HOUSTON AMERICAN ENERGY CORP
Form 10-K
March 16, 2017

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, 2016

[ ] 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	**(I.R.S. Employer**
incorporation or organization)	**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 MKT**

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [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, or a smaller reporting company. See definition of "accelerated filer," "large accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [X]

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, 2016, based on the closing sales price of the registrant's common stock on that date, was approximately $9.0 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 13, 2017 was 51,277,388.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for its 2017 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 in the U.S. Permian Basin and Gulf Coast regions, particularly Texas and Louisiana, and in the South American country of Colombia.

We focus on early identification of, and entrance into, existing and emerging resource plays, particularly in the U.S. Permian Basin and Gulf Coast and in Colombia. We do not operate properties but typically seek to partner with, or invest in, 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 and partnering with, investing in 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, 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, 2016:

	Net acreage	Average working interest %		Gross producing wells	Net proved reserves (boe)	2016 Net Production Oil (bbls)	Natural Gas (mcf)
Oklahoma	4.0	2.4	%	1	636.7	4.48	676
Louisiana	74.9	4.9	%	7	10,363.3	2,854.71	19,272
Texas	122.5	1.4	%	1	4,350.0	73.33	256
Total U.S.	201.4	2.6	%	9	15,350.0	2,932.52	20,204
Colombia	49,025.0	12.5	%	—	—	—	—
Total	49,226.4	12.5	%	9	15,350.0	2,932.52	20,204

In February 2017, we acquired a 25% working interest in two blocks in the Texas Permian Basin covering approximately 717 gross (179 net) acres.

- 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

With our 2017 acquisition of Reeves County acreage, we anticipate that our near term focus will be the exploration and development of that acreage and assembly of additional acreage positions in the Texas Permian Basin. The acreage is prospective for horizontal development of the upper and lower Wolfcamp and Bone Spring formations. The operator of the acreage, Founders Oil & Gas, has indicated that an initial well is expected to be drilled commencing on or about the first week of May 2017 targeting the Wolfcamp A shale formation.

Our principal exploration properties in Texas consist of the following:

Matagorda County — we hold a 2.71% working interest in the 779 acre Harrison Prospect.

Reeves County – we hold a 25% working interest, subject to a proportionate 5% back-in after payout, in two lease blocks covering approximately 717 gross acres.

Louisiana Properties

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

East Baton Rouge Parish — we hold (i) a 4.557% royalty interest in 2,485 royalty acres, as well as a 3.547% royalty interest in the Crown Paper #01 well, and (ii) a 5% working interest in a 11,000 foot well and 625 net acre lease block.

Plaquemines Parish — we hold a 1.8% working interest in the SL 180771 well and 300 gross acre lease block.

Vermilion Parish — we hold a 1.5% working interest in a 15,000 foot Discorbis well and 450+ net acre lease block.

Iberville Parish — we hold a 3% working interest in a 13,500 foot Cib Haz well and 618 acre lease block.

Assumption Parish – we hold a 5% working interest before payout and 4% working interest after payout in a 15,200 foot Rob L well and 238 acre lease block.

Jefferson Davis Parish — we hold a 10.9% working interest before payout and a 9.375% working interest after payout in a 7,000 foot Cris H well.

- Colombian Properties:

At December 31, 2016, 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, 2016:

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, 2016, 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, 2016, 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 are reevaluating 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 2016, 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 2016, we drilled no wells. The following table summarizes the number of wells drilled during 2016, 2015, and 2014, 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,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	—	—	—	—	1	0.1094
Non-productive	—	—	—	—	—	—
Total development wells	—	—	—	—	1	0.1094
Exploratory wells, completed as:						
Productive	—	—	—	—	7 (1)	0.6244
Non-productive	—	—	2	0.11375	5	1.2095
Total exploratory wells	—	—	2	0.11375	12	1.8339

(1) Includes one well successfully completed and subsequently shut-in and one well successfully completed and temporarily abandoned.

