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

FORM 10-K

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

For the fiscal year ended December 31, 2017

OR

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

For the transition period from ______ to ______

Commission File Number 001-5507

TELLURIAN

Tellurian Inc.

(Exact name of registrant as specified in its charter)

Delaware	**06-0842255**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Louisiana Street, Suite 3100, Houston, TX	**77002**
(Address of principal executive offices)	(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Common stock, $0.01 par value	**NASDAQ Capital Market**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☒ No ☐

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

The aggregate market value of the voting and non-voting stock held by non-affiliates of the Registrant, as of June 30, 2017, the last business day of the Registrant's most recently completed second fiscal quarter, was approximately $646,384,724. Solely for purposes of this disclosure, shares of common stock held by executive officers and directors of the Registrant, as well as certain stockholders, as of such date have been excluded because such persons may be deemed to be affiliates. This determination of executive officers and directors as affiliates is not necessarily a conclusive determination for any other purposes.

228,392,249 shares of common stock were issued and outstanding as of March 9, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the 2018 annual meeting of stockholders, to be filed within 120 days after December 31, 2017, are incorporated by reference in Part III of this annual report on Form 10-K.

Tellurian Inc.

Form 10-K

For the Fiscal Year Ended December 31, 2017

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FORWARD-LOOKING STATEMENTS AND RISK

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,” “estimate,” “expect,” “forecast,” “initial,” “intend,” “may,” “plan,” “potential,” “project,” “proposed,” “should,” “will,” “would” and similar expressions are intended to identify forward-looking statements. These forward-looking statements relate to, among other things:

- our businesses and prospects;
- planned or estimated capital expenditures;
- availability of liquidity and capital resources;
- our ability to obtain additional financing as needed;
- 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 that Tellurian holds; 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;
- uncertainties regarding our ability to maintain sufficient liquidity and 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 to meet their contractual obligations;
- risks and uncertainties inherent in management estimates of future operating results and cash flows;
- development risks, operational hazards and regulatory approvals;
- our ability to enter and consummate planned transactions; 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.

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
Bcf/d	Billion cubic feet per day
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
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
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.
LNG	Liquefied natural gas
LSTK	Lump Sum Turnkey
Mcf	Thousand cubic feet of natural gas
Mcf/d	Mcf per day
MMcf	Million cubic feet of natural gas
MMcf/d	MMcf per day
MMcfe	Million of cubic feet 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
oil	Crude oil and condensate
PSD	Prevention of Significant Deterioration
PUD	Proved undeveloped reserves
SEC	U.S. Securities and Exchange Commission
Train	An industrial facility comprised of a series of refrigerant compressor loops used to cool natural gas into LNG
U.K.	United Kingdom
U.S.	United States
USACE	U.S. Army Corps of Engineers

With respect to information relating to our working interest 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") intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide (the "Business"). Tellurian is developing a portfolio of natural gas production, LNG marketing, and infrastructure assets that includes an LNG terminal facility (the "Driftwood terminal") and an associated pipeline (the "Driftwood pipeline") in southwest Louisiana (the Driftwood terminal and the Driftwood pipeline collectively, the "Driftwood Project"). Our Business may be developed in phases.

The proposed Driftwood terminal will have a liquefaction capacity of approximately 27.6 mtpa and will be situated on approximately 1,000 acres in Calcasieu Parish, Louisiana. The proposed terminal facility will include up to 20 liquefaction Trains, three full containment LNG storage tanks and three marine berths. In November 2017, we entered into four LSTK EPC agreements totaling $15.2 billion with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for construction of the Driftwood terminal.

The proposed Driftwood pipeline is a new 96-mile large diameter pipeline that will interconnect with 14 existing interstate pipelines throughout southwest Louisiana to secure adequate natural gas feedstock for the Driftwood terminal. The Driftwood pipeline will be comprised of 48-inch, 42-inch, 36-inch and 30-inch diameter pipeline segments and three compressor stations totaling approximately 274,000 horsepower, all as necessary to provide approximately 4 Bcf/d of average daily natural gas transportation service. Tellurian estimates construction costs for the Driftwood pipeline of approximately $2.3 billion before owners' costs, financing costs and contingencies.

We intend to develop the Driftwood pipeline as part of what we refer to as the "Tellurian Pipeline Network." In addition to the Driftwood pipeline, the Tellurian Pipeline Network would include two pipelines which are currently in the early stages of development. One, the Haynesville Global Access Pipeline, would run 200 miles from northern to southwest Louisiana. The other, the Permian Global Access Pipeline, would run 625 miles from west Texas to southwest Louisiana. Each would have a diameter of 42 inches and would be capable of delivering approximately 2 Bcf/d of natural gas. We currently estimate that construction costs would be approximately $1.4 billion for the Haynesville Global Access Pipeline and approximately $3.7 billion for the Permian Global Access Pipeline.

We have also initiated natural gas production and LNG marketing and shipping activities as described below in "— 2017 Developments — Significant Transactions."

2017 Developments

Significant Transactions

TOTAL Investment. In January 2017, TOTAL Delaware, Inc. ("TOTAL"), a subsidiary of TOTAL, S.A., purchased approximately 35.4 million shares of Tellurian Investments common stock for an aggregate purchase price of approximately $207 million. In connection with the merger, described below under "— Merger with Magellan," those shares were exchanged for approximately 46 million shares of Tellurian common stock. Tellurian and TOTAL entered into a pre-emptive rights agreement pursuant to which TOTAL was granted a right to purchase its pro rata portion of any new equity securities that Tellurian Investments may issue to a third party on the same terms and conditions as such equity securities are offered and sold to such party, subject to certain excepted offerings.

Merger with Magellan. In February 2017, Tellurian Inc., which was formerly known as Magellan Petroleum Corporation ("Magellan"), completed a merger (the "Merger") with Tellurian Investments Inc. ("Tellurian Investments"). At the effective time of the Merger, a subsidiary of Magellan merged with and into Tellurian Investments, with Tellurian Investments continuing as the surviving corporation and a subsidiary of Magellan. Immediately following the completion of the Merger, Magellan amended its certificate of incorporation and bylaws to change its name to "Tellurian Inc." In connection with the Merger, each outstanding share of common stock of Tellurian Investments was exchanged for 1.3 shares of Magellan common stock. The Merger is accounted for as a "reverse acquisition," with Tellurian Investments being treated as the accounting acquirer.

Initiation of LNG Marketing. In September 2017, we entered into a six-month time charter contract with Maran Gas Maritime Inc. for an LNG tanker, the Maran Gas Mystras. We took delivery of the tanker at Galle, Sri Lanka contemporaneously with entering into the contract. The vessel charter enabled Tellurian to execute a number of LNG purchases and sales opportunities, as well as sub-charter opportunities while the LNG shipping market was short vessel capacity, resulting in revenue for 2017 of $4.9 million.

Natural Gas Property Acquisitions. As of December 31, 2017, we owned interests in approximately 11,844 net developed and undeveloped acres of natural gas properties in northern Louisiana. In November 2017, we acquired 9,119 net developed and undeveloped acres, including 20 producing operated wells with net current production of approximately 4 MMcf/d, for

$87.4 million, subject to customary adjustments. Further, in December 2017, we acquired 2,725 net undeveloped acres in the same area for $2.7 million.

EPC Agreements. As noted above, in November 2017, we entered into four LSTK EPC agreements with Bechtel for construction of the Driftwood terminal, each covering one phase of construction:

- Phase 1 - two LNG plants with expected production capacity up to 11.04 mtpa, two 235,000m^3 full containment LNG tanks, one marine loading berth, and related utilities, facilities and appurtenances;
- Phase 2 - an LNG plant with expected production capacity up to 5.52 mtpa, one marine loading berth, and related utilities, facilities and appurtenances;
- Phase 3 - an LNG plant with expected production capacity up to 5.52 mtpa, one 235,000m^3 full containment LNG tank, one marine loading berth, and related utilities, facilities and appurtenances; and
- Phase 4 - an LNG plant with expected production capacity up to 5.52 mtpa, and related utilities, facilities and appurtenances.

Upon issuance of the notice to proceed with construction of the Driftwood terminal, the aggregate contract price for the services and equipment to be provided is $15.2 billion. In addition, we began detailed engineering work with Bechtel on the Driftwood terminal in July 2017.

Public Equity Offering. In December 2017, we sold 10.0 million shares of common stock for proceeds of approximately $94.8 million, net of approximately $5.2 million in fees and commissions. The underwriters were granted an option to purchase up to an additional 1.5 million shares of common stock within 30 days. The option was exercised in full in January 2018, resulting in total proceeds of approximately $109.3 million, net of approximately $5.7 million in fees and commissions.

Regulatory Developments

Export Approval. In February 2017, the DOE/FE issued an order authorizing Tellurian to export 27.6 mtpa of LNG to FTA countries, on its own behalf and as agent for others, for a term of 30 years. Our application for authority to export LNG to non-FTA countries is currently pending before the DOE/FE and is expected to be ruled upon in the first quarter of 2019.

FERC Application. In March 2017, Tellurian filed an application with FERC for authorization pursuant to Section 3 of the NGA to site, construct and operate the Driftwood terminal, and simultaneously sought authorization pursuant to Section 7 of the NGA for authorization to construct and operate interstate natural gas pipeline facilities. In December 2017, FERC issued the notice of schedule for the environmental review of both the Driftwood terminal and the Driftwood pipeline. Based on this notice, FERC plans to issue its final Environmental Impact Statement on October 12, 2018 and has established a 90-day federal authorization decision deadline on January 10, 2019.

Environmental Permits. In March 2017, we submitted permit applications to the USACE under the Clean Water Act and the Rivers and Harbors Act for certain dredging and wetland mitigation activities relating to the Driftwood Project. Also in March 2017, we submitted Title V and PSD air permit applications to the Louisiana Department of Environmental Quality under the Clean Air Act for air emissions relating to the Driftwood Project. The regulatory review and approval process for the USACE permit as well as the Title V and PSD permits is expected to be completed in the fourth quarter of 2018.

Natural Gas Properties

Reserves

We had no natural gas properties, and no proved reserves, as of December 31, 2016. As discussed in "— 2017 Developments — Significant Transactions — Natural Gas Property Acquisitions," we subsequently acquired 11,844 net developed and undeveloped acres of natural gas properties in northern Louisiana, including 20 producing operated wells with net current production of approximately 4 MMcf/d. All of our proved reserves as of December 31, 2017 were associated with those properties. 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, 2017 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 for each month from January through December 2017. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. The prices used were $2.976 per MMbtu of natural gas and $51.34 per barrel of condensate, adjusted for energy content, transportation fees and market differentials.

The following table shows changes in our proved reserves from December 31, 2016 to December 31, 2017:

	Gas (MMcf)	Condensate (Mbbl)	Gas Equivalent (MMcfe)
Proved reserves (as of December 31, 2017):			
Developed producing	5,720	10	5,782
Undeveloped	321,398	—	321,398
Total	327,118	10	327,180
Proved reserves:			
December 31, 2016	—	—	—
Extensions, discoveries and other additions	—	—	—
Revisions of previous estimates	—	—	—
Production	(190)	—	(191)
Sale of reserves-in-place	—	—	—
Purchases of reserves-in-place	327,308	10	327,371
December 31, 2017	327,118	10	327,180

The standardized measure of discounted future net cash flow from our proved reserves (the "standardized measure") as of December 31, 2017 was $88.2 million.

We had no material capital expenditures relating to our natural gas properties from the closing of the acquisitions through December 31, 2017.

Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used

Our December 31, 2017 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 prepares 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 provide to them. This information is reviewed by knowledgeable members of our Company for accuracy and completeness prior to submission to NSAI.

A letter which identifies the professional qualifications of the individual at NSAI who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2017, has been filed as an addendum to Exhibit 99.2 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 16 years' 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 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

From the closing of the acquisitions of the natural gas properties through December 31, 2017, we produced 190 MMcf of natural gas at an average sales price of $2.42 MMcf and 150 barrels of condensate at an average sales price of $57.01 per barrel. Natural gas and condensate production and operating costs for the period ended December 31, 2017, was $1.25 per MMcfe.

Drilling Activity

We are not engaged in any material drilling activities or subject to any drilling commitments.

Wells and Acreage

As of December 31, 2017, we owned interests in 32 gross (18 net) productive natural gas wells and held by production 9,435 gross (9,119 net) developed leasehold acreage. Additionally, we hold 2,854 gross (2,725 net) undeveloped leasehold acreage. While all of the undeveloped leasehold acreage is set to expire in 2018, 1,720 gross (1,653 net) of said acreage allows for two-year contractual extensions.

Volume Commitments

We are not currently subject to any 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 either third-party gathering systems or interstate pipelines. The gathering systems provide the treating and processing necessary to ensure that the natural gas meets the pipeline quality specifications. We believe that these systems and other available midstream facilities and services in the area 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 (the "EPAct"), the Oil Pollution Act, the National Environmental Protection 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 ("PSIA"), and the Coastal Zone Management Act (the "CZMA"). These statutes cover areas related to the authorization, construction and operation of LNG facilities 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 FERC, the U.S. Environmental Protection Agency (the "EPA"), the DOE/FE, the U.S. Department of Transportation ("DOT"), 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 Services, 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, the DOT Pipeline and Hazardous Materials Safety Administration ("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.

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 our LNG facilities, we are required to obtain authorizations from FERC under Section 3 of the NGA as well as several other material governmental and regulatory approvals and permits. The EPAct 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 the EPAct, nothing in the EPAct is intended to affect otherwise applicable law related to any other federal agency's authorities or responsibilities related to LNG terminals.

In 2002, FERC concluded that it would apply light-handed regulation over the rates, terms and conditions agreed to by parties for LNG terminalling services, such that LNG terminal owners would not be required to provide open-access service at non-discriminatory rates or maintain a tariff or rate schedule on file with FERC, as distinguished from the requirements applied to FERC-regulated natural gas pipelines. Though the EPAct 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 terminals.

FERC has 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. FERC has the authority to grant certificates authorizing the construction and operation of facilities, such as pipelines, used in interstate natural gas transportation and the provision of services. 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.

The EPAct amends 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. The EPAct 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

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 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.”

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.

Tellurian’s proposed 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 mitigation actions.

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

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 Project will be subject to additional federal permits, orders, approvals and consultations required by other federal agencies, including DOT, Advisory Council on Historic Preservation, USACE, U.S. Department of Commerce, National Marine Fisheries Services, U.S. Department of the Interior, U.S. Fish and Wildlife Service, the EPA and U.S. Department of Homeland Security.

Three significant permits that may apply to the Driftwood Project are the USACE Section 404 of the Clean Water Act/Section 10 of the Rivers and Harbors Act Permit, the Clean Air Act Title V Operating Permit and the PSD Permit, of which the latter two permits are issued by the Louisiana Department of Environmental Quality. The Driftwood Project will also have to comply with the requirements of NEPA. Many of these requirements will apply to the other pipelines in the Tellurian Pipeline Network as well.

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.

Clean Air Act. The CAA and comparable state laws and regulations regulate and restrict the emission of air pollutants from many sources and impose various monitoring and reporting requirements, among other requirements. The Driftwood Project and other pipelines will be, and our natural gas production activities are, subject to the federal CAA and comparable state and local laws. 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.

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 the past, Congress has considered proposed legislation to reduce emissions of GHGs. Congress has not adopted any significant legislation in this respect to date, but could do so in the future. In addition, many states and regions have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs.

The EPA issued the Clean Power Plan in 2015, which would have required existing power plants to reduce their carbon dioxide emissions. The Supreme Court stayed implementation of the Clean Power Plan in February 2016. In October 2017, the EPA proposed to repeal the Clean Power Plan. It is uncertain whether the EPA will impose any requirements on existing power plants to reduce carbon dioxide emissions.

The Obama administration reached an agreement during the December 2015 United Nations climate change conference in Paris pursuant to which the U.S. initially pledged to make a 26-28 percent reduction in its GHG emissions by 2025 against a 2005 baseline and committed to periodically update this pledge every five years starting in 2020. In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement.

Coastal Zone Management Act. The siting and construction of our Driftwood Project within the coastal zone may be subject to the requirements of the CZMA. The CZMA is administered by the states (in Louisiana, by the Department of Natural Resources). This program is implemented to ensure that impacts to coastal areas are consistent with the intent of the CZMA to manage the coastal areas.

Clean Water Act. The Driftwood Project and other pipelines will be, and our natural gas producing activities 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 U.S. or waters of the state, including discharges of wastewater and storm water runoff and discharges of dredged or fill material into waters of the U.S., 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 Project and other pipelines may potentially 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. The approval timeframe may also be longer than expected and could potentially affect project schedules.

In June 2015, the EPA issued a final rule that attempts to clarify the CWA's jurisdictional reach over waters of the U.S.. In February 2018, the EPA issued a rule that delays the applicability of the new definition of the waters of the U.S. until February 2020. The EPA intends to propose a rule with a new definition of waters of the U.S.. Until the EPA finalizes a new rule, the definition of waters of the U.S. from the Supreme Court case *Rapanos v. United States* (2006) applies. If and when a final rule (as issued or revised) goes into effect, it could expand the scope of the CWA's jurisdiction, which could result in increased costs and delays with respect to obtaining permits for discharges or pollutants or dredge and fill activities in waters of the U.S., including wetland areas.

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 have entered into an agreement pursuant to which the EPA is required to propose, no later than March 15, 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. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the EPA will be required to take final action following notice and comment rulemaking no later than July 15, 2021. A loss of the exclusion from RCRA coverage for drilling fluids, produced waters and related wastes could result in a significant increase in our costs to manage and dispose of waste associated with our production operations.

