HOUSTON AMERICAN ENERGY CORP
Form 10-K
April 01, 2019

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2018

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File No. 1-32955

HOUSTON AMERICAN ENERGY CORP.

(Exact name of registrant specified in its charter)

Delaware	**76-0675953**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

801 Travis Street, Suite 1425, Houston, Texas 77002

(Address of principal executive offices)(Zip code)

Issuer's telephone number, including area code: (713) 222-6966

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

Title of each class	**Name of each exchange on which each is registered**
Common Stock, $0.001 par value	**NYSE American**

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

None

(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] No [X]

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

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 [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes [X] 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. [X]

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 definition of "accelerated filer," "large 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	[X]
Smaller reporting company	[X]	Emerging growth company	[ ]		

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2018, based on the closing sales price of the registrant's common stock on that date, was approximately $15.2 million. Shares of common stock held by each current executive officer and director and by each person known by the registrant to own 10% or more of the outstanding common stock have been excluded from this computation in that such persons may be deemed to be affiliates.

The number of shares of the registrant’s common stock, $0.001 par value, outstanding as of March 15, 2019 was 62,425,140.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s Proxy Statement for its 2019 Annual Meeting are incorporated by reference into Part III of this Report.

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FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. These forwarding-looking statements include without limitation statements regarding our expectations and beliefs about the market and industry, our goals, plans, and expectations regarding our properties and drilling activities and results, our intentions and strategies regarding future acquisitions and sales of properties, our intentions and strategies regarding the formation of strategic relationships, our beliefs regarding the future success of our properties, our expectations and beliefs regarding competition, competitors, the basis of competition and our ability to compete, our beliefs and expectations regarding our ability to hire and retain personnel, our beliefs regarding period to period results of operations, our expectations regarding revenues, our expectations regarding future growth and financial performance, our beliefs and expectations regarding the adequacy of our facilities, and our beliefs and expectations regarding our financial position, ability to finance operations and growth and the amount of financing necessary to support operations. These statements are subject to risks and uncertainties that could cause actual results and events to differ materially. See “Item 1A. Risk Factors” for a discussion of certain risk factors. We undertake no obligation to update forward-looking statements to reflect events or circumstances occurring after the date of this annual report on Form 10-K.

As used in this annual report on Form 10-K, unless the context otherwise requires, the terms “we,” “us,” “the Company,” and “Houston American” refer to Houston American Energy Corp., a Delaware corporation.

PART I

Item 1. Business

General

Houston American Energy Corp is an independent oil and gas company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil properties. Our principal properties, and operations, are in the U.S. Permian Basin. Additionally, we have properties in the U.S. Gulf Coast region, particularly Texas and Louisiana, and in the South American country of Colombia.

We focus on early identification of, and opportunistic entrance into, existing and emerging resource plays. We do not operate properties but typically seek to partner with, or invest along-side, larger operators in the development of resources or retain interests, with or without contribution on our part, in prospects identified, packaged and promoted to larger operators. By entering these plays earlier, identifying stranded blocks and partnering with, investing along-side or promoting to, larger operators, we believe we can capture larger resource potential at lower cost and minimize our exposure to drilling risks and costs and ongoing operating costs.

We, along with our partners, actively manage our resources through opportunistic acquisitions and divestitures where reserves can be identified, developed, monetized and financial resources redeployed with the objective of growing reserves, production and shareholder value.

Properties

Our exploration and development projects are focused on existing property interests, and future acquisition of additional property interests, in the Texas Permian Basin, the onshore Texas and Louisiana Gulf Coast region and in the South American country of Colombia.

Each of our property interests differ in scope and character and consists of one or more types of assets, such as 3-D seismic data, owned mineral interests, leasehold positions, lease options, working interests in leases, partnership or limited liability company interests, corporate equity interests or other mineral rights. Our percentage interest in each property represents the portion of the interest in the property we share with other partners in the property. Because each property consists of a bundle of assets that may or may not include a working interest in the project, our stated interest in a property simply represents our proportional ownership in the bundle of assets that constitute the property. Therefore, our interest in a property should not be confused with the working interest that we will own when a given well is drilled. Each of our exploration and development projects represents a negotiated transaction between the project partners relating to one or more properties. Our working interest may be higher or lower than our stated interest.

The following table sets forth information relating to our principal properties as of December 31, 2018:

		Average		**Gross**	Net proved	2018 Net Production	
	Net acreage[(1)]	working interest %		producing wells[(1)]	reserves (boe)	Oil (bbls)	**Natural Gas (mcf)**
Texas	260	16.1	%	2	786,327	21,526	246,378
Louisiana	301	17.7	%	2	16,546	2,303	6,036
Oklahoma	4	2.8	%	1	1,814	13	639
Total U.S.	565	16.3	%	5	804,687	23,842	253,053
Colombia	49,025	12.5	%	—	—	—	—
Total	49,590	12.5	%	5	804,687	23,842	253,053

(1) Excludes acreage and one well on which we hold royalty interests but no working interest.

In 2018, we acquired a 12.5% working interest (subject to a proportionate 10% back-in after payout) in an approximately 650-acre lease block in Yoakum County, Texas.

- United States Properties:

In the United States, our properties and operations are principally located in the on-shore Permian Basin and Gulf Coast regions of Louisiana and Texas.

Texas Properties

Reeves County. We hold an 18.6% average working interest in 960 gross acres in Reeves County, Texas, consisting of (1) the 320 gross acre Johnson Lease, in which we hold a 25% working interest, subject to a proportionate 5% back-in after payout, and (2) the 640 gross acre O’Brien Lease, in which we hold an average 15.489% working interest. Our Reeves County acreage lies within the Delaware sub-basin of the Permian Basin, with resource potential in the Wolfcamp, Bone Spring and Avalon formations. During 2017, we drilled and completed our initial wells on both lease blocks, the Johnson State #1H well and the O’Brien #3H well, both horizontally drilled and hydraulically fractured wells in the Wolfcamp A formation.

In June 2018, a new operator took control of operations of our Reeves County acreage, following the acquisition of the interests of the former operator. No wells were drilled on our Reeves County acreage during 2018 pending development and presentation of drilling plans by the new operator. We anticipate resumption of drilling operations on our Reeves County acreage but the timing, number of wells drilled, anticipated costs and related matters are subject to our review and acceptance of development plans expected to be provided by the new operator, as well as our ability to finance our share of costs, market conditions and other factors, many of which are beyond our control.

Yoakum County. We hold a 12.5% working interest, subject to a proportionate 10% back-in after payout, in an approximately 650 gross acre block in Yoakum County, Texas. Our Yoakum County acreage lies within the Midland sub-basin of the Permian Basin.

In early 2019, we drilled the Frost #1H well, the first well on our Yoakum County acreage. The well was horizontally drilled and, following drilling operations, the operator commenced build out of the site to support production. We anticipate that construction of production facilities will be complete and that the well will be hydraulically fractured in the San Andres Formation during the second quarter of 2019. Subject to the operator's evaluation of the performance of the initial well, we anticipate that additional wells will be drilled on our Yoakum County acreage in the future.

Louisiana Properties

Our principal producing and exploration properties in Louisiana consist of the following:

East Baton Rouge Parish — we hold a 23.437% mineral interest in 2,485 gross acres, of, or as to, which (i) we hold a 3.547% net royalty interest in 498.12 acres, including the Crown Paper #01 well, (ii) we hold a 5.273% net royalty interest in 743.94 acres, and (iii) 1,242.94 acres are unleased.

Vermilion Parish — we hold a 1.974% working interest in a 15,000 foot Discorbis well and 450+ gross acre lease block.

Jefferson Davis Parish — we hold a 10.938% working interest before payout and a 9.375% working interest after payout in a 7,000 foot Cris H well and 10 gross acre lease block.

The operator/lessee of 743.94 gross acres in East Baton Rouge Parish has indicated that it plans to drill an initial well to test the Lower Tuscaloosa Formation below 19,000 feet. Otherwise, there are no known present plans to conduct additional drilling operations on our Louisiana acreage.

- Colombian Properties:

At December 31, 2018, we held interests in multiple prospects in Colombia covering 392,205 gross acres. We identify our Colombian prospects by the concessions operated.

The following table sets forth information relating to our interests in prospects in Colombia at December 31, 2018:

Property	Operator	Ownership Interest		Total Gross Acres	**Total Gross Developed Acres**	Gross Productive Wells
Los Picachos	Hupecol	12.5	%	86,235	—	—
Macaya	Hupecol	12.5	%	195,201	—	—
Serrania	Hupecol	12.5	%	110,769	—	—
Total				392,205	—	—

At December 31, 2018, we held interests in three concessions operated by Hupecol Operating Co. in Colombia. The Loc Picachos, Macaya and Serrania concessions are located in the Caguan Putumayo Basin of Colombia. The concessions cover an aggregate area of 392,205 acres. Our interest in each of the concessions is subject to an escalating royalty ranging from 8% to 20% depending upon production volumes and pricing and an additional 6% to 10% per concession when 5,000,000 barrels of oil have been produced on a field in a concession.

As of December 31, 2018, no wells had been drilled and no production had taken place on any of the fields in our then existing concessions in Colombia.

As operator of our various prospects, Hupecol has substantial control over the timing of drilling and selection of prospects to be drilled and we have limited ability to influence the selection of prospects to be drilled or the timing of such drilling operations and have no effective means of controlling the costs of such drilling operations. Accordingly, our drilling budget is subject to fluctuation based on the prospects selected to be drilled by Hupecol, the decisions of Hupecol regarding timing of such drilling operations and the ability of Hupecol to drill and operate wells within estimated budgets.

Commencement of drilling of each of our concessions has been delayed on multiple occasions, and continues to be delayed, due to numerous factors of a political nature, including conflicts between federal and local authorities over environmental and permitting issues and lingering security concerns arising from the long-standing conflict between the federal government and the Revolutionary Armed Forces of Colombia, also known as FARC.

In June 2016, a peace accord was announced between the Colombian government and FARC. The peace accord was ultimately rejected in a popular referendum although both government and FARC representatives have indicated a desire to cease all hostilities and seek to arrive at an acceptable final peace accord. While there is no assurance as to how the peace initiative will, or will not, impact our assets, we continue to evaluate our plans regarding our Colombian assets in light of the peace initiatives and the potential of the same to enhance our prospects of arriving at a favorable resolution to the impasse that has prevented the commencement of drilling operations on our Colombian properties.

Serrania Block

Our interest in the Serrania concession was acquired through a Farmout Agreement with the original operator of the block pursuant to which we will pay 25% of designated Phase 1 geological and seismic costs in return for a 12.5% interest in the Contract for Exploration and Production covering the concession.

Seismic work on the Serrania Block was completed in 2010. Drilling preparation and seismic processing work was performed in 2011 and 2012 in connection with the planned drilling of initial test wells on the concession. The National Hydrocarbon Agency of Colombia (the "ANH") has granted extensions of required development commitments, including drilling of a first test well on the Serrania concession, until conditions in the area allow operations.

During 2018, Hupecol continued to experience opposition, at the local level, to their efforts to secure necessary permits to commence drilling operations on the Serrania block. The federal government, which originally granted the concession, granted necessary permits to commence drilling and subsequently rescinded the permits. Given the ongoing opposition, Hupecol has determined to defer further efforts to commence drilling on the block for the foreseeable future and has commenced discussions with the ANH with a view to arriving at a final definitive settlement either permitting drilling or compensating Hupecol for the block.

Los Picachos and Macaya Prospects

Our Los Picachos and Macaya prospects adjoin our Serrania concession. Hupecol has advised us that they have put on hold plans to begin seismic and other work on the Los Picachos and Macaya concessions until a satisfactory resolution of the ongoing permitting disputes. The ANH has granted extensions of required development commitments, including seismic acquisition, until conditions in the area allow operations.

Drilling Activity

During 2018, we drilled no wells. The following table summarizes the number of wells drilled during 2018, 2017, and 2016, excluding any wells drilled under farmout agreements, royalty interest ownership, or any other wells in which we do not have a working interest.

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—
Total development wells	—	—	—	—	—	—
Exploratory wells, completed as:						
Productive	—	—	2	0.36	—	—
Non-productive	—	—	—	—	—	—

Total exploratory wells	—	—	2	0.36	—	—

Productive wells are wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

As of December 31, 2018, we had pre-drilling operations ongoing on a single well on our Yoakum County acreage. Otherwise, we had no drilling operations in progress at December 31, 2018.

Productive Wells

Productive wells consist of producing wells and wells capable of production, including shut-in wells. A well bore with multiple completions is counted as only one well. As of December 31, 2018, we owned interests in 5 gross wells (excluding wells in which we hold only royalty interests). As of December 31, 2018, we had ownership interests in productive wells, categorized by geographic area, as follows:

	Oil Wells	Gas Wells
United States		
Gross	3	2
Net	0.47	0.05
Colombia		
Gross	—	—
Net	—	—
Total		
Gross	3	2
Net	0.47	0.05

Volume, Prices and Production Costs

The following table sets forth certain information regarding the production volumes, average prices received and average production costs associated with our sales of gas and oil, categorized by geographic area, for each of the three years ended December 31, 2018, 2017, and 2016:

	Year Ended December 31,		
	2018	2017	2016
Net Production:			
Gas (Mcf):			
United States	253,053	30,997	20,204
Colombia	—	—	—
Total	253,053	30,997	20,204
Oil (Bbls):			
United States	23,842	10,038	2,933
Colombia	—	—	—
Total	23,842	10,038	2,933
Average sales price:			
Gas ($ per Mcf)			
United States	$3.27	$3.88	$2.35
Colombia	—	—	—
Total	$3.27	$3.88	$2.35
Oil ($ per Bbl)			
United States	$57.43	$50.81	$40.40
Colombia	—	—	—
Total	$57.43	$50.81	$40.40
Average production costs ($ per BOE):			
United States	$53.19	$14.23	$14.15
Colombia	—	—	—
Total	$53.19	$14.23	$14.15

Natural Gas and Oil Reserves

Reserve Estimates

The following tables sets forth, by country and as of December 31, 2018, our estimated net proved oil and natural gas reserves, and the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (“PV-10”) and after future income taxes (“Standardized Measure”) of our proved reserves, each prepared in accordance with assumptions prescribed by the Securities and Exchange Commission (“SEC”).

The PV-10 value is a widely used measure of value of oil and natural gas assets and represents a pre-tax present value of estimated cash flows discounted at ten percent. PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that our PV-10 presentation is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account the related future income taxes, as such taxes may differ among various companies because of differences in the amounts and timing of deductible basis, net operating loss carry forwards and other factors. We believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our proved reserves to the reserve estimates of other companies. PV-10 is not a measure of financial or operating performance under GAAP and is not intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

	Reserves [1]		
	Oil (bbls)	Natural Gas (mcf)	**Total** [2] (boe)
Reserve category			
Proved Developed Producing			
United States	107,748	1,544,383	365,145
Colombia	—	—	—
Total Proved Developed Producing Reserves	107,748	1,544,383	365,145
Proved Undeveloped			
United States	242,949	1,179,557	439,542
Colombia	—	—	—
Total Proved Undeveloped Reserves	242,949	1,179,557	439,542
Total Proved Reserves	350,697	2,723,940	804,687

	Proved Developed	Proved Undeveloped	Total Proved
PV-10 [1]	$4,343,505	$ 3,371,143	$7,714,648
Standardized measure [3]	$4,343,505	$ 3,371,143	$7,714,648

(1) In accordance with applicable financial accounting and reporting standards of the SEC, the estimates of our proved reserves and the PV-10 set forth herein reflect estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2018. For purposes of determining prices, we used the unweighted arithmetical average of the prices on the first day of each month within the 12-month period ended December 31, 2018. The average prices utilized for purposes of estimating our proved reserves were $62.19 per barrel of oil and $1.79 per mcf of natural gas for our US properties, adjusted by property for energy content, quality, transportation fees and regional price differentials. The prices should not be interpreted as a prediction of future prices. The amounts shown do not give effect to non-property related expenses, such as corporate general administrative expenses and debt service, future income taxes or to depreciation, depletion and amortization.

(2) Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

(3) The Standard Measure differs from PV-10 only in that the Standard Measure reflects estimated future income taxes.

Due to the inherent uncertainties and the limited nature of reservoir data, proved reserves are subject to change as additional information becomes available. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 and Standard Measure estimates, set forth above were prepared by Russell K. Hall & Associates, Inc. for our Reeves County, Texas reserves and by Lonquist & Co., LLC for all other reserves.

These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

Our year-end reserve reports are prepared by reserve engineering firms 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, geosciences and engineering data, and other information provided to them by our management team. Upon analysis and evaluation of data provided, the reserve engineering firms issue a preliminary appraisal report of our reserves. The preliminary appraisal report and changes in our reserves are reviewed by our President and board for reasonableness of the results obtained. Once any questions have been addressed, the reserve engineering firms issue final appraisal reports, reflecting their conclusions.