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, 2016, we had no wells in progress or awaiting hook up.

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, 2016, we owned interests in nine gross wells. As of December 31, 2016, we had ownership interests in productive wells, categorized by geographic area, as follows:

	Oil Wells	Gas Wells
United States		
Gross	7	2
Net	0.31	0.16
Colombia		
Gross	—	—
Net	—	—
Total		
Gross	7	2
Net	0.31	0.16

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, 2016:

	Year Ended December 31,		
	2016	2015	2014
Net Production:			
Gas (Mcf):			
United States	20,204	32,146	12,717
Colombia	—	—	—
Total	20,204	32,146	12,717
Oil (Bbls):			
United States	2,933	6,068	3,152
Colombia	—	—	—
Total	2,933	6,068	3,152
Average sales price:			
Gas ($ per Mcf)			
United States	$2.35	$3.23	$4.80
Colombia	—	—	—
Total	$2.35	$3.23	$4.80
Oil ($ per Bbl)			
United States	$40.40	$53.64	$95.95
Colombia	—	—	—
Total	$40.40	$53.64	$95.95
Average production costs ($ per BOE):			
United States	$14.15	$8.60	$13.65
Colombia	—	—	—
Total	$14.15	$8.60	$13.65

Natural Gas and Oil Reserves

Reserve Estimates

The following tables sets forth, by country and as of December 31, 2016, 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	Natural Gas	**Total** [2]
	(bbls)	(mcf)	(boe)
Reserve category			
Proved Developed			
United States	8,680	40,020	15,350
Colombia	—	—	—
Total Proved Developed Reserves	8,680	40,020	15,350
Proved Undeveloped			
United States	—	—	—
Colombia	—	—	—
Total Proved Undeveloped Reserves	—	—	—
Total Proved Reserves	8,680	40,020	15,350

	Proved Developed	Proved Undeveloped	Total Proved
PV-10 [1]	$ 164,130	$ —	$ 164,130
Standardized measure [3]	$ 164,130	$ —	$ 164,130

(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, 2016. 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, 2016. The average prices utilized for purposes of estimating our proved reserves were $40.99 per barrel of oil and $2.60 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 Lonquist & Co., LLC.

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 report is prepared by Lonquist & Co. 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. Lonquist & Co. also prepares reserve estimates for the various Hupecol entities. Upon analysis and evaluation of data provided, Lonquist & Co. issues a preliminary appraisal report of our reserves. The preliminary appraisal report and changes in our reserves are reviewed by our President for reasonableness of the results obtained. Once any questions have been addressed, Lonquist & Co. issues the final appraisal report, reflecting their conclusions.

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.

Lonquist & Co. 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

As of December 31, 2016 and 2015, we had no proved undeveloped reserves.

Developed and Undeveloped Acreage

The following table sets forth the gross and net developed and undeveloped acreage (including both leases and concessions), categorized by geographical area, which we held as of December 31, 2016:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States	4,478	201.4	—	—
Colombia	—	—	392,205	49,025
Total	4,478	201.4	392,205	49,025

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, 2016, the expiration periods of the gross and net acres that are subject to leases or concessions summarized in the above table of undeveloped acreage.

Twelve Months Ending:	Undeveloped Acres Expiring Gross	Net
December 31, 2017	—	—
December 31, 2018	—	—
December 31, 2019	—	—
December 31, 2020	—	—
December 31, 2021 and later	392,205	49,025
Total	392,205	49,025

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, 2016, 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, 2016, we had three 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 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

Our Web site address is *www.houstonamericanenergy.com.* We make available, free of charge on or through our Web site, our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments to these reports as soon as reasonably practicable after such material is electronically filed with, or furnished to, the United States Securities and Exchange Commission. Information contained on our website is not incorporated by reference into this report and you should not consider information contained on our website as part of this report.

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.