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 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, on specified classes of persons 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 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 from operations were sent. Although CERCLA currently exempts petroleum (including oil and natural gas) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. We cannot ensure that this exemption will be preserved in any future amendments of the act. Such amendments could have a material impact on our costs or operations. Additionally, our operations may involve the use or handling of other materials that 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 investigation, management and disposal of contaminated soils or dredge spoils in connection with our operations.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at a majority 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.

Hydraulic Fracturing. Hydraulic fracturing is commonly used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. We plan to use hydraulic fracturing extensively in our natural gas production 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.

Beginning in 2012, the EPA implemented CAA standards (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants) applicable to new and modified hydraulically fractured natural gas wells and certain storage vessels. The standards require, among other things, use of reduced emission completions, or "green" completions, to reduce volatile organic compound emissions during well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers, and dehydrators.

In February 2014, the EPA issued permitting guidance under the Safe Drinking Water Act ("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 by the EPA.

In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act 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.

The U.S. Department of the Interior, through the Bureau of Land Management (the “BLM”), finalized a rule in 2015 requiring the disclosure of chemicals used, mandating well integrity measures and imposing other requirements relating to hydraulic fracturing on federal lands. The BLM rescinded the rule in December 2017; however, the BLM’s rescission has been challenged by several states in the U.S. District Court of the District of Northern California.

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.

In June 2016, EPA finalized additional new source performance standards under the CAA to reduce methane emissions from new and modified sources in the oil and natural gas sector. These new regulations impose, among other things, new requirements for leak detection and repair, control requirements at oil well completions, and additional control requirements for gathering, boosting, and compressor stations. These standards are currently effective, although the EPA has proposed a two-year stay of the effective dates of several requirements of the standards.

In November 2016, the BLM finalized rules to further regulate venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. The rules became effective in January 2017, but are subject to ongoing litigation. In December 2017, the BLM published a rule to temporarily suspend or delay certain rule requirements until January 2019; that rule, however, was enjoined by the U.S. District Court for the Northern District of California in February 2018. Accordingly, the 2016 rules are currently in effect.

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.” 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.

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 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.

Regulation of Natural Gas Production

Our natural gas production 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, counties 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 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 Laws

Our international operations are subject to one or more 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 employees and intermediaries from bribing or making other prohibited payments to foreign officials or other persons to obtain or retain business or gain some other business advantage. We participate in relationships with third parties whose actions could potentially subject us to liability under the FCPA or 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 certain employees with regard to business ethics, designed to ensure that we and our employees 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, 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 or the Criminal Finances Act 2017 by the U.S. or foreign authorities could also have a material adverse impact on our reputation, business, financial condition and results of operations.

Competition

We are subject to a high degree of competition in all aspects of our business. See "Item 1.A — 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 undeveloped 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

As we began our operations in the fourth quarter of 2017, we do not have any major customers.

Facilities

Certain subsidiaries of Tellurian have entered into operating leases for office space in Houston, Texas, Washington, D.C., London, England and Singapore. The tenors of the leases are three, five, 10 and 11 years for Singapore, London, Houston and Washington, D.C., respectively.

Employees

As of December 31, 2017, Tellurian had 126 full-time employees worldwide.

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. You may also read or copy any document we file at the SEC's public reference room in Washington, D.C., located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the public reference room. 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.

ITEM 1A. RISK FACTORS

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments. Our risk factors are grouped into the following categories:

- Risks Relating to Financial Matters;
- Risks Relating to Our Common Stock;
- Risks Relating to Our LNG Business;
- Risks Relating to Our Natural Gas and Oil Production Activities; and
- Risks Relating to Our Business in General.

Risks Relating to Financial Matters

Tellurian may be required to seek additional equity and/or debt financing in the future to complete the Driftwood Project and to grow its other operations, and may not be able to secure such financing on acceptable terms, or at all.

Tellurian will be unable to generate any revenue from the Driftwood Project for multiple years, and expects cash flow from its other lines of business to be modest for an extended period as it focuses on the development and growth of these operations. Tellurian will therefore need substantial amounts of additional financing to execute its business plan.

There can be no assurance that Tellurian will be able to raise sufficient capital on acceptable terms, or at all. If such financing is not available on satisfactory terms, or is not available at all, Tellurian may be required to delay, scale back or cancel the development of business opportunities, and this could adversely affect its operations and financial condition to a significant extent. Tellurian intends to pursue a variety of potential financing transactions, including sales of equity to purchasers of its LNG. We do not know whether, and to what extent, LNG purchasers and other potential sources of financing will find the terms we propose acceptable.

Debt or preferred equity financing, if obtained, may involve agreements that include liens or restrictions on Tellurian's assets and covenants limiting or restricting our ability to take specific actions, such as paying dividends or making distributions, incurring additional debt, acquiring or disposing of assets and increasing expenses. Debt financing would also be required to be repaid regardless of Tellurian's operating results.

In addition, the ability to obtain financing for the proposed Driftwood Project may depend in part on Tellurian's ability to enter into sufficient commercial agreements prior to the commencement of construction. To date, Tellurian has not entered into any definitive third-party agreements for the proposed Driftwood Project, and it may not be successful in negotiating and entering into such agreements.

We have a very limited operating history and expect to incur losses for a significant period of time.

We only recently commenced operations. Although Tellurian's current directors, managers and officers have prior professional and industry experience, our business is in an early stage of development. Accordingly, the prior history, track record and historical financial information you may use to evaluate our prospects are limited.

Tellurian has not yet commenced the construction of the Driftwood Project and expects to incur significant additional costs and expenses through completion of development and construction of that project. The Company also expects to devote substantial amounts of capital to the growth and development of its natural gas production activities and other operations. Tellurian expects that operating losses will increase substantially in 2018 and thereafter, and expects to continue to incur operating losses and to experience negative operating cash flows through at least 2022.

Tellurian's exposure to the performance and credit risks of its counterparties may adversely affect its operating results, liquidity and access to financing.

Our operations involve our entering into various construction, purchase and sale, hedging, supply and other transactions with numerous third parties. In such arrangements, we will be exposed to the performance and credit risks of our counterparties, including the risk that one or more counterparties fail to perform their obligations under the agreement. Some of these risks may increase during periods of commodity price volatility. In some cases, we will be dependent on a single counterparty or a small group of counterparties, all of whom may be similarly affected by changes in economic and other conditions. These risks include, but are not limited to, risks related to the construction of the Driftwood Project discussed below in "—Risks Relating to Our LNG Business—Tellurian will be dependent on third-party contractors for the successful completion of the Driftwood Project, and these contractors may be unable to complete the Driftwood Project." Defaults by suppliers and other counterparties may adversely affect our operating results, liquidity and access to financing.

Our use of hedging arrangements may adversely affect our future operating results or liquidity.

As we continue to ramp up our LNG and natural gas marketing activities, in an effort to reduce our exposure to fluctuations in price and timing risk, any hedging arrangements entered into would expose us to the risk of financial loss when (i) the counterparty to the hedging contract defaults on its contractual obligations or (ii) there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received. Also, commodity derivative arrangements may limit the benefit we would otherwise receive from a favorable change in the relevant commodity price. In addition, regulations issued by the Commodities Futures Trading Commission, the SEC and other federal agencies establishing regulation of the over-the-counter derivatives market could adversely affect our ability to manage our price risks associated with our LNG and natural gas activity and therefore have a negative impact on our operating results and cash flows.

Changes in tax laws or exposure to additional income tax liabilities could have a material impact on our financial condition, results of operations and liquidity.

Factors that could materially affect our future effective tax rates include but are not limited to:

- changes in the regulatory environment;
- changes in accounting and tax standards or practices;
- changes in the composition of operating income by tax jurisdiction; and
- our operating results before taxes.

We are subject to income taxes in the U.S. and several foreign jurisdictions. Our future effective tax rates could be affected by changes in the composition of earnings in countries with differing tax rates, changes in deferred tax assets and liabilities or changes in tax laws. Foreign jurisdictions have also increased the volume of tax audits of multinational corporations. Further, many countries have either recently changed or are considering changes to their tax laws. Changes in tax laws could affect the distribution of our earnings, result in double taxation and adversely affect our results.

In December 2017, the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act of 2017 (the "Tax Act") was signed into law, making significant changes to the Internal Revenue Code of 1986, as amended. Substantial changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017 and the partial transition of U.S. international taxation from a worldwide tax system to a territorial system, which includes a one-time transition tax on the mandatory deemed repatriation of cumulative foreign earnings as of December 31, 2017. Additionally, new provisions were added to mitigate the potential erosion of the U.S. tax base and to discourage use of low-tax jurisdictions to own intellectual property and other valuable intangible assets. While these provisions were intended to prevent specific perceived taxpayer abuse, they may have adverse, unexpected consequences to many taxpayers. At this time, the U.S. Department of Treasury has not yet issued regulations on how the provisions of the Tax Act should be applied and how the underlying calculations are to be prepared. As there is little official guidance at this time regarding the preparation of these complex calculations, estimates and judgment are required in assessing the consequences. We urge our stockholders to consult with their legal and tax advisors with respect to the legislation and potential tax consequences of investing in our stock.

In addition to the impact of the Tax Act on our federal taxes, it may impact taxation in other jurisdictions such as state income taxes. The various state legislatures have not had sufficient time to respond to the Tax Act. Accordingly, it is uncertain as to how the laws will apply in the various state jurisdictions. Additionally, other foreign governing bodies may enact changes in their tax laws in reaction to the Tax Act that could result in changes to our global tax position and materially affect our financial position.

We are also subject to examination by the Internal Revenue Service (the "IRS") and other tax authorities, including state revenue agencies and other foreign governments. While we regularly assess the likelihood of favorable or unfavorable outcomes resulting from examinations by the IRS and other tax authorities to determine the adequacy of our provision for income taxes, there can be no assurance that the actual outcome resulting from these examinations will not materially adversely affect our financial condition and operating results. Additionally, the IRS and several foreign tax authorities have increasingly focused attention on intercompany transfer pricing with respect to sales of products and services and the use of intangibles. Tax authorities could disagree with our intercompany charges, cross-jurisdictional transfer pricing or other matters and assess additional taxes. If we do not prevail in any such disagreements, our profitability may be affected.

Tellurian does not expect to generate sufficient cash to pay dividends until the completion of construction of the Driftwood Project.

Tellurian's directly and indirectly held assets currently consist primarily of cash held for certain start-up and operating expenses, applications for permits from regulatory agencies relating to the Driftwood Project, certain real property interests related to that project and 11,844 net acres of natural gas properties. Tellurian's cash flow, and consequently its ability to distribute earnings, is solely dependent upon the cash flow its subsidiaries receive from the Driftwood Project and its other operations. Tellurian's ability to complete the Driftwood Project, as discussed further below, is dependent upon its subsidiaries' ability to obtain necessary regulatory approvals and raise the capital necessary to fund the development of the project. We expect that cash flows from our operations will be reinvested in the business rather than used to fund dividends, that pursuing our strategy will require substantial amounts of capital, and that the required capital will exceed cash flows from operations for a significant period.

Tellurian's ability to pay dividends in the future is uncertain and will depend on a variety of factors, including limitations on the ability of it or its subsidiaries to pay dividends under applicable law and/or the terms of debt or other agreements, and the judgment of the board of directors or other governing body of the relevant entity.

Risks Relating to Our Common Stock

The price of our common stock has been and may continue to be highly volatile, which may make it difficult for shareholders to sell our common stock when desired or at attractive prices.

The market price of our common stock is highly volatile, and we expect it to continue to be volatile for the foreseeable future. Adverse events could trigger a significant decline in the trading price of our common stock, including, among others, failure to obtain necessary permits, unfavorable changes in commodity prices or commodity price expectations, adverse regulatory developments, loss of a relationship with a partner, litigation and departures of key personnel. Furthermore, general market conditions, including the level of, and fluctuations in, the trading prices of equity securities generally could affect the price of our stock. The stock markets frequently experience price and volume volatility that affects many companies' stock prices, often in ways unrelated to the operating performance of those companies. These fluctuations may affect the market price of our common stock.

The market price of our common stock could be adversely affected by sales of substantial amounts of our common stock by us or our major shareholders.

Sales of a substantial number of shares of our common stock in the market by us or any of our major shareholders, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares in the public market, or the possibility of such sales, could impair our ability to raise capital through the sale of additional equity securities. Our insider trading policy permits our officers and directors, some of whom own substantial percentages of our outstanding common stock, to pledge shares of stock that they own as collateral for loans subject to certain requirements. Some of our officers and directors have pledged shares of stock in accordance with this policy. In some circumstances, such pledges could result in large amounts of shares of our stock being sold in the market in a short period, which would be expected to have a significant adverse effect on the trading price of the common stock. In addition, in the future, we may issue shares of our common stock in connection with acquisitions of assets or businesses or for other purposes. Such issuances could have an adverse effect on the market value of shares of our common stock, depending on market conditions at the time, the terms of the issuance, and if applicable, the value of the business or assets acquired and our success in exploiting the properties or integrating the businesses we acquire.

Risks Relating to Our LNG Business

Various economic and political factors could negatively affect the development, construction and operation of LNG facilities, including the Driftwood Project, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

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

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

Our failure to execute our business plan within budget and on schedule could materially adversely affect our business, financial condition, operating results, liquidity and prospects.

Tellurian's estimated costs for the Driftwood Project and other projects may not be accurate and are subject to change due to several factors.

Tellurian currently estimates that construction costs will be approximately $15.2 billion for the Driftwood terminal, approximately $2.3 billion for the Driftwood pipeline, approximately $1.4 billion for the Haynesville Global Access Pipeline and approximately $3.7 billion for the Permian Global Access Pipeline. However, cost estimates for these and other projects we may pursue are only approximations of the actual costs of construction and are before owners' costs, financing costs and contingencies. Moreover, cost estimates may be inaccurate and may change due to various factors, such as cost overruns, change orders, delays in construction, legal and regulatory requirements, site issues, increased component and material costs, escalation of labor costs, labor disputes, changes in commodity prices, changes in foreign currency exchange rates, increased spending to maintain Tellurian's construction schedule and other factors. For example, new or increased tariffs on materials needed in the construction process have been proposed or may be proposed in the future and such new or increased tariffs could materially increase construction costs. In particular, recently announced tariffs on imported steel may significantly increase our construction costs. Similarly, cost overruns could occur as a result of dredging-related expenditures incurred to comply with water depth regulations in the Calcasieu Ship Channel. Our cost estimates for the Haynesville Global Access Pipeline and the Permian Global Access Pipeline are more preliminary than the estimate for the Driftwood pipeline. Substantially all of the risks discussed in this section that are applicable to the Driftwood pipeline are equally applicable to the other pipelines comprising the proposed Tellurian Pipeline Network.

Our failure to achieve our cost estimates could materially adversely affect our business, financial condition, operating results, liquidity and prospects.

If third-party pipelines and other facilities interconnected to our LNG facilities become unavailable to transport natural gas, this could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

We will depend upon third-party pipelines and other facilities that will provide natural gas delivery options to our natural gas production operations and our LNG facilities. If the construction of new or modified pipeline connections is not completed on schedule or any pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to meet our LNG sale and purchase agreement obligations and continue shipping natural gas from producing operations or regions to end markets could be restricted, thereby reducing our revenues. This could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects.

Tellurian's ability to generate cash is substantially dependent upon it entering into contracts with third-party customers and the performance of those customers under those contracts.

Tellurian has not yet entered into, and may never be able to enter into, satisfactory commercial arrangements with third- party customers for products and services from the Driftwood Project.

Tellurian's business strategy may change regarding how and when the proposed Driftwood Project's export capacity is marketed. Also, Tellurian's business strategy may change due to an inability to enter into agreements with customers or based on a variety of factors, including the future price outlook, supply and demand of LNG, natural gas liquefaction capacity, and global regasification capacity. If our efforts to market the proposed Driftwood Project and the LNG it will produce are not successful, Tellurian's business, results of operations, financial condition and prospects may be materially and adversely affected.

We may not be able to purchase, receive or produce sufficient natural gas to satisfy our delivery obligations under our LNG sale and purchase agreements, which could have an adverse effect on us.

Under LNG sale and purchase agreements with our customers, we will be required to make available to them a specified amount of LNG at specified times. However, we may not be able to acquire or produce sufficient quantities of natural gas or LNG to satisfy those obligations, which may provide affected customers with the right to terminate their LNG sale and purchase agreements. Our failure to purchase, receive or produce sufficient quantities of natural gas or LNG in a timely manner could have an adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The construction and operation of the Driftwood Project and the Tellurian Pipeline Network remains subject to further approvals, and some approvals may be subject to further conditions, review and/or revocation.

The design, construction and operation of LNG export terminals is a highly regulated activity. The approval of FERC under Section 3 of the NGA, as well as several other material governmental and regulatory approvals and permits, is required to construct and operate an LNG terminal. Even if the necessary authorizations initially required to operate our proposed LNG facilities are obtained, such authorizations are subject to ongoing conditions imposed by regulatory agencies, and additional approval and permit requirements may be imposed. Numerous permits and approvals will also be required in connection with the construction and operation of the Tellurian Pipeline Network.

Tellurian and its affiliates will be required to obtain governmental approvals and authorizations to implement its proposed business strategy, which includes the construction and operation of the Driftwood Project. In particular, authorization from FERC and the DOE/FE is required to construct and operate our proposed LNG facilities. In addition to seeking to obtain approval for export to FTA countries, Tellurian has filed an application to obtain approval for export to non-FTA countries. There is no assurance that Tellurian will obtain and maintain these governmental permits, approvals and authorizations, and failure to obtain and maintain any of these permits, approvals or authorizations could have a material adverse effect on its business, results of operations, financial condition and prospects.

Tellurian will be dependent on third-party contractors for the successful completion of the Driftwood Project, and these contractors may be unable to complete the Driftwood Project.