Russell K. Hall & Associates is an independent Midland, Texas based professional engineering firm providing reserve evaluation services to the oil and gas industry. Their report was prepared under the direction of Russell K. Hall, founder and President of Russell K. Hall & Associates. Mr. Hall holds a BS in Mechanical Engineering from the University of Oklahoma, is a registered professional engineer and a member of the Society of Petroleum Engineers, the Society of Independent Professional Earth Scientists and the West Texas Geological Society. Mr. Hall has more than 30 years of experience in reserve evaluation for the oil and gas industry and the oil and gas finance industry. Russell K. Hall & Associates, and its employees, have no interest in our company or our properties and were objective in determining our reserves.

Lonquist & Co. is an independent professional engineering firm specializing in the technical and financial evaluation of oil and gas assets. Lonquist & Co's report was conducted under the direction of Don E. Charbula, P.E., Vice President of Lonquist & Co. Mr. Charbula holds a BS in Petroleum Engineering from The University of Texas at Austin and is a registered professional engineer with more than 30 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management. Lonquist & Co., and its employees, have no interest in our Company and were objective in determining our reserves.

The SEC's rules with respect to technologies that a company can use to establish reserves allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Our reserve engineering firms used a combination of production and pressure performance, simulation studies, offset analogies, seismic data and interpretation, geophysical logs and core data to calculate our reserves estimates.

Proved Undeveloped Reserves

The following table summarizes activity within our proved undeveloped reserve category for the year ended December 31, 2018:

	For the Year Ended December 31, 2018
Proved undeveloped reserves (MBoe):	
Beginning of year	437,797
Increase due to evaluation reassessments	1,786
End of year	439,583

At December 31, 2018, all proved undeveloped reserves were attributable to our Reeves County, Texas acreage.

As a result of the change in operator of our Reeves County acreage and their pending drilling plans, we incurred no costs relating to the development of proved undeveloped acreage during 2018.

We expect to develop all of our proved undeveloped reserves as of December 31, 2018 within five years of their initial booking. None of our proved undeveloped locations have been booked for longer than five years.

Developed and Undeveloped Acreage

The following table sets forth the gross and net developed and undeveloped acreage (including both leases and concessions, but excluding acreage in which we hold a royalty interest but no working interest), categorized by geographical area, which we held as of December 31, 2018:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States	2,343	434	970	131
Colombia	—	—	392,205	49,025
Total	2,343	434	393,175	49,156

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well.

As is customary in the oil and natural gas industry, we can generally retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by paying delay rentals during the remaining primary term of leases. The oil and natural gas leases in which we have an interest are for varying primary terms and, if production under a lease continues from our developed lease acreage beyond the primary term, we are entitled to hold the lease for as long as oil or natural gas is produced.

Many of the leases and concessions comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the acreage has been established prior to such date, in which event the lease or concession will remain in effect until the cessation of production. The following table sets forth, as of December 31, 2018, the expiration periods of the gross and net acres that are subject to leases or concessions summarized in the above table of undeveloped acreage.

	Undeveloped Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2019	320	50
December 31, 2020	650	81
December 31, 2021	—	—
December 31, 2022	—	—
December 31, 2023 and later	—	—
Total	970	131

Title to Properties

Title to properties is subject to royalty, overriding royalty, carried working, net profits, working and other similar interests and contractual arrangements customary in the gas and oil industry, liens for current taxes not yet due and other encumbrances. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than preliminary review of local records).

Investigation, including a title opinion of local counsel, generally is made before commencement of drilling operations.

Marketing

At December 31, 2018, we had no contractual agreements to sell our gas and oil production and all production was sold on spot markets.

Employees

As of December 31, 2018, we had 2 full-time employees and no part time employees. The employees are not covered by a collective bargaining agreement, and we do not anticipate that any of our future employees will be covered by such agreements.

Competition

We encounter intense competition from other oil and gas companies in all areas of our operations, including the acquisition of producing properties and undeveloped acreage. Our competitors include major integrated oil and gas companies, numerous independent oil and gas companies and individuals. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources and have been engaged in the oil and gas business for a much longer time than our Company. These companies may be able to pay more for productive oil and gas properties, exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Regulatory Matters

Regulation of Oil and Gas Production, Sales and Transportation

The oil and gas industry is subject to regulation by numerous national, state and local governmental agencies and departments. Compliance with these regulations is often difficult and costly and noncompliance could result in substantial penalties and risks. Most jurisdictions in which we operate also have statutes, rules, regulations or guidelines governing the conservation of natural resources, including the unitization or pooling of oil and gas properties, minimum well spacing, plugging and abandonment of wells and the establishment of maximum rates of production from oil and gas wells. Some jurisdictions also require the filing of drilling and operating permits, bonds and reports. The failure to comply with these statutes, rules and regulations could result in the imposition of fines and penalties and the suspension or cessation of operations in affected areas.

Environmental Regulation

Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect our exploration, development and production operations and the costs of those operations. These laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the discharge and disposition of generated waste materials and waste management, the reclamation and abandonment of wells, sites and facilities, financial assurance and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to our U.S. operations include, among others, the following United States federal laws and regulations:

Clean Air Act, and its amendments, which govern air emissions;

Clean Water Act, which governs discharges into waters of the United States;

Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as “Superfund”);

Resource Conservation and Recovery Act, which governs the management of solid waste;

Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;

Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;

Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and

U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

Colombia has similar laws and regulations designed to protect the environment.

We routinely obtain permits for our facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations.

The ultimate financial impact of these environmental laws and regulations is neither clearly known nor easily determined as new standards are enacted and new interpretations of existing standards are rendered. Environmental laws and regulations are expected to have an increasing impact on our operations. In addition, any non-compliance with such laws could subject us to material administrative, civil or criminal penalties, or other liabilities. Potential permitting costs are variable and directly associated with the type of facility and its geographic location. Costs, for example, may be incurred for air emission permits, spill contingency requirements, and discharge or injection permits. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

Although we do not operate the properties in which we hold interests, noncompliance with applicable environmental laws and regulations by the operators of our oil and gas properties could expose us, and our properties, to potential costs and liabilities associated with such environmental laws. While we exercise no oversight with respect to any of our operators, we believe that each of our operators is committed to environmental protection and compliance. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Hydraulic Fracturing Regulation

Hydraulic fracturing, or “fracking”, is a common practice used to stimulate production of oil and natural gas from tight formations, including shales. Fracking involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore.

Except as applies to federal lands, fracking generally is exempt from regulation under many federal environmental rules and is generally regulated at the state level.

For example, in Texas, the Texas Railroad Commission administers regulations related to oil and gas operations, including regulations pertaining to protection of water resources in connection with those operations. The Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit after February 1, 2012. This law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

There has been increasing public controversy regarding fracking with regard to the use of fracking fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause operators to incur substantial compliance costs, and compliance or the consequences of any failure to comply could have a material adverse effect on well operations and economics.

We do not operate wells but contract well operations to third party operators. Operators of our wells may perform fracking operations, or contract third parties to perform such operations, on wells in which we participate. Many newer wells would not be economical without the use of fracking to stimulate production from the well. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Climate Change Legislation and Greenhouse Gas Regulation

Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects the emission of "greenhouse gases" may have on the environment and climate worldwide. These effects are widely referred to as "climate change." Since its December 2009 endangerment finding regarding the emission of greenhouse gases, the Environmental Protection Agency (the "EPA") has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its "tailoring rule" in May 2010 that determines which stationary sources of greenhouse gases are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In November 2010, the EPA also finalized its greenhouse gas reporting requirements, beginning in March 2012, for certain oil and gas production facilities.

Moreover, in recent past the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases. Under past proposals, the EPA would issue or sell a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of such legislation, if ever adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states have adopted, or are in the process of adopting, similar cap-and-trade programs.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

Web Site Access to Reports

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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 ability to operate profitably and our financial condition are highly dependent on energy prices. A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Global economic growth drives demand for energy from all sources, including fossil fuels. Should the U.S. and global economies experience weakness, demand for energy may decline. Similarly, should growth in global energy production outstrip demand, excess supplies may arise. Declines in demand and excess supplies may result in accompanying declines in commodity prices and deterioration of our financial position along with our ability to operate profitably and our ability to obtain financing to support operations. With respect to our business, beginning in the second half of 2014 and continuing through 2016, declines in demand thought to be associated with slowing economic growth in certain markets coupled with new oil and gas supplies coming on line in recent years resulted in oil and gas supply exceeding global demand which, in turn, resulted in a steep decline in prices of oil and natural gas. As a result, our average realized prices for oil and natural gas declined 44% and 33%, respectively, from 2014 to 2015 and 28% and 24%, respectively, from 2015 to 2016. While oil and natural gas prices have rebounded from 2016 levels, energy prices remain well below 2014 levels and there can be no assurance that a reoccurrence of price weakness will not arise in the future.

Past declines in prices reduced, and any declines that may occur in the future can be expected to reduce, our revenues and profitability as well as the value of our reserves. Such declines adversely affect well and reserve economics and may reduce the amount of oil and natural gas that we can produce economically, resulting in deferral or cancellation of planned drilling and related activities until such time, if ever, as economic conditions improve sufficiently to support such operations. Any extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read “Reserve estimates depend on many assumptions that may turn out to be inaccurate” (below) for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

Cost overruns, curtailments, delays and cancellations of operations as a result of the above factors and other factors common in our industry may materially adversely affect our operating results and financial position and our ability to maintain our interests in prospects.

We have experienced recurring operating losses and may be unable to support operations and future capital commitments without additional capital, the sale of assets or other measures.

As a result of continuing operating losses, unless we are able to grow production through drilling, acquisitions or otherwise, we may not be able to support our operations and future capital commitments and may require additional capital, or may be required to take additional measures, to support operations and future capital commitments over the next year. Our estimated drilling budget for 2019 is $325,000, principally relating to the preparation for drilling, drilling, fracturing and completion of a second well in Yoakum County, Texas expected to commence in second half of 2019. Additionally, we expect the operator of our Reeves County acreage to drill an additional well during 2019, although no proposal in that regard has been provided and no budget has been set should such well be drilled. Our actual drilling budget can vary substantially based on the timing and results of drilling operations as well as determinations to participate in the drilling and development of prospects. If an additional well is drilled in Reeves County during 2019, we do not believe that our existing financial resources will be adequate to support our share of such cost. If our financial resources are not adequate to support ongoing operations and/or drilling of additional wells, we may be required to seek additional capital, to divest certain assets, to curtail certain expenditures and/or to forego participation in drilling of additional wells which may result in the partial or complete loss of our interest in prospects. We have no commitments to provide additional financing and there is no guarantee that we will be able to secure additional financing on acceptable terms, or at all, if needed to support our ongoing operations and our 2019 drilling budget.

Our oil and gas holdings and operations are concentrated, and we are dependent upon the results of drilling and production operations on a small number of prospects and wells; in particular, our Permian Basin holdings and wells. If those properties and wells perform below expectations, we may experience production, revenues and profitability below expectations.

At December 31, 2018, we owned interests in 565 net acres and 0.52 net wells in the United States and our drilling plans for the foreseeable future are focused exclusively on our Permian Basis acreage where we drilled two initial wells in 2017 and one well in early 2019. Our Permian Basin wells accounted for 91% of our total production volumes during 2018. Our production, revenues and profitability for the foreseeable future are expected to be highly dependent upon the results of existing and future wells we may drill in the Permian Basis. In order grow our revenues and improve profitability, we must continue to drill productive wells. If existing wells, or future wells we may drill, in the Permian Basin perform below expectations, we may experience flat or declining production and revenues and may be unable to attain profitability.

We may be unable to make attractive acquisitions and any acquisitions may be subject to substantial risks that could adversely affects our business.

Acquisitions of additional mineral acreage at favorable prices is part of our strategy to increase and diversify our holdings and grow our production and revenues. We expect to focus our acquisition efforts in the Permian Basin with an emphasis on acquiring smaller "stranded" acreage positions at favorable prices. Competition for mineral acreage in the Permian Basin is intense. Other operators, particularly large operators, have historically paid substantially higher prices for Permian Basin acreage than we have paid. There can be no assurance that we will be able to successfully acquire additional acreage in the Permian Basin or elsewhere at favorable prices or at all. Even if we are successful in acquiring additional acreage on favorable terms, it is possible that such acreage (i) will be more speculative than higher priced acreage, (ii) may face challenges or limitations in drilling and operations such as lack of, or limited access to, critical infrastructure, due to the "stranded" nature of such acreage, or (iii) may prove uneconomical.

Our ability to acquire additional mineral acreage and to drill and develop our existing acreage as well as other acreage that may be acquired is subject to availability of financing on satisfactory terms.

Our financial resources are limited and may not be adequate to conduct additional drilling operations on our acreage or to consummate any meaningful acquisition. Our share of well costs on our initial two wells, which varies depending on our working interest in the tracts comprising our Reeves County acreage, averaged approximately $1.6 million per well. While we continually learn from our prior operations and look to continually bring down costs, for each additional well on which we plan to participate, we may be required to secure financing to support our share of such costs.

We may continue to seek to access the capital markets to support planned drilling operations or acquisitions through sales of common stock, preferred stock or other securities or may seek debt financing to support such capital requirements. We do not presently have any commitments to provide equity or debt financing to support any future drilling operations or acquisitions and there can be no assurance that such financing will be available if and when needed on acceptable terms or at all. If we are unable to fund our share of drilling and completion costs of future wells on our Permian Basin acreage, we may experience flat and declining production and revenues and decreased profitability and may be subject to penalties with respect to our interest in our Permian Basin acreage.

Our Permian Basin operations involve use of horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations in the Permian Basin involve utilizing some of the latest drilling and completion techniques as developed by our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- The ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Drilling in emerging areas is more uncertain than drilling in areas that are more developed and have a longer history of established drilling operations. New discoveries and emerging formations have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are worse than anticipated, the return on investment for a particular project may not be as attractive as anticipated and we may recognize noncash impairment charges to reduce the carrying value of our unproved properties in those areas.

We are dependent upon third party operators of our oil and gas properties.

Under the terms of the operating agreements related to our oil and gas properties, third parties act as the operator of each of our oil and gas wells and control the drilling and operating activities to be conducted on our properties. Therefore, we have limited control over certain decisions related to activities on our properties, which could affect our results of operations. Decisions over which we have limited control include:

- the timing and amount of capital expenditures;
- the timing of initiating the drilling and recompleting of wells;
- the extent of operating costs; and
- the level of ongoing production.

Decisions made by our operators may be different than those we would make reflecting priorities different than our priorities and may materially adversely affect our operating results and financial position.

During 2018, the original operator of our Reeves County acreage sold its interest in the acreage and the acquirer of that interest assumed operatorship of the acreage. The new operator of the acreage has not as yet provided a plan to develop our Reeves County acreage. Our ability to realize production, revenues and value from our Reeves County acreage is dependent upon, among other things, the new operator’s presentation of, and execution on, an acceptable development plan. If the new operator does not present and execute on a plan to develop our Reeves County acreage, we may incur falling production and revenues and a decline in value of our acreage.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel, water disposal and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget and operate profitably.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations. If the price of oil and natural gas increases, the demand for production equipment and personnel will likely also increase, potentially resulting, at least in the near-term, in shortages of equipment and personnel. In addition, larger producers may be more likely to secure access to such equipment by virtue of offering drilling companies more lucrative terms. In particular, high levels of horizontal drilling and hydraulic fracturing operations in the Permian Basin have created increased demand, and higher costs, for associated drilling and completion services, water supply, handling and disposal and access to production handling and transportation infrastructure, each of which have resulted in higher than anticipated prices with respect to our initial Reeves County wells. If we are unable to acquire access to such resources, or can obtain access only at higher prices, not only would this potentially delay our ability to convert our reserves into cash flow but could also significantly increase the cost of producing those reserves, thereby negatively impacting anticipated net income.

We may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation and refining facilities to market our oil and gas production; we rely on a limited number of purchasers of our products.

The marketing of oil and gas production depends in large part on the availability, proximity and capacity of pipelines and storage facilities, gathering systems and other transportation, processing, fractionation and refining facilities, as well as the existence of adequate markets. If there were insufficient capacity available on these systems, if these systems were unavailable to us, or if access to these systems were to become commercially unreasonable, the price offered for our production could be significantly depressed, or we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while we construct our own facility or await the availability of third party facilities. We rely on facilities developed and owned by third parties in order to store, process, transport, fractionate and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transportation, storage or processing and fractionation facilities to us, especially in areas of planned expansion where such facilities do not currently exist.

For example, as a result of the absence of gathering systems to handle production from our initial Reeves County wells, production was deferred, or associated gas flared pending construction of gathering systems and associated infrastructure serving the relevant leases. The amount of oil and gas that can be produced is subject to limitations in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. Curtailments arising from these and similar circumstances may last from a few days to several months, resulting in lost or curtailed production and revenues.

