midstream and Marketing & Trading components as the Company's operating segments. The Company's prior period information was retrospectively revised to reflect this change in reportable segments.

These functions have been defined as the operating segments of the Company because (1) they are engaged in business activities from which revenues are recognized and expenses are incurred, (2) their operating results are regularly reviewed by the Company's CODM to make decisions about resources to be allocated to the segment and to assess its performance, and (3) they are segments for which discrete financial information is available.

Factors used to identify these operating segments are based on the nature of the business activities that are undertaken by each component. The Upstream segment is organized and operates to produce and gather natural gas. The Midstream segment is organized to develop, construct and operate LNG terminals and pipelines. The Marketing & Trading segment is organized and operates to purchase and sell natural gas, market the Driftwood terminal's LNG production capacity and trade LNG. These operating segments represent the Company's reportable segments. The remainder of our business is presented as "Corporate," and consists of corporate costs and intersegment eliminations. The Company's CODM does not currently assess segment performance or allocate resources based on a measure of total assets. Accordingly, a total asset measure has not been provided for segment disclosure.

Year ended December 31, 2021	Upstream	Midstream	Marketing & Trading	Corporate	Consolidated
Revenues from external customers (1)	2,317	—	68,958	—	$ 71,275
Intersegment revenues (purchases) (2) (3)	49,182	—	(44,755)	(4,427)	—
Segment operating loss (4)	(5,651)	(42,040)	(22,889)	(42,153)	(112,733)
Interest expense, net	(1,642)	(4,722)	—	(3,014)	(9,378)
Gain on extinguishment of debt, net	(665)	2,087	—	—	1,422
Other (loss) income , net	(1,284)	(2,494)	9,460	269	5,951
Consolidated loss before tax					$ (114,738)

Year ended December 31, 2020	Upstream	Midstream	Marketing & Trading	Corporate	Consolidated
Revenues from external customers (1)	2,358	—	35,076	—	$ 37,434
Intersegment revenues (purchases) (2)	28,083	—	(28,083)	—	—
Segment operating loss (4)	(100,788)	(15,027)	(13,886)	(36,938)	(166,639)
Interest expense, net	(6,215)	(14,424)	—	(22,806)	(43,445)
Other income (loss), net	2,452	195	(408)	(2,851)	(612)

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Consolidated loss before tax	$ (210,696)

Year ended December 31, 2019	Upstream	Midstream	Marketing & Trading	Corporate	Consolidated
Revenues from external customers (1)	7,716	—	21,058	—	$ 28,774
Intersegment revenues (purchases) (2)	21,058	—	(21,058)	—	—
Segment operating loss (4)	(39,104)	(41,380)	(17,687)	(47,688)	(145,859)
Interest (expense) income, net	(5,460)	(12,818)	—	1,923	(16,355)
Other income, net	7,176	—	—	3,271	10,447
Consolidated loss before tax					$ (151,767)

(1) The Marketing & Trading segment markets to third party-purchasers most of the Company's natural gas production from the Upstream segment.

(2) The Marketing & Trading segment purchases most of the Company's natural gas production from the Upstream segment. Intersegment revenues are eliminated at consolidation.

(3) Intersegment revenues related to the Marketing & Trading segment are a result of cost allocations to the Corporate component using a cost plus transfer pricing methodology. Intersegment revenues are eliminated at consolidation.

(4) Operating profit (loss) is defined as operating revenues less operating costs and allocated corporate costs.

Capital expenditures	Year Ended December 31, 2021	2020	2019
Upstream	$ 32,364	$ 1,307	$ 45,354
Midstream	25,501	—	26,177
Marketing & Trading	—	—	1,104
Total capital expenditures for reportable segments	57,865	1,307	72,635
Corporate capital expenditures	—	—	1,447
Consolidated capital expenditures	$ 57,865	$ 1,307	$ 74,082

NOTE 20 — SUBSEQUENT EVENTS

At-the-Market Programs

Since January 1, 2022, and through February 7, 2022, we sold approximately $1.2 million aggregate principal amount of Senior Notes for total proceeds of approximately $1.1 million after fees and commissions and 17.9 million shares of common stock for total proceeds of approximately $48.2 million, net of approximately $1.5 million in fees and commissions under our at-the-market debt and equity offering programs, respectively. As of the date of this filing, we have remaining availability to raise aggregate gross sales proceeds of approximately $581.9 million under our at-the-market debt and equity offering programs.