There is limited recent industry experience in the U.S. regarding the construction or operation of large-scale LNG facilities. The construction of the Driftwood Project is expected to take several years, will be confined to a limited geographic area and could be subject to delays, cost overruns, labor disputes and other factors that could adversely affect financial performance or impair Tellurian's ability to execute its proposed business plan.

Timely and cost-effective completion of the Driftwood Project in compliance with agreed-upon specifications will be highly dependent upon the performance of Bechtel and other third-party contractors pursuant to their agreements. However, Tellurian has not yet entered into definitive agreements with all of the contractors, advisors and consultants necessary for the development and construction of the Driftwood Project. Tellurian may not be able to successfully enter into such construction contracts on terms or at prices that are acceptable to it.

Further, faulty construction that does not conform to Tellurian's design and quality standards may have an adverse effect on Tellurian's business, results of operations, financial condition and prospects. For example, improper equipment installation may lead to a shortened life of Tellurian's equipment, increased operations and maintenance costs or a reduced availability or production capacity of the affected facility. The ability of Tellurian's third-party contractors to perform successfully under any agreements to be entered into is dependent on a number of factors, including force majeure events and such contractors' ability to:

- design, engineer and receive critical components and equipment necessary for the Driftwood Project to operate in accordance with specifications and address any start-up and operational issues that may arise in connection with the commencement of commercial operations;
- attract, develop and retain skilled personnel and engage and retain third-party subcontractors, and address any labor issues that may arise;
- post required construction bonds and comply with the terms thereof, and maintain their own financial condition, including adequate working capital;
- adhere to any warranties the contractors provide in their EPC contracts; and
- respond to difficulties such as equipment failure, delivery delays, schedule changes and failure to perform by subcontractors, some of which are beyond their control, and manage the construction process generally, including engaging and retaining third-party contractors, coordinating with other contractors and regulatory agencies and dealing with inclement weather conditions.

Furthermore, Tellurian may have disagreements with its third-party contractors about different elements of the construction process, which could lead to the assertion of rights and remedies under the related contracts, resulting in a contractor's unwillingness to perform further work on the relevant project. Tellurian may also face difficulties in commissioning a newly constructed facility. Any significant delays in the development of the Driftwood Project could materially and adversely affect Tellurian's business, results of operations, financial condition and prospects.

Tellurian's construction and operations activities are subject to a number of development risks, operational hazards, regulatory approvals and other risks, which could cause cost overruns and delays and could have a material adverse effect on its business, results of operations, financial condition, liquidity and prospects.

Siting, development and construction of the Driftwood Project will be subject to the risks of delay or cost overruns inherent in any construction project resulting from numerous factors, including, but not limited to, the following:

- difficulties or delays in obtaining, or failure to obtain, sufficient equity or debt financing on reasonable terms;
- failure to obtain all necessary government and third-party permits, approvals and licenses for the construction and operation of any of our proposed LNG facilities;
- difficulties in engaging qualified contractors necessary to the construction of the contemplated Driftwood Project or other LNG facilities;
- shortages of equipment, material or skilled labor;
- natural disasters and catastrophes, such as hurricanes, explosions, fires, floods, industrial accidents and terrorism;
- unscheduled delays in the delivery of ordered materials;
- work stoppages and labor disputes;
- competition with other domestic and international LNG export terminals;
- unanticipated changes in domestic and international market demand for and supply of natural gas and LNG, which will depend in part on supplies of and prices for alternative energy sources and the discovery of new sources of natural resources;
- unexpected or unanticipated need for additional improvements; and
- adverse general economic conditions.

Delays beyond the estimated development periods, as well as cost overruns, could increase the cost of completion beyond the amounts that are currently estimated, which could require Tellurian to obtain additional sources of financing to fund the activities until the proposed Driftwood Project is constructed and operational (which could cause further delays). Any delay in completion of the Driftwood Project may also cause a delay in the receipt of revenues projected from the Driftwood Project or cause a loss of one or more customers. As a result, any significant construction delay, whatever the cause, could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects. Similar risks may affect the construction of other facilities and projects we elect to pursue.

Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect Tellurian's LNG business and the performance of our customers and could lead to the reduced development of LNG projects worldwide.

Tellurian's plans and expectations regarding its business and the development of domestic LNG facilities and projects are generally based on assumptions about the future price of natural gas and LNG and the conditions of the global natural gas and LNG markets. Natural gas and LNG prices have been, and are likely to remain in the future, volatile and subject to wide fluctuations that are difficult to predict. Such fluctuations may be caused by various factors, including, but not limited to, one or more of the following:

- competitive liquefaction capacity in North America;
- insufficient or oversupply of natural gas liquefaction or receiving capacity worldwide;
- insufficient or oversupply of LNG tanker capacity;
- weather conditions;
- reduced demand and lower prices for natural gas;
- increased natural gas production deliverable by pipelines, which could suppress demand for LNG;
- decreased oil and natural gas exploration activities, which may decrease the production of natural gas;

- cost improvements that allow competitors to offer LNG regasification services or provide natural gas liquefaction capabilities at reduced prices;
- changes in supplies of, and prices for, alternative energy sources such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas;
- changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas;
- political conditions in natural gas producing regions; and
- cyclical trends in general business and economic conditions that cause changes in the demand for natural gas.

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

Technological innovation may render Tellurian's anticipated competitive advantage or its processes obsolete.

Tellurian's success will depend on its ability to create and maintain a competitive position in the natural gas liquefaction industry. In particular, although Tellurian plans to construct the Driftwood Project using proven technologies that it believes provide it with certain advantages, Tellurian does not have any exclusive rights to any of the technologies that it will be utilizing. In addition, the technology Tellurian anticipates using in the Driftwood Project may be rendered obsolete or uneconomical by legal or regulatory requirements, technological advances, more efficient and cost-effective processes or entirely different approaches developed by one or more of its competitors or others, which could materially and adversely affect Tellurian's business, results of operations, financial condition, liquidity and prospects.

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

Operations of the Driftwood Project will be dependent upon our ability to deliver LNG supplies from the U.S., which is primarily dependent upon LNG being a competitive source of energy internationally. The success of our business plan is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be supplied from North America and delivered to international markets at a lower cost than the cost of alternative energy sources. Through the use of improved exploration technologies, additional sources of natural gas may be discovered outside the U.S., which could increase the available supply of natural gas outside the U.S. and could result in natural gas in those markets being available at a lower cost than that of LNG exported to those markets.

Additionally, our liquefaction projects will be subject to the risk of LNG price competition at times when we need to replace any existing LNG sale and purchase contract, whether due to natural expiration, default or otherwise, or enter into new LNG sale and purchase contracts. Factors relating to competition may prevent us from entering into a new or replacement LNG sale and purchase contract on economically comparable terms as prior LNG sale and purchase contracts, or at all. Factors which may negatively affect potential demand for LNG from our liquefaction projects are diverse and include, among others:

- increases in worldwide LNG production capacity and availability of LNG for market supply;
- increases in demand for LNG but at levels below those required to maintain current price equilibrium with respect to supply;
- increases in the cost to supply natural gas feedstock to our liquefaction projects;
- decreases in the cost of competing sources of natural gas or alternate sources of energy such as coal, heavy fuel oil, diesel, nuclear, hydroelectric, wind and solar;
- decreases in the price of non-U.S. LNG, including decreases in price as a result of contracts indexed to lower oil prices;
- increases in capacity and utilization of nuclear power and related facilities;
- increases in the cost of LNG shipping; and
- displacement of LNG by pipeline natural gas or alternative fuels in locations where access to these energy sources is not currently available.

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

As a result of these and other factors, LNG may not be a competitive source of energy internationally. The failure of LNG to be a competitive supply alternative to local natural gas, oil and other alternative energy sources in markets accessible to our customers could adversely affect the ability of our customers to deliver LNG from the U.S. on a commercial basis. Any significant impediment to the ability to deliver LNG from the U.S. generally, or from the Driftwood Project specifically, could have a material adverse effect on our customers and our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

There may be shortages of LNG vessels worldwide, which could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

The construction and delivery of LNG vessels require significant capital and long construction lead times, and the availability of the vessels could be delayed to the detriment of Tellurian's business and customers due to a variety of factors, including, but not limited to, the following:

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

Any of these factors could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

We will rely on third-party engineers to estimate the future capacity ratings and performance capabilities of the Driftwood Project, and these estimates may prove to be inaccurate.

We will rely on third parties for the design and engineering services underlying our estimates of the future capacity ratings and performance capabilities of the Driftwood Project. Any of our LNG facilities, when constructed, may not have the capacity ratings and performance capabilities that we intend or estimate. Failure of any of our facilities to achieve our intended capacity ratings and performance capabilities could prevent us from achieving the commercial start dates under our future LNG sale and purchase agreements and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

The Driftwood Project and the Tellurian Pipeline Network will be subject to a number of environmental laws and regulations that impose significant compliance costs, and existing and future environmental and similar laws and regulations could result in increased compliance costs, liabilities or additional operating restrictions.

We will be subject to extensive federal, state and local environmental regulations and laws, including regulations and restrictions related to discharges and releases to the air, land and water and the handling, storage, generation and disposal of hazardous materials and solid and hazardous wastes in connection with the development, construction and operation of our LNG facilities and pipelines. These regulations and laws, which include the CAA, the Oil Pollution Act, the CWA and RCRA, and analogous state and local laws and regulations, will restrict, prohibit or otherwise regulate the types, quantities and concentration of substances that can be released into the environment in connection with the construction and operation of our facilities. These laws and regulations, including NEPA, will require us to obtain and maintain permits with respect to our facilities, prepare environmental impact assessments, provide governmental authorities with access to our facilities for inspection and provide reports related to compliance. Federal and state laws impose liability, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment. Violation of these laws and regulations could lead to substantial liabilities, fines and penalties, the denial or revocation of permits necessary for our operations, governmental orders to shut down our facilities or capital expenditures related to pollution control equipment or remediation measures that could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects. As the owner and operator of the Driftwood Project, we could be liable for the costs of investigating and cleaning up hazardous substances released into the environment and for damage to natural resources, whether caused by us or our contractors or existing at the time construction commences. Hazardous substances present in soil, groundwater and dredge spoils may need to be processed, disposed of or otherwise managed to prevent releases into the environment. Tellurian or its affiliates may be responsible for investigation, cleanup, monitoring, removal, disposal and other remedial actions with respect to hazardous substances on, in or under properties Tellurian owns or operates, without regard to fault or the origin of such hazardous substances. Such liabilities may involve material costs that are unknown and not predictable.

Changes in legislation and regulations could have a material adverse impact on Tellurian's business, results of operations, financial condition, liquidity and prospects.

Tellurian's business will be subject to governmental laws, rules, regulations and permits that impose various restrictions and obligations that may have material effects on our results of operations. In addition, each of the applicable regulatory requirements and limitations is subject to change, either through new regulations enacted on the federal, state or local level, or by new or modified regulations that may be implemented under existing law. The nature and effects of these changes in laws, rules, regulations and permits may be unpredictable and may have material effects on our business. Future legislation and regulations, such as those relating to the transportation and security of LNG exported from our proposed LNG facilities through the Calcasieu Ship Channel, could cause additional expenditures, restrictions and delays in connection with the proposed LNG facilities and their construction, the extent of which cannot be predicted and which may require Tellurian to limit substantially, delay or cease operations in some circumstances. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating costs and restrictions could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

Our operations will be subject to significant risks and hazards, one or more of which may create significant liabilities and losses that could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

We will face numerous risks in developing and conducting our operations. For example, the plan of operations for the proposed Driftwood Project is subject to the inherent risks associated with LNG operations, including explosions, pollution, leakage or release of toxic substances, fires, hurricanes and other adverse weather conditions, leakage of LNG, and other hazards, each of which could result in significant delays in commencement or interruptions of operations and/or result in damage to or destruction of the proposed Driftwood Project or damage to persons and property. In addition, operations at the proposed Driftwood Project and vessels or facilities of third parties on which Tellurian's operations are dependent could face possible risks associated with acts of aggression or terrorism.

In 2005, 2008 and 2017, hurricanes damaged coastal and inland areas located in the Gulf Coast area, resulting in disruption and damage to certain LNG terminals located in the area. Future storms and related storm activity and collateral effects, or other disasters such as explosions, fires, floods or accidents, could result in damage to, or interruption of operations at, the Driftwood Project or related infrastructure, as well as delays or cost increases in the construction and the development of the Driftwood Project or other facilities. Storms, disasters and accidents could also damage or interrupt the activities of vessels that we or third parties operate in connection with our LNG business. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods and rising sea levels. If any such effects were to occur, they could have an adverse effect on our coastal operations.

Our LNG business will face other types of risks and liabilities as well. For instance, our LNG marketing activities will expose us to possible financial losses and various regulatory risks.

Tellurian does not, nor does it intend to, maintain insurance against all of these risks and losses, and many risks are not insurable. Tellurian may not be able to maintain desired or required insurance in the future at rates that it considers reasonable. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on Tellurian's business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

Risks Relating to Our Natural Gas and Oil Production Activities

Acquisitions of natural gas and oil properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.

We expect to pursue acquisitions of natural gas and oil properties from time to time. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues, and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform due diligence that we believe is generally consistent with industry practices. However, our due diligence activities are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition, and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may not always discover structural, subsurface, and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we may acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. We may not be entitled to contractual indemnification associated with acquired properties. We may acquire interests in properties on an "as is" basis with limited or no remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks, and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

In addition, acquiring additional natural gas and oil properties, or businesses that own or operate such properties, when attractive opportunities arise is a significant component of our strategy, and we may not be able to identify attractive acquisition opportunities. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. It may be difficult to agree on the economic terms of a transaction, as a potential seller may be unwilling to accept a price that we believe to be appropriately reflective of prevailing economic conditions. If we are unable to complete suitable acquisitions, it will be more difficult to pursue our overall strategy.

Natural gas and oil prices fluctuate widely, and lower prices for an extended period of time may have a material adverse effect on the profitability of our natural gas or oil production activities.

The revenues, operating results and profitability of our natural gas or oil production activities will depend significantly on the prices we receive for the natural gas or oil we sell. We will require substantial expenditures to replace reserves, sustain production and fund our business plans. Low natural gas or oil prices can negatively affect the amount of cash available for acquisitions and capital expenditures and our ability to raise additional capital and, as a result, could have a material adverse effect on our revenues, cash flow and reserves. In addition, low natural gas or oil prices may result in write-downs of our natural gas or oil properties. Conversely, any substantial or extended increase in the price of natural gas would adversely affect the competitiveness of LNG as a source of energy. See risks discussed above in "—Risks Relating to Our LNG Business—Failure of exported LNG to be a competitive source of energy for international markets could adversely affect our customers and could materially and adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and prospects."

Historically, the markets for natural gas and oil have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas or oil prices may result from relatively minor changes in the supply of or demand for natural gas or oil, market uncertainty and other factors that are beyond our control. The volatility of the energy markets makes it extremely difficult to predict future natural gas or oil price movements, and we will be unable to fully hedge our exposure to natural gas or oil prices.

Significant capital expenditures will be required to grow our natural gas or oil production activities in accordance with our plans.

Our planned development and acquisition activities will require substantial capital expenditures. We intend to fund our capital expenditures for our natural gas and oil production activities through cash on hand and financing transactions that may include public or private equity or debt offerings or borrowings under a revolving credit facility. We expect to generate only modest cash flows for a significant period of time from our producing properties. Our ability to generate operating cash flow in the future will be subject to a number of risks and variables, such as the level of production from existing wells, the price of natural gas or oil, our success in developing and producing new reserves and the other risk factors discussed in this section. If we are unable to fund our capital expenditures for natural gas or oil production activities as planned, we could experience a curtailment of our development activity and a decline in our natural gas or oil production, and that could affect our ability to pursue our overall strategy.

We have limited control over the activities on properties we do not operate.

Some of the properties in which we have an interest are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. In addition, a third-party operator could also decide to shut-in or curtail production from wells, or plug and abandon marginal wells, on properties owned by that operator during periods of lower natural gas or oil prices. These limitations and our dependence on the operator and third-party working interest owners for these projects could cause us to incur unexpected future costs, reduce our production and materially and adversely affect our financial condition and results of operations.

Drilling and producing operations can be hazardous and may expose us to liabilities.

Natural gas and oil operations are subject to many risks, including well blowouts, explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, leakages or releases of hydrocarbons, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. For our non-operated properties, we will be dependent on the operator for regulatory compliance and for the management of these risks. These risks could materially and adversely affect our revenues and expenses by reducing production from wells, causing wells to be shut in or otherwise negatively impacting our projected economic performance. If any of these risks occurs, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- facility or equipment malfunctions and equipment failures or accidents;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

Any of these events could expose us to liabilities, monetary penalties or interruptions in our business operations. In addition, certain of these risks are greater for us than for many of our competitors in that some of the natural gas we produce has a high sulphur content (sometimes referred to as “sour” gas), which increases its corrosiveness and the risk of an accidental release of hydrogen sulfide gas, exposure to which can be fatal. We may not maintain insurance against such risks, and some risks are not insurable. Even when we are insured, our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future, we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which we are not fully insured may expose us to liabilities.

Our drilling efforts may not be profitable or achieve our targeted returns and our reserve estimates are based on assumptions that may not be accurate.

Drilling for natural gas and oil may involve unprofitable efforts from wells that are productive but do not produce sufficient commercial quantities to cover drilling, operating and other costs. In addition, even a commercial well may have production that is less, or costs that are greater, than we projected. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons.