We may operate in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. This may be particularly true with respect to our Colombian acreage where infrastructure is limited or, in some cases, non-existent. Such restrictions on our ability to sell our oil or natural gas could have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

To the extent that we enter into transportation contracts with pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with FERC’s regulations and policies or with an interstate pipeline’s tariff could result in the imposition of civil and criminal penalties.

A limited number of companies purchase a majority of our production. The loss of a significant purchaser could have a material adverse effect on our ability to sell production.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

A substantial percentage of our properties are unproven and undeveloped; therefore, the cost of proving and developing our properties and risk associated with our success is greater than would be the case if the majority of our properties were categorized as proved developed producing.

Because a substantial percentage of our properties are unproven and/or undeveloped, we require significant capital to prove and develop such properties before they may become productive. Because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be successfully drilled and developed to the extent that they result in positive cash flow. Even if we are successful in our drilling and development efforts, it could take several years for a significant portion of our unproven properties to be converted to positive cash flow.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our prospects are properties on which we have identified what we believe, based on available seismic and geological information, to be indications of oil or natural gas potential. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

We may incur substantial uninsured losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of a significant accident or other event that is not fully covered by insurance could have a material adverse effect on our business, results of operations or financial condition.

Our divestiture strategy exposes us to risks associated with a lack of diversification and a concentration of properties, increased dependence on a small number of properties, large variances in production and profitability and disproportionate risk of loss associated with drilling results and operations of one or a small number of properties.

Because a significant element of our strategy has been the opportunistic divestiture of properties and redeployment of resources to new properties, we have historically been focused on development of a small number of geographically concentrated prospects. Accordingly, we lack diversification with respect to the nature and geographic location of our holdings. As a result, we are exposed to higher dependence on individual resource plays, have experience large fluctuations in cash flows and profitability as a result of such divestitures and may experience substantial losses should a single individual prospect prove unsuccessful. Absent other operating properties, the failure or underperformance of a single prospect could materially adversely affect our financial resources, reserve and production outlook and profitability.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties, potentially negatively impacting the trading value of our securities.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we wrote down the carrying value of our oil and natural gas properties during 2016 and 2015 and may be required to further write down the carrying value of oil and gas properties in the future. A write-down would constitute a non-cash charge to earnings. It is likely the cumulative effect of a write-down could also negatively impact the trading price of our securities.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex, requiring interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves reported.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development activities, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves, as reported from time to time, should not be assumed to be the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on costs on the date of the estimate and average prices over the preceding twelve months. Actual future prices and costs may differ materially from those used in the present value estimate. If future prices decline or costs increase it could negatively impact our ability to finance operations, and individual properties could cease being commercially viable, affecting our decision to continue operations on producing properties or to attempt to develop properties. All of these factors would have a negative impact on earnings and net income, and most likely the trading price of our securities.

Our operations in Colombia are subject to uncertainty, delays and other risks relating to political and economic instability.

We currently have interests in multiple oil and gas concessions in Colombia and anticipate that operations in Colombia may constitute a substantial element of our strategy going forward.

The political climate in Colombia is unstable and could be subject to radical change over a very short period of time. While each of our past and current oil and gas concessions in Colombia have been granted by the federal government, we have experienced multiple extended delays in obtaining necessary permits to commence drilling operations on our current concessions. The delays in obtaining necessary permits have been attributed to numerous factors beyond our control but not uncommon in Colombia, including strong local opposition to drilling operations based on environmental and other concerns. In the face of such opposition, our operator has shelved any near term drilling on our current concessions and is pursuing discussions with the federal government and local governments to determine if there are any viable options to drill those concessions or if acceptable arrangements can be made to compensate for the inability to drill and develop the concessions. Unless we are able to secure necessary permits or to secure substitute concessions, we may be forced to abandon or suspend our operations in Colombia and record a loss of our entire investment in our current concessions.

Armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups—both funded by the drug trade—has persisted in Colombia for more than 40 years with insurgents attacking civilians and violent guerilla activity continues in many parts of the country. During 2016, the government and the insurgents announced a peace accord to end hostilities. The peace accord was, however, rejected in a popular referendum. While the parties have expressed a continuing commitment to the peace process, until such process is finalized, any operations we may conduct in Colombia, and any assets we may hold in Colombia, may continue to be subject to risk associated with guerilla activity that may disrupt operations and result in losses from operations and of assets. There can also be no assurance that we can maintain the safety of our operations and personnel in Colombia or that this violence will not affect our operations in the future. Continued or heightened security concerns in Colombia could also result in a significant loss to us.

Where the local political climate and/or guerilla activity in an area threaten our ability to secure necessary support of the local populace or necessary permits to operate, or our ability to assure the safety of our personnel and/or assets, we have, in the past delayed, and may in the future delay, the commencement of operations on prospects until such concerns are satisfactorily resolved. While our operator works diligently with local and federal officials to overcome such uncertainties and obstacles, there can be no assurance that conditions in the vicinity of our planned operations will ever support exploration and/or development operations with respect to one or multiple prospects. Even though we have conducted successful operations on multiple prospects in Colombia, our current prospects continue to be characterized by political risks and, in fact, our operator has on more than one occasion delayed planned operations on prospects due to such political risks with such delays extending, in some cases, for multiple years. In the event of continued, or future, delays in operations on prospects arising from political risks, we may experience financial loss associated with our cost of holding prospects, the incurrence of costs associated with addressing political risks or the loss of value associated with our inability to explore and develop potentially valuable prospects.

Additionally, Colombia is among several nations whose eligibility to receive foreign aid from the United States is dependent on its progress in stemming the production and transit of illegal drugs, which is subject to an annual review by the President of the United States. Although Colombia is currently eligible for such aid, Colombia may not remain eligible in the future. A finding by the President that Colombia has failed demonstrably to meet its obligations under international counter-narcotics agreements may result in the loss of certain financial aid and the imposition of trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with key governmental agencies and the Colombian government’s ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets. Accordingly, the imposition of the foregoing economic and trade sanctions on Colombia would likely result in a substantial loss and a decrease in the price of our common stock.

Our operations in Colombia are controlled by operators which may carry out transactions affecting our Colombian assets and operations without our consent.

Our operations in Colombia are subject to a substantial degree of control by the operators of the properties in which we hold interests in Colombia. We are an investor in a number of properties operated by Hupecol and our interest in the assets and operations of Hupecol related entities and ventures represent all of our current assets in Colombia. During 2008, 2010 and 2012, respectively, Hupecol sold its interest in multiple concessions and entities holding multiple concessions each representing, at the time, the largest prospect(s) in terms of reserves and revenues in which we then held an interest. In early March 2009, Hupecol determined to temporarily shut-in production from our Colombian properties. It is possible that Hupecol will carry out similar sales or acquisitions of prospects or make similar decisions in the future. Our management intends to closely monitor the nature and progress of future transactions by Hupecol in order to protect our interests. However, we have no effective ability to alter or prevent a transaction and are unable to predict whether or not any such transactions will in fact occur or the nature or timing of any such transaction.

We may be exposed to additional expenses and losses arising from the financial position of our joint interest partners in Colombia.

Our Colombian properties are developed under financial arrangements with various joint interest partners. If other joint interest partners are unable, or unwilling, to satisfy their various obligations relating to prospects, we may be required to pay a proportionately higher share of development costs on those prospects or the prospect may be inadequately capitalized to achieve optimal results.

We may be exposed to substantial fines and penalties if we or our partners fail to comply with laws and regulations associated with our activities in foreign countries, including Colombia, regarding U.S. laws such as the Foreign Corrupt Practices Act and local laws prohibiting corrupt payments to governmental officials and other corrupt practices.

Third parties act as the operator of each of our oil and gas wells and control all drilling and operating activities conducted with respect to our Colombian properties. Therefore, we have limited control over decisions related to activities on our properties, and we cannot provide assurance that our partners or their employees, contractors or agents will not take actions in violation of applicable anti-corruption laws and regulations. In the course of conducting business in Colombia, we have relied primarily on the representations and warranties made by our operating and non-operating partners in the farmout and joint operating agreements which govern our respective project interests to the effect that:

- each party has not and will not offer or make payments to any person, including a government official, that would violate the laws of the country of operations, the country of formation of any of the partners or the principals described in the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions; and

- each party will maintain adequate internal controls, properly record and report all transactions and comply with the laws applicable to the transaction.

While we periodically inquire as to the continuing accuracy of these representations, as a minority non-operator, we are limited in our ability to assure compliance. Consequently, we cannot provide assurance that the procedural safeguards, if any, adopted by our partners or the representations and warranties contained in these agreements and our reliance on them will protect us from liability should a violation occur. Any violations of the anti-bribery, accounting controls or books and records provisions of the Foreign Corrupt Practices Act by us or our partners could subject us and, where deemed appropriate, individuals, in certain cases, to a broad range of civil and criminal penalties, including but not limited to, imprisonment, injunctive relief, disgorgement, substantial fines or penalties, prohibitions on our ability to offer our products in one or more countries, imposed modifications to business practices and compliance programs, including retention of an independent monitor to oversee compliance, and could also materially damage our reputation, our business and our operating results.

Our operations will be subject to environmental and other government laws and regulations that are costly and could potentially subject us to substantial liabilities.

Crude oil and natural gas exploration and production operations in the United States and in Colombia are subject to extensive federal, state and local laws and regulations. Oil and gas companies are subject to laws and regulations addressing, among others, land use and lease permit restrictions, bonding and other financial assurance related to drilling and production activities, spacing of wells, unitization and pooling of properties, environmental and safety matters, plugging and abandonment of wells and associated infrastructure after production has ceased, operational reporting and taxation. Failure to comply with such laws and regulations can subject us to governmental sanctions, such as fines and penalties, as well as potential liability for personal injuries and property and natural resources damages. We may be required to make significant expenditures to comply with the requirements of these laws and regulations, and future laws or regulations, or any adverse change in the interpretation of existing laws and regulations, could increase such compliance costs. Regulatory requirements and restrictions could also delay or curtail our operations and could have a significant impact on our financial condition or results of operations.

Our oil and gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from operations.

Failure to comply with these laws and regulations may result in:

- the imposition of administrative, civil and/or criminal penalties;
- incurring investigatory or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to be in compliance in all material respects with all applicable environmental laws and regulations, we cannot assure you that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability.

We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations.

In addition, many countries as well as several states and regions of the U.S. have agreed to regulate emissions of “greenhouse gases.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning of natural gas and oil, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for some of our services or products in the future.

Increased regulation, or limitations on the use, of hydraulic fracturing could increase our cost of operations and reduce profitability.

Our existing Permian Basin wells have been hydraulically fractured and future wells that we may drill in the Permian Basin are expected to be economically viable only if hydraulic fracturing is utilized to increase flows of oil and natural gas, particularly in shale formations. The use of hydraulic fracturing has been the subject of much scrutiny and debate in recent years with many activists and state and federal legislators and regulators actively pushing for most stringent regulation of such operations or even the ban of such operations.

In the event that state or federal regulation of hydraulic fracturing is increased or hydraulic fracturing is substantially curtailed or prohibited through law or regulation, our cost of drilling and operating wells may increase substantially. In some cases, increased costs associated with increased regulation of hydraulic fracturing, or the prohibition of hydraulic fracturing, may result in wells being uneconomical to drill and operate that would otherwise be economical to drill and operate in the absence of such regulations or prohibitions. Should wells be determined to be uneconomical as a result of increasing regulation of hydraulic fracturing, we may be required to write-down or abandon oil and gas properties that are determined to be uneconomical to drill and develop. Additionally, potential litigation arising from alleged harm resulting from hydraulic fracturing may materially adversely affect our financial results and position regardless of whether we prevail on the merits of such litigation.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Our success depends on our staff, which is small in size and limited in technical capabilities, and third party consultants, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to attract and retain key staff members. Our staff is extremely small in size and possesses limited technical capabilities. We do not presently maintain any significant internal technical capabilities but rely on the engineering, geological and other technical skills of our board and, from time to time, third party consultants. If members of our staff should resign or we are unable to attract the necessary personnel, our business operations could be adversely affected.

The price of our common stock may fluctuate significantly, and this may make it difficult to resell common stock when, or at prices, desired.

The price of our common stock constantly changes. We expect that the market price of our common stock will continue to fluctuate.

Our stock price may fluctuate as a result of a variety of factors, many of which are beyond our control. These factors include:

- quarterly variations in our operating results;
- operating results that vary from the expectations of management, securities analysts and investors;

changes in expectations as to our future financial performance;

announcements by us, our partners or our competitors of leasing and drilling activities;

the operating and securities price performance of other companies that investors believe are comparable to us;

future sales of our equity or equity-related securities;

changes in general conditions in our industry and in the economy, the financial markets and the domestic or international political situation;

fluctuations in oil and gas prices;

departures of key personnel; and

regulatory considerations.

The stock market periodically experiences extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons often unrelated to their operating performance. These broad market fluctuations may adversely affect our stock price, regardless of our operating results.

The sale of a substantial number of shares of our common stock may affect our stock price.

We expect to require additional capital to support our future drilling plans and may issue additional shares of our common stock or equity-related securities to secure such capital. Future sales of substantial amounts of our common stock or equity-related securities in the public market or privately, or the perception that such sales could occur, could adversely affect prevailing trading prices of our common stock and could impair our ability to raise capital through future offerings of equity or equity-related securities. No prediction can be made as to the effect, if any, that future sales of shares of common stock or the availability of shares of common stock for future sale will have on the trading price of our common stock.

Our charter and bylaws, as well as provisions of Delaware law, could make it difficult for a third party to acquire our company and also could limit the price that investors are willing to pay in the future for shares of our common stock.

Delaware corporate law and our charter and bylaws contain provisions that could delay, deter or prevent a change in control of our Company or our management. These provisions could also discourage proxy contests and make it more difficult for our stockholders to elect directors and take other corporate actions without the concurrence of our management or board of directors. These provisions:

- authorize our board of directors to issue "blank check" preferred stock, which is preferred stock that can be created and issued by our board of directors, without stockholder approval, with rights senior to those of our common stock;
- provide for a staggered board of directors and three-year terms for directors, so that no more than one-third of our directors could be replaced at any annual meeting;
- provide that directors may be removed only for cause; and
- establish advance notice requirements for submitting nominations for election to the board of directors and for proposing matters that can be acted upon by stockholders at a meeting.

We are also subject to anti-takeover provisions under Delaware law, which could also delay or prevent a change of control. Taken together, these provisions of our charter, bylaws, and Delaware law may discourage transactions that otherwise could provide for the payment of a premium over prevailing market prices of our common stock and also could limit the price that investors are willing to pay in the future for shares of our common stock.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

We currently lease approximately 4,739 square feet of office space in Houston, Texas as our executive offices. Management anticipates that our space will be sufficient for the foreseeable future. The average monthly rental under the lease, which expires on October 31, 2022, is approximately $11,000. A description of our interests in oil and gas properties is included in "Item 1. Business."

Item 3. Legal Proceedings

We may from time to time be a party to lawsuits incidental to our business. As of March 15, 2019, we were not aware of any current, pending or threatened litigation or proceedings that could have a material adverse effect on our results of operations, cash flows or financial condition.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock is listed on the NYSE American under the symbol “HUSA.”

Holders

As of March 15, 2019, there were approximately 876 shareholders of record of our common stock.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2018 with respect to the shares of our common stock that may be issued under our existing equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [1]	4,078,674	$ 0.77	4,291,667
Equity compensation plans not approved by security holders	—	—	—

4,078,674	$	0.77	4,291,667

(1) Consists of shares (a) reserved for issuance pursuant to outstanding options granted and (b) shares remaining available for future issuance; under the Houston American Energy Corp. 2008 Equity Incentive Plan and the Houston American Energy Corp. 2017 Equity Incentive Plan.

Item 6. Selected Financial Data

Not applicable.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

We are an independent energy company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil properties with principal holdings in the U.S. Permian Basin and additional holdings in the U.S. Gulf Coast region and in the South American country of Colombia.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Our strategy is to focus on early identification of, and opportunistic entrance into, existing and emerging resource plays. We do not operate wells but typically seek to partner with larger operators in development of resources or retain interests, with or without contribution on our part, in prospects identified, packaged and promoted to larger operators. By entering these plays earlier, identifying stranded blocks and partnering with, or promoting to, larger operators, we believe we can capture larger resource potential at lower cost and minimize our exposure to drilling risks and costs and ongoing operating costs.

We, along with our partners, actively manage our resources through opportunistic acquisitions and divestitures where reserves can be identified, developed, monetized and financial resources redeployed with the objective of growing reserves, production and shareholder value.

Generally, we generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil, whether through royalty interests, working interests or other arrangements. We may also realize gains and additional cash flows from the periodic divestiture of assets.

Recent Developments

Permian Basin Acreage Leasing

In 2017, we acquired a 25% working interest, subject to a proportionate 5% back-in after prospect payout, in two lease blocks (the Johnson and O'Brien leases), covering 717.25 gross acres, in Reeves County, Texas. The acreage lay in the Delaware Basin region of the larger Permian Basin.