We have had limited operating revenues and have incurred losses from operations for an extended period.

Since our 2010 sale of certain operating assets in Colombia, we have had limited operating revenues and have incurred recurring losses from operations. Unless and until we are successful in growing our production through drilling, acquisition or otherwise, we expect to continue to experience limited operating revenues and recurring losses from operations.

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, and the levels of 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 has resulted in oil and gas supply exceeding global demand which has, 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 28% and 24%, respectively from 2015 to 2016. There can be no assurance as to the duration of the current weak price environment, the timing and level of any recovery in prices or the reoccurrence of price weakness in the future.

The ongoing decline in prices has 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.

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.

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 undeveloped, we require significant capital to prove and develop such properties before they may become productive. Following the sale of our principal producing property in Colombia in March 2012, substantially all of our net acreage was unproven and undeveloped. 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.

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.

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

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. 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.

Our cash flows and profitability may fluctuate by large amounts as a result of our strategy of investment in drilling and exploration of unproven properties and opportunistic asset divestitures.

We have historically experienced large fluctuations in our cash flows and profitability associated with our drilling and development of properties, divestitures of interests in select properties and reinvestment in drilling and development of unproven properties. Our strategy has historically focused on early identification of, and entrance into, existing and emerging resource plays. As part of that strategy, we and our partners have participated in accumulating positions and drilling unproven acreage, that may be perceived to be higher risk, where acquisition, drilling and operation costs may be lower with a view to proving reserves, divesting selected assets on an opportunistic basis to operators willing to pay higher prices for proven prospects without early stage drilling risk and reinvesting operating cash flow and sales proceeds in accumulating, drilling and developing additional, and larger, acreage positions. As a result of such strategy, we sold acreage positions in 2008, 2010 and 2012 that provided one-time profits and cash proceeds and substantially reduced our proved reserves, production and operating cash flows immediately following such sales and after which we invested substantial portions of sales proceeds in the accumulation and exploratory drilling of larger acreage positions. While our reserves, production, operating cash flows and operating profitability have historically grown as properties have been drilled and developed and have fallen following strategic asset divestitures when we are incurring costs to drill and develop properties, there is no assurance that our strategy will produce such results in the future and, in fact, that strategy did not produce new reserves, production, cash flow or profitability when deployed on our CPO 4 prospect. As a result of drilling and other risks, there can be no assurance that our reserve and production growth strategy will allow us to grow, and replace, our acreage position, reserves, production and profitability following divestitures and we may continue to experience large fluctuations in such positions.

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 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 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. In particular, during 2011 and 2012 we committed a substantial portion of the proceeds received from our 2010 divestiture of Hupecol properties to a drilling program on our CPO 4 prospect. Between 2011 and 2012, we participated in the drilling of three test wells on our CPO 4 prospect, each of which was determined to be noncommercial and, ultimately, plugged and abandoned. Given our focus on development of the CPO 4 prospect, including the commitment of substantial financial resources and the lack of current production from our other prospects, the failure to complete a commercial well on the prospect materially adversely affected our financial position and operating outlook.

Our audit report includes a "going concern" paragraph; we will need additional financing to support operations and future capital commitments.

As a result of continuing operating losses, low energy prices and financial commitments, our financial statements include a going concern qualification reflecting substantial doubt as to our ability to continue as a going concern. Our estimated drilling budget for 2017 is $3.4 million, principally relating to the planned drilling of up to two wells on our recently acquired Reeves Count, Texas Permian Basin properties. Our 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 new prospects. We do not presently have sufficient financial resources to finance our anticipated share of 2017 drilling costs on our Permian Basin properties and will need to seek additional capital to fund such commitments. We have no commitments to provide any 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 fully fund our 2017 drilling budget and to support future operations.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business.

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 operations in Colombia 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.

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.

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.

Wells in which we participate in the future may, in some cases, 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.