Natural gas and oil reserve engineering requires estimates of underground accumulations of hydrocarbons and assumptions concerning future prices, production levels and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be incorrect. Our estimates of proved reserves are determined at prices and costs at the date of the estimate. Any significant variance from these prices and costs could greatly affect our estimates of reserves. At December 31, 2017, approximately 98% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflected our plans to make significant capital expenditures to convert our PUDs into proved developed reserves. The estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC’s reserve reporting rules, PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, and we may therefore be required to downgrade to probable or possible any PUDs that are not developed within this five-year time frame.

Our production activities are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner and feasibility of doing business, and further regulation in the future could increase costs, impose additional operating restrictions and cause delays.

Our natural gas production activities and properties are (and to the extent that we acquire oil producing properties, these properties will be) subject to numerous federal, regional, state and local laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- conduct of drilling, completion, production and midstream activities;
- amounts and types of emissions and discharges;
- generation, management, and disposal of hazardous substances and waste materials;
- reclamation and abandonment of wells and facility sites; and
- remediation of contaminated sites.

In addition, these laws and regulations may result in substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area.

Environmental laws and regulations change frequently, and these changes are difficult to predict or anticipate. Future environmental laws and regulations imposing further restrictions on the emission of pollutants into the air, discharges into state or U.S. waters, wastewater disposal and hydraulic fracturing, or the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our natural gas or oil production. We cannot predict the actions that future regulation will require or prohibit, but our business and operations could be subject to increased operating and compliance costs if certain regulatory proposals are adopted. In addition, such regulations may have an adverse impact on our ability to develop and produce our reserves.

Federal, state or local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Several states are considering adopting regulations that could impose more stringent permitting, public disclosure and/or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. These studies assess, among other things, the risks of groundwater contamination and earthquakes caused by hydraulic fracturing and other exploration and production activities. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate or even ban such activities, as some state and local governments have already done. We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions. Among other things, this could adversely affect the cost to produce natural gas, either by us or by third-party suppliers, and therefore LNG, and this could adversely affect the competitiveness of LNG relative to other sources of energy.

We expect to drill the locations we acquire over a multi-year period, making them susceptible to uncertainties that could materially alter the occurrence or timing of drilling.

Our management team has identified certain well locations on our natural gas properties. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these factors, we do not know if the well locations we have identified will ever be drilled or if we will be able to produce natural gas from these or any other potential locations.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and services could adversely affect our ability to execute our development plans within budgeted amounts and on a timely basis.

The demand for qualified and experienced field and technical personnel to conduct our operations can fluctuate significantly, often in correlation with hydrocarbon prices. The price of services and equipment may increase in the future and availability may decrease. In addition, it is possible that oil prices could increase without a corresponding increase in natural gas prices, which could lead to increased demand and prices for equipment, facilities and personnel without an increase in the price at which we sell our natural gas to third parties. In this scenario, necessary equipment, facilities and services may not be available to us at economical prices. Any shortages in availability or increased costs could delay us or cause us to incur significant additional expenditures, which could have a material adverse effect on the competitiveness of the natural gas we sell and therefore on our business, financial condition and results of operations.

Our natural gas and oil production may be adversely affected by pipeline and gathering system capacity constraints.

Our natural gas and oil production activities will rely on third parties to meet our needs for midstream infrastructure and services. Capital constraints could limit the construction of new infrastructure by third parties. We may experience delays in producing and selling natural gas or oil from time to time when adequate midstream infrastructure and services are not available. Such an event could reduce our production or result in other adverse effects on our business.

Risks Relating to Our Business in General

We are pursuing a strategy of participating in multiple aspects of the natural gas business, which exposes us to risks.

We plan to develop, own and operate a global natural gas business and to deliver natural gas to customers worldwide. We may not be successful in executing our strategy in the near future, or at all. Our management will be required to understand and manage a diverse set of business opportunities, which may distract their focus and make it difficult to be successful in increasing value for shareholders.

Tellurian will be subject to risks related to doing business in, and having counterparties based in, foreign countries.

Tellurian may engage in operations or make substantial commitments and investments, or enter into agreements with counterparties, located outside the U.S., which would expose Tellurian to political, governmental, and economic instability and foreign currency exchange rate fluctuations.

Any disruption caused by these factors could harm Tellurian's business, results of operations, financial condition, liquidity and prospects. Risks associated with operations, commitments and investments outside of the U.S. include but are not limited to risks of:

- currency fluctuations;
- war or terrorist attack;
- expropriation or nationalization of assets;
- renegotiation or nullification of existing contracts;
- changing political conditions;
- changing laws and policies affecting trade, taxation, and investment;
- multiple taxation due to different tax structures;
- general hazards associated with the assertion of sovereignty over areas in which operations are conducted; and
- the unexpected credit rating downgrade of countries in which Tellurian's LNG customers are based.

Because Tellurian's reporting currency is the U.S. dollar, any of the operations conducted outside the U.S. or denominated in foreign currencies would face additional risks of fluctuating currency values and exchange rates, hard currency shortages and controls on currency exchange. In addition, Tellurian would be subject to the impact of foreign currency fluctuations and exchange rate changes on its financial reports when translating the value of its assets, liabilities, revenues and expenses from operations outside of the U.S. into U.S. dollars at then-applicable exchange rates. These translations could result in changes to the results of operations from period to period.

Tellurian Investments and certain other Tellurian subsidiaries (collectively, the "Tellurian Defendants") are defendants in a lawsuit that could result in equitable relief and/or monetary damages that could have a material adverse effect on Tellurian's operating results and financial condition.

The Tellurian Defendants, along with Tellurian director Martin Houston and three other individuals as well as certain entities in which each of them owned membership interests, as applicable, have been named as defendants in a lawsuit as described in "Item 3 — Legal Proceedings". Although the Tellurian Defendants believe the plaintiffs' claims are without merit, the Tellurian Defendants may not ultimately be successful and any potential liability they may incur is not reasonably estimable. Moreover, even if the Tellurian Defendants are successful in defense of this litigation, they could incur costs and suffer both an economic loss and an adverse impact on their reputations, which could have a material adverse effect on our business. In addition, any adverse judgment or settlement of the litigation could have an adverse effect on our operating results and financial condition.

Potential legislative and regulatory actions addressing climate change, and the physical effects of climate change, could significantly impact us.

Various state governments and regional organizations have considered enacting new legislation and promulgating new regulations governing or restricting the emission of GHGs, including GHG emissions from stationary sources such as oil and natural gas production equipment and facilities. At the federal level, the EPA has already made findings and issued regulations that will require us to establish and report an inventory of GHG emissions. Additional legislative and/or regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program. Even without federal legislation or regulation of GHG emissions, states may impose these requirements either directly or indirectly.

Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could adversely affect our facilities and operations, and have an adverse effect on our financial condition and results of operations. Further, adverse weather events may accelerate changes in law and regulations aimed at reducing GHG emissions, which could result in declining demand for natural gas and LNG, and could adversely affect our business generally.

A major health and safety incident relating to our business could be costly in terms of potential liabilities and reputational damage.

Tellurian will be subject to extensive federal, state and local health and safety regulations and laws. Health and safety performance is critical to the success of all areas of our business. Any failure in health and safety performance may result in personal harm or injury, penalties for non-compliance with relevant laws and regulations or litigation, and a failure that results in a significant health and safety incident is likely to be costly in terms of potential liabilities. Such a failure could generate public concern and have a corresponding impact on our reputation and our relationships with relevant regulatory agencies and local communities, which in turn could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

A terrorist attack or military incident could result in delays in, or cancellation of, construction or closure of our facilities or other disruption to our business.

A terrorist or military incident could disrupt our business. For example, an incident involving an LNG carrier or LNG facility may result in delays in, or cancellation of, construction of new LNG facilities, including our proposed LNG facilities, which would increase Tellurian's costs and decrease its cash flows. A terrorist incident may also result in the temporary or permanent closure of Tellurian facilities or operations, which could increase costs and decrease cash flows, depending on the duration of the closure. Our operations could also become subject to increased governmental scrutiny that may result in additional security measures at a significant incremental cost. In addition, the threat of terrorism and the impact of military campaigns may lead to continued volatility in prices for natural gas or oil that could adversely affect Tellurian's business and customers, including by impairing the ability of Tellurian's suppliers or customers to satisfy their respective obligations under Tellurian's commercial agreements.

Cyber-attacks targeting systems and infrastructure used in our business may adversely impact our operations.

We depend on digital technology in many aspects of our business, including the processing and recording of financial and operating data, analysis of information, and communications with our employees and third parties. Cyber-attacks on our systems and those of third party vendors and other counterparties occur frequently, and have grown in sophistication. A successful cyber-attack on us or a vendor or other counterparty could have a variety of adverse consequences, including theft of proprietary or commercially sensitive information, data corruption, interruption in communications, disruptions to our existing or planned activities or transactions, and damage to third parties, any of which could have a material adverse impact on us. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks.

Failure to retain and attract key personnel such as Tellurian's Chairman, Vice Chairman or other skilled professional and technical employees could have an adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

The success of Tellurian's business relies heavily on key personnel such as its Chairman and Vice Chairman. Should such persons be unable to perform their duties on behalf of Tellurian, or should Tellurian be unable to retain or attract other members of management, Tellurian's business, results of operations, financial condition, liquidity and prospects could be materially impacted.

Additionally, we are dependent upon an available labor pool of skilled employees. We will compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct and operate our facilities and to provide our customers with the highest quality service. A shortage of skilled workers or other general inflationary pressures or changes in applicable laws and regulations could make it more difficult for us to attract and retain qualified personnel and could require an increase in the wage and benefits packages that we offer, thereby increasing our operating costs. Any increase in our operating costs could materially and adversely affect our business, financial condition, operating results, liquidity and prospects.

Competition is intense in the energy industry and some of Tellurian's competitors have greater financial, technological and other resources.

Tellurian plans to operate in various aspects of the natural gas and oil business and will face intense competition in each area. Depending on the area of operations, competition may come from independent, technology-driven companies, large, established companies and others.

For example, many competing companies have secured access to, or are pursuing development or acquisition of, LNG facilities to serve the North American natural gas market, including other proposed liquefaction facilities in North America. Tellurian may face competition from major energy companies and others in pursuing its proposed business strategy to provide liquefaction and export products and services at its proposed Driftwood Project. In addition, competitors have developed and are developing additional LNG terminals in other markets, which will also compete with our proposed LNG facilities.

As another example, our business will face competition in, among other things, buying and selling reserves and leases and obtaining goods and services needed to operate properties and market natural gas and oil. Competitors include multinational oil companies, independent production companies and individual producers and operators.

Many of our competitors have longer operating histories, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources than Tellurian currently possesses. The superior resources that some of these competitors have available for deployment could allow them to compete successfully against Tellurian, which could have a material adverse effect on Tellurian's business, results of operations, financial condition, liquidity and prospects.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

In July 2017, Tellurian Investments, Driftwood LNG LLC ("Driftwood LNG"), Martin Houston, and three other individuals were named as third-party defendants in a lawsuit filed in state court in Harris County, Texas between Cheniere Energy, Inc. and one of its affiliates, on the one hand (collectively, "Cheniere"), and Parallax Enterprises LLC and certain of its affiliates (not including Parallax Services LLC, n/k/a Tellurian Services) on the other hand (collectively, "Parallax"). In October 2017, Driftwood Pipeline LLC ("Driftwood Pipeline") and Tellurian Services were also named by Cheniere as third-party defendants. Cheniere alleges that it entered into a note and a pledge agreement with Parallax. Cheniere claims that the third-party defendants tortiously interfered with the note and pledge agreement and aided in the fraudulent transfer of Parallax assets. Cheniere is seeking unspecified amounts of monetary damages and certain equitable relief. We believe that Cheniere's claims against Tellurian Investments, Driftwood LNG, Driftwood Pipeline and Tellurian Services are without merit and do not expect the resolution of the suit to have a material effect on our results of operation or financial condition. Trial has been set for September 2018.

ITEM 4. MINE SAFETY DISCLOSURE

None.

PART II

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

Market Information, Holders and Dividends

Our common stock trades on the NASDAQ Capital Market ("NASDAQ") under the symbol "TELL." The table below presents the high and low sales prices of our common stock, as reported by the NASDAQ, for each quarter during 2017 and 2016. Prior to the Merger, our common stock traded under the symbol "MPET."

	High	Low
Quarter ended		
December 31, 2017	$ 13.74	$ 9.17
September 30, 2017	11.24	8.19
June 30, 2017	12.54	8.27
March 31, 2017	21.74	9.69
Quarter ended		
December 31, 2016	$ 11.95	$ 4.85
September 30, 2016	7.17	1.11
June 30, 2016	1.41	0.80
March 31, 2016	1.49	0.20

As of March 9, 2018, there were approximately 540 record holders of Tellurian's common stock.

Tellurian has never paid a cash dividend on its common stock. The Company does not intend to pay cash dividends on its common stock in the foreseeable future.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the surrender to the Company of shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock:

	Total Number of Shares Purchased [1]	Average Price Paid per Share
October 2017	—	$ —
November 2017	10,488	11.03
December 2017	—	—
Total	10,488	

(1) Reflects the surrender to the Company of shares of common stock to pay withholding taxes in connection with the vesting of restricted stock issued to employees pursuant to the Omnibus Plan.

ITEM 6. SELECTED FINANCIAL DATA

Not applicable.

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

Explanatory Note

In February 2017, Tellurian Inc., which was formerly known as Magellan Petroleum Corporation, completed the Merger with Tellurian Investments Inc. At the effective time of the Merger, a subsidiary of Magellan merged with and into Tellurian Investments, with Tellurian Investments continuing as the surviving corporation and a subsidiary of Magellan. Immediately following the completion of the Merger, Magellan amended its certificate of incorporation and bylaws to change its name to "Tellurian Inc." In connection with the Merger, each outstanding share of common stock of Tellurian Investments was exchanged for 1.3 shares of Magellan common stock. The Merger is accounted for as a "reverse acquisition," with Tellurian Investments being treated as the accounting acquirer.

Except where the context indicates otherwise, (i) references to "we," "us," "our," "Tellurian" or the "Company" refer, for periods prior to the completion of the Merger, to Tellurian Investments and its subsidiaries, and for periods following the completion of the Merger, to Tellurian Inc. and its subsidiaries and (ii) references to "Magellan" refer to Tellurian Inc. and its subsidiaries prior to the completion of the Merger.

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
- Off-balance Sheet Arrangements
- Summary of Critical Accounting Estimates
- Recent Accounting Standards

Our Business

Tellurian intends to create value for shareholders by building a low-cost, global natural gas business, profitably delivering natural gas to customers worldwide (the "Business"). Tellurian is developing a portfolio of natural gas production, LNG marketing, and infrastructure assets that includes an LNG terminal facility (the "Driftwood terminal") and an associated pipeline (the "Driftwood pipeline") in southwest Louisiana (the Driftwood terminal and the Driftwood pipeline collectively, the "Driftwood Project"). Our Business may be developed in phases.

The proposed Driftwood terminal will have a liquefaction capacity of approximately 27.6 mtpa and will be situated on approximately 1,000 acres in Calcasieu Parish, Louisiana. The proposed terminal facility will include up to 20 liquefaction Trains, three full containment LNG storage tanks and three marine berths. In November 2017, we entered into four LSTK EPC agreements totaling $15.2 billion with Bechtel Oil, Gas and Chemicals, Inc. ("Bechtel") for construction of the Driftwood terminal.

The proposed Driftwood pipeline is a new 96-mile large diameter pipeline that will interconnect with 14 existing interstate pipelines throughout southwest Louisiana to secure adequate natural gas feedstock for the Driftwood terminal. The Driftwood pipeline will be comprised of 48-inch, 42-inch, 36-inch and 30-inch diameter pipeline segments and three compressor stations totaling approximately 274,000 horsepower, all as necessary to provide approximately 4 Bcf/d of average daily natural gas transportation service. Tellurian estimates construction costs for the Driftwood pipeline of approximately $2.3 billion before owners' costs, financing costs and contingencies.

We intend to develop the Driftwood pipeline as part of what we refer to as the "Tellurian Pipeline Network." In addition to the Driftwood pipeline, the Tellurian Pipeline Network would include two pipelines which are currently in the early stages of development. One, the Haynesville Global Access Pipeline, would run 200 miles from northern to southwest Louisiana. The other, the Permian Global Access Pipeline, would run 625 miles from west Texas to southwest Louisiana. Each would have a diameter of 42 inches and would be capable of delivering approximately 2 Bcf/d of natural gas. We currently estimate that construction costs would be approximately $1.4 billion for the Haynesville Global Access Pipeline and approximately $3.7 billion for the Permian Global Access Pipeline.

We have also initiated natural gas production and LNG marketing and shipping activities as described below in "— Overview of Significant Events."

Overview of Significant Events

Significant Transactions

TOTAL Investment. In January 2017, TOTAL, a subsidiary of TOTAL, S.A., purchased approximately 35.4 million shares of Tellurian Investments common stock for an aggregate purchase price of approximately $207 million. In connection with the Merger, those shares were exchanged for approximately 46 million shares of Tellurian common stock. Tellurian and TOTAL entered into a pre-emptive rights agreement pursuant to which TOTAL was granted a right to purchase its pro rata portion of any new equity securities that Tellurian Investments may issue to a third party on the same terms and conditions as such equity securities are offered and sold to such party, subject to certain excepted offerings.

Merger with Magellan. In February 2017, Tellurian Inc., which was formerly known as Magellan Petroleum Corporation, completed the Merger with Tellurian Investments Inc. Immediately following the completion of the Merger, Magellan amended its certificate of incorporation and bylaws to change its name to "Tellurian Inc." As described in "— Explanatory Note," in connection with the Merger, each outstanding share of common stock of Tellurian Investments was exchanged for 1.3 shares of Magellan common stock.