Cancellation of a Commitment to Purchase LNG Cargos

On January 26, 2022, our wholly owned subsidiary Tellurian Trading UK Ltd entered into an agreement to cancel three LNG cargos that the Company was committed to purchase in April, July and October 2022. The Company will be required to pay a cancellation fee of approximately $1.0 million for all three LNG cargos. Refer to Note 11, *Commitments and Contingencies*, for further information.

TELLURIAN INC.
SUPPLEMENTAL INFROMATION CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SUPPLEMENTAL DISCLOSURES ABOUT NATURAL GAS PRODUCING ACTIVITIES

In accordance with FASB and SEC disclosure requirements for natural gas producing activities, this section provides supplemental information on Tellurian's natural gas producing activities in six separate tables. Tables I through III provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables IV through VI present information on the Company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves and changes in estimated discounted future net cash flows.

Table I — Capitalized Costs Related to Natural Gas Producing Activities

Capitalized costs related to Tellurian's natural gas producing activities are summarized as follows (in thousands):

	December 31,		
	2021	2020	2019
Proved properties	$ 113,950	$ 62,718	$ 142,494
Unproved properties	—	—	—
Gross capitalized costs	113,950	62,718	142,494
Accumulated DD&A	(48,637)	(37,639)	(21,010)
Net capitalized costs	$ 65,313	$ 25,079	$ 121,484

Table II — Costs Incurred in Exploration, Property Acquisitions and Development

Costs incurred in natural gas property acquisition (inclusive of producing well costs), exploration and development activities are summarized as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Property acquisitions:			
Proved	$ 3,409	$ 1,307	$ 45,484
Unproved	—	—	—
Exploration costs	—	—	—
Development	28,955	—	800
Costs incurred	$ 32,364	$ 1,307	$ 46,284

Table III — Results of Operations for Natural Gas Producing Activities

The following table includes revenues and expenses directly associated with our natural gas and condensate producing activities. It does not include any interest costs or indirect general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas operations. Tellurian's results of operations from natural gas and condensate producing activities for the periods presented are as follows (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Natural gas sales	$ 51,499	$ 30,441	$ 28,774
Operating costs	20,576	15,814	14,923
Depreciation, depletion and amortization	10,998	16,703	19,736
Impairment charge	—	81,065	—
Total operating costs and expenses	31,574	113,582	34,659
Results of operations	$ 19,925	$ (83,141)	$ (5,885)

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Table IV — Natural Gas Reserve Quantity Information

Our estimated proved reserves are located in Louisiana. We caution that there are many uncertainties inherent in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are expected to change as further information becomes available. Material revisions of reserve estimates may occur in the future, development and production of the natural gas and condensate reserves may not occur in the periods assumed, and actual prices realized and actual costs incurred may vary significantly from those used in these estimates.

The estimates of our proved reserves as of December 31, 2021, 2020 and 2019 have been prepared by Netherland, Sewell & Associates, Inc., independent petroleum consultants.

	Gas (MMcf)	Condensate (Mbbl)	Gas Equivalent (MMcfe)
Proved reserves:			
December 31, 2018	264,854	7	264,899
Extensions, discoveries and other additions	12,848	—	12,848
Revisions of previous estimates	4,737	(6)	4,696
Production	(13,901)	(1)	(13,905)
Sale of reserves-in-place	—	—	—
Purchases of reserves-in-place	—	—	—
December 31, 2019	268,538	—	268,538
Extensions, discoveries and other additions	—	—	—
Revisions of previous estimates	(152,132)	—	(152,132)
Production	(16,898)	—	(16,898)
Sale of reserves-in-place	—	—	—
Purchases of reserves-in-place	—	—	—
December 31, 2020	99,508	—	99,508
Extensions, discoveries and other additions	202,897	—	202,897
Revisions of previous estimates	35,237	—	35,237
Production	(14,306)	—	(14,306)
Sale of reserves-in-place	—	—	—
Purchases of reserves-in-place	—	—	—
December 31, 2021	323,336	—	323,336
Proved developed reserves:			
December 31, 2019	30,699	—	30,699
December 31, 2020	26,593	—	26,593
December 31, 2021	73,927	—	73,927
Proved undeveloped reserves:			
December 31, 2019	237,839	—	237,839
December 31, 2020	72,915	—	72,915
December 31, 2021	249,409	—	249,409

2020 to 2021 Overall Reserve Changes

- Added 203 Bcfe of proved reserves comprised of 152 Bcfe from additional proved undeveloped locations and 51 Bcfe of proved developed reserves from drilling activities.

- Had total positive revisions of approximately 35 Bcfe, comprised primarily of a 9 Bcfe positive revision due to an increase in commodity prices, a 15 Bcfe positive revision from changes in ownership and an 11 Bcfe positive revision from improved well performance.