Our stock has suffered significant declines over the past several years mirroring, among other things, the delays in drilling and ultimate determination to cease completion efforts on test wells on the CPO 4 prospect and the announcement that the SEC was conducting an investigation of our company and the steep decline in oil and natural gas prices commencing in the second half of 2014.

In addition, in recent years, the stock market in general has experienced 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.

Our stock is at-risk to delisting from the NYSE Mkt.

Our common stock is presently listed on the NYSE Mkt. During 2016, we received notice from the NYSE Mkt that we were not in compliance with the continued listing standards of the NYSE Mkt. In particular, the NYSE Mkt noted our failure to satisfy the minimum shareholders' equity requirement of the exchange. Since that time, our common stock has continued to be listed on the NYSE Mkt pursuant to a plan to regain compliance with the NYSE Mkt listing standards. If we should fail to regain compliance with the listing standards or, in the view of the exchange, fail to make adequate progress under the plan to regain compliance, our common stock is subject to delisting from the NYSE Mkt. In the event of delisting, our stockholders may experience decreased liquidity.

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

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 May 31, 2017, is $7,701. 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 13, 2017, 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 MKT under the symbol "HUSA." The following table sets forth the range of high and low sale prices of our common stock for each quarter during the past two fiscal years.

		High	Low
Calendar Year 2016	Fourth Quarter	$0.25	$0.16
	Third Quarter	0.23	0.18
	Second Quarter	0.30	0.16
	First Quarter	0.22	0.16
Calendar Year 2015	Fourth Quarter	$0.20	$0.16
	Third Quarter	0.23	0.16
	Second Quarter	0.23	0.18
	First Quarter	0.25	0.16

At March 13, 2017, the closing price of the common stock on NYSE MKT was $0.30 per share.

Holders

As of March 13, 2017, there were approximately 877 shareholders of record of our common stock.

Dividends

No dividends were paid during calendar years 2015 or 2016. The payment of future cash dividends will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects, contractual restrictions and any other factors considered relevant by the Board of Directors.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2016 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]	5,232,165	$ 2.11	818,835
Equity compensation plans not approved by security holders	—	—	—
	5,232,165	2.11	818,835

(1) Consists of 51,000 shares reserved for issuance pursuant to outstanding options granted under the Houston American Energy Corp. 2005 Stock Option Plan and 6,000,000 shares reserved for issuance under the Houston American Energy 2008 Equity Incentive Plan.

Item 6. Selected Financial Data

Not applicable.

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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 in the U.S. Permian Basin and Gulf Coast regions 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 entrance into, existing and emerging resource plays, particularly in the U.S. Permian Basin and Gulf Coast and in Colombia. 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 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

Commodity Pricing

Steep declines in the price of oil and natural gas during 2015, which persisted with moderate price recovery late in 2016, adversely affected our revenues, profitability and financial position. Average realized prices from sales our oil and natural gas decreased 28% and 24%, respectively, from 2015 to 2016 and were 52% and 58%, respectively, below 2014 levels.

Drilling and Related Activity

With the weakness in oil and natural gas prices we conducted no drilling activities during 2016.

During 2016, our capital investment expenditures in Colombia related to the preparation and evaluation of our three concessions in Colombia totaled $170,812.

During 2016, Hupecol, the operator of our Colombian concessions, continued to experience opposition, at the local level, to their efforts to secure necessary permits to commence drilling operations on our Serrania concession. Commencement of drilling operations remains contingent upon receipt of final permits in Colombia. Notwithstanding the federal government's grant of the concession, local opposition to drilling in the vicinity of the Serrania concession has resulted in repeated delays in issuance of, including the issuance and subsequent rescission of, necessary permits and there is no assurance as to if, and when, necessary permits will be issued or the concession will be drilled and/or developed. While Hupecol continues to pursue discussions with the government regarding issuance of permits or compensation should the necessary permits not be forthcoming, given the continuing permitting issues, we, through Hupecol, are evaluating our rights and options with respect to Serrania and have shelved plans to drill the concession for the foreseeable future. Hupecol is also expected to defer commencement of work on the Los Picachos and Macaya concessions until satisfactory resolution of the permitting issues on the Serrania concession.