Initiation of LNG Marketing. In September 2017, we entered into a six-month time charter contract with Maran Gas Maritime Inc. for an LNG tanker, the Maran Gas Mystras. We took delivery of the tanker at Galle, Sri Lanka contemporaneously with entering into the contract. The vessel charter enabled Tellurian to execute a number of LNG purchases and sales opportunities, as well as sub-charter opportunities while the LNG shipping market was short vessel capacity, resulting in revenue for 2017 of $4.9 million.

Natural Gas Property Acquisitions. As of December 31, 2017, we owned interests in approximately 11,844 net developed and undeveloped acres of natural gas properties in northern Louisiana. In November 2017, we acquired 9,119 net developed and undeveloped acres, including 20 producing operated wells with net current production of approximately 4 MMcf/d, for $87.4 million, subject to customary adjustments. Further, in December 2017, we acquired 2,725 net undeveloped acres in the same area for $2.7 million.

EPC Agreements. As noted above, in November 2017, we entered into four LSTK EPC agreements with Bechtel for construction of the Driftwood terminal, each covering one phase of construction:

- Phase 1 - two LNG plants with expected production capacity up to 11.04 mtpa, two 235,000m^3 full containment LNG tanks, one marine loading berth, and related utilities, facilities and appurtenances;
- Phase 2 - an LNG plant with expected production capacity up to 5.52 mtpa, one marine loading berth, and related utilities, facilities and appurtenances;
- Phase 3 - an LNG plant with expected production capacity up to 5.52 mtpa, one 235,000m^3 full containment LNG tank, one marine loading berth, and related utilities, facilities and appurtenances; and
- Phase 4 - an LNG plant with expected production capacity up to 5.52 mtpa, and related utilities, facilities and appurtenances.

Upon issuance of the notice to proceed with construction of the Driftwood terminal, the aggregate contract price for the services and equipment to be provided is $15.2 billion. In addition, we began detailed engineering work with Bechtel on the Driftwood terminal in July 2017.

Public Equity Offering. In December 2017, we sold 10.0 million shares of common stock for proceeds of approximately $94.8 million, net of approximately $5.2 million in fees and commissions. The underwriters were granted an option to purchase up to an additional 1.5 million shares of common stock within 30 days. The option was exercised in full in January 2018, resulting in total proceeds of approximately $109.3 million, net of approximately $5.7 million in fees and commissions.

Regulatory Developments

Export Approval. In February 2017, the DOE/FE issued an order authorizing Tellurian to export 27.6 mtpa of LNG to FTA countries, on its own behalf and as agent for others, for a term of 30 years. Our application for authority to export LNG to non-FTA countries is currently pending before the DOE/FE and is expected to be ruled upon in the first quarter of 2019.

FERC Application. In March 2017, Tellurian filed an application with FERC for authorization pursuant to Section 3 of the NGA to site, construct and operate the Driftwood terminal, and simultaneously sought authorization pursuant to Section 7 of the NGA for authorization to construct and operate interstate natural gas pipeline facilities. In December 2017, FERC issued the notice of schedule for the environmental review of both the Driftwood terminal and the Driftwood pipeline. Based on this notice, FERC plans to issue its final Environmental Impact Statement on October 12, 2018 and has established a 90-day federal authorization decision deadline on January 10, 2019.

Environmental Permits. In March 2017, we submitted permit applications to the USACE under the Clean Water Act and the Rivers and Harbors Act for certain dredging and wetland mitigation activities relating to the Driftwood Project. Also in March 2017, we submitted Title V and PSD air permit applications to the Louisiana Department of Environmental Quality under the Clean Air Act for air emissions relating to the Driftwood Project. The regulatory review and approval process for the USACE permit as well as the Title V and PSD permits is expected to be completed in the fourth quarter of 2018.

Liquidity and Capital Resources

Capital Resources

The Company is currently funding its development activities and general working capital needs through its cash on hand. Our current capital resources consist of approximately $128.3 million of cash and cash equivalents as of December 31, 2017 on a consolidated basis, which are primarily the result of issuances of common stock, including our December 2017 equity raise and the issuance of common stock to TOTAL in January 2017. Tellurian considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

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,	
	2017	**2016**
Cash used in operating activities	$ (109,229)	$ (50,430)
Cash used in investing activities	(95,565)	(10,506)
Cash provided by financing activities	311,669	82,334
Net increase in cash and cash equivalents	106,875	21,398
Cash and cash equivalents, beginning of the period	21,398	—
Cash and cash equivalents, end of the period	$ 128,273	$ 21,398
Net working capital	$ 81,393	$ 17

Cash used in operating activities for the year ended December 31, 2017 increased approximately $58.8 million compared to the same period in 2016. The increase in cash used in operating activities primarily relates to one-time payments of approximately$12.5 million related to our development activities, approximately $4.9 million of Merger-related expenses and approximately $41.4 million of disbursements in the normal course of business. Disbursements in the normal course of business increased primarily due to the increased development activities and a substantial increase in the number of Tellurian employees, which resulted in an increase of approximately $21.6 million and $12.3 million, respectively.

Cash used in investing activities for the year ended December 31, 2017 increased approximately $85.1 million compared to the same period in 2016. The increase in cash used in investing activities primarily relates to approximately $90.1 million paid for the acquisition of natural gas properties in northern Louisiana, net of an accrual of $0.1 million offset by approximately $4.6 million of proceeds received from the sale of investment securities.

Cash provided by financing activities for the year ended December 31, 2017 increased approximately $229.3 million compared to the same period in 2016. The increase in cash provided by financing activities primarily relates to net proceeds from the issuance of common shares.

Capital Development Activities

The activities we have proposed will require significant amounts of capital and are subject to risks and delays in completion. Even if successfully completed, we will not begin to operate and generate significant cash flows until at least several years from now, which management currently anticipates being 2023. We expect to receive all regulatory approvals and commence construction of the Driftwood terminal and Driftwood pipeline in 2019, produce the first LNG in 2023 and achieve full operations in 2026. 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.

Tellurian estimates construction costs of approximately $15.2 billion, or $550 per tonne, for the Driftwood terminal and approximately $2.3 billion for the Driftwood pipeline, in each case before owners' costs, financing costs and contingencies. We also are in the preliminary routing stage of developing the Haynesville Global Access Pipeline and the Permian Global Access Pipeline, which combined are estimated to cost approximately $5.1 billion before owners' costs, financing costs and contingencies. In addition, the natural gas production activities we are pursuing will require considerable capital resources. We anticipate funding our more immediate liquidity requirements relative to the detailed engineering work and other developmental and general and administrative costs through the use of cash from the completed equity issuances discussed above and future issuances of equity or debt securities by us.

We currently expect that our long-term capital requirements will be financed by proceeds from future debt and equity offerings. In addition, part of our financing strategy is expected to involve seeking equity investments by LNG customers at a subsidiary level. If the types of financing we expect to pursue are not available, we will be required to seek alternative sources of financing, which may not be available on acceptable terms, if at all.

Results of Operations

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

	Successor		Predecessor
	Year Ended December 31,		For the period from January 1, 2016 through April 9, 2016
	2017	2016	
Total revenue	$ 5,441	$ —	$ 31
Cost of sales	7,565	—	—
Development expenses	59,498	47,146	44
Depreciation, depletion and amortization	479	69	8
General and administrative expenses	98,874	46,515	617
Goodwill impairment	77,592	—	—
Loss from operations	(238,567)	(93,730)	(638)
Gain (loss) on preferred stock exchange feature	2,209	(3,308)	—
Other income, net	5,084	217	—
Income tax benefit (provision)	(185)	166	—
Net loss	$ (231,459)	$ (96,655)	$ (638)

Our consolidated net loss was approximately $231.5 million for the year ended December 31, 2017, compared to a net loss of approximately $96.7 million for the year ended December 31, 2016. This $134.8 million increase in net loss is primarily a result of the following:

- Development expenses for the year ended December 31, 2017 increased approximately $12.4 million compared to the same period in 2016. This increase is due to an overall increase in activity associated with the permitting process with FERC.

- General and administrative expenses during the year ended December 31, 2017 increased approximately $52.4 million compared to the same period in 2016. The increase is attributable to non-cash share-based payments related to commercial development and management consulting contractors of approximately $19.4 million which were not incurred in 2016, an increase in salaries and benefits of approximately $14.3 million due to a substantial increase in the number of employees, and an increase in corporate marketing and investor development activities.
- Goodwill impairment during the year ended December 31, 2017 increased approximately $77.6 million due to goodwill recognized as a result of the Merger that was subsequently determined to be unrecoverable.
- Cost of sales during the year ended December 31, 2017 increased approximately $7.6 million compared to the same period in 2016. This increase is primarily due to LNG marketing transaction costs of approximately $7.1 million.

The increase in expenses for the year ended December 31, 2017 was partially offset by the following:

- Revenue during the year ended December 31, 2017 increased approximately $5.4 million compared to the same period in 2016. This increase is primarily due to LNG sales revenue of approximately $3.3 million and LNG sub-charter revenue of approximately $1.7 million.
- A change of approximately $5.5 million was recognized due to an exchange feature of the Tellurian Investments Series A convertible preferred stock issued during 2016.
- Other income, net for the year ended December 31, 2017 increased approximately $4.9 million compared to the same period in 2016. The increase is primarily attributable to a gain on sale of securities of approximately $3.5 million.

Off-Balance Sheet Arrangements

As of December 31, 2017, we had no transactions that met the definition of off-balance sheet arrangements that may have a current or future material effect on our consolidated financial position or operating results.

Summary of Critical Accounting Estimates

Our accounting policies are more fully described in Note 1 of the Consolidated Financial Statements. As disclosed in Note 1, 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 identified our most critical accounting estimates to be:

- valuations of long-lived assets, including intangible assets and goodwill;
- purchase price allocation for acquired businesses;
- forecasting our effective income tax rate, including the realizability of deferred tax assets;
- impairment considerations for tangible and intangible assets; and
- share-based compensation.

We believe the following discussion addresses our critical accounting policies, which are those that require our most difficult, subjective or complex judgments about future events and related estimations that are fundamental to our results of operations.

Fair Value

When necessary or required by GAAP, we estimate the fair value of (i) long-lived assets for impairment testing, (ii) reporting units for goodwill impairment testing and (iii) assets acquired and liabilities assumed in business combinations. When there is not a market-observable price for the asset or liability or a similar asset or liability, we use the cost, income, or market valuation approach depending on the quality of information available to support management’s assumptions. The cost approach is based on management’s best estimate of the current asset replacement cost. The income approach is based on management’s best assumptions regarding expectations of projected cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management’s best assumptions regarding prices and other relevant information from market transactions involving comparable assets. Such evaluations involve significant judgment and the results are based on expected future events or conditions. Assumptions used in fair value measurement would reflect a market participant’s view of long-term prices, costs and other factors, and are consistent with assumptions used in our business plans and investment decisions.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the tax basis of assets and liabilities and their reported amounts in the Consolidated Financial Statements.

Deferred tax assets and liabilities are included in the Consolidated Financial Statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the current period's provision for income taxes. A full valuation allowance equal to our net deferred tax asset balance has been established due to the uncertainty of realizing the tax benefits related to our net deferred tax assets.

Reserves Estimates

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. 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.

Impairments

When circumstances indicate that proved natural gas properties may be impaired, 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. In certain instances, we utilize accepted offers from third-party purchasers as the basis for determining fair value. Estimates of undiscounted future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. In addition, such assumptions and estimates are reasonably likely to change in the future.

We test goodwill for impairment annually during the fourth quarter, or more frequently as circumstances dictate. The first step in assessing whether an impairment of goodwill is necessary is an optional qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is greater than its carrying amount. If we conclude that it is more likely than not that the fair value of the reporting unit exceeds the related carrying amount, further testing is not necessary. If the qualitative assessment is not performed or indicates that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we compare the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill. An impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value is then recognized.

See Note 2, *Merger and Acquisition,* to the Consolidated Financial Statements for additional information regarding impairment of goodwill.

Share-Based Compensation

Share-based payment transactions are measured based on 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 the 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.

Recent Accounting Standards

For descriptions of recently issued accounting standards, see Note 14, *Recent Accounting Standards,* of our Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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TELLURIAN INC.

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MANAGEMENT'S REPORT ON INTERNAL CONTROLS 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, 2017.

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, 2017, as stated in their report beginning on page 33.

/s/ Meg A. Gentle	/s/ Antoine J. Lafargue	/s/ Khaled Sharafeldin
Meg A. Gentle	Antoine J. Lafargue	Khaled Sharafeldin
President and Chief Executive Officer *(as Principal Executive Officer)*	*Senior Vice President and Chief Financial Officer* *(as Principal Financial Officer)*	*Chief Accounting Officer* *(as Principal Accounting Officer)*

Houston, Texas
March 15, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Tellurian, Inc.
Houston, Texas

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Tellurian, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2017 (Successor statements of operations, stockholders' equity, and cash flows), as well as the consolidated statements of operations and cash flows for the period from January 1, 2016 through April 9, 2016 (Predecessor statements of operations and cash flows), and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017, as well as the period from January 1, 2016 through April 9, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, 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 these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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
March 15, 2018

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

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share amounts)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 128,273	$ 21,398
Accounts receivable	583	—
Accounts receivable due from related parties	1,377	1,333
Prepaid assets and other	3,458	2,012
Total current assets	133,691	24,743
Property, plant and equipment, net	115,856	10,993
Deferred engineering costs	18,000	—
Other non-current assets	9,276	3,342
Total assets	$ 276,823	$ 39,078
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 50,563	$ 24,403
Accounts payable due to related parties	—	323
Other current liabilities	1,735	—
Total current liabilities	52,298	24,726
Asset retirement obligation	638	—
Total liabilities	52,936	24,726
Embedded derivative	—	8,753
Commitments and contingencies (Note 7)		
Stockholders' equity:		
Series A convertible preferred stock: par value $0.001 per share; zero and 5.5 million shares authorized and issued, respectively	—	5
Common stock: par value $0.01 and $0.001 per share, respectively; 400 million shares and 200 million shares authorized, respectively; 222.7 million shares and 109.6 million shares issued, respectively	2,043	101
Additional paid-in capital	549,958	102,148
Accumulated deficit	(328,114)	(96,655)
Total stockholders' equity	223,887	5,599
Total liabilities and stockholders' equity	$ 276,823	$ 39,078

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)

	Successor		Predecessor
	Year Ended December 31,		For the period from January 1, 2016 through April 9, 2016
	2017	2016	
Revenues			
Natural gas sales	$ 503	$ —	$ —
LNG sales	3,273	—	—
Other LNG revenue	1,665	—	—
Related party	—	—	31
Total revenue	5,441	—	31
Operating costs and expenses			
Cost of sales (exclusive of items shown separately below)	7,565	—	—
Development expenses	59,498	47,146	44
Depreciation, depletion and amortization	479	69	8
General and administrative expenses	98,874	46,515	617
Goodwill impairment	77,592	—	—
Total operating costs and expenses	244,008	93,730	669
Loss from operations	(238,567)	(93,730)	(638)
Gain (loss) on preferred stock exchange feature	2,209	(3,308)	—
Other income, net	5,084	217	—
Loss before income taxes	(231,274)	(96,821)	(638)
Income tax benefit (provision)	(185)	166	—
Net loss attributable to common stockholders	$ (231,459)	$ (96,655)	$ (638)
Net loss per common share:			
Basic and diluted	$ (1.23)	$ (1.01)	
Weighted average shares outstanding			
Basic and diluted	188,536	95,795	

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

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock		Treasury Stock		Convertible Preferred Stock				
	Shares	Par Value Amount	Shares	Cost	Shares	Par Value Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Equity
BALANCE AT JANUARY 1, 2016 (Successor)	—	$ —	—	$ —	—	$ —	$ —	$ —	$ —
Common stock issued for acquisition	500	1	—	—	—	—	999	—	1,000
Issuance of common stock	98,356	98	—	—	—	—	57,276	—	57,374
Issuance of Series A preferred stock	—	—	—	—	5,468	5	19,380	—	19,385
Share-based compensation	10,753	2	—	—	—	—	24,493	—	24,495
Net loss	—	—	—	—	—	—	—	(96,655)	(96,655)
BALANCE AT DECEMBER 31, 2016 (Successor)	109,609	$ 101	—	$ —	5,468	$ 5	$ 102,148	$ (96,655)	$ 5,599
Merger adjustments	51,540	1,390	(1,209)	—	—	—	86,533	—	87,923
Share-based compensation	9,350	16	—	—	—	—	23,003	—	23,019
Issuance of common stock	46,373	465	—	—	—	—	311,459	—	311,924
Share-based payments	1,700	17	—	—	—	—	21,148	—	21,165
Reclass of embedded derivative	—	—	—	—	—	—	6,544	—	6,544
Treasury stock	—	—	(82)	(828)	—	—	—	—	(828)
Retirement of treasury stock	(1,291)	(1)	1,291	828	—	—	(827)	—	—
Exchange from Series A preferred stock	—	—	—	—	(5,468)	(5)	—	—	(5)
Exchange to Series B preferred stock	—	—	—	—	5,468	55	(50)	—	5
Exchange from Series B to common stock	5,468	55	—	—	(5,468)	(55)	—	—	—
Net loss	—	—	—	—	—	—	—	(231,459)	(231,459)
BALANCE AT DECEMBER 31, 2017 (Successor)	222,749	$ 2,043	—	$ —	—	$ —	$ 549,958	$ (328,114)	$ 223,887

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

TELLURIAN INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Successor		Predecessor
	Year Ended December 31,		For the period from January 1, 2016 through April 9, 2016
	2017	2016	
Cash flows from operating activities:			
Net loss	$ (231,459)	$ (96,655)	$ (638)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion and amortization	479	69	8
Goodwill impairment	77,592	—	—
Loss on disposal of assets	—	185	3
Provision for income tax benefit	—	(170)	—
(Gain) loss on Series A convertible preferred stock exchange feature	(2,209)	3,308	—
Gain on sale of securities	(3,481)	—	—
Share-based compensation	23,019	24,495	—
Share-based payments	19,397	—	—
Net changes in working capital (Note 13)	7,433	18,338	516
Net cash used in operating activities	(109,229)	(50,430)	(111)
Cash flows from investing activities:			
Cash received in acquisition	56	210	—
Acquisition of natural gas properties	(90,099)	—	—
Deferred engineering costs	(9,000)	—	—
Purchase of property - land	—	(9,491)	—
Purchase of property and equipment	(1,114)	(1,225)	(268)
Proceeds from sale of available-for-sale securities	4,592	—	—
Net cash used in investing activities	(95,565)	(10,506)	(268)
Cash flows from financing activities:			
Proceeds from the issuance of common stock	318,204	59,015	—
Tax payments for net share settlement of equity awards	(828)	—	—
Proceeds from the issuance of preferred stock	—	25,000	—
Equity offering costs	(5,707)	(1,681)	—
Net cash provided by financing activities	311,669	82,334	—
Net increase (decrease) in cash and cash equivalents	106,875	21,398	(379)
Cash and cash equivalents, beginning of period	21,398	—	589
Cash and cash equivalents, end of period	$ 128,273	$ 21,398	$ 210

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

NOTE 1 — BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Tellurian Inc., a Delaware corporation based in Houston, Texas ("Tellurian"), plans to develop, own and operate a global natural gas business and to deliver natural gas to customers worldwide. Tellurian is establishing a portfolio of natural gas production, LNG marketing, and infrastructure including an LNG terminal facility (the "Driftwood terminal") and an associated pipeline (the "Driftwood pipeline") in southwest Louisiana (the Driftwood terminal and the Driftwood pipeline collectively, the "Driftwood Project").