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2020 to 2021 PUD Changes

- Added approximately 152 Bcfe from additional proved undeveloped locations.

- Had total positive revisions of approximately 25 Bcfe, comprised of a 3 Bcfe positive revision due to an increase in commodity prices, a 16 Bcfe positive revision from changes in ownership and a 6 Bcfe positive revision from improved well performance.

2019 to 2020 Overall Reserve Changes

- Had total negative revisions of approximately 152 Bcfe, comprised primarily of a 149 Bcfe negative revision due to the downturn in commodity prices and a 17 Bcfe negative revision from the loss of leases. These downward revisions were offset by a 14 Bcfe positive revision due to improved well performance.

2019 to 2020 PUD Changes

- Had total negative revisions of approximately 165 Bcfe, comprised of a 148 Bcfe negative revision due to the downturn in commodity prices and a 17 Bcfe negative revision from lease expirations.

2018 to 2019 Overall Reserve Changes

- Added approximately 13 Bcfe of proved reserves, comprised of 12 Bcfe from additional proved undeveloped locations and 1 Bcfe from drilling activities.

- Had total positive revisions of approximately 4 Bcfe, comprised of a 4 Bcfe negative revision due to prices, a 2 Bcfe negative revision from changes in operating expenses, a 9 Bcfe positive revision from well performance and a 1 Bcfe positive revision from changes in ownership.

2018 to 2019 PUD Changes

- Converted approximately 29 Bcfe to proved developed reserves.

- Added approximately 12 Bcfe from additional proved undeveloped locations.

- Had total positive revisions of approximately 8 Bcfe, comprised primarily of a 9 Bcfe positive revision from well performance, a 2 Bcfe negative revision due to prices and a 1 Bcfe positive revision from changes in ownership.

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Table V — Standardized Measure of Discounted Future Net Cash Flows Related to Proved Natural Gas Reserves

ASC 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Tellurian has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2021, 2020 and 2019 were determined by applying the average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of natural gas and condensate to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on the continuation of the economic conditions applied for that year. Estimated future income taxes are computed using current statutory income tax rates, including consideration of the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the FASB and do not necessarily reflect our expectations of actual revenue to be derived from those reserves or their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved natural gas and condensate reserves based on the standardized measure (in thousands):

	Year Ended December 31,		
	2021	2020	2019
Future cash inflows	$ 945,651	$ 132,563	$ 534,577
Future production costs	(133,909)	(34,624)	(102,268)
Future development costs	(211,836)	(71,557)	(287,111)
Future income tax provisions	(54,401)	—	(6,612)
Future net cash flows	545,505	26,382	138,586
Less effect of a 10% discount factor	(181,302)	(19,497)	(85,415)
Standardized measure of discounted future net cash flows	$ 364,203	$ 6,885	$ 53,171

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Table VI — Changes in Standardized Measure of Discounted Future Net Cash Flows Related to Proved Natural Gas Reserves

The following table sets forth the changes in the standardized measure of discounted future net cash flows (in thousands):

December 31, 2018	$	145,811
Sales and transfers of gas and condensate produced, net of production costs		(21,704)
Net changes in prices and production costs		(134,366)
Extensions, discoveries, additions and improved recovery, net of related costs		2,019
Development costs incurred		23,485
Revisions of estimated development costs		6,165
Revisions of previous quantity estimates		(12,660)
Accretion of discount		17,821
Net change in income taxes		28,316
Purchases of reserves in place		—
Sales of reserves in place		—
Changes in timing and other		(1,716)
December 31, 2019	$	53,171
Sales and transfers of gas and condensate produced, net of production costs		(20,211)
Net changes in prices and production costs		(58,136)
Extensions, discoveries, additions and improved recovery, net of related costs		—
Development costs incurred		—
Revisions of estimated development costs		—
Revisions of previous quantity estimates		26,133
Accretion of discount		5,725
Net change in income taxes		4,077
Purchases of reserves in place		—
Sales of reserves in place		—
Changes in timing and other		(3,874)
December 31, 2020	$	6,885
Sales and transfers of gas and condensate produced, net of production costs		(39,806)
Net changes in prices and production costs		110,850
Extensions, discoveries, additions and improved recovery, net of related costs		255,246
Development costs incurred		—
Revisions of estimated development costs		10,643
Revisions of previous quantity estimates		35,012
Accretion of discount		688
Net change in income taxes		(27,455)
Purchases of reserves in place		—
Sales of reserves in place		—
Changes in timing and other		12,140
December 31, 2021	$	364,203