In June 2016, a peace accord was announced between the Colombian government and the Revolutionary Armed Forces of Colombia, also known as 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 are reevaluating 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.

Leasehold Developments

During 2015, we disposed of some or all of our interest in three non-producing domestic prospects for which we received $56,705 of proceeds. Proceeds received from disposal of such interests were accounted for as a reduction in capitalized cost of oil and gas properties.

Strategic Initiatives – Permian Basin Assets

In May 2016, our board approved the exploration of strategic alternatives, including, among other options, seeking merger and acquisition candidates, asset acquisitions or sales. To facilitate our exploration of strategic alternatives, in June 2016, we engaged an investment banking firm, to assist in making merger and acquisition introductions, negotiating deals, capital sourcing and other supporting services. We subsequently terminated our engagement of the investment banking firm but continue our exploration of strategic alternatives.

Pursuant to our exploration of strategic alternatives, we evaluated numerous opportunities to acquire direct or indirect interests in oil and gas assets in the U.S. and in international markets.

In January 2017, we executed an agreement to acquire a 25% working interest, subject to a proportionate 5% back-in after prospect payout, in two lease blocks in Reeves County, Texas. In February 2017, we completed the acquisition of a working interest in 717 acres in Reeves County, Texas at a price of $986,000. The acreage lay in the Delaware Basin region of the larger Permian Basin. Founders Oil & Gas, our operator anticipates drilling an initial well on the acreage commencing on or about the first week of May 2017 and drilling a second well before year-end 2017. Our share of drilling cost for the initial well is estimated at $1.7 million. The well is expected to target the Wolfcamp A shale formation.

While our near term operating plans are expected to focus on exploration and development of the Reeves County, Texas acreage, we continue to evaluate opportunities to acquire and participate in attractive oil and gas plans within and outside of the Permian Basin and with various operators, including Founders Oil & Gas

Sale of Convertible Preferred Stock

In order to fund our acquisition of the Reeves County, Texas acreage, in January 2017, we issued 1,200 shares of 12% Series A Convertible Preferred Stock for aggregate gross proceeds of $1.2 million. The Series A Convertible 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 our 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.

Cost Containment

While our strategic initiatives have entailed increased consulting fees and professional fees during 2016, in late 2016, we reduced our headcount and consulting fees and anticipate a reduction in such costs in 2017.

Supplemental Director Option Grants

In light of the limited cash compensation paid to non-employee directors and the anticipated increased demands on non-employee directors associated with the search for and consideration of strategic alternatives, in June 2016, in addition to ordinary annual option grants to non-employee directors, we granted supplemental stock options pursuant to which each of the non-employee directors may acquire up to 150,000 shares of common stock (or an aggregate of 600,000 shares) for a term of ten years at an exercise price of $0.2201 per share. The supplement options vest: (i) 50% on the earlier of June 7, 2017 or the day preceding the next annual shareholders meeting at which directors are elected, (ii) 50% on the earlier of June 7, 2018 or the day preceding the second annual shareholders meeting (after the grant date) at which directors are to be elected, and (iii) in the event that the Company consummates a transaction(s) (after the option grant date) in the nature of a sale of shares of equity securities for cash or assets resulting in a net addition(s) to the Company’s stockholders’ equity of not less than $2 million, all unvested options vest in full.

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, 2016. 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.

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, 2016 and 2015:

	At December	At December

	31, 2015	31, 2016
Acquisition costs	$902,864	$141,318
Evaluation costs	1,976,199	2,149,863
Total	$2,879,063	$2,291,181

The carrying value of unevaluated oil and gas prospects includes $2,284,187 and $79,511 expended for properties in South America at December 31, 2016 and 2015, 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, 2016 Compared to Year Ended December 31, 2015

Oil and Gas Revenues. Total oil and gas revenues decreased 61%, to $165,910 from $429,435 in 2015.