On February 10, 2017 (the "Merger Date"), Tellurian Investments Inc. ("Tellurian Investments") completed a merger (the "Merger") with a subsidiary of Magellan Petroleum Corporation ("Magellan"). Magellan changed its corporate name to Tellurian Inc. shortly after completing the Merger. The Merger was accounted for as a "reverse acquisition," with Tellurian Investments being treated as the accounting acquirer. As such, the historical consolidated comparative information as of and for all periods in 2016 in this report relates to Tellurian Investments and its subsidiaries. Subsequent to the Merger Date, the information relates to the consolidated entities of Tellurian Inc., with Magellan reflected as the accounting acquiree. In connection with the Merger, each issued and outstanding share of Tellurian Investments common stock was exchanged for 1.3 shares of Magellan common stock. All share and per share amounts in the Consolidated Financial Statements and related notes have been retroactively adjusted for all periods presented to give effect to this exchange, including reclassifying an amount equal to the change in par value of common stock from additional paid-in capital.

On April 9, 2016, Tellurian Investments acquired Tellurian Services LLC ("Tellurian Services"), formerly known as Parallax Services LLC ("Parallax Services"). Under the financial reporting rules of the SEC, Parallax Services ("Predecessor") has been deemed to be the predecessor to Tellurian ("Successor") for financial reporting purposes.

Except where the context indicates otherwise, (i) references to "we," "us," "our," "Tellurian" or the "Company" refer, for periods prior to the completion of the Merger, to Tellurian Investments and its subsidiaries, and for periods following the completion of the Merger, to Tellurian Inc. and its subsidiaries and (ii) references to "Magellan" refer to Tellurian Inc. and its subsidiaries prior to the completion of the Merger.

While we recently commenced operations, we are still subject to significant risks and uncertainties, including failing to secure additional funding to construct the Driftwood Project.

Basis of Presentation

Our Consolidated Financial Statements were prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of Tellurian Inc. and its wholly and majority owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

Segments

Management allocates resources and assesses financial performance on a consolidated basis. As such, for the purposes of financial reporting under GAAP during the years ended December 31, 2017 and 2016, the Company operated as a single operating segment.

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

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.

Goodwill

Goodwill resulting from a business combination is not subject to amortization. The Company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

Revenue Recognition

Revenues associated with sales of natural gas, condensate, LNG and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Purchases and sales of 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. Payments received relating to future revenues are deferred and recognized when all revenue recognition criteria are met.

Cash Equivalents

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

Concentration of Cash

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

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 unproved or proved) are capitalized when incurred. Lease rentals are expensed as incurred. Natural gas exploratory costs are expensed as incurred and costs to develop proved reserves are capitalized. All costs related to production, general corporate overhead, and similar activities are expensed as incurred. 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 Statements of Operations. Management tests property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of property, plant and equipment might not be recoverable.

Accounting for LNG Development Activities

As we have been in the preliminary stage of developing the Driftwood terminal, substantially all of the costs to date related to such activities have been expensed. These costs primarily include professional fees associated with FEED studies and applying to FERC for authorization to construct our terminals 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 achieved: (i) regulatory approval has been received, (ii) financing for the project is available and (iii) management has committed to commence construction. In addition to the above, certain costs incurred prior to achieving the NTP State will be capitalized though 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.

Share-Based Compensation

Share-based payment transactions are measured based on 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.

Income Taxes

Income taxes are accounted for using the asset and liability approach. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to carryforwards and differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. Management assesses the realizability of deferred tax assets and recognizes valuation allowances as appropriate.

Earnings Per Share

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

NOTE 2 — MERGER AND ACQUISITION

The Merger

As discussed in Note 1, *Basis of Presentation and Summary of Significant Accounting Policies*, Tellurian Investments merged with a subsidiary of Magellan on February 10, 2017. The Merger has been accounted for as a "reverse acquisition," with Tellurian Investments being treated as the accounting acquirer using the acquisition method.

The total consideration exchanged was as follows (in thousands, except share and per-share amounts):

Number of shares of Magellan common stock outstanding (1)		5,985,042		
Price per share of Magellan common stock (2)	$	14.21		
Aggregate value of Tellurian common stock issued			$	85,048
Fair value of stock options (3)				2,821
Net purchase consideration to be allocated			$	87,869

(1) The number of shares of Magellan common stock issued and outstanding as of February 9, 2017.

(2) The closing price of Magellan common stock on the NASDAQ on February 9, 2017.

(3) The estimated fair value of Magellan stock options for pre-Merger services rendered.

We utilized estimated fair values at the Merger Date for the allocation of consideration to the net tangible and intangible assets acquired and liabilities assumed. The purchase price allocation to assets acquired and liabilities assumed in the Merger was as follows (in thousands):

Fair Value of Assets Acquired:		
Cash	$	56
Securities available-for-sale		1,111
Other current assets		93
Unproved properties		13,000
Wells in progress		332
Land, buildings and equipment, net		67
Other long-term assets		19
Total assets acquired		14,678
Fair Value of Liabilities Assumed:		
Accounts payable and other liabilities		4,393
Notes payable		8
Total liabilities assumed		4,401
Total net assets acquired		10,277
Goodwill as a result of the Merger	$	77,592

We valued our interests acquired in unproved oil and gas properties using a market approach based on commercial negotiations and bids received for the interests (see Note 5, *Property, Plant and Equipment*, for more information about the properties). The fair value of other property, plant and equipment and wells in progress was determined to be the carrying value of Magellan. Securities available-for-sale were valued based on quoted market prices. The carrying values of cash, other current assets, accounts payable and accrued liabilities and other non-current assets and liabilities approximated fair value at the Merger Date. The Company has determined that such fair value measures for the overall allocation are classified as Level 3 in the fair value hierarchy.

Goodwill recognized as a result of the Merger totaled approximately $77.6 million, none of which is deductible for income tax purposes. Subsequent to the Merger, the Company determined that there is no evidence that we will recover the value of this goodwill and an impairment expense of approximately $77.6 million was recognized during the year ended December 31, 2017.

For purposes of determining the goodwill impairment, we utilized qualitative factors as well as the fair values determined when allocating consideration as of the Merger Date.

Parallax Services Acquisition

On April 9, 2016, Tellurian Investments acquired Parallax Services, which was renamed Tellurian Services, with equity consideration valued at approximately $1 million. The transaction was accounted for using the acquisition method. As of December 31, 2017, goodwill of approximately $1.2 million, included within Other non-current assets, net, on our Consolidated Balance Sheets, was entirely related to the acquisition of Tellurian Services.

Pro Forma Results

The following table provides unaudited pro forma results for the year ended December 31, 2017, and 2016, as if the Merger occurred and Parallax Services had been acquired as of January 1, 2016 (in thousands, except per-share amounts):

	Year Ended December 31,	
	2017	**2016**
Pro forma net loss	$ (235,201)	$ (100,734)
Pro forma net loss per basic share	$ (1.24)	$ (0.98)
Pro forma basic and diluted weighted average common shares outstanding	189,246	102,281

The unaudited pro forma results include adjustments for the historical net loss of Magellan and Parallax Services as well as an increase in compensation expense associated with the addition of three new directors. The pro forma information is provided for informational purposes only and is not necessarily indicative of what Tellurian's results of operations would have been if the Merger and acquisition of Parallax Services had occurred on January 1, 2016. Following the Merger Date, approximately $0.8 million of net loss related to the acquired activities has been included in our Consolidated Financial Statements.

NOTE 3 — DEFERRED ENGINEERING COSTS

Deferred engineering costs of $18.0 million at December 31, 2017, represent detailed engineering services related to the Driftwood terminal. Such costs will be deferred until construction commences on the Driftwood terminal, at which time they will be transferred to construction in progress. The $18.0 million of deferred engineering costs includes $9.0 million which is recorded in accounts payable.

NOTE 4 — TRANSACTIONS WITH RELATED PARTIES

Accounts Receivable due from Related Parties

Tellurian's accounts receivable due from related parties primarily consists of tax indemnities from employees who received share-based compensation.

Accounts Payable due to Related Parties

In December 2017, Tellurian and Martin Houston, a major shareholder and Vice Chairman of the Company, agreed to mutually discharge $0.3 million owed by Tellurian to entities partially owned by Mr. Houston.

Non-current Note Receivable due from Related Party

In July 2017, the $0.3 million non-current note receivable due from Mr. Houston was repaid in full, and the demand note evidencing the receivable was canceled.

Other

During the year ended December 31, 2017, the Company incurred $0.7 million in legal fees to a law firm for advice associated with a lawsuit that was settled in April 2017. A member of our board of directors is a partner at such law firm.

NOTE 5 — PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of fixed assets and oil and natural gas properties, as shown below (in thousands):

	December 31,	
	2017	2016
Land	$ 9,491	$ 9,491
Proved oil and natural gas properties	90,869	—
Unproved oil and natural gas properties	13,000	—
Wells in progress	345	—
Corporate and other	2,693	1,571
Total fixed assets, at cost	116,398	11,062
Accumulated depreciation and depletion	(542)	(69)
Total property, plant and equipment, net	$ 115,856	$ 10,993

Depreciation and depletion expense for the years ended December 31, 2017, and 2016 was approximately $0.5 million and $0.1 million, respectively.

Oil and Natural Gas Properties

Proved Properties

Tellurian has acquired producing and non-producing acreage in northern Louisiana. For more information about these properties, please see "Supplemental Disclosures about Natural Gas Producing Activities."

Unproved Properties

In connection with the Merger, the Company acquired interests in certain unproved properties in the Weald Basin, United Kingdom and the Bonaparte Basin, Australia. In the United Kingdom, Tellurian holds non-operating interests in two licenses which expire in June and September 2021, respectively. In Australia, Tellurian holds an operating interest in an exploration permit which expires in May 2019.

NOTE 6 — ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

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

	December 31,	
	2017	2016
Project development activities	$ 14,870	$ 12,549
Payroll and compensation	25,833	6,311
Accrued taxes	2,764	—
Professional services (e.g., legal, audit)	3,696	2,323
Contingency loss	—	2,560
Other	3,400	660
Total accounts payable and accrued liabilities	$ 50,563	$ 24,403

NOTE 7 — COMMITMENTS AND CONTINGENCIES

Litigation

In July 2017, Tellurian Investments, Driftwood LNG LLC ("Driftwood LNG"), Martin Houston, and three other individuals were named as third-party defendants in a lawsuit filed in state court in Harris County, Texas between Cheniere Energy, Inc. and one of its affiliates, on the one hand (collectively, "Cheniere"), and Parallax Enterprises LLC and certain of its affiliates (not including Parallax Services, n/k/a Tellurian Services) on the other hand (collectively, "Parallax"). In October 2017, Driftwood Pipeline LLC ("Driftwood Pipeline") and Tellurian Services were also named by Cheniere as third-party defendants. Cheniere alleges that it entered into a note and a pledge agreement with Parallax. Cheniere claims that the third-party defendants tortiously interfered with the note and pledge agreement and aided in the fraudulent transfer of Parallax assets. Cheniere is seeking unspecified amounts of monetary damages and certain equitable relief. We believe that Cheniere's claims against Tellurian Investments, Driftwood LNG, Driftwood Pipeline and Tellurian Services are without merit and do not expect the resolution of the suit to have a material effect on our results of operation or financial condition. Trial has been set for September 2018.

Contractual Obligations

A t December 31, 2017, contractual obligations for long-term operating leases and purchase obligations are as follows (in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Office leases	$ 1,854	$ 2,760	$ 2,871	$ 2,909	$ 2,946	$ 10,903	$ 24,243
Project development activities	1,340	1,578	624	24	24	486	4,076
Other	449	198	198	—	—	—	845
	$ 3,643	$ 4,536	$ 3,693	$ 2,933	$ 2,970	$ 11,389	$ 29,164

NOTE 8 — SHARE-BASED COMPENSATION

At a special meeting of stockholders on February 9, 2017, Magellan stockholders approved the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan, as amended (the "Omnibus Plan"), which replaced the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (the "Legacy Plan"). We have granted equity to employees, outside directors, and consultants under the Omnibus Plan and the Legacy Plan. No further awards can be made under the Legacy Plan. The maximum number of shares of Tellurian common stock authorized for issuance under the Omnibus Plan is 40 million shares of common stock.

For the year ended December 31, 2017, share-based compensation expense related to all share-based awards totaled approximately $23.0 million, approximately $2 million of which was issued in settlement of bonuses accrued at December 31, 2016. For the year ended December 31, 2016, share-based compensation expense related to all share-based awards totaled approximately $24.5 million. As of December 31, 2017, unrecognized compensation expense, based on the grant date fair value, for all share-based awards totaled approximately $147.2 million.

Restricted Stock and Restricted Stock Units

Omnibus Plan participants may be granted restricted stock and/or restricted stock units (collectively, "Restricted Stock"). Upon vesting of restricted stock, shares of common stock are released to the employee. Upon vesting, restricted stock units will be converted into shares of common stock and released to the employee. As of December 31, 2017, there was no Restricted Stock that will be settled in cash.

During the year ended December 31, 2017, the Company granted Restricted Stock with service-based and performance-based vesting criteria. Of the performance-based awards, 19.6 million shares vest based upon an affirmative final investment decision by the Company's board of directors, as defined in the award agreements, and no expense has been recognized in connection with these awards. Additionally, a portion of the performance awards vest based on the achievement of certain project development activities.

The fair value of the Restricted Stock was established by the market price on the date of grant and, for service-based awards, is being recognized as compensation expense ratably over the vesting term.

The following table provides a summary of our Restricted Stock transactions for the year ended December 31, 2017 (shares and units in thousands):

	Shares	Weighted-Average Grant Date Fair Value
Unvested at January 1, 2017	8,848	$ 3.52
Granted	12,422	9.59
Vested	(398)	9.28
Forfeited	(384)	11.14
Unvested at December 31, 2017	20,488	

The total grant date fair value of restricted stock vested during the year ended December 31, 2017 was approximately $3.7 million.

Stock Options

During the year ended December 31, 2017, Omnibus Plan participants were 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. Stock options vest equally over a three-year period from the date of grant. Options shall be exercisable at such time and under such conditions set forth in the underlying award agreement, but in no event shall any option be exercisable later than the tenth anniversary of the date of its grant. The fair value of each stock option award is estimated using the Black-Scholes option pricing model.

The following table provides a summary of our stock option transactions for the year ended December 31, 2017 (stock options in thousands):

	Stock Options	Weighted Average Exercise Price
Outstanding at January 1, 2017	—	$ —
Granted	2,015	10.32
Exercised	—	—
Forfeited or Expired	(4)	10.32
Outstanding at December 31, 2017	2,011	$ 10.32
Exercisable at December 31, 2017	—	$ —

Valuation assumptions used to value stock options for the year ended December 31, 2017, were as follows:

Expected term (in years)	6.0
Expected volatility	22.13%
Expected dividend yields	—%
Risk-free rate	2.05%

Due to our limited history, the Company has elected to apply the simplified method to determine the expected term. Additionally, due to our limited history, expected volatility is based on the implied volatility of the Company's peer group as identified by our board of directors. 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 grant.

The weighted average grant date fair value of stock options granted during the year ended December 31, 2017, was $2.72. There were no stock options exercised during the year ended December 31, 2017, and there were no stock options granted or exercised during the year ended December 31, 2016.

NOTE 9 — SHARE-BASED PAYMENTS

For the year ended December 31, 2017, Tellurian recognized approximately $19.4 million as share-based expense for vendors.

In February 2017, the Company issued 409,800 shares of Tellurian common stock, valued at approximately $5.8 million, to a financial adviser in connection with the successful completion of the Merger. This cost has been included in general and administrative expenses in the Consolidated Statements of Operations. Additionally, on the Merger Date, the Company issued 90,350 shares of Tellurian common stock to settle a liability assumed in the Merger valued at approximately $1.3 million.