In conjunction with planned drilling and development of the O'Brien tract, and in order to optimize the length of planned horizontal leg and anticipated recoveries, we entered into a pooling arrangement pursuant to which the owner of adjoining acreage block contributed a portion of that acreage to the contract area covering by the O'Brien tract. As a result, our effective gross acreage in Reeves County increased to 960 acres and our average working interest across the acreage was reduced to 18.7%.

In 2018, we acquired a 12.5% working interest, subject to a proportionate 10% back-in after payout, in an approximately 650-acre lease block in Yoakum County, Texas. The acreage lay in the Midland Basin region of the larger Permian Basin.

Louisiana Acreage Lease/Royalty Interest

We hold a 23.437% mineral interest in 2,485 gross acres in East Baton Rouge Parish, Louisiana. Out of that acreage, in 2018, we leased to an operator/lessee 743.94 acres. Under the terms of that lease, we received a lease bonus totaling $113,335 and a royalty of 22.5% gross, entitling us to a 5.27% net interest in all production from the acreage free of operating costs, other than production and ad valorem taxes.

The operator/lessee has indicated that it plans to drill an initial well to test the Lower Tuscaloosa Formation below 19,000 feet.

Drilling and Related Activity

During 2017, our drilling activities were focused solely on our Reeves County acreage were we successfully drilled and completed our first two wells, consisting of:

- Johnson State #1H well, a horizontally drilled (4,510' horizontal leg) hydraulically fractured well in the Wolfcamp A formation; and

- O'Brien #3H well, a horizontally drilled (4,575' horizontal leg) hydraulically fractured well in the Wolfcamp A formation.

Gathering systems and related infrastructure were constructed to serve both the Johnson and O'Brien blocks. Production and sales infrastructure were completed, and commercial oil and natural gas sales from the initial wells, commenced during the fourth quarter of 2017.

In 2018, the operator of our Reeves County acreage sold its interest in the acreage and the buyer assumed operatorship of the acreage. Pending development of a drilling plan by the new operator, and pending construction of supporting infrastructure by third parties, no drilling operations were conducted during 2018. We anticipate that the new operator will present a drilling plan and, subject to our approval of the same and our ability to finance our share of related costs, that we will resume drilling operations in Reeves County during 2019.

In late 2018, pre-drilling operations commenced on our Yoakum County acreage. In January 2019, we began drilling the Frost #1H well, our first well on our Yoakum County acreage, and reached total depth of approximately 10,000 feet, including an approximately 4,800-foot horizontal leg. Casing on the well has been set, construction of production facilities commenced and fracturing of the well is anticipated to commence in the second quarter of 2019.

Financing Activities

In order to support operations and finance acquisition of our Yoakum County acreage, we raised an aggregate of $747,205 of capital during 2018 from the sale of 2,433,903 shares of common stock in our "at-the-market" offering.

Employment Arrangements

During 2018, our board determined to terminate the services of John Boylan as Chairman, CEO and President. A member of our board is serving as interim CEO and President, and our board has commenced a search for a replacement CEO and President.

Recovery of Escrow Account

In 2010, we, and our operator in Colombia, Hupecol, sold our interests in two entities in Colombia. Pursuant to the terms of those sales, a portion of the sales price was escrowed to secure certain representations of the selling parties. Our share of amounts escrowed was recorded as escrow receivables.

In 2016, we recorded an allowance in the amount of $262,016 relating to the undisbursed balance of escrow receivables.

In 2018, we received payments totaling $86,553, net, representing recoveries of escrowed funds relating to the previously written-off escrow receivables. As a result of the receipt of such funds, we recorded non-recurring other income in the amount of $86,553 in 2018.

Critical Accounting Policies

The following describes the critical accounting policies used in reporting our financial condition and results of operations. In some cases, accounting standards allow more than one alternative accounting method for reporting. Such is the case with accounting for oil and gas activities described below. In those cases, our reported results of operations would be different should we employ an alternative accounting method.

Full Cost Method of Accounting for Oil and Gas Activities. We follow the full cost method of accounting for oil and gas property acquisition, exploration and development activities. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisition, geological and geophysical work, delay rentals, costs of drilling, completing and equipping successful and unsuccessful oil and gas wells and related internal costs that can be directly identified with acquisition, exploration and development activities, but does not include any cost related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized unless significant amounts of oil and gas reserves are involved. No corporate overhead has been capitalized as of December 31, 2018. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves, are amortized on a units-of-production method over the estimated productive life of the reserves. Unevaluated oil and gas properties are excluded from this calculation. The capitalized oil and gas property costs, less accumulated amortization, are limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, calculated using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) and a discount factor of 10%; (b) the cost of unproved and unevaluated properties excluded from the costs being amortized; (c) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (d) related income tax effects. Costs in excess of this ceiling are charged to proved properties impairment expense.

Revenue recognition. On January 1, 2018, we adopted the new revenue guidance using the modified retrospective method for contracts that were not complete at December 31, 2017. ASU 2014-09, *"Revenue from Contracts with Customers (Topic 606)"*, supersedes the revenue recognition requirements and industry-specific guidance under *Revenue Recognition (Topic 605)*. Topic 606 requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. We adopted Topic 606 on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. Under the modified retrospective method, prior period financial positions and results are not adjusted. The cumulative effect adjustment recognized in the opening balances included no significant changes as a result of this adoption. While our 2018 net earnings were not materially impacted by revenue recognition timing changes, Topic 606 requires certain changes to the presentation of revenues and related expenses beginning January 1, 2018.

Our revenue is comprised principally of revenue from exploration and production activities. Our oil is sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers. Payment is generally received from the customer in the month following delivery.

Contracts with customers have varying terms, including spot sales or month-to-month contracts, contracts with a finite term, and life-of-field contracts where all production from a well or group of wells is sold to one or more customers. The Company recognizes sales revenues for oil, natural gas, and NGLs based on the amount of each product sold to a customer when control transfers to the customer. Generally, control transfers at the time of delivery to the customer at a pipeline interconnect, the tailgate of a processing facility, or as a tanker lifting is completed. Revenue is measured based on the contract price, which may be index-based or fixed, and may include adjustments for market differentials and downstream costs incurred by the customer, including gathering, transportation, and fuel costs.

Revenues are recognized for the sale of the Company's net share of production volumes.

Unevaluated Oil and Gas Properties. Unevaluated oil and gas properties consist principally of our cost of acquiring and evaluating undeveloped leases, net of an allowance for impairment and transfers to depletable oil and gas properties. When leases are developed, expire or are abandoned, the related costs are transferred from unevaluated oil and gas properties to oil and gas properties subject to amortization. Additionally, we review the carrying costs of unevaluated oil and gas properties for the purpose of determining probable future lease expirations and abandonments, and prospective discounted future economic benefit attributable to the leases.

Unevaluated oil and gas properties not subject to amortization include the following at December 31, 2018 and 2017:

	At December 31, 2018	At December 31, 2017
Acquisition costs	$141,318	$141,318
Evaluation costs	2,315,181	2,168,023
Total	$2,456,499	$2,309,341

The carrying value of unevaluated oil and gas prospects includes $2,321,170 and $2,309,341 expended for properties in South America at December 31, 2018 and 2017, respectively. We are maintaining our interest in these properties.

Stock-Based Compensation. We use the Black-Scholes option-pricing model, which requires the input of highly subjective assumptions. These assumptions include estimating the volatility of our common stock price over the expected life of the options, dividend yield, an appropriate risk-free interest rate and the number of options that will ultimately not complete their vesting requirements. Changes in the subjective assumptions can materially affect the estimated fair value of stock-based compensation and consequently, the related amount recognized on the Statements of Operations.

Results of Operations

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Oil and Gas Revenues. Total oil and gas revenues increased 256% to $2,243,325 in 2018 from $630,392 in 2017. The increase in revenues was attributable to a combination of higher production and an increase in average prices realized from oil and gas sales.

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2018 and 2017:

	2018	2017
Gross producing wells	5	10
Net producing wells	0.52	0.98
Net oil production (Bbls)	23,842	10,038
Net gas production (Mcf)	253,053	30,997
Oil—Average sales price per barrel	$57.43	$50.81
Gas—Average sales price per mcf	$3.27	$3.88

The increase in production reflects the commencement of production from our Johnson #1H and O'Brien #3H wells during the fourth quarter of 2017. The decline in well count reflects the termination of operation of certain marginal wells.

The change in average sales prices realized reflects fluctuations in global commodity prices. Realized prices stabilized and began increasing in late 2016 and continuing through mid-2018 with some moderation in prices late in 2018 and into 2019.

Oil, gas and natural gas liquids sales revenues for 2018 and 2017 by region were as follows:

	Colombia	U.S.	Total
2018			
Oil sales	$ —	$1,416,946	$1,416,946
Gas sales	$ —	$663,389	$663,389
Natural gas liquids sales	$ —	$162,987	$162,987
2017			
Oil sales	$ —	$510,006	$510,006
Gas sales	$ —	$120,386	$120,386
Natural gas liquids sales	$ —	$—	$—

Lease Bonus Revenue. During 2018, lease bonus revenue totaled $113,335 as compared to $0 in 2017. Lease bonus revenue related to a non-recurring lease to a third party operator of a mineral interest held by the Company is Louisiana.

Lease Operating Expenses. Lease operating expenses, excluding joint venture expenses relating to our Colombian operations discussed below, increased 322% to $914,269 in 2018 from $216,429 in 2017.

The increase in lease operating expenses was attributable to the commencement of production from our first two Reeves County wells, the resumption of production from a well that had been offline and increased salt water disposal fees.

Following is a summary comparison of lease operating expenses for the periods.

	Colombia	U.S.	Total
2018	$ —	$914,269	$914,269
2017	$ —	$216,429	$216,429

Consistent with our business model and operating history, we experienced steep declines in lease operating expenses in 2017 following strategic divestitures and anticipate lease operating expenses to continue to ramp up to levels consistent with regional costs as new wells are brought on line. With the commencement of production in Reeves County and additional drilling in Yoakum County and expected in Reeves County, lease operating expenses in the U.S. and overall, are expected to increase in 2019, partially offset by expected savings in transportation costs associated with the completion of an adjacent salt water disposal well, which is expected to come on line by early April 2019.

Depreciation and Depletion Expense. Depreciation and depletion expense increased by 122% to $357,822 in 2018 from $161,489 in 2017. The increase in depreciation and depletion during 2018 was due to investments in, and commencement of production from, our initial Reeves County wells late in 2017. Depreciation and depletion are expected to increase in 2019 as a result of investment in our Yoakum and Reeves County drilling program and increased production expected to result from the same.

General and Administrative Expenses. General and administrative expense decreased by 33% to $1,422,560 in 2018 from $2,128,667 in 2017. The change in general and administrative expense was primarily attributable to (i) a reduction in legal fees compared to 2017 when we were significantly more active in acquisition and financing activities, and (ii) a reduction in compensation expense following the termination of our chief executive officer.

Other Income (Expense). Other income/expense, net, totaled $86,655 of income during 2018 as compared to $161,421 of expense during 2017. Other income during 2018 consisted of $102 of interest income and $86,553 of other income arising from the recovery of escrowed funds previously written-off. Other expense, net, during 2017 consisted of $171,605 of interest expense with respect to the Bridge Loan Notes, including $12,871 of cash interest expense, $30,000 of amortization of debt discount arising from the sale of the Bridge Loan Notes at a discount to face amount and $128,734 of deemed value of the Bridge Loan Warrants issued in conjunction with the Bridge Loan Notes; partially offset by interest earned on cash balances and one-time lease participation fee of $10,000 received during 2017.

Financial Condition

Liquidity and Capital Resources. At December 31, 2018, we had a cash balance of $755,702 and working capital of $895,366 compared to a cash balance of $392,062 and working capital of $591,703 at December 31, 2017.

Cash Flows. Operating activities provided cash of $360,792 during 2018, compared $1,716,847 of cash used during 2017. The change in cash used in operations was primarily attributable to the $1,786,278 decrease in net loss in 2018 compared to 2017 which improvement was attributable to the commencement of production in late 2017 from our Reeves County wells.

Investing activities used cash of $505,407 during 2018, compared to $4,412,456 of cash used during 2017. The decrease in cash used in investing activities reflects lower investments in acreage ($135,329 in 2018 attributable to Yoakum County acreage compared to $1,043,977 in 2017 attributable to Reeves County acreage) and lower investments in drilling operations ($390,216 in 2018 compared to $3,368,479 in 2017 to drill, complete and construct infrastructure for the two initial Reeves County wells). 2018 investing activities reflect a credit of $131,864 attributable to cash advances previously reflected as development costs on the Reeves County acreage.

Financing activities provided cash of $508,255 during 2018, compared $6,040,193 of cash provided during 2017. During 2018, cash provided by financing activities consisted of sales of common in our 2017 “at-the-market” offering, or ATM Offering, $747,205 partially offset by dividend distributions on outstanding preferred stock ($238,950). During 2017, cash provided by financing activities consisted of sales of common stock under our ATM Offering ($4,101,013), Series A Preferred Stock ($1,200,000), Series B Preferred and Series B Warrants ($909,600), and Bridge Loan Notes and Bridge Loan Warrants ($570,000), partially offset by the payment of dividends on preferred stock ($140,420) and repayment of Bridge Loan Notes ($600,000).

Long-Term Liabilities. At December 31, 2018, we had long-term liabilities of $82,719 as compared to $84,903 at December 31, 2017. Long-term liabilities, as of December 31, 2018, consisted of a reserve for plugging costs of

$38,754 and deferred rent of $43,965.

Capital and Exploration Expenditures and Commitments. Our principal capital and exploration expenditures relate to ongoing efforts to acquire, drill and complete prospects, in particular our Reeves County and Yoakum County acreage. Our principal capital and exploration expenditures during 2019 are expected to relate to drilling additional wells on our Reeves County acreage, drilling an initial well on our Yoakum County acreage and possibly opportunistic acquisitions of additional acreage in the Permian Basin. The actual timing and number of wells drilled during 2019 will be principally controlled by the operators of our Reeves County and Yoakum County acreage, based on a number of factors, including but not limited to availability of financing, performance of existing wells on the subject acreage, energy prices and industry condition and outlook, costs of drilling and completion services and equipment and other factors beyond our control or that of our operators.

During 2018, we invested $405,510, net, for the acquisition and development of oil and gas properties, consisting of (1) cost of acquisition of U.S. properties ($135,329), attributable to acreage acquired in Yoakum County, Texas, (2) pre-drilling preparation costs ($144,989) relating to our Yoakum County acreage, (3) preparation and evaluation costs in Colombia ($11,829), and (4) other development and acquisition costs related to our US oil and gas properties ($245,227); offset by a credit of $131,864 attributable to cash advances previously reflected as development costs on our Reeves County acreage. Of the amount invested, we capitalized $147,158 to oil and gas properties not subject to amortization and reduced net costs capitalized to oil and gas properties subject to amortization by $99,470. Capital investments during 2018 were curtailed pending proposals of new drilling operations from the operators of our Reeves County and Yoakum County acreage.

As our allocable share of well costs will vary depending on the timing and number of wells drilled as well as our working interest in each such well and the level of participation of other interest owners, we have not established a drilling budget but will budget on a well-by-well basis as our operators propose wells. With the completion of sales lines and other infrastructure serving our Reeves County acreage and experience gained from drilling our initial wells, we anticipate that costs to drill and bring future wells onto production will decrease, and delays in bringing production on line will be minimized or eliminated, as compared to our experience in bringing our initial wells onto production.

We have incurred continuing losses since 2011, including a loss of approximately $251,000 for the year ended December 31, 2018. However, during 2018, we raised, net of offering costs, approximately $747,000 in our ATM offering, and have substantially reduced our general and administrative costs, increased revenues, and generated approximately $361,000 from our operating activities, thereby mitigating going concern considerations. Further, as of December 31, 2018, we have a cash balance of approximately $756,000 and working capital of approximately $895,000.

Our principal capital and exploration expenditures during 2019 are expected to relate to drilling an additional well on our Yoakum County lease and, possibly, on our Reeves County acreage. The operator in Yoakum County has committed to drill a second well during 2019 at an approximate cost to us of $325,000. We believe that we have the ability to fund our cost for such a well from cash on hand. The new operator of our Reeves County wells has not yet communicated definitive plans to drill an additional well on that acreage in 2019. If they proceed with drilling plan for an additional well, we may require additional capital to participate in the drilling of that well. We believe that we has sufficient cash on hand to fund our expected drilling operations and our operations for the twelve months following the issuance of these financial statements.

Given the ongoing delays in our operator’s proposing new wells in Reeves County, we continue to actively seek opportunities to acquire additional acreage or other strategic transactions with a view to adding scale to our operations.