The decrease in revenue was due to natural production declines, with no new wells drilled during 2016 to replace reserves, and a decrease in average sales price.

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2016 and 2015:

	2015	2016
Gross producing wells	9	9
Net producing wells	0.47	0.47
Net oil production (Bbls)	6,068	2,933
Net gas production (Mcf)	32,146	20,204
Oil—Average sales price per barrel	$53.64	$40.40
Gas—Average sales price per mcf	$3.23	$2.35

The change in average sales prices realized reflects fluctuations in global commodity prices. Realized prices declined sharply and steadily from fourth quarter of 2014, continuing through 2015 and into 2016 with some price recovery and stabilization during the second half of 2016.

Oil and gas sales revenues for 2016 and 2015 by region were as follows:

	Colombia	U.S.	Total
2016			
Oil sales	$ —	$118,504	$118,504
Gas sales	$ —	$47,406	$47,406
2015			
Oil sales	$ —	$325,504	$325,504
Gas sales	$ —	$103,931	$103,931

Lease Operating Expenses. Lease operating expenses, excluding joint venture expenses relating to our Colombian operations discussed below, decreased 34% to $97,203 in 2016 from $148,067 in 2015.

The decrease in total lease operating expenses was attributable to operation of fewer wells during 2016 and receipt of a severance tax abatement on one well during 2016.

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

	Colombia	U.S.	Total
2016	$ —	$97,203	$97,203
2015	$ —	$148,067	$148,067

Consistent with our business model and operating history, we experience steep declines in lease operating expenses following strategic divestitures and anticipate lease operating expenses to ramp up to levels consistent with regional costs as new wells are brought on line. With the planned drilling of our Permian Basin prospect, assuming a successful well is drilled, lease operating expenses in the U.S. and overall, are expected to increase in 2017.

Depreciation and Depletion Expense. Depreciation and depletion expense decreased by 60% to $302,782 in 2016 from $756,757 in 2015. The decrease in depreciation and depletion was due to decreased production during 2016 and a lower capital costs being completed as a result of impairment charges in 2015.

Impairment of Oil and Gas Properties. We reported an impairment charge of $584,086 during 2016 and $1,718,088 during 2015. The charge resulted from the effects of steeply lower commodity prices when applying the ceiling test under the full cost method of accounting.

General and Administrative Expenses. General and administrative expense increased by 19% to $1,830,670 in 2016 from $1,541,294 in 2015. The change in general and administrative expense reflects a combination of (1) a $114,445 increase in directors and officers insurance cost attributable to our claims history, (2) a write-off of $262,016 related to the company's escrow receivable, (3) $47,286 increase in share-based compensation expense attributable to one time option grants in 2016 and (4) costs associated with strategic initiatives undertaken during 2016, which resulted in higher legal fees and consulting fees, among others, which increases were partially offset by a decrease in salaries of $124,490 due to salary reductions.

Other Income (Expense). Other income (expense) consisted of interest earned on cash balances net of other bank fees and currency losses relating to funds held for operations in Colombia. Net other income (expense) totaled $7,206 in 2016 as compared to $(76,570) in 2015. The change was attributable to a currency loss of $97,103 during 2015.

Income Tax Expense. We reported no income tax expense in 2016 as compared to income tax expense of $18,865 in 2015.

Financial Condition

Liquidity and Capital Resources. At December 31, 2016, we had a cash balance of $481,172 and working capital of $423,795 compared to a cash balance of $2,123,520 and working capital of $2,384,283 at December 31, 2015. The decrease in cash and working capital during 2016 was attributable to the operating loss during 2016.