In March 2017, the Company’s board of directors approved the issuance of 1 million shares that were purchased at a discount by a commercial development consultant under the Omnibus Plan. The terms of the share purchase agreement did not contain performance obligations or similar vesting provisions; accordingly, the full amount of approximately $11.4 million, representing the aggregate difference between the purchase price of $0.50 per share and the fair value on the date of issuance of $11.88 per share, was recognized on the date of the share purchase and has been included in general and administrative expenses in the Consolidated Statements of Operations.

Also in March 2017, the Company issued 200,000 shares under a management consulting arrangement for specified services performed from March 2017 through May 2017. The services were valued at $11.34 per share on the date of issuance. The total cost of approximately $2.3 million was amortized to general and administrative expenses on a straight-line basis over the three-month service period in the Consolidated Statements of Operations.

NOTE 10 — INCOME TAXES

The Company calculates its provision for federal, state and international income taxes based on current tax law. The Tax Cuts and Jobs Act of 2017 (the “Act”) was enacted on December 22, 2017, and has several key provisions impacting the accounting for, and reporting of, income taxes. Although most provisions of the Act are not effective until 2018, we are required to record the effect of a change in tax law in the period of enactment.

The Act amended the Internal Revenue Code (the “Code”) in several areas; however, given the Company’s deferred tax position and full valuation allowance, the Act did not affect our results of operations and statement of financial position as of, and for, the year ended December 31, 2017.

As a result of the changes under the Act, our provision for income taxes and effective tax rate in 2017 included a $30.6 million unfavorable impact to the Company’s gross U.S. deferred tax assets and a corresponding $30.6 million favorable impact to the valuation allowance due to the remeasurement of our U.S. deferred tax assets and liabilities at the tax rate expected to apply when temporary differences are realized.

The other key provision that requires recognition in the period of enactment is the one-time toll charge resulting from the mandatory deemed repatriation of undistributed foreign earnings and profits. As it relates to our operations, there was no impact in 2017 from the mandatory deemed repatriation as we had no net undistributed foreign earnings and profits subject to the toll charge.

On December 22, 2017, the SEC issued Staff Accounting Bulletin No. 118, which allows companies to report the income tax effects of the Act as a provisional amount based on a reasonable estimate, which would be subject to adjustment during a reasonable measurement period, not to exceed twelve months, until the accounting and analysis under ASC 740 is complete. Due to the timing of the enactment of the Act, there continues to be a significant amount of uncertainty as to the appropriate application of several underlying provisions, pending further guidance and clarification from the relevant authorities. We will continue to monitor developments in this area and adjust our estimates throughout the year in 2018, as and if necessary, as additional guidance and clarification become available.

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

	Year Ended December 31,	
	2017	**2016**
Current:		
Federal	$ —	$ —
State	—	(4)
Foreign	(185)	—
Total Current	(185)	(4)
Deferred:		
Federal	—	170
State	—	—
Foreign	—	—
Total Deferred	—	170
Total income tax benefit (provision)	$ (185)	$ 166

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

	Year Ended December 31,	
	2017	**2016**
Domestic	$ (223,991)	$ (95,739)
Foreign	(7,283)	(1,082)
Total loss before income taxes	$ (231,274)	$ (96,821)

The differences between income taxes expected at the U.S. federal statutory income tax rate of 35% and the reported income tax benefit are summarized as follows (in thousands):

	Year Ended December 31,	
	2017	2016
Income tax benefit (provision) at U.S. statutory rate	$ 80,946	$ 33,887
Share-based compensation	—	(5,911)
Impairment	(27,969)	—
Change in U.S. tax rate	(30,562)	—
Change in valuation allowance due to change in U.S. tax rate	30,562	—
Change in valuation allowance	(51,030)	(26,398)
Other	(2,132)	(1,412)
Total income tax benefit (provision)	$ (185)	$ 166

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

	December 31,	
	2017	2016
Deferred tax assets:		
Capitalized engineering costs	$ 2,812	$ 11,749
Capitalized start-up costs	17,881	7,489
Compensation and benefits	5,465	2,052
Net operating loss carryforwards and credits:		
Federal	19,423	4,230
State	522	—
Foreign	1,694	—
Other, net	3,541	878
Deferred tax assets	51,338	26,398
Less valuation allowance	(50,942)	(26,398)
Deferred tax assets, net of valuation allowance	396	—
Deferred tax liabilities	(396)	—
Net deferred tax assets	$ —	$ —

As of December 31, 2017, the Company had net operating loss ("NOL") carryforwards for federal, state and international income tax reporting purposes of $19.4 million, $0.5 million and $1.7 million respectively. The majority of these NOL carryforwards will expire between 2036 and 2037.

Due to our history of NOLs, current year NOLs and significant risk factors related to our ability to generate taxable income, we have established a valuation allowance to offset our deferred tax assets as of December 31, 2017, and 2016. We will continue to evaluate our ability to release the valuation allowance in the future. The increase in the valuation allowance was $24.5 million for the year ended December 31, 2017. Deferred tax assets and deferred tax liabilities are classified as non-current in our Consolidated Balance Sheets.

The Company performed a Section 382 ownership change analysis for Magellan to determine if there were any Section 382 limitations on the utilization of Magellan's pre-Merger NOLs. Based on this analysis, the Company has determined that the Magellan pre-Merger NOL carryforwards are subject to annual Section 382 limitations. Because of these limitations, it is expected that the clear majority of Magellan's NOL carryforwards generated prior to the Merger will expire unused.

In addition, we experienced a Section 382 ownership change on April 20, 2017. An analysis of the annual limitation on the utilization of our NOLs was performed in accordance with the Code. It was determined that Section 382 will not materially limit the use of our NOLs over the carryover period. We will continue to monitor activity in the Company's shares which could cause an ownership change. If the Company experiences a Section 382 ownership change, it could further affect our ability to utilize our existing NOL carryforwards.

The provision for income taxes recorded in the accompanying Consolidated Financial Statements is for foreign income taxes resulting from disposition proceeds on the Company’s sale of available-for-sale securities. The taxable gain on the disposition will be included in the Company’s total profits chargeable to U.K. corporation income tax.

As of December 31, 2017, 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. The Company is not currently under audit by any taxing authority. Tax returns filed with each jurisdiction remain open to examination under the normal three-year statute of limitations.

Unremitted Earnings

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, 2017, 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 11 — STOCKHOLDERS' EQUITY

Equity Offering

In December 2017, the Company issued 10.0 million shares of common stock for proceeds of approximately $94.8 million, net of approximately $5.2 million in fees and commissions. The underwriters were granted an option to purchase up to an additional 1.5 million shares of common stock within 30 days. See Note 15, *Subsequent Events*, for more information.

At-the-Market Program

Tellurian maintains an at-the-market equity offering program pursuant to which we may sell shares of our common stock from time to time on the NASDAQ or any other market for the common stock in the U.S., through Credit Suisse acting as sales agent, for aggregate sales proceeds of up to approximately $200 million. For the year ended December 31, 2017, the Company issued 1.0 million shares of common stock under this program, for proceeds of approximately $10.3 million, net of approximately $0.5 million in fees and commissions.

TOTAL Investment

In January 2017, pursuant to a common stock purchase agreement dated as of December 19, 2016, between Tellurian Investments and TOTAL Delaware, Inc. (“TOTAL”), TOTAL purchased, and Tellurian Investments sold and issued to TOTAL, approximately 35.4 million shares of Tellurian Investments common stock for an aggregate purchase price of $207 million, net of offering costs. In connection with the Merger, the shares purchased by TOTAL were exchanged for approximately 46 million shares of Tellurian common stock.

In May 2017, Tellurian and TOTAL entered into a pre-emptive rights agreement pursuant to which TOTAL was granted a right to purchase its pro rata portion of any new equity securities that Tellurian may issue to a third party on the same terms and conditions as such equity securities are offered and sold to such party, subject to certain excepted offerings (the “Pre-emptive Rights Agreement”). Pursuant to the common stock purchase agreement dated as of December 19, 2016, between Tellurian Investments and TOTAL, the terms and conditions of the Pre-emptive Rights Agreement are similar to those contained in the pre-emptive rights agreement dated as of January 3, 2017, between Tellurian Investments and TOTAL, but the Pre-emptive Rights Agreement is subject to additional excepted offerings.

Tellurian Preferred Stock

In March 2017, GE Oil & Gas, Inc. (now known as GE Oil & Gas, LLC) (“GE”), as the holder of all 5.5 million outstanding shares of Tellurian Investments Series A convertible preferred stock (the “Tellurian Investments Preferred Shares”), exchanged those shares into an equal number of shares of Tellurian Inc. Series B convertible preferred stock (the “Series B Preferred Stock”) pursuant to the terms of the Tellurian Investments Certificate of Incorporation (the “Preferred Share Exchange”). The terms of the Series B Preferred Stock were substantially similar to those of the Tellurian Investments Preferred Shares. The Series B Preferred Stock were exchangeable at any time into shares of the Company’s common stock on a one-for-one basis, subject to anti-dilution adjustments in certain circumstances.

The ability of GE to exchange the Tellurian Investments Preferred Shares into shares of Series B Preferred Stock or into shares of Tellurian common stock following the Merger required the fair value of such features to be bifurcated from the contract and recognized as an embedded derivative until the Merger Date.

The fair value of the embedded derivative was determined through the use of a model which utilizes certain observable inputs such as the price of Magellan common stock at various points in time and the volatility of Magellan common stock over an assumed half-year and one-year holding period from February 10, 2017 and December 31, 2016, respectively. At each valuation date, the model also included (i) unobservable inputs related to the weighted probabilities of certain Merger-related scenarios and (ii) a discount for the lack of marketability determined through the use of commonly accepted methods. We have therefore classified the fair value measurements of this embedded derivative as Level 3 inputs. On the Merger Date, the embedded derivative was reclassified to additional paid-in capital in accordance with GAAP.

The following table summarizes the changes in fair value for the embedded derivative (in thousands):

	February 10, 2017	December 31, 2016
Fair value at the beginning of period and initial fair value, respectively	$ 8,753	$ 5,445
(Gain) loss on exchange feature	(2,209)	3,308
Fair value at the end of the period and year, respectively	$ 6,544	$ 8,753

In June 2017, GE, as the holder of all 5.5 million outstanding shares of Series B Preferred Stock, exercised its right to convert all such shares of Series B Preferred Stock into 5.5 million shares of Tellurian common stock pursuant to and in accordance with the terms of the Series B Preferred Stock.

Retirement of Treasury Stock

In December 2017, the Company retired approximately 1.3 million shares of treasury stock. These retired shares are now included in the Company's pool of authorized unissued shares.

NOTE 12 — EARNINGS PER SHARE

The following table summarizes the computation of basic and diluted loss per share (in thousands, except per-share amounts):

	Year Ended December 31,	
	2017	2016
Net loss	$ (231,459)	$ (96,655)
Basic weighted average common shares outstanding	188,536	95,795
Loss per share:		
Basic and diluted	$ (1.23)	$ (1.01)

As of December 31, 2017, and 2016, the effect of 19.9 million and 11.5 million, respectively, of unvested restricted stock awards that could potentially dilute basic EPS in the future were not included in the computation of diluted EPS because to do so would have been antidilutive for the periods presented. As such, basic and diluted EPS are the same for all periods presented.

NOTE 13 — SUPPLEMENTAL CASH FLOW INFORMATION

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

	Successor		Predecessor
	Year Ended December 31,		For the period from January 1, 2016 through April 9, 2016
	2017	2016	
Accounts receivable	$ (442)	$ (39)	$ 1
Accounts receivable due from related parties	(60)	(124)	(32)
Prepaid expenses and other current assets	(1,419)	(1,936)	13
Note receivable due from related party	251	—	—
Accounts payable and accrued expenses	11,338	22,393	281
Accounts payable due to related parties	—	(53)	253
Other, net	(2,235)	(1,903)	—
Net changes in working capital	$ 7,433	$ 18,338	$ 516

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

	Successor		Predecessor
	Year Ended December 31,		For the period from January 1, 2016 through April 9, 2016
	2017	2016	
Net cash paid for income taxes	$ —	$ 4	$ —
Property, plant and equipment non-cash accruals	83	46	75
Equity offering cost accrual	65	128	—

NOTE 14 — RECENT ACCOUNTING STANDARDS

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

Standard	Description	Expected Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2014-09, *Revenue from Contracts with Customers (Topic 606), and subsequent amendments thereto*	This standard amends existing revenue recognition guidance and requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This standard may be early adopted beginning January 1, 2017, and may be adopted either retrospectively to each prior reporting period presented or as a cumulative-effect adjustment as of the date of adoption.	January 1, 2018	The Company adopted the new standard on January 1, 2018, utilizing the modified retrospective approach. Adoption of this ASU is not expected to have a material impact on our Consolidated Financial Statements. The Company developed an accounting policy, implemented changes to the relevant business processes and the control activities within them, and continues to evaluate the disclosure requirements as a result of the provisions of this ASU.
ASU 2016-02, *Leases (Topic 842)*	This standard requires a lessee to recognize leases on its balance sheet by recording a liability representing the obligation to make future lease payments and a right-of-use asset representing the right to use the underlying asset for the lease term. A lessee is permitted to make an election not to recognize lease assets and liabilities for leases with a term of 12 months or less. The standard also modifies the definition of a lease and requires expanded disclosures. This standard may be early adopted and must be adopted using a modified retrospective approach with certain available practical expedients.	January 1, 2019	We are currently evaluating the impact of the provisions of this guidance on our Consolidated Financial Statements and related disclosures.

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

Standard	Description	Date of Adoption	Effect on our Consolidated Financial Statements or Other Significant Matters
ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*	This update clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses by providing a screen to determine when an integrated set of assets or activities is not a business.	January 1, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or disclosures.
ASU 2017-04, *Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment*	This update eliminated Step 2 from the goodwill impairment test. Step 2 required entities to compute the implied fair value of goodwill if it was determined that the carrying amount of a reporting unit exceed its fair value. The goodwill impairment test now consists of comparing the fair value of a reporting unit with its carrying amount, and a company should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value.	January 1, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or disclosures.
ASU 2017-09, *Compensation — Stock Compensation (Topic 718): Scope of Modification Accounting*	This update clarifies what changes to the terms and conditions of share-based awards require an entity to apply modification accounting. Modification accounting is required only if the fair value, the vesting conditions, or the classification of the award (as equity or liability) changes as a result of the change in terms or conditions.	April 1, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or disclosures.
ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*	This update requires that restricted cash be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows.	April 1, 2017	The adoption of this guidance did not have a material impact on our Consolidated Financial Statements or disclosures.

NOTE 15 — SUBSEQUENT EVENTS

In January 2018, in connection with the Company's December 2017 equity offering, the underwriters exercised their option to purchase an additional 1.5 million shares for proceeds of $14.5 million, net of $0.5 million in fees and commissions.

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 and condensate producing activities are summarized as follows (in thousands):

	December 31, 2017
Proved properties	$ 90,869
Unproved properties	13,000
Gross capitalized costs	103,869
Accumulated DD&A	(149)
Net capitalized costs	$ 103,720

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

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

	December 31, 2017
Property acquisitions:	
Proved	$ 90,869
Unproved	13,000
Exploration costs	—
Development	949
Costs incurred	$ 104,818

Table III — Results of Operations for Natural Gas & Condensate 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 2017 are as follows (in thousands):

	December 31, 2017
Natural gas sales	$ 503
Operating costs and expenses:	
Cost of sales	414
Development expenses	949
Depreciation, depletion and amortization	115
General and administrative expenses	305
Total operating costs and expenses	1,783
Results of operation	$ (1,280)

Table IV — Natural Gas & Condensate Reserve Quantity Information

Our estimated proved reserves are located within 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, 2017 have been prepared by Netherland, Sewell & Associates, Inc., independent petroleum consultants.

	Gas (MMcf)	Condensate (Mbbl)	Gas Equivalent (MMcfe)
Proved reserves:			
December 31, 2016	—	—	—
Extensions, discoveries and other additions	—	—	—
Revisions of previous estimates	—	—	—
Production	(190)	—	(191)
Sale of reserves-in-place	—	—	—
Purchases of reserves-in-place	327,308	10	327,371
December 31, 2017	327,118	10	327,180
Proved developed reserves:			
December 31, 2016	—	—	—
December 31, 2017	5,720	10	5,782
Proved undeveloped reserves:			
December 31, 2016	—	—	—
December 31, 2017	321,398	—	321,398

Table V — Standardized Measure of Discounted Future Net Cash Flows Related to Proved Natural Gas & Condensate 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, 2017 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 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):

	December 31, 2017
Future cash inflows	$ 777,711
Future production costs	(144,991)
Future development costs	(331,297)
Future income tax provisions	(52,212)
Future net cash flows	249,211
Less effect of a 10% discount factor	(161,009)
Standardized measure of discounted future net cash flows	$ 88,202

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

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

December 31, 2016	$ —
Sales and transfers of gas and condensate produced, net of production costs	(265)
Net changes in prices and production costs	—
Extensions, discoveries, additions and improved recovery, net of related costs	—
Development costs incurred	—
Revisions of estimated development costs	—
Revisions of previous quantity estimates	—
Accretion of discount	—
Net change in income taxes	(22,921)
Purchases of reserves in place	111,388
Sales of reserves in place	—
Changes in timing and other	—
December 31, 2017	$ 88,202

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

As previously disclosed, (i) upon the closing of the Merger, our audit committee replaced EKS&H LLLP ("EKS&H") as the Company's independent registered accounting firm with Deloitte & Touche LLP and (ii) there were no "disagreements" with EKS&H or "reportable events" (as those terms are defined in Item 304 of SEC Regulation S-K) during the fiscal years ended June 30, 2015 or 2016 and the subsequent period through February 13, 2017.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Meg A. Gentle, the Company's Chief Executive Officer and President, in her capacity as principal executive officer, and Antoine J. Lafargue, the Company's Senior Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2017, the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company's disclosure controls and procedures were effective, providing effective means to ensure that the information we are required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure. We made no changes in internal controls over financial reporting during the year ended December 31, 2017, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. We periodically review the design and effectiveness of our disclosure controls, including compliance with various laws and regulations that apply to our operations both inside and outside the U.S. We make modifications to improve the design and effectiveness of our disclosure controls and may take other corrective action if our reviews identify deficiencies or weaknesses in our controls.