In order to fund our estimated drilling and completion costs of additional wells in Reeves County, our costs of any new acquisition or other strategic transactions, and possibly our costs of drilling and completion of additional Yoakum County wells, we expect that we will be required to raise additional capital. In the event that we do require additional capital to fund our share of costs for drilling wells during 2019, we expect that we would seek additional capital from one or more sources of additional sales of shares in its ATM Offering and private sales of equity and debt securities.

While we may, among other efforts, seek additional funding from “at-the-market” sales of common stock, and private sales of equity and debt securities, we presently have no commitments to provide additional funding, and there can be no assurance that we can secure the necessary capital to fund our share of drilling, acquisition or other costs on acceptable terms or at all. If, for any reason, we are unable to fund our share of drilling and completion costs and fail to satisfy commitments relative to our interest in our acreage, we may be subject to penalties or to the possible loss of some of our rights and interests in prospects with respect to which we fail to satisfy funding commitments and we may be required to curtail operations and forego opportunities.

Contractual Obligations. At December 31, 2018, our only material contractual obligation requiring determinable future payments on our part was our lease relating to our executive offices.

The following table details our contractual obligations as of December 31, 2018:

	Payments due by period				
	Total	< 1 year	1-3 years	3-5 years	> 5 years
Operating leases	$504,703	$128,348	$376,355	$ —	$ —
Total	$504,703	$128,348	$376,355	$ —	$ —

In addition to the contractual obligations requiring that we make fixed payments, in conjunction with our efforts to secure oil and gas prospects, financing and services, we have, from time to time, granted overriding royalty interests (“ORRI”) in various properties, and may grant ORRIs in the future, pursuant to which we will be obligated to pay a portion of our interest in revenues from various prospects to third parties. Our Reeves County and Yoakum County acreage are subject to a ORRI’s ranging from 1% to 2%, in aggregate, in favor of current and former employees and officers. All present and future prospects in Colombia are subject to a 1.5% ORRI in favor of each of a current employee and a former director.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2018.

Inflation

We believe that inflation has not had a significant impact on our operations since inception.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for production depends on numerous factors beyond our control.

We have not historically entered into any hedges or other derivative commodity instruments or transactions designed to manage, or limit exposure to oil and gas price volatility.

Item 8. Financial Statements and Supplementary Data

Our financial statements appear immediately after the signature page of this report. See "Index to Financial Statements" on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive who also serves as our principal financial officer, we conducted an evaluation as of December 31, 2018 of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer concluded that our disclosure controls and procedures were not effective as of December 31, 2018.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of management, including our principal executive officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the 2013 framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework, management concluded that our internal control over financial reporting was not effective as of December 31, 2018. Such conclusion reflects our interim chief executive officer's assumption of duties of the principal financial officer and the resulting lack of segregation of duties. Until we are able to remedy this material weakness, we are relying on third party consultants to assist with financial reporting.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit smaller reporting companies to provide only management's report in this annual report.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fourth quarter of 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Executive Officers

Our executive officers as of December 31, 2018, and their ages and positions as of that date, are as follows:

Name	Age	Position
James Schoonover	62	Interim President and Interim Chief Executive Officer

James Schoonover has served as our Interim President and Interim CEO since June 2018 and as a director since April 2018. Mr. Schoonover has, since 2016, served as Chief Operating Officer of Encompass Compliance Corporation, an OTC Market traded company providing compliance and risk mitigation services to U.S. employers. Previously, from February 2014 to July 2015, Mr. Schoonover served as National Sales Director for Cordant Health Services, a consolidator of independent toxicology laboratories, and, from 1998 to December 2012, as Chief Marketing Officer of MedTox Scientific, Inc., a Nasdaq-listed provider of specialized laboratory testing services and on-site/point-of-collection testing devices. From 2012 to 2017, Mr. Schoonover served as Chairman of the Board of H2O For Life, a non-profit organization focused on service-learning opportunities for students. Mr. Schoonover holds a B.A. degree from Cornell University and an MBA from the University of St. Thomas.

There are no family relationships among the executive officers and directors. Except as otherwise provided in employment agreements, each of the executive officers serves at the discretion of the Board.

Item 11. Executive Compensation

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Equity compensation plan information is set forth in Part II, Item 5 of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

1. Financial statements. See "Index to Financial Statements" on page F-1.
2. Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date	Number	Filed Herewith
1.1	At-the-Market Issuance Sales Agreement, dated July 10, 2017, by and between Houston American Energy Corp. and WestPark Capital, Inc.	8-K	07/11/17	1.1	
1.2	At-the-Market Issuance Sales Agreement, dated October 5, 2018, by and between Houston American Energy Corp. and WestPark Capital, Inc.	8-K	10/05/18	1.1	
3.1	Certificate of Incorporation of Houston American Energy Corp. filed April 2, 2001	SB-2	08/03/01	3.1	
3.2	Amended and Restated Bylaws of Houston American Energy Corp. adopted November 26, 2007	8-K	11/29/07	3.1	
3.3	Certificate of Amendment to the Certificate of Incorporation of Houston American Energy Corp. filed September 25, 2001	SB-2	10/01/01	3.4	
4.1	Text of Common Stock Certificate of Houston American Energy Corp.	SB-2	08/03/01	4.1	
4.2	Certificate of Designations of 12.0% Series A Convertible Preferred Stock	8-K	02/02/17	4.1	
4.3	Certificate of Designations of 12.0% Series B Convertible Preferred Stock	8-K	05/08/17	4.1	
10.1	Form of Securities Purchase Agreement, dated January 31, 2017, relating to the sale of shares of 12.0% Series A Convertible Preferred Stock	8-K	02/02/17	10.1	
10.2	Form of Securities Purchase Agreement, dated May 3, 2017, relating to the sale of shares of 12.0% Series B Convertible Preferred Stock and Warrants	8-K	05/08/17	10.2	

10.3	Form of Warrant, dated May 3, 1017	8-K	05/08/17	10.1
10.4	Form of Bridge Loan Agreement	8-K	06/28/17	10.1
10.5	Form of Bridge Loan Note	8-K	06/28/17	10.2
10.6	Form of Warrant	8-K	06/28/17	10.3
10.7	Participation Agreement, dated January 4, 2017, with Founders Oil and Gas III, LLC	8-K	01/05/17	10.1
10.8	Houston American Energy Corp. 2008 Equity Incentive Plan*	Sch 14A	04/28/08	Ex A
10.9	Houston American Energy Corp. 2017 Equity Incentive Plan*	Sch 14A	07/24/17	Ex A

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date	Number	Filed Herewith
10.10	Form of Change in Control Agreement, dated June 11, 2012*	8-K	06/14/12	10.1	
10.11	Production Incentive Compensation Plan*	10-Q	08/14/13	10.1	
14.1	Code of Ethics for CEO and Senior Financial Officers	10-KSB	03/26/04	14.1	
23.1	Consent of Marcum, LLP				X
23.2	Consent of Lonquist & Co., LLC				X
23.3	Consent of Russell K. Hall & Associates, Inc.				X
23.4	Consent of GBH CPAs, PC				X
31.1	Section 302 Certification of CEO and CFO				X
32.1	Section 906 Certification of CEO and CFO				X
99.1	Code of Business Ethics	8-K	07/07/06	99.1	
99.2	Report of Lonquist & Co., LLC				X
99.3	Report of Russell K. Hall & Associates, Inc.				X

*Compensatory plan or arrangement.

Item 16. Form 10-K Summary

Not applicable

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SIGNATURES

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

Dated: April 1, 2019	HOUSTON AMERICAN ENERGY CORP.
	By: ***/s/ James Schoonover*** **James Schoonover**
	Interim President

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

Signature	**Title**	**Date**
/s/ James Schoonover **James Schoonover**	Interim Chief Executive Officer, Interim President and Director (Principal Executive Officer and Principal Financial Officer)	April 1, 2019
/s/ Stephen Hartzell **Stephen Hartzell**	Director	April 1, 2019
/s/ Keith Grimes **Keith Grimes**	Director	April 1, 2019

HOUSTON AMERICAN ENERGY CORP.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of

Houston American Energy Corp.

Houston, TX

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Houston American Energy Corp. (the "Company") as of December 31, 2018, the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Marcum llp

Marcum llp

We have served as the Company's auditor since 2010.

Houston, Texas
April 1, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of

Houston American Energy Corp.

Houston, TX

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Houston American Energy Corp. (the "Company") as of December 31, 2017, the related consolidated statements of operations, stockholders' equity, and cash flows for the year then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for each of the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ GBH CPAs, PC

We served as the Company’s auditor from 2010 to 2018.

GBH CPAs, PC
www.gbhcpas.com
Houston, Texas
March 30, 2018

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2018	2017
ASSETS		
CURRENT ASSETS		
Cash	$755,702	$392,062
Accounts receivable – oil and gas sales	136,042	347,548
Prepaid expenses and other current assets	66,381	3,750
TOTAL CURRENT ASSETS	958,125	743,360
PROPERTY AND EQUIPMENT		
Oil and gas properties, full cost method		
Costs subject to amortization	60,397,878	60,139,526
Costs not being amortized	2,456,499	2,309,341
Office equipment	90,004	90,004
Total	62,944,381	62,538,871
Accumulated depletion, depreciation, amortization, and impairment	(56,082,902)	(55,725,080)
PROPERTY AND EQUIPMENT, NET	6,861,479	6,813,791
Other assets	3,167	3,167
TOTAL ASSETS	$7,822,771	$7,560,318
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$61,826	$127,036
Accrued expenses	933	24,621
TOTAL CURRENT LIABILITIES	62,759	151,657
LONG-TERM LIABILITIES		
Reserve for plugging and abandonment costs	38,754	35,658
Deferred rent obligation	43,965	49,245
TOTAL LONG-TERM LIABILITIES	82,719	84,903
TOTAL LIABILITIES	145,478	236,560
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Preferred stock, par value $ 0.001; 10,000,000 shares authorized	1	1

Series A Convertible Redeemable Preferred Stock, Par value $ 0.001; 2,000 shares authorized; 1,085 and 1,175 shares issued and outstanding, respectively; liquidation preference of $ 1,085,000		
Series B Convertible Redeemable Preferred Stock, Par value $ 0.001; 1,000 shares authorized; 835 and 895 shares issued and outstanding, respectively; liquidation preference of $ 835,000	1	1
Common stock, par value $ 0.001; 150,000,000 shares authorized 62,425,140 and 59,260,101 shares issued	62,425	59,260
Additional paid-in capital	73,084,009	72,482,303
Accumulated deficit	(65,469,143)	(65,217,807)
TOTAL SHAREHOLDERS' EQUITY	7,677,293	7,323,758
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$7,822,771	$7,560,318

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

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HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

	2018			2017		
REVENUES						
Oil and gas revenue	$	2,243,325		$	630,392	
Lease bonus revenue		113,335			—	
Total operating revenue		2,356,660			630,392	
EXPENSES OF OPERATIONS						
Lease operating expense and severance tax		914,269			216,429	
General and administrative expense		1,422,560			2,128,667	
Depreciation and depletion		357,822			161,489	
Total operating expenses		2,694,651			2,506,585	
Loss from operations		(337,991	)		(1,876,193	)
OTHER INCOME (EXPENSE)						
Interest income		102			184	
Other income		86,553			10,000	
Interest expense		—			(171,605	)
Total other income (expense), net		86,655			(161,421	)
Loss before taxes		(251,336	)		(2,037,614	)
Income tax expense (benefit)		—			—	
Net loss		(251,336	)		(2,037,614	)
Dividends to Series A and B Preferred shareholders		(238,950	)		(140,232	)

Net loss attributable to common shareholders	$	(490,286	)	$	(2,177,846	)
Basic and diluted net loss per common share outstanding	$	(0.01	)	$	(0.04	)
Basic and diluted weighted average number of common shares outstanding		60,616,220			53,879,606	

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

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2018 and 2017

	Preferred Stock		Common Stock		Additional Paid-in	Treasury Stock		Earnings	Retained
	Shares	Amount	Shares	Amount	Capital	Shares	Amount	(Deficit)	Total
Balance at December 31, 2016	—	$—	52,169,945	$52,170	$66,158,912	892,557	$(174,125)	$(63,180,193)	$2,856,445
Issuance of common shares for cash, net	—	—	7,817,157	7,818	4,093,195	—	—	—	4,101,013
Issuance of Series A and Series B Preferred Stock for cash	2,109.6	2	—	—	2,109,598	—	—	—	2,109,600
Conversion of Series A and Series B Preferred Stock to common stock	(39.6)	—	165,556	165	(165)	—	—	—	—
Stock-based compensation	—	—	—	—	306,000	—	—	—	306,000
Retirement of treasury shares	—	—	(892,557)	(893)	(173,232)	(892,557)	174,125	—	—
Series A and Series B Preferred Stock dividends paid	—	—	—	—	(140,232)	—	—	—	(140,232)
Debt discount from issuance of warrants as debt inducement	—	—	—	—	128,734	—	—	—	128,734
Net loss	—	—	—	—	—	—	—	(2,037,614)	(2,037,614)
	2,070	2	59,260,101	59,260	72,482,303	—	—	(65,217,807)	7,323,758

Balance at December 31, 2017									
Issuance of common stock for cash, net	—	—	2,433,993	2,434	744,771	—	—	—	747,205
Conversion of Series A and Series B Preferred Stock to common stock	(150)	—	616,667	617	(617)	—	—	—	—
Cashless exercise of options	—	—	114,379	114	(114)	—	—	—	—
Stock-based compensation	—	—	—	—	96,616	—	—	—	96,616
Series A and Series B Preferred Stock dividends paid	—	—	—	—	(238,950)	—	—	—	(238,950)
Net loss	—	—	—	—	—	—	—	(251,336)	(251,336)
Balance at December 31, 2018	1,920	$2	62,425,140	$62,425	$73,084,009	$—	$—	$(65,469,143)	$7,677,293

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

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

	2018	2017
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	$(251,336)	$(2,037,614)
Adjustments to reconcile net loss to net cash used in operations		
Depreciation and depletion	357,822	161,489
Accretion of plugging and abandonment costs	3,096	2,214
Stock-based compensation	96,616	306,000
Amortization of debt discount	—	158,734
Change in operating assets and liabilities:		
(Increase)/decrease in accounts receivable	211,506	(347,548)
Increase in prepaid expense and other current assets	(62,631)	—
Increase/(decrease) in accounts payable and accrued expenses	10,999	(9,367)
Increase/(decrease) in deferred rent obligation	(5,280)	49,245
Net cash provided by (used in) operating activities	360,792	(1,716,847)
CASH FLOW FROM INVESTING ACTIVITIES		
Payments for the acquisition and development of oil and gas properties	(505,407)	(4,412,456)
Net cash used in investing activities	(505,407)	(4,412,456)
CASH FLOW FROM FINANCING ACTIVITIES		
Proceeds from issuance of notes payable, net of debt discount	—	570,000
Payments on notes payable	—	(600,000)
Proceeds from issuance of Series A Preferred Stock	—	1,200,000
Proceeds from issuance of Series B Preferred Stock	—	909,600
Proceeds from issuance of common stock for cash, net of offering costs	747,205	4,101,013
Payment of preferred stock dividends	(238,950)	(140,420)
Net cash provided by financing activities	508,255	6,040,193
INCREASE (DECREASE) IN CASH	363,640	(89,110)
Cash, beginning of year	392,062	481,172
Cash, end of year	$755,702	$392,062
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid	$—	$12,871
Taxes paid	$—	$—

SUPPLEMENTAL NON-CASH INVESTING AND FINANCING ACTIVITIES		
Change in accrued oil and gas development costs	$99,897	$99,897
Debt discount from issuance of warrants as debt inducement	$—	$128,734
Increase in reserve for plugging and abandonment costs	$—	$6,000
Conversion of Series A and Series B Preferred Stock to common stock	$617	$165
Cashless exercise of options	$114	$—
Retirement of treasury shares	$—	$174,125

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

HOUSTON AMERICAN ENERGY CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—NATURE OF COMPANY AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Houston American Energy Corp. (a Delaware Corporation) ("the Company" or "HUSA") was incorporated in 2001. The Company is engaged, as a non-operating joint owner, in the exploration, development, and production of natural gas, crude oil, and condensate from properties. The Company's principal properties are in the Texas Permian Basin with additional holdings in Gulf Coast areas of the United States and international holdings in Colombia, South America.

Consolidation

The accompanying consolidated financial statements include all accounts of HUSA and its subsidiaries (HAEC Louisiana E&P, Inc., HAEC Oklahoma E&P, Inc. and HAEC Caddo Lake E&P, Inc.). All significant inter-company balances and transactions have been eliminated in consolidation.

***Liquidity and Capital Requirements*.**

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business for the twelve-month period following the issuance date of these consolidated financial statements. The Company has incurred continuing losses since 2011, including a loss of approximately $251,000 for the year ended December 31, 2018. However, during 2018, the Company raised, net of offering costs, approximately $747,000 in its ATM offering, and has substantially reduced its general and administrative costs, increased revenues, and generated approximately $361,000 from its operating activities, thereby mitigating going concern considerations. Further, as of December 31, 2018, the Company had a cash balance of approximately $756,000 and working capital of approximately $895,000.