Cash Flows. Operating activities used $1,297,153 during 2016 compared to $1,837,977 of cash used during 2015. The change in cash used in operations was primarily attributable to a large reduction ($552,273) in accounts payable and accrued expenses during 2015.

Investing activities used $209,222 of cash during 2016 compared to $52,565 of cash used during 2015. The change in cash used in investing activities reflects an increase ($40,542) in costs associated with preparation of drilling sites and infrastructure in Colombia and development activities in the U.S. and the receipt during 2015 of proceeds from the sale of mineral interests ($56,705) and from escrow receivables ($59,412).

Financing activities used $135,973 of cash during 2016 compared to $38,152 used during 2015. In 2016 and 2015, financing activities consisted of open market purchases of 702,557 shares and 190,000 shares, respectively, of treasury stock.

Long-Term Liabilities. At December 31, 2016, we had long-term liabilities of $27,444 as compared to $25,262 at December 31, 2015. Long-term liabilities consisted of a reserve for plugging costs.

Capital and Exploration Expenditures. During 2016, we invested $209,222 for the development of oil and gas properties, consisting of (1) preparation and evaluation costs in Colombia of $170,812, and (2) costs on U.S. properties of $38,410. Of the amount invested, we capitalized $31,415 to oil and gas properties subject to amortization, and $177,807 to oil and gas properties not subject to amortization.

Planned Capital and Exploration Spending. Our principal capital and exploration expenditures relate to ongoing efforts to acquire, drill and complete prospects. We expect that future capital and exploration expenditures will be funded principally through funds on hand.

Our estimated capital expenditure budget for 2017 is approximately $4.4 million and relates to the acquisition and planned drilling of two wells on our Reeves County, Texas property. We acquired our interest in the Reeves County acreage in February 2017 for approximately $1.0 million and estimate our share of the cost of wells at $1.7 million each. We also intend to continue to seek out attractive opportunities to acquire additional acreage positions in, and outside of, the Permian Basin. Additionally, we have not budgeted any 2017 expenditures with respect to our Colombian properties. Should a resolution of ongoing permitting and other issues in Colombia be resolved, we may be required to meet certain financing commitments associated with maintaining our ownership interest in those properties. Accordingly, our actual capital expenditures during 2017 may fluctuate substantially from our current budget based on possible acreage acquisitions and drilling of additional wells as well as field conditions and factors beyond our control or the control of the operators of our properties.

Our capital expenditure budget for 2017 includes approximately $1.0 million applicable to the acquisition of the Reeves County property. That amount was paid in February 2017 and was funded by the sale of $1.2 million of 12.0% Series A Convertible Preferred Stock.

Our current financial resources are not sufficient to pay the balance of our planned 2017 capital expenditure budget. Accordingly, we expect to seek additional financing during 2017 to support our capital spending plans. We do not presently have any commitments to provide financing needed to fund our capital spending budget and there can be no assurance that such financing will be available on satisfactory terms or at all. If, for any reason, we are unable to fully fund our drilling commitments and operations, we may be subject to penalties or to the possible loss of some or all of our rights and interests in our Reeves County properties or other prospects with respect to which we fail to satisfy funding commitments.

Outlook

Continued low oil and natural gas prices during 2015 and 2016 and recurring delays in drilling of our Serrania prospect in Colombia had a significant adverse impact on our business. Our financial statements include a "going concern" qualification reflecting substantial doubt as to our ability to continue as a going concern. While we have no debt and have reduced our overhead, we continue to operate at a loss in the current low price environment. We have budgeted $3.4 million for drilling of two wells on our Reeves County, Texas property during 2017 and presently lack the financial resources to satisfy our share of budgeted drilling costs. Given those financial commitments and continuing negative cash flow from operations, we will be required to seek additional financing to support such commitment. Depending upon our ability to secure such financing and the timing and ultimate drilling results on our Reeves County, Texas property, we may be required to seek additional financing to support day-to-day operations or may be required divest certain assets in order to support operations until such point, if ever, as our revenues increase sufficiently, either through price increases or the addition of production, to cover our operating costs and overhead. We can provide no assurance that our efforts will be sufficient to reverse the trend of operating losses or to provide adequate financial resources to support our share of drilling costs associated with the Reeves County, Texas property or to sustain operations and retention of our assets pending attainment of profitable operations.