Management's Annual Report on Internal Control Over Financial Reporting; Report of Independent Registered Public Accounting Firm

The management report called for by Item 308(a) of Regulation S-K is set forth in Item 8 of Part II of this Annual Report on Form 10-K.

The independent auditors report called for by Item 308(b) of Regulation S-K is set forth in Item 8 of Part II of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the year ended December 31, 2017, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

Pursuant to Section 13(r) of the Exchange Act, if during the year ended December 31, 2017, we or any of our affiliates had engaged in certain transactions with Iran or with persons or entities designated under certain executive orders, we would be required to disclose information regarding such transactions in our annual report on Form 10-K as required under Section 219 of the Iran Threat Reduction and Syria Human Rights Act of 2012 (the "ITRSHRA"). Disclosure is generally required even if the activities were conducted outside the U.S. by non-U.S. entities in compliance with applicable law. During the year ended December 31, 2017, we did not engage in any transactions with Iran or with persons or entities related to Iran.

TOTAL and TOTAL S.A. have beneficial ownership of over 20% of the outstanding Tellurian common stock. TOTAL has the right to designate for election one member of Tellurian's board of directors, and Jean Jaylet is the current TOTAL designee. TOTAL will retain this right for so long as its percentage ownership of Tellurian voting stock is at least 10%. On March 17, 2017, TOTAL S.A. included information in its Annual Report on Form 20-F for the year ended December 31, 2016 (the "TOTAL 2016 Annual Report") regarding activities during 2016 that require disclosure under the ITRSHRA. The relevant disclosures were reproduced in Exhibit 99.1 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 filed with the SEC on May 10, 2017 and are incorporated by reference herein. We have no involvement in or control over such activities, and we have not independently verified or participated in the preparation of the disclosures made in the TOTAL 2016 Annual Report.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTER

The information required by this Item with respect to security ownership of certain beneficial owners and management is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference from Tellurian's Definitive Proxy Statement with respect to its 2018 Annual Meeting of Stockholders to be filed not later than April 30, 2018.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements.* Tellurian's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules.* No financial statement schedules are applicable or required.
3. *Exhibits.* The exhibits listed below are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

Exhibit No.	Description
2.1††	Agreement and Plan of Merger, dated as of August 2, 2016, by and among Magellan Petroleum Corporation, Tellurian Investments Inc., and River Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on August 3, 2016), as amended by the First Amendment to Agreement and Plan of Merger, dated as of November 23, 2016 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on November 29, 2016) and the Second Amendment to Agreement and Plan of Merger, dated as of December 19, 2016 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on December 21, 2016)
2.2††	Purchase and Sale Agreement, dated as of September 6, 2017, by and between Rockcliff Energy Operating LLC and Tellurian Production LLC (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
3.1	Amended and Restated Certificate of Incorporation of Tellurian Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on September 22, 2017)
3.2	Amended and Restated Bylaws of Tellurian Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on September 22, 2017)
10.1††	Common Stock Purchase Agreement, dated as of December 19, 2016, by and between Tellurian Investments Inc. and TOTAL Delaware, Inc. (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed on December 21, 2016)
10.2	Guaranty and Support Agreement, dated as of January 3, 2017, by and between Magellan Petroleum Corporation and TOTAL Delaware, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 5, 2017)
10.3	Voting Agreement, dated as of January 3, 2017, by and among Magellan Petroleum Corporation, Tellurian Investments Inc., TOTAL Delaware, Inc., Charif Souki, the Souki Family 2016 Trust and Martin Houston (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 5, 2017)
10.4	Pre-emptive Rights Agreement, dated as of May 10, 2017, by and between Tellurian Inc. and TOTAL Delaware, Inc. (incorporated by reference to Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017)
10.5††	Preferred Stock Purchase Agreement, dated as of November 23, 2016, by and between Tellurian Investments Inc. and GE Oil & Gas, Inc. (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed on November 29, 2016)
10.6	Guaranty and Support Agreement, dated as of November 23, 2016, by and between Magellan Petroleum Corporation and GE Oil & Gas, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 29, 2016)
10.7	Registration Rights Agreement, dated as of June 28, 2017, by and between Tellurian Inc. and GE Oil & Gas, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 3, 2017)
10.8	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 1 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 13, 2017)
10.9	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 2 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 13, 2017)

Exhibit No.	Description
10.10	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 3 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on November 13, 2017)
10.11	Lump Sum Turnkey Agreement for the Engineering, Procurement and Construction of the Driftwood LNG Phase 4 Liquefaction Facility, dated as of November 10, 2017, by and between Driftwood LNG LLC and Bechtel Oil, Gas and Chemicals, Inc. (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on November 13, 2017)
10.12†	Employment Letter Agreement by and between Tellurian Investments Inc. and Meg A. Gentle, dated as of August 31, 2016 (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-4/A filed on November 8, 2016)
10.13†	Employment Letter Agreement by and between Tellurian Investments Inc. and R. Keith Teague, dated as of September 23, 2016 (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-4/A filed on November 8, 2016)
10.14†	Employment Letter Agreement by and between Tellurian Services LLC and Daniel A. Belhumeur, dated as of September 23, 2016 (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-4/A filed on November 8, 2016)
10.15†	Employment Agreement, dated as of February 9, 2017, by and between Tellurian Services LLC and Antoine Lafargue (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 13, 2017)
10.16†	Employment Letter Agreement, by and between Tellurian Services LLC and Khaled Sharafeldin, dated as of January 9, 2017 (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.17†	Form of Indemnification Agreement (Officers) (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.18†	Form of Indemnification Agreement (Directors) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on February 28, 2017)
10.19†	Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 22, 2017)
10.20†	Form of Stock Award Agreement pursuant to the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 28, 2017)
10.21†	Form of Stock Award Agreement pursuant to the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (Directors) (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.22†	Restricted Stock Agreement pursuant to the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan, dated as of February 13, 2017, by and between Tellurian Inc. and Antoine Lafargue (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on February 13, 2017)
10.23†	Form of Restricted Stock Agreement pursuant to the Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (Directors) (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
10.24†	Form of Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (Time-Based Vesting) (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.25†	Form of Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (Milestone-Based Vesting) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 31, 2018)
10.26†	Form of Stock Option Agreement pursuant to the Amended and Restated Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (U.S. Selected Senior Management) (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.27†	2017-2021 Long Term Incentive Compensation Program (LTIP) under the Amended and Restated 2016 Tellurian Inc. 2016 Omnibus Incentive Compensation Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017)
10.28†	Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on February 13, 2017)

Exhibit No.	Description
10.29†	Form of Restricted Stock Amendment Letter regarding the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on February 13, 2017)
10.30†	Form of Notice of Grant and Restricted Stock Award Agreement pursuant to the 2016 Tellurian Investments Omnibus Incentive Plan (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on February 13, 2017)
10.31†	Form of Amendment to Restricted Stock Agreement pursuant to the Amended and Restated Tellurian Investments Inc. 2016 Omnibus Incentive Plan (Employees) (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017)
14.1	Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 to the Company's Current Report on Form 8-K filed on March 31, 2017)
21.1*	Subsidiaries of Tellurian Inc.
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2*	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1**	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Section 13(r) Disclosure (incorporated by reference to Exhibit 99.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017)
99.2*	Summary Reserves Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

†† Pursuant to Item 601(b)(2) of Regulation S-K, certain schedules and similar attachments have been omitted. The registrant hereby agrees to furnish supplementally a copy of any omitted schedule or attachment to the Securities and Exchange Commission upon request.

ITEM 16. FORM 10-K SUMMARY

None.

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, thereunto duly authorized.

TELLURIAN INC.

Date:	March 15, 2018	By:	/s/ Antoine J. Lafargue
			Antoine J. Lafargue Senior Vice President and Chief Financial Officer (as Principal Financial Officer) Tellurian Inc.
Date:	March 15, 2018	By:	/s/ Khaled Sharafeldin
			Khaled Sharafeldin Chief Accounting Officer (as Principal Accounting Officer) Tellurian Inc.

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

/s/ Meg A. Gentle	Date: March 15, 2018
Meg A. Gentle, Director, President and Chief Executive Officer, Tellurian Inc. (as Principal Executive Officer)	
/s/ Antoine J. Lafargue	Date: March 15, 2018
Antoine J. Lafargue, Senior Vice President and Chief Financial Officer, Tellurian Inc. (as Principal Financial Officer)	
/s/ Khaled Sharafeldin	Date: March 15, 2018
Khaled Sharafeldin, Chief Accounting Officer, Tellurian Inc. (as Principal Accounting Officer)	
/s/ Charif Souki	Date: March 15, 2018
Charif Souki, Director and Chairman, Tellurian Inc.	
/s/ Martin Houston	Date: March 15, 2018
Martin Houston, Director and Vice Chairman, Tellurian Inc.	
/s/ Diana Derycz-Kessler	Date: March 15, 2018
Diana Derycz-Kessler, Director, Tellurian Inc.	
/s/ Dillon J. Ferguson	Date: March 15, 2018
Dillon J. Ferguson, Director, Tellurian Inc.	
/s/ Jean Jaylet	Date: March 15, 2018
Jean Jaylet, Director, Tellurian Inc.	
/s/ Brooke A. Peterson	Date: March 15, 2018
Brooke A. Peterson, Director, Tellurian Inc.	

/s/ Don A. Turkleson Date: March 15, 2018

Don A. Turkleson, Director, Tellurian Inc.

Exhibit 21.1

SUBSIDIARIES OF THE REGISTRANT

Below is a list of all direct and indirect subsidiaries of Tellurian Inc. as of March 15, 2018:

Subsidiary	**State or Other Jurisdiction of Incorporation or Organization**	**Ownership**
Tellurian Inc. owns the following subsidiaries directly:		
Tellurian Investments LLC (formerly known as Tellurian Investments Inc.)	Delaware	100.0%
Magellan Petroleum (UK) Investment Holdings Limited	United Kingdom	100.0%
Magellan Petroleum Australia Pty Ltd	Queensland, Australia	70.0% (1)
Tellurian Investments LLC owns the following subsidiaries directly:		
Driftwood Holdings LLC	Delaware	100.0%
Tellurian LandCo LLC (formerly known as Parallax LNG LandCo LLC and MBTU LandCo LLC)	Delaware	100.0%
Tellurian LNG LLC (formerly known as Parallax LNG LLC)	Delaware	100.0%
Tellurian Midstream Holdings LLC	Delaware	100.0%
Tellurian Production Holdings LLC	Delaware	100.0%
Tellurian Services LLC (formerly known as Parallax Services LLC)	Delaware	100.0%
Tellurian Supply & Trade LLC	Delaware	100.0%
Tellurian International Holdings Ltd	United Kingdom	100.0%
Tellurian LNG UK Ltd	United Kingdom	100.0%
Tellurian Trading UK Ltd	United Kingdom	100.0%
Tellurian LNG Singapore Pte. Ltd.	Singapore	100.0%
Driftwood Holdings LLC owns the following subsidiary directly:		
Tellurian O&M LLC	Delaware	100.0%
Tellurian LNG LLC owns the following subsidiaries directly:		
Driftwood LNG LLC	Delaware	100.0%
Driftwood LNG Tug Services LLC	Delaware	100.0%
Driftwood Pipeline LLC (formerly known as Driftwood LNG Pipeline LLC)	Delaware	100.0%
Tellurian Midstream Holdings LLC owns the following subsidiary directly:		
Tellurian Pipeline LLC	Delaware	100.0%
Tellurian Pipeline LLC owns the following subsidiaries directly:		
Haynesville Global Access Pipeline LLC	Delaware	100.0%
Permian Global Access Pipeline LLC	Delaware	100.0%
Tellurian Production Holdings LLC owns the following subsidiaries directly:		
Tellurian Operating LLC	Delaware	100.0%
Tellurian Production LLC	Delaware	100.0%
Magellan Petroleum (UK) Investment Holdings Limited owns the following subsidiary directly:		
Magellan Petroleum (UK) Limited	United Kingdom	100.0%
Magellan Petroleum Australia Pty Ltd owns the following subsidiaries directly:		
Magellan Petroleum (Offshore) Pty Ltd	Queensland, Australia	100.0%

(1) Tellurian Inc. directly owns 70% of Magellan Petroleum Pty Ltd (“MPA”), and the remaining 30% of MPA is directly owned by Magellan Petroleum (UK) Limited, a wholly owned subsidiary of Magellan Petroleum (UK) Investment Holdings Limited.

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements Nos. 333-216013 and 333-216011 on Form S-3 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 March 15, 2018, relating to the consolidated financial statements of Tellurian Inc. and its subsidiaries, and the effectiveness of Tellurian Inc and its subsidaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Tellurian Inc. for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 15, 2018

Exhibit 23.2

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 of Tellurian Inc. (No. 333-216013 and No. 333-216011) and to the incorporation by reference in the Registration Statements on Form S-8 of Tellurian Inc. (No. 333-220641, No. 333-216010, No. 333-189614, No. 333-171149, No. 333-162668 and No. 333-70567) of all references to our firm and information from our reserves report dated February 9, 2018, included in or made a part of Tellurian Inc.'s Annual Report on Form 10-K for the year ended December 31, 2017, and our summary report attached as Exhibit 99.2 to the Annual Report on Form 10-K.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas

March 15, 2018

Exhibit 31.1

CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT

I, Meg A. Gentle, certify that:

1. I have reviewed this annual report on Form 10-K of Tellurian Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2018

/s/ Meg A. Gentle

Meg A. Gentle
Chief Executive Officer
(as Principal Executive Officer)
Tellurian Inc.

Exhibit 31.2

CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13a-14(a) AND 15d-14(a) UNDER THE EXCHANGE ACT

I, Antoine J. Lafargue, certify that:

1. I have reviewed this annual report on Form 10-K of Tellurian Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2018

/s/ Antoine J. Lafargue

Antoine J. Lafargue
Senior Vice President and Chief Financial Officer
(as Principal Financial Officer)
Tellurian Inc.

Exhibit 32.1

CERTIFICATION BY CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Tellurian Inc. (the “Company”) on Form 10-K for the year ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Meg A. Gentle, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2018

/s/ Meg A. Gentle

Meg A. Gentle
Chief Executive Officer
(as Principal Executive Officer)
Tellurian Inc.

Exhibit 32.2

**CERTIFICATION BY CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Tellurian Inc. (the "Company") on Form 10-K for the year ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Antoine J. Lafargue, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 15, 2018

/s/ Antoine J. Lafargue
Antoine J. Lafargue
Senior Vice President and Chief Financial Officer
(as Principal Financial Officer)
Tellurian Inc.

Exhibit 99.2

February 9, 2018

Ms. Ami Arief
Tellurian Production LLC
1201 Louisiana Street, Suite 3100
Houston, Texas 77002

Dear Ms. Arief:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Tellurian Production LLC (Tellurian) interest in certain gas properties located in Louisiana. We completed our evaluation on or about January 26, 2018. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Tellurian. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Tellurian Inc.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Tellurian interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Gas (MMCF)	Condensate (MBBL)	Gas Equivalent (MMCFE)	Total	Present Worth at 10%
Proved Developed Producing	5,720.4	10.3	5,782.5	4,754.0	3,597.1
Proved Undeveloped	321,397.6	0.0	321,397.6	296,669.2	107,526.0
Total Proved	327,118.0	10.3	327,180.1	301,423.1	111,123.1

Totals may not add because of rounding.

Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Condensate volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas equivalent volumes are expressed in millions of cubic feet equivalent (MMCFE), determined using the ratio of 6 MCF of gas to 1 barrel of liquids.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2017, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Tellurian's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Tellurian's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For gas volumes, the average Henry Hub spot price of $2.976 per MMBTU is adjusted for energy content, transportation fees, and market differentials. The fees associated with Tellurian's transportation contract are included as a deduction to gas revenue. For condensate volumes, the average West Texas Intermediate spot price of $51.34 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted product prices of $2.376 per MCF of gas and $46.22 per barrel of condensate are held constant throughout the lives of the properties.

We have estimated operating costs based on our knowledge of similar operations in the area. These costs are intended to include the per-well overhead expenses allowed under joint operating agreements along with costs to be incurred at and below the district and field levels. It is also intended that the headquarters general and administrative overhead expenses are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by Tellurian and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and any production equipment necessary to connect the wells to sales. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Tellurian's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Tellurian interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Tellurian receiving its net revenue interest share of estimated future gross production. Additionally, we have been informed by Tellurian that it is not party to any firm transportation contracts for these properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Tellurian, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Tellurian, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Stephan D. Cadwallader, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2016 and has over 6 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Stephan D. Cadwallader
Stephan D. Cadwallader, P.E. 115542
Petroleum Engineer

Date Signed: February 9, 2018

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 9, 2018

SDC:TTS

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

> *Supplemental definitions from the 2007 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by

being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

- (i) Oil and gas producing activities include:
  - (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
  - (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
  - (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
    - *(1)* Lifting the oil and gas to the surface; and
    - *(2)* Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
  - (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

- (ii) Oil and gas producing activities do not include:
  - (A) Transporting, refining, or marketing oil and gas;
  - (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
  - (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
  - (D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.