The Company’s principal capital and exploration expenditures during 2019 are expected to relate to drilling an additional well on its Yoakum County lease and, possibly, on its Reeves County acreage. The operator in Yoakum County has committed to drill a second well during 2019 at an approximate cost to the Company of $325,000. The Company believes that it has the ability to fund its cost for such a well from cash on hand. The new operator of the Company’s Reeves County wells has not yet communicated definitive plans to drill an additional well on that acreage in 2019. If they proceed with drilling plan for an additional well, the Company may require additional capital to participate in the drilling of that well. The Company believes that it has sufficient cash on hand to fund its expected drilling operations and its operations for the twelve months following the issuance of these financial statements.

In the event that the Company requires additional capital to fund its share of costs for drilling wells during 2019, the Company expects that it would seek additional capital from one or more sources of additional sales of shares in its ATM Offering and private sales of equity and debt securities. However there can be no assurance that the Company can secure the necessary capital to fund its share of drilling, acquisition or other costs on acceptable terms or at all. If, for any reason, the Company is unable to fund its share of drilling and completion costs, it would forego participation in one or more of such wells. In such event, the Company may be subject to penalties or to the possible loss of some of its rights and interests in prospects with respect to which it fails to satisfy funding obligations and it may be required to curtail operations and forego opportunities.

General Principles and Use of Estimates

The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. In preparing financial statements, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews its estimates, including those related to such potential matters as litigation, environmental liabilities, income taxes, and determination of proved reserves of oil and gas and asset retirement obligations. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Reclassification

Certain amounts for prior periods have been reclassified to conform to the current presentation.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and cash investments with initial maturity dates of less than three months when purchased. As of December 31, 2018 and 2017, the Company had no cash equivalents outstanding.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash, cash equivalents and marketable securities (if any). The Company had cash deposits of $292,649 in excess of the FDIC’s current insured limit of $250,000 at December 31, 2018 for interest bearing accounts. The Company also had cash deposits of $26,964 in Colombian banks at December 31, 2018 that are not insured by the FDIC. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Revenue Recognition

ASU 2014-09, *“Revenue from Contracts with Customers (Topic 606)”*, supersedes the revenue recognition requirements and industry-specific guidance under *Revenue Recognition (Topic 605)*. Topic 606 requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company adopted Topic 606 on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. Under the modified retrospective method, prior period financial positions and results are not adjusted. The cumulative effect adjustment recognized in the opening balances included no significant changes as a result of this adoption. While the Company’s 2018 net earnings were not materially impacted by revenue recognition timing changes, Topic 606 requires certain changes to the presentation of revenues and related expenses beginning January 1, 2018. Refer to Note 2 – Revenue from Contracts with Customers for additional information.

The Company's revenue is comprised principally of revenue from exploration and production activities. The Company's oil is sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers. Payment is generally received from the customer in the month following delivery.

Contracts with customers have varying terms, including spot sales or month-to-month contracts, contracts with a finite term, and life-of-field contracts where all production from a well or group of wells is sold to one or more customers. The Company recognizes sales revenues for oil, natural gas, and NGLs based on the amount of each product sold to a customer when control transfers to the customer. Generally, control transfers at the time of delivery to the customer at a pipeline interconnect, the tailgate of a processing facility, or as a tanker lifting is completed. Revenue is measured based on the contract price, which may be index-based or fixed, and may include adjustments for market differentials and downstream costs incurred by the customer, including gathering, transportation, and fuel costs.

Revenues are recognized for the sale of the Company's net share of production volumes.

Loss per Share

Basic loss per share is computed by dividing net loss available to common shareholders by the weighted average common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted in common shares that then shared in the earnings of the Company. In periods in which the Company reports a net loss, dilutive securities are excluded from the calculation of diluted net loss per share amounts as the effect would be anti-dilutive.

For the years ended December 31, 2018 and 2017, the following convertible preferred stock and warrants and options to purchase shares of common stock were excluded from the computation of diluted net loss per share, as the inclusion of such shares would be anti-dilutive:

	Year Ended December 31,	
	2018	2017
Series A Convertible Preferred Stock	5,425,000	5,875,000
Series B Convertible Preferred Stock	2,320,556	2,487,222
Stock warrants	12,500	3,651,680
Stock options	4,978,832	6,012,165
Totals	12,736,888	18,026,067

Accounts Receivable

Accounts receivable – other and escrow receivables have been evaluated for collectability and are recorded at their net realizable values.

Allowance for Accounts Receivable

The Company regularly reviews outstanding receivables and provides for estimated losses through an allowance for doubtful accounts when necessary. In evaluating the need for an allowance, the Company makes judgments regarding its customers' ability to make required payments, economic events and other factors. As the financial condition of these parties change, circumstances develop or additional information becomes available, an allowance for doubtful accounts may be required. When the Company determines that a customer may not be able to make required payments, the Company increases the allowance through a charge to income in the period in which that determination is made. As of December 31, 2018, the Company evaluated their receivables and determined that no allowance was necessary.

Oil and Gas Properties

The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. Capitalized costs include lease acquisition, geological and geophysical work, delay rentals, costs of drilling, completing and equipping the wells and any internal costs that are directly related to acquisition, exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Proceeds from the sale or other disposition of oil and gas properties are generally treated as a reduction in the capitalized costs of oil and gas properties, unless the impact of such a reduction would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The Company categorizes its full cost pools as costs subject to amortization and costs not being amortized. The sum of net capitalized costs subject to amortization, including estimated future development and abandonment costs, are amortized using the unit-of-production method. Depletion and amortization for oil and gas properties was $357,822 and $161,378 for the years ended December 31, 2018 and 2017, respectively and accumulated amortization, depreciation and impairment was $55,992,898 and $55,635,076 at December 31, 2018 and 2017, respectively.

Costs Excluded

Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties. The Company excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the costs subject to amortization.

Ceiling Test

Under the full cost method of accounting, a ceiling test is performed each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X. The ceiling test determines a limit, on a country-by-country basis, on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion, amortization and impairment *("DD&A")* and the related deferred income taxes, may not exceed the estimated future net cash flows from proved oil and gas reserves, calculated for 2018 using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) with consideration of price change only to the extent provided by contractual arrangement, discounted at 10%, net of related tax effects. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional accumulated DD&A. During 2018 and 2017, the Company recorded no impairments of oil and gas properties.

Furniture and Equipment

Office equipment is stated at original cost and is depreciated on the straight-line basis over the useful life of the assets, which ranges from three to five years.

Depreciation expense for office equipment was $0 and $111 for 2018 and 2017, respectively, and accumulated depreciation was $90,004 and $90,004 at December 31, 2018 and 2017, respectively.

Asset Retirement Obligations

For the Company, asset retirement obligations ("ARO") represent the systematic, monthly accretion and depreciation of future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, an adjustment is made to the full cost pool, with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. Although the Company's domestic policy with respect to ARO is to assign depleted wells to a salvager for the assumption of abandonment obligations before the wells have reached their economic limits, the Company has estimated its future ARO obligation with respect to its domestic operations. The ARO assets, which are carried on the balance sheet as part of the full cost pool, have been included in our amortization base for the purposes of calculating depreciation, depletion and amortization expense. For the purposes of calculating the ceiling test, the future cash outflows associated with settling the ARO liability have been included in the computation of the discounted present value of estimated future net revenues. Asset retirement obligations are classified as Level 3 (unobservable inputs) fair value measurements.

Joint Venture Expense

Joint venture expense reflects the indirect field operating and regional administrative expenses billed by the operator of the Colombian concessions.

Income Taxes

Deferred income taxes are provided on a liability method whereby deferred tax assets and liabilities are established for the difference between the financial reporting and income tax basis of assets and liabilities as well as operating loss and tax credit carry forwards. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

Stock-Based Compensation

The Company measures the cost of employee services received in exchange for stock and stock options based on the grant date fair value of the awards. The Company determines the fair value of stock option grants using the Black-Scholes option pricing model. The Company determines the fair value of shares of non-vested stock based on the last quoted price of our stock on the date of the share grant. The fair value determined represents the cost for the award and is recognized over the vesting period during which an employee is required to provide service in exchange for the award. As stock-based compensation expense is recognized based on awards ultimately expected to vest, the Company reduces the expense for estimated forfeitures based on historical forfeiture rates. Previously recognized compensation costs may be adjusted to reflect the actual forfeiture rate for the entire award at the end of the vesting period. Excess tax benefits, if any, are recognized as an addition to paid-in capital.

Concentration of Risk

As a non-operator oil and gas exploration and production company, and through its interest in a limited liability company (“Hupecol”) and concessions operated by Hupecol in the South American country of Colombia, the Company is dependent on the personnel, management and resources of the operators of its various properties to operate efficiently and effectively.

As a non-operating joint interest owner, the Company has a right of investment refusal on specific projects and the right to examine and contest its division of costs and revenues determined by the operator.

The Company’s Permian Basin, Texas properties accounted for all of the Company’s drilling operations and substantially all of its oil and gas investments in 2018 and 2017. In the event of a significant negative change in operations or operating outlook pertaining to the Company’s Permian Basin properties, the Company may be forced to abandon or suspend such operations, which abandonment or suspension could be materially harmful to the Company.

Additionally, the Company currently has interests in concessions in Colombia and expects to be active in Colombia for the foreseeable future. The political climate in Colombia is unstable and could be subject to radical change over a very short period of time. In the event of a significant negative change in political and economic stability in the vicinity of the Company's Colombian operations, the Company may be forced to abandon or suspend its efforts. Either of such events could be harmful to the Company's expected business prospects.

For 2018, our oil production from the Company's mineral interests was sold to U.S. oil marketing companies based on the highest bid. The gas production is sold to U.S. natural gas marketing companies based on the highest bid. No purchaser accounted for more than 10% of our oil and gas sales.

The Company reviews accounts receivable balances when circumstances indicate a balance may not be collectible. Based upon the Company's review, no allowance for uncollectible accounts was deemed necessary at December 31, 2018 and 2017, respectively.

Recent Accounting Developments

In February 2016, the FASB issued ASU 2016-02 (Topic 842) was issued by the FASB that creates new accounting and reporting guidelines for leasing arrangements. The new guidance requires organizations that lease assets to recognize assets and liabilities on the balance sheet related to the rights and obligations created by those leases, regardless of whether they are classified as finance or operating leases. Consistent with current guidance, the recognition, measurement and presentation of expenses and cash flows arising from a lease primarily will depend on its classification as a finance or operating lease. The guidance also requires new disclosures to help financial statement users better understand the amount, timing, and uncertainty of cash flows arising from leases. The new standard is effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period, with early application permitted. The new standard is to be applied using a modified retrospective approach. The Company is still in the process of evaluating the impact of this new standard; however, the Company believes the initial impact of adopting the standard will result in increases to its assets and liabilities on its consolidated balance sheets, and changes to the timing and presentation of certain operating expenses on its consolidated statements of operations.

In May 2017, the FASB issued ASU 2017-09, Compensation-Stock Compensation (Topic 718) Scope of Modification Accounting. The ASU clarifies which changes to the terms or conditions of a stock-based payment award require an entity to apply modification accounting in Topic 718. The standard is effective for the Company on January 1, 2018, with early adoption permitted. The impact of this new standard will depend on the extent and nature of future changes to the terms of Company's stock-based payment awards.

In August 2018, the FASB issued ASU 2018-13, “Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement”. The amendments in this update are to improve the effectiveness of disclosures in the notes to the financial statements by facilitating clear communication of the information required by GAAP that is most important to users of each entity’s financial statements. The amendments in this Update apply to all entities that are required, under existing GAAP, to make disclosures about recurring or nonrecurring fair value measurements. The amendments in this update are effective for all entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. The Company does not expect that this guidance will have a material impact on its consolidated financial statements.

In July 2018, the FASB issued ASU 2018-11, “Leases (Topic 842): Target Improvements”. The amendments in this Update also clarify which Topic (Topic 842 or Topic 606) applies for the combined component. Specifically, if the non-lease component or components associated with the lease component are the predominant component of the combined component, an entity should account for the combined component in accordance with Topic 606. Otherwise, the entity should account for the combined component as an operating lease in accordance with Topic 842. An entity that elects the lessor practical expedient also should provide certain disclosures. The Company is currently evaluating the adoption of this guidance and does not expect that this guidance will have a material impact on its consolidated financial statements. The Company has not adopted this Standard and will do so when specified by the FASB.

In July 2018, the FASB issued ASU 2018-10, "Codification Improvements to Topic 842, Leases". The amendments in this Update affect narrow aspects of the guidance issued in the amendments in Update 2016-02 as described in the table below. The amendments in this Update related to transition do not include amendments from proposed Accounting Standards Update, Leases (Topic 842): Targeted Improvements, specific to a new and optional transition method to adopt the new lease requirements in Update 2016-02. That additional transition method will be issued as part of a forthcoming and separate Update that will result in additional amendments to transition paragraphs included in this Update to conform with the additional transition method. The Company is currently evaluating the adoption of this guidance and does not expect that this guidance will have a material impact on its consolidated financial statements. The Company has not adopted this Standard and will do so when specified by the FASB.

In June 2018, the FASB issued ASU 2018-07, "Compensation—Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting". The amendments in this update are to maintain or improve the usefulness of the information provided to the users of financial statements while reducing cost and complexity in financial reporting. The areas for simplification in this Update involve several aspects of the accounting for nonemployee share-based payment transactions resulting from expanding the scope of Topic 718, to include share-based payment transactions for acquiring goods and services from nonemployees. Some of the areas for simplification apply only to nonpublic entities. The amendments in this update are effective for all entities for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Company does not expect that this guidance will have a material impact on its consolidated financial statements.

The Company does not expect the adoption of any recently issued accounting pronouncements to have a significant impact on its financial position, results of operations, or cash flows.

Subsequent Events

The Company evaluated subsequent events for disclosure from December 31, 2018 through the date the consolidated financial statements were issued.

NOTE 2 – REVENUE FROM CONTRACTS WITH CUSTOMERS

Change in Accounting Policy

The Company adopted ASU 2014-09, *"Revenue from Contracts with Customers (Topic 606)"*, on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. Refer to

Note 1 – Basis of Presentation and Significant Accounting Policies for additional information.

Exploration and Production

There were no significant changes to the timing or valuation of revenue recognized for sales of production from exploration and production activities.

Lease Bonus Revenue

There were no significant changes to the timing or valuation of revenue recognized for lease bonus revenue.

Disaggregation of Revenue from Contracts with Customers

The following table disaggregates revenue by significant product type for the years ended December 31, 2018 and 2017:

	Year Ended December 31,	
	2018	2017
Oil sales	$1,416,946	$510,006
Natural gas sales	663,389	118,504
Natural gas liquids sales	162,987	1,882
Lease bonus revenue	113,335	—
Total revenue from customers	$2,356,660	$630,392

There were no significant contract liabilities or transaction price allocations to any remaining performance obligations as of December 31, 2018 or 2017.

NOTE 3 – REVENUE FROM LEASE OF MINERAL INTERESTS

The Company holds a 23.437% mineral interest in 2,485 gross acres in East Baton Rouge Parish, Louisiana. Out of that acreage, in 2018, the Company leased to an operator/lessee 743.94 acres. Under the terms of that lease, the Company received a lease bonus totaling $113,335 and a royalty of 22.5% gross, entitling the Company to a 5.27% net interest in all production from the acreage free of operating costs, other than production and ad valorem taxes. The lease bonus received was recorded as lease bonus revenue on the statement of operations when the drilling did not commence under the terms of the lease.

NOTE 4—ESCROW RECEIVABLE

In 2010, the Company, and its operator in Colombia, Hupecol, sold its interests in two entities in Colombia. Pursuant to the terms of those sales, a portion of the sales price was escrowed to secure certain representations of the selling parties. The Company's share of amounts escrowed was recorded as escrow receivables.

In 2016, the Company recorded an allowance in the amount of $262,016 relating to the undisbursed balance of escrow receivables.

In October 2018, the Company received payments totaling $86,553 representing recoveries of escrowed funds related to the previously written-off escrow receivables. As a result of the receipt of such funds, the Company recorded non-recurring other income of $86,553 during 2018 on the statement of operations.

NOTE 5—OIL AND GAS PROPERTIES

Evaluated Oil and Gas Properties

Evaluated oil and gas properties subject to amortization at December 31, 2018 included the following:

	United States	South America	Total

Evaluated properties being amortized	$10,943,176	$49,454,702	$60,397,878
Accumulated depreciation, depletion, amortization and impairment	(6,538,196)	(49,454,702)	(55,992,898)
Net capitalized costs	$4,404,980	$—	$4,404,980

Evaluated oil and gas properties subject to amortization at December 31, 2017 included the following:

	United States	South America	Total
Evaluated properties being amortized	$10,684,824	$49,454,702	$60,139,526
Accumulated depreciation, depletion, amortization and impairment	(6,180,374)	(49,454,702)	(55,635,076)
Net capitalized costs	$4,504,450	$—	$4,504,450

Unevaluated Oil and Gas Properties

Unevaluated oil and gas properties not subject to amortization at December 31, 2018 included the following:

	United States	South America	Total
Leasehold acquisition costs	$—	$141,318	$141,318
Geological, geophysical, screening and evaluation costs	135,329	2,179,852	2,315,181
Total	$135,329	$2,321,170	$2,456,499

Unevaluated oil and gas properties not subject to amortization at December 31, 2017 included the following:

	United States	South America	Total
Leasehold acquisition costs	$ —	$141,318	$141,318
Geological, geophysical, screening and evaluation costs	—	2,168,023	2,168,023
Total	$ —	$2,309,341	$2,309,341

During 2018, the Company invested $405,510, net, for the acquisition and development of oil and gas properties consisting of (1) the cost of the acquisition of U.S. properties of $258,352, net, principally attributable to acreage acquired in Yoakum County, Texas, (2) preparation and evaluation costs of the Company's Permian Basin, Texas, acreage of $135,329, and (3) preparation and evaluation of costs in Colombia of $11,829. Of the amount invested, the Company capitalized $147,158 to oil and gas properties not subject to amortization and capitalized $258,352 to oil and gas properties subject to amortization.

NOTE 6—ASSET RETIREMENT OBLIGATIONS

The following table describes changes in our asset retirement liability ("ARO") during each of the years ended December 31, 2018 and 2017.

	2018	2017
ARO liability at January 1	$35,658	$27,444
Accretion expense	3,096	2,214
Obligations incurred for development of oil and gas properties	—	6,000
ARO liability at December 31	$38,754	$35,658

NOTE 7 – NOTES PAYABLE

In June 2017, the Company issued promissory notes (the "Bridge Loan Notes") in the principal amount of $600,000, with an original issue discount of 5%, and warrants (the "Bridge Loan Warrants") to purchase 600,000 shares of the Company's common stock. The aggregate consideration received by the Company for the Bridge Loan Notes and Warrants was $570,000.

The Bridge Loan Notes were unsecured obligations bearing interest at 12.0% per annum and payable interest only on the last day of each calendar month with any unpaid principal and accrued interest being payable in full on October 21, 2017.

The Bridge Loan Notes were subject to mandatory prepayment from and to the extent of (i) 100% of net proceeds received by the Company from any sales, for cash, of equity or debt securities (other than Bridge Loan Notes) of the Company, (ii) 100% of net proceeds received by the Company from the sale of assets (other than sales in the ordinary course of business); and (iii) 75% of net proceeds received from the sale of oil and gas produced from the Company's

Reeves County, Texas properties. Additionally, the Company had the option to prepay the Bridge Loan Notes, at its sole election, without penalty.

The Bridge Loan Notes were recorded net of debt discount in the amount of $158,734. The debt discount consists of (i) $30,000 excess in the face amount of the Bridge Loan Notes over the consideration paid plus (ii) the value of the Bridge Loan Warrants, totaling $128,734. The debt discount is amortized over the life of the Bridge Loan Notes as additional interest expense using the effective interest method. During 2017, interest expense paid in cash totaled $12,871 and interest expense attributable to amortization of debt discount totaled $158,734. See "Note 6 – Capital Stock – Warrants – Bridge Loan Warrants."

The holders of $300,000 in the face amount of the Bridge Loan Notes waived mandatory prepayment at both July 31, 2017 and August 31, 2017 and the holders of the remaining $300,000 in face amount of the Bridge Loan Notes were repaid in full pursuant to the mandatory prepayment provision. The balance of the Bridge Loan Notes, in the amount of $300,000, were repaid in full as of December 30, 2017.

NOTE 8—STOCK-BASED COMPENSATION

In 2008, the Company adopted the Houston American Energy Corp. 2008 Equity Incentive Plan (the "2008 Plan"). The terms of the 2008 Plan, as amended in 2012 and 2013, allow for the issuance of up to 6,000,000 shares of the Company's common stock pursuant to the grant of stock options and restricted stock.

In 2017, the Company adopted the Houston American Energy Corp. 2017 Equity Incentive Plan (the "2017 Plan" and, together with the 2008 Plan, the "Plans"). The terms of the 2017 Plan allow for the issuance of up to 5,000,000 shares of the Company's common stock pursuant to the grant of stock options and restricted stock. Persons eligible to participate in the Plans are key employees, consultants and directors of the Company.

Stock Option Activity

In March 2017, options to purchase an aggregate of 1,200,000 shares were granted to an executive officer, a non-executive officer and an advisor to the Company. All of the options had a ten-year life and were exercisable at $0.30 per share, the fair market value on date of grant. The executive officer's option grant vested 1/3 on each of the first three anniversaries of the grant date; subject to vesting in full on December 31, 2017 if the Company's common stock continued to be listed on the NYSE MKT (or another national securities exchange) on that date. The non-executive officer's option grant vested 25% on June 12, 2017 and 25% on each of the first three anniversaries of the grant date. The advisor option grant vested on the grant date. The non-executive officer options were forfeited unvested on termination of service to the Company during the six months ended June 30, 2017. The options were valued on the date of grant at $234,947 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 2.19%; (2) expected life in years of 5.50; (3) expected stock volatility of 109.16%; and (4) expected dividend yield of 0%. The Company determined the options qualified as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In September 2017, options to purchase an aggregate of 200,000 shares were granted to the Company's independent directors. All of the options had a ten-year life and were exercisable at $0.485 per share, the fair market value on date of grant. The options vested 20% on the date of grant and 80% nine months from the date of grant. The options were valued on the date of grant at $71,064 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.76%; (2) expected life in years of 5.67; (3) expected stock volatility of 102.38%; and (4) expected dividend yield of 0%. The Company determined the options qualified as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In February 2018, options to purchase an aggregate of 1,000,000 shares were granted to an executive officer. The options had a ten-year life, vested 1/3 on each of the first three anniversaries of the grant date and were exercisable at $0.2922 per share, the fair market value on the date of grant. The executive officer was terminated in June 2018 and the options were forfeited unvested on termination of employment. The options were valued on the date of grant at $166,940 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 2.68%; (2) expected life in years of 5.79; (3) expected stock volatility of 105.4%; and (4) expected dividend yield of 0%. The Company determined the options qualified as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In March 2018, options to purchase an aggregate of 500,000 shares were granted to a non-officer employee. The options had a ten-year life, vested 1/3 on each of the first three anniversaries of the grant date and were exercisable at $0.30 per share, the fair market value on the date of grant. The options were valued on the date of grant at $89,808 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 2.72%; (2) expected life in years of 5.81; (3) expected stock volatility of 105.0%; and (4) expected dividend yield of 0%. The Company determined the options qualified as 'plain vanilla' under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In April 2018, options to purchase 8,333 shares were granted to a newly appointed non-employee director. The options had a ten-year life, vested 20% on the date of grant and 80% nine months from the date of grant and an exercise price of $0.267 per share, the fair market value on the date of grant. The options were valued on the date of grant at $1,770 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 2.69%; (2) expected life in years of 5.8; (3) expected stock volatility of 105.0%; and (4) expected dividend yield of 0%. The Company determined the options qualified as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In June 2018, options to purchase an aggregate of 150,000 shares were granted to three non-employee directors. The options had a ten-year life, vested 20% on the date of grant and 80% nine months from the date of grant and exercise prices of $0.2425 per share, the fair market value on the date of grant. The options were valued on the date of grant at $27,422 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 2.79%; (2) expected life in years of 5.88; (3) expected stock volatility of 103.9%; and (4) expected dividend yield of 0%. The Company determined the options qualified as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In June 2018, stock options to purchase 250,000 shares of common stock were exercised, in a cashless exercise, resulting in the issuance of 114,379 shares of common stock.

Option activity during 2018 and 2017 was as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2016	5,232,165	$ 2.11		
Granted	1,400,000	$ 0.33		
Exercised	—	$ —		
Forfeited	(620,000)	$ 0.47		
Outstanding at December 31, 2017	6,012,165	$ 1.86		
Granted	1,658,333	$ 0.29		
Exercised	(250,000)	$ 0.22		
Forfeited	(2,441,666)	$ 3.79		
Outstanding at December 31, 2018	4,978,832	$ 0.77	6.24	$ —
Exercisable at December 31, 2018	4,406,473	$ 0.83	5.85	$ —

During 2018 and 2017, the Company recognized $94,846 and $304,189, respectively, of stock-based compensation expense attributable to outstanding stock option grants, including current period grants and unamortized expense associated with prior period grants.

As of December 31, 2018, non-vested options totaled 572,359 and total unrecognized stock-based compensation expense related to non-vested stock options was $85,080. The unrecognized expense is expected to be recognized over a weighted average period of 1.95 years. The weighted average remaining contractual term of the outstanding options and exercisable options at December 31, 2018 is 6.24 years and 5.85 years, respectively.

As of December 31, 2018, there were 6,021,168 shares of common stock available for issuance pursuant to future stock or option grants under the Plans.

Stock-Based Compensation Expense

The following table reflects stock-based compensation recorded by the Company for 2018 and 2017:

	2018	2017
Stock-based compensation expense from stock options and warrants included in general and administrative expense	$96,616	$306,999
Earnings per share effect of stock-based compensation expense	$(0.00)	$(0.00)

NOTE 9 – CAPITAL STOCK

Common Stock - At-the-Market Offering

In July 2017, the Company entered into an At-the-Market Issuance Sales Agreement (the "Sales Agreement") with WestPark Capital, Inc. ("WestPark Capital") pursuant to which the Company could sell, at its option, up to an aggregate of $5 million in shares of its common stock through WestPark Capital, as sales agent. Sales of shares under the Sales Agreement (the "2017 ATM Offering") were made, in accordance with one or more placement notices delivered by the Company to WestPark Capital, which notices set parameters under which shares could be sold. The 2017 ATM Offering was made pursuant to a shelf registration statement by methods deemed to be "at the market," as defined in Rule 415 promulgated under the Securities Act of 1933. The Company paid WestPark a commission in cash equal to 3% of the gross proceeds from the sale of shares in the 2017 ATM Offering. Additionally, the Company reimbursed WestPark Capital for $25,000 of expenses incurred in connection with the 2017 ATM Offering. During the year ended December 31, 2017, the Company sold an aggregate of 7,817,157 shares in the 2017 ATM Offering and received proceeds, net of commissions and expenses, of $4,101,013.

In October 2018, the Company entered into another Sales Agreement with WestPark Capital pursuant to which the Company could sell, at its option, up to an aggregate of $1.9 million in shares of its common stock through WestPark Capital, as sales agent. Sales of shares under the Sales Agreement (the “2018 ATM Offering”) were made, in accordance with one or more placement notices delivered by the Company to WestPark Capital, which notices shall set parameters under which shares could be sold. The 2018 ATM Offering was made pursuant to a shelf registration statement by methods deemed to be “at the market,” as defined in Rule 415 promulgated under the Securities Act of 1933. The Company will pay WestPark a commission in cash equal to 3% of the gross proceeds from the sale of shares in the 2018 ATM Offering. Additionally, the Company reimbursed WestPark Capital for $18,000 of expenses incurred in connection with the 2018 ATM Offering.

During the year ended December 31, 2018, in connection with the 2017 and 2018 ATM Offerings, the Company sold an aggregate of 2,433,963 shares of its common stock and received net proceeds of $747,205, net of commissions and expenses of $40,956.

Preferred Stock

The Company has authorized 10,000,000 shares of preferred stock with a par value of $0.001. The Board of Directors shall determine the designations, rights, preferences, privileges and voting rights of the preferred stock as well as any restrictions and qualifications thereon. As of December 31, 2018, the Company had 1,085 shares of 12.0% Series A Convertible Preferred Stock and 835 shares of 12.0% Series B Convertible Preferred Stock issued and outstanding.

Series A Convertible Preferred Stock

In January 2017, the Company issued 1,200 shares of 12% Series A Convertible Preferred Stock (the “Series A Preferred Stock”) for aggregate gross proceeds of $1.2 million. The Series A Preferred Stock (i) accrues a cumulative dividend, commencing July 1, 2017, at 12% payable, if and when declared, quarterly; (ii) is convertible at the option of the holder into shares of common stock at a conversion price of $0.20 per share, (iii) has a liquidation preference of $1,000 per share plus accrued and unpaid dividends; and (iv) is redeemable at the Company’s option, commencing on the second anniversary of the issue date, at a premium to issue price, which premium decreases from 12% to 0% following the fifth anniversary of the issue date, plus accrued and unpaid dividends.

During 2018 and 2017, respectively, the Company paid $132,900 and $70,500 of dividends on its Series A Preferred Stock.

During 2018 and 2017, respectively, 90 shares and 25 shares of Series A Preferred Stock were converted to 450,000 shares and 125,000 shares of Common Stock. At December 31, 2018, there were 1,085 shares of Series A Preferred Stock issued and outstanding.

Series B Convertible Preferred Stock

In May 2017, the Company received $909,600 from the sale of 909.6 Units (the "Units"), each Unit consisting of one share of 12.0% Series B Convertible Preferred Stock (the "Series B Preferred Stock") and a Warrant (the "Series B Warrant").

The Series B Preferred Stock (i) accrues a cumulative dividend at 12% payable, if and when declared, quarterly; (ii) is convertible at the option of the holder into shares of common stock at a conversion price of $0.36 per share, (iii) has a liquidation preference of $1,000 per share plus accrued and unpaid dividends; and (iv) is redeemable at the Company's option, commencing on the second anniversary of the issue date, at a premium to issue price, which premium decreases from 12% to 0% following the fifth anniversary of the issue date, plus accrued and unpaid dividends.

During 2018 and 2017, respectively, the Company paid $106,050 and $81,920 of dividends on its Series B Preferred Stock.

During 2018 and 2017, respectively, 60 shares and 14.6 shares of Series B Preferred Stock were converted to 166,667 shares and 40,556 shares of Common Stock. At December 31, 2018, there were 835 shares of Series B Preferred Stock issued and outstanding.

Warrants

Series B Warrants. The Series B Warrants, issued as part of Units along with Series B Preferred Stock, are exercisable, for a period of 9 months, expiring February 3, 2018, to purchase an aggregate of 3,001,680 shares of common stock at $0.43 per share. The relative value of the warrants were valued on the date of grant at $194,934 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.10%; (2) expected life in years of 0.75; (3) expected stock volatility of 92.36%; and (4) expected dividend yield of 0%.

Bridge Loan Warrants. The Bridge Loan Warrants, issued in conjunction with the Bridge Loan Notes, are exercisable, for a period of one year, expiring June 23, 2018, to purchase an aggregate of 600,000 shares of common stock at $0.50 per share. The relative fair value of the warrants were valued on the date of grant at $128,734 using the Black Scholes option-pricing model with the following parameters: (1) risk free interest rate of 1.20%; (2) expected life in years of 1.00; (3) expected stock volatility of 93.67%; and (4) expected dividend yield of 0%. The relative fair value of the warrants was recorded as debt discount of the Bridge Loan Notes and is amortized over the life of the notes.

Consultant Warrants. In September 2017, the Company issued warrants (the “Consultant Warrants”) to a consultant. The Consultant Warrants were exercisable to purchase 50,000 shares of common stock at $0.55 per share and expire December 31, 2021. The Consultant Warrants are first exercisable, subject to continuing provision of services under a services agreement, as to 12,500 shares on each of December 6, 2017, September 6, 2018, September 6, 2019 and September 6, 2020. The consultant was terminated in May 2018, resulting in the termination of the unvested portion of the warrant as to 37,500 shares. The relative value of the warrants were valued on the date of grant at $16,132 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.63%; (2) expected life in years of 4.32; (3) expected stock volatility of 99.75%; and (4) expected dividend yield of 0%. The Company recognized $1,770 and $1,811, respectively, of stock-based compensation expense related to the vesting of the Consultant Warrants during the years ended December 31, 2018 and 2017.

A summary of warrant activity and related information for 2018 is presented below:

	Warrants	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding at January 1, 2017	—	$ —	
Issued	3,651,680	0.44	
Exercised	—	—	
Expired	—	—	
Outstanding at January 1, 2018	3,651,680	$ 0.44	
Issued	—	—	
Exercised	—	—	
Expired	(3,601,680)	0.44	
Outstanding at December 31, 2018	50,000	$ 0.55	$ —
Exercisable at December 31, 2018	12,500	$ 0.55	$ —

NOTE 10—TAXES

The following table sets forth a reconciliation of the statutory federal income tax for the years ended December 31, 2018 and 2017.

	2018	2017
Income (loss) before income taxes	$(251,336)	$(2,037,615)
Income tax expense (benefit) computed at statutory rates	$(52,781)	$(713,165)
Permanent differences, nondeductible expenses	405	5,371

Increase (decrease) in valuation allowance	(1,386,204)	(7,283,514)
State and Local Taxes	6,548	—
Other adjustment	1,090,595	44,279
Deferred True-Up	341,437	—
Federal tax rate change	—	7,947,029
Tax provision	$—	$—
Total provision		
Foreign	$—	$—
Total provision (benefit)	$—	$—

For years beginning January 1, 2018, the Tax Cuts and Jobs Act ("the Act") includes significant changes to the U.S. corporate income tax system including the reduction of the corporate tax rate from 35% to 21%.

At December 31, 2018 the Company has a federal tax loss carry forward of $53,001,669 and a foreign tax credit carry forward of $505,745, both of which have been fully reserved.

The tax effects of the temporary differences between financial statement income and taxable income are recognized as a deferred tax asset and liabilities. Significant components of the deferred tax asset and liability as of December 31, 2018 and 2017 are set out below.

	2018	2017
Non-Current Deferred tax assets:		
Net operating loss carry forward	$11,128,619	$11,130,350
Foreign tax credit carry forward	505,745	505,745
Deferred state tax	13,966	13,966
Stock compensation	471,534	1,891,857
Book in excess of tax depreciation, depletion and capitalization methods on oil and gas properties	(883,220)	(919,070)
Other	(196,560)	(196,560)
Colombia future tax obligations	—	—
Total Non-Current Deferred tax assets	11,040,084	12,426,288
Valuation Allowance	(11,040,084)	(12,426,288)
Net deferred tax asset	$—	$—

Schedule of Net Operating Loss Carryforwards

We are currently subject to a three-year statute of limitation for federal tax purposes and, in general, three to four-year statute of limitation for state tax purposes. State NOL expiration will occur beginning in 2019 and Federal NOL expiration will begin in 2035.

Under the Tax Cuts and Jobs Act of 2017, net operating losses incurred for tax years beginning after 12/31/2017 will have no expiration date but utilization will be limited to 80% of taxable income. For losses generated prior to 1/1/2018, there will be no limitation on the utilization, but there is an expiration on the carryforward of 20 years for federal tax purposes.

Foreign Income Taxes

The Company owns direct ownership in several properties in Colombia operated by Hupecol. Colombia’s current income tax rate is 25%. During 2018 and 2017, we recorded no foreign tax expense.

Effect of New Federal Tax Reform Legislation

New tax reform legislation was enacted on December 22, 2017, known as the Tax Cuts and Jobs Act of 2017 (“The Act”). The Act moved from a worldwide tax system to a quasi-territorial tax system and was comprised of broad and complex changes to the U.S. tax code including, but not limited to, (1) reduced the U.S. tax rate from 35% to 21%; (2) added a deemed repatriation transition tax on certain foreign earnings and profits; (3) generally eliminated U.S. federal income taxes on dividends from foreign subsidiaries; (4) included certain income of controlled foreign companies in U.S. taxable income (“GILTI”); (5) created a new minimum tax referred to as a base erosion anti-abuse income tax; (6) limited certain U.S. Federal research based credits; and (7) eliminated the domestic manufacturing deduction. The accounting for the reduction of deferred tax ass and the tax charge for the deemed repatriation transition tax is complete as of December 31, 2018, which resulted in no material changes from the Company’s preliminary assessment.

NOTE 11—COMMITMENTS AND CONTINGENCIES

Lease Commitment

The Company leases office facilities under an operating lease agreement that expires October 31, 2022. The lease agreement requires future payments as follows:

Year	Amount
2019	$128,348
2020	130,717
2021	133,087
2022	112,551
2023	—
Total	$504,703

Total rental expense was $129,370 and $119,619 in 2018 and 2017, respectively. The Company does not have any capital leases or other operating lease commitments.

Legal Contingencies

The Company is subject to legal proceedings, claims and liabilities that arise in the ordinary course of its business. The Company accrues for losses associated with legal claims when such losses are probable and can be reasonably estimated. These accruals are adjusted as further information develops or circumstances change.

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Environmental Contingencies

The Company's oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require the Company to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition as well as the industry in general. Under these environmental laws and regulations, the Company could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether the Company was responsible for the release or if its operations were standard in the industry at the time they were performed. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks.

Development Commitments

During the ordinary course of oil and gas prospect development, the Company commits to a proportionate share for the cost of acquiring mineral interests, drilling exploratory or development wells and acquiring seismic and geological information.

Production Incentive Arrangements and ORRIs

In conjunction with our efforts to secure oil and gas prospects, financing and services, we have, from time to time, granted overriding royalty interests ("ORRI") in various properties and have adopted a Production Incentive Compensation Plan under which grant interests in pools, which may take the form of ORRIs, to provide additional incentive identify and secure attractive oil and gas properties.

Production Incentive Compensation Plan. In August 2013, the Company's compensation committee adopted a Production Incentive Compensation Plan. The purpose of the Plan is to encourage employees and consultants participating in the Plan to identify and secure for the Company participation in attractive oil and gas opportunities.

Under that Plan, the committee may establish one or more Pools and designate employees and consultants to participate in those Pools and designate prospects and wells, and a defined percentage of the Company's revenues from those wells, to fund those Pools. Only prospects acquired on or after establishment of the Plan, and excluding all prospects in Colombia, may be designated to fund a Pool. The maximum percentage of the Company's share of revenues from a well that may be designated to fund a Pool is 2% (the "Pool Cap"); provided, however, that with respect to wells with a net revenue interest to the 8/8 of less than 73%, the Pool Cap with respect to such wells shall be reduced on a 1-for-1 basis such that no portion of the Company's revenues from a well may be designated to fund a Pool if the NRI is 71% or less.

Designated participants in a Pool will be assigned a specific percentage out of the Company's revenues assigned to the Pool and will be paid that percentage of such revenues from all wells designated to such Pool and spud during that participant's employment or services with the Company. In no event may the percentage assigned to the Company's chief executive officer relative to any well within a Pool exceed one-half of the applicable Pool Cap for that well. Payouts of revenues funded into Pools shall be made to participants not later than 60 days following year end, subject to the committee's right to make partial interim payouts. Participants will continue to receive their percentage share of revenues from wells included in a Pool and spud during the term of their employment or service so long as revenues continue to be derived by the Company from those wells even after termination of employment or services of the Participant; provided, however, that a participant's interest in all Pools shall terminate on the date of termination of employment or services where such termination is for cause.

In the event of certain changes in control of the Company, the acquirer or survivor of such transaction must assume all obligations under the Plan; provided, however, that in lieu of such assumption obligation, the committee may, at its sole discretion, assign overriding royalty interests in wells to substantially mirror the rights of participants under the Plan. Similarly, the committee may, at any time, assign overriding royalty interests in wells in settlement of obligations under the Plan.

The Plan is administered by the Company's compensation committee which shall consult with the Company's chief executive officer relative to Pool participants, prospects, wells and interests assign although the committee will have final and absolute authority to make all such determinations.

During 2018, a Pool was established under the Plan representing an aggregate of 1% of the Company's interest in the Company's Yoakum County acreage.

The Company records amounts payable under the plan as a reduction to revenue as revenues are recognized from prospects included in pools covered by the plan based on the participants' interest in such prospect revenues and records the same as accounts payable until such time as such amounts are paid out.

ORRI Grants. All present and future prospects in Colombia are subject to a 1.5% ORRI in favor of each of a current director and our former Chairman and Chief Executive Officer. During 2017, ORRIs were issued to two employees in full settlement of obligations under the Plan with respect to the Pool established relating to the Reeves County acreage.

Payments made by the Company under the Plan and ORRI's paid totaled $1,439 and $6,016 in 2018 and 2017, respectively. As of December 31, 2018 and 2017, the Company had accrued $0 and $7,781, respectively, under the Plan as accounts payable.

NOTE 12—GEOGRAPHICAL INFORMATION

The Company currently has operations in two geographical areas, the United States and Colombia. Revenues for the years ended December 31, 2018 and 2017 and long-lived assets as of December 31, 2018 and 2017 attributable to each geographical area are presented below:

	2018		2017	
	Revenues	Long Lived Assets, Net	Revenues	Long Lived Assets, Net
North America	$2,243,325	$4,540,309	$630,392	$4,504,450
South America	—	2,321,170	—	2,309,341
Total	$2,243,325	$6,861,479	$630,392	$6,813,791

NOTE 13—SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

This footnote provides unaudited information required by FASB ASC Topic 932, *Extractive Activities—Oil and Gas*.

Geographical Data

The following table shows the Company's oil and gas revenues and lease operating expenses, which excludes the joint venture expenses incurred in South America, by geographic area:

	2018	2017
Revenues		
North America	$2,243,325	$630,392
South America	—	—
	$2,243,325	$630,392
Production Cost		
North America	$914,269	$216,429
South America	—	—
	$914,269	$216,429

Capital Costs

Capitalized costs and accumulated depletion relating to the Company's oil and gas producing activities as of December 31, 2018, all of which are onshore properties located in the United States and Colombia, South America are summarized below:

	United States	South America	Total
Unproved properties not being amortized	$135,329	$2,321,170	$2,456,499
Proved properties being amortized	10,943,176	49,454,702	60,284,542
Accumulated depreciation, depletion, amortization and impairment	(6,538,195)	(49,454,702)	(55,992,897)
Net capitalized costs	$4,540,309	$2,321,170	$6,861,479

Amortization Rate

The amortization rate per unit based on barrel of oil equivalents was $5.47 for the United States and $0 for South America for the year ended December 31, 2018.

Acquisition, Exploration and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities as of December 31, 2018 and 2017 are summarized below:

	2018 United States	South America
Property acquisition costs:		
Proved	$258,352	$—
Unproved	135,329	11,829
Exploration costs	—	—
Development costs	—	—
Total costs incurred	$393,681	$11,829

	2017 United States	South America
Property acquisition costs:		
Proved	$ 1,043,977	$ —
Unproved	—	25,154
Exploration costs	3,443,222	—
Development costs	—	—
Total costs incurred	$ 4,487,199	$ 25,154

Reserve Information and Related Standardized Measure of Discounted Future Net Cash Flows

The unaudited supplemental information on oil and gas exploration and production activities has been presented in accordance with reserve estimation and disclosures rules issued by the SEC in 2008. Under those rules, average first-day-of-the-month price during the 12-month period before the end of the year are used when estimating whether reserve quantities are economical to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technology to estimate proved oil and gas reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes. Disclosures by geographic area include the United States and South America, which consists of our interests in Colombia. The supplemental unaudited presentation of proved reserve quantities and related standardized measure of discounted future net cash flows provides estimates only and does not purport to reflect realizable values or fair market values of the Company’s reserves. Volumes reported for proved reserves are based on reasonable estimates. These estimates are consistent with current knowledge of the characteristics and production history of the reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, significant changes to these estimates can be expected as future information becomes available.

Proved reserves are those estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The reserve estimates set forth below were prepared by Russell K. Hall and Associates, Inc. (“R.K. Hall”) and Lonquist & Co., LLC (“Lonquist”), utilizing reserve definitions and pricing requirements prescribed by the SEC. R.K. Hall and Lonquist are independent professional engineering firms specializing in the technical and financial evaluation of oil and gas assets. R.K. Hall’s report was conducted under the direction of Russell K. Hall, founder and President of R.K. Hall. Mr. Hall holds a BS in Mechanical Engineering from the University of Oklahoma and is a registered professional engineer with more than 30 years of experience in reserve evaluation services. Lonquist’s report was conducted under the direction of Don E. Charbula, P.E., Vice President of Lonquist. Mr. Charbula holds a BS in

Petroleum Engineering from The University of Texas at Austin and is a registered professional engineer with more than 30 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management. R.K. Hall, Lonquist and their respective employees have no interest in the Company, and were objective in determining the results of the Company's reserves. Lonquist used a combination of production performance, offset analogies, seismic data and their interpretation, subsurface geologic data and core data, along with estimated future operating and development costs as provided by the Company and based upon historical costs adjusted for known future changes in operations or development plans, to estimate our reserves. The Company does not operate any of its oil and gas properties.

Total estimated proved developed and undeveloped reserves by product type and the changes therein are set forth below for the years indicated.

	United States		South America		Total	
	Gas (mcf)	Oil (bbls)	Gas (mcf)	Oil (bbls)	Gas (mcf)	Oil (bbls)
Total proved reserves						
Balance December 31, 2016	40,020	8,680	—	—	40,020	8,680
Discoveries	2,782,055	389,455	—	—	2,782,055	389,455
Revisions of prior estimates	48,983	3,116	—	—	48,983	3,116
Production	(30,997)	(10,038)	—	—	(30,997)	(10,038)
Balance December 31, 2017	2,840,061	391,213	—	—	2,840,061	391,213
Revisions to prior estimates	136,932	(16,674)	—	—	136,932	(16,674)
Production	(253,053)	(23,842)	—	—	(253,053)	(23,842)
Balance December 31, 2018	2,723,940	350,697	—	—	2,723,940	350,697
Proved developed reserves						
at December 31, 2017	1,666,031	149,088	—	—	1,666,031	149,088
at December 31, 2018	1,544,383	107,548	—	—	1,544,383	107,548
Proved undeveloped reserves						
at December 31, 2017	1,174,030	242,125	—	—	1,174,030	242,125
at December 31, 2018	1,179,557	242,949	—	—	1,179,557	242,949

As of December 31, 2018, the Company had proved undeveloped ("PUD") reserves totaling 242,949 bbls and 1,179,557 mcf. As of December 31, 2017, the Company had PUD reserves totaling 242,125 bbls and 1,174,030 mcf. No PUD reserves were converted to proved developed producing reserves in 2018 or 2017.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is computed using average first-day-of the-month prices for oil and gas during the preceding 12 month period (with consideration of price changes only to the extent provided by contractual arrangements), applied to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated related future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated), and assuming continuation of existing economic conditions. Future income tax expenses give effect to permanent differences and tax credits but do not reflect the impact of continuing operations including property acquisitions and exploration. The estimated future cash flows are then discounted using a rate of ten percent a year to reflect the estimated timing of the future cash flows.

Standardized measure of discounted future net cash flows at December 31, 2018:

	United States	South America	Total
Future cash flows from sales of oil and gas	$31,125,778	$ —	$31,125,778
Future production cost	(7,611,052)	—	(7,611,052)
Future development cost	(4,758,170)	—	(4,758,170)
Future net cash flows	18,756,556	—	18,756,556
10% annual discount for timing of cash flow	(11,041,908)	—	(11,041,908)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$7,714,648	$ —	$7,714,648
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	$(1,465,985)	$ —	$(1,465,985)
Change due to revisions in standardized variables:			
Accretion of discount	684,886	—	684,886
Net change in sales and transfer price, net of production costs	1,656,330	—	1,656,330
Revision and others	84,038	—	84,038
Changes in production rates and other	(93,476)	—	(93,476)
Net	865,793	—	865,793
Beginning of year	6,848,855	—	6,848,855
End of year	$7,714,648	$ —	$7,714,648

Standardized measure of discounted future net cash flows at December 31, 2017:

	United States	South America	Total
Future cash flows from sales of oil and gas	$27,514,923	$ —	$27,514,923
Future production cost	(6,628,886)	—	(6,628,886)
Future development cost	(4,758,170)	—	(4,758,170)
Future net cash flows	16,127,867	—	16,127,867
10% annual discount for timing of cash flow	(9,279,012)	—	(9,279,012)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$6,848,855	$ —	$6,848,855

Changes in standardized measure:

Change due to current year operations Sales, net of production costs	$(413,962)	$ —	$(413,962)
Change due to revisions in standardized variables:			
Accretion of discount	16,413	—	16,413
Net change in sales and transfer price, net of production costs	197	—	197
Net change in future development cost	(4,758,170)	—	(4,758,170)
Discoveries	6,517,865	—	6,517,865
Revision and others	(57,247)	—	(57,247)
Changes in production rates and other	5,379,629	—	5,379,629
Net	6,684,725	—	6,684,725
Beginning of year	164,130	—	164,130
End of year	$6,848,855	$ —	$6,848,855

NOTE 12—SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
2018				
Operating revenue	$754,157	$574,580	$552,946	$474,977
Loss from operations	(52,911)	(146,259)	(116,933)	(21,888)
Net income (loss)	(52,911)	(146,259)	(116,831)	64,665
Loss per common share – basic	$(0.00)	$(0.00)	$(0.00)	$(0.00)
Loss per common share – diluted	$(0.00)	$(0.00)	$(0.00)	$(0.00)
2017				
Operating revenue	$57,633	$46,275	$111,741	$414,743
Loss from operations	(502,514)	(469,238)	(621,778)	(282,663)
Net loss	(502,399)	(466,274)	(786,278)	(282,663)
Loss per common share – basic	$(0.01)	$(0.01)	$(0.01)	$(0.00)
Loss per common share – diluted	$(0.01)	$(0.01)	$(0.01)	$(0.00)