Contractual Obligations. At December 31, 2016, 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, 2016:

	Payments due by period				
	Total	< 1 year	1-3 years	3-5 years	> 5 years
Operating leases	$40,469	$40,469	$ —	$ —	$ —
Total	$40,469	$40,469	$ —	$ —	$ —

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. 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.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2016.

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 and principal financial officers, we conducted an evaluation as of December 31, 2016 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, who also serves as our principal financial officer, concluded that our disclosure controls and procedures were not effective as of December 31, 2016.

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, who also serves as principal financial 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, 2016. Such conclusion reflects our 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 these material weaknesses, 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 2016 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, 2016, and their ages and positions as of that date, are as follows:

Name	Age	Position
John P. Boylan	50	President, Chief Executive Officer and Chairman

John P. Boylan has served as our President, CEO and Chairman since April 2015 and as a director since 2006. Since 2008, Mr. Boylan has owned and operated EJC Ventures, LP, a financial and management consulting firm providing executive and financial management, asset management, corporate finance, risk management, complex financial reporting, crisis management and turnaround services to the oil and gas industry. Mr. Boylan holds a BBA with a major in Accounting from the University of Texas and an MBA with majors in Finance, Economics and International Business from New York University. Mr. Boylan is a licensed CPA in the State of Texas.

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			Filed Herewith
		Form	**Date**	**Number**	
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	
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	Participation Agreement, dated January 4, 2017, with Founders Oil and Gas III, LLC	8-K	01/05/17	10.1	
10.3	Houston American Energy Corp. 2008 Equity Incentive Plan*	Sch 14A	04/28/08	Ex A	
10.4	Form of Change in Control Agreement, dated June 11, 2012*	8-K	06/14/12	10.1	
10.5	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 GBH CPAs, PC				X
23.2	Consent of Lonquist & Co., LLC				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

* 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: March 16, 2017	HOUSTON AMERICAN ENERGY CORP. By: ***/s/ John P. Boylan*** **John P. Boylan** **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/ John P. Boylan **John P. Boylan**	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer and Principal Financial Officer)	March 16, 2017
/s/ O. Lee Tawes, III **O. Lee Tawes, III**	Director	March 16, 2017
/s/ Stephen Hartzell **Stephen Hartzell**	Director	March 16, 2017
/s/ Roy Jageman **Roy Jageman**	Director	March 16, 2017
/s/ Keith Grimes **Keith Grimes**	Director	March 16, 2017

HOUSTON AMERICAN ENERGY CORP.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

Houston American Energy Corp.

Houston, Texas

We have audited the accompanying consolidated balance sheets of Houston American Energy Corp. (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the years ended December 31, 2016 and 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Houston American Energy Corp. as of December 31, 2016 and 2015, and the results of their operations and their cash flows for the years ended December 31, 2016 and 2015, in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, The Company has suffered recurring losses from operations, which raises substantial doubt about its ability to continue as a going concern. Management's plans regarding those matters are described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ GBH CPAs, PC

www.gbhcpas.com

Houston, Texas

March 16, 2017

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HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2016	2015
ASSETS		
CURRENT ASSETS		
Cash	$481,172	$2,123,520
Escrow receivable	—	262,016
Prepaid expenses and other current assets	3,750	38,257
TOTAL CURRENT ASSETS	484,922	2,423,793
PROPERTY AND EQUIPMENT		
Oil and gas properties, full cost method		
Costs subject to amortization	55,639,333	54,840,599
Costs not being amortized	2,291,181	2,879,063
Office equipment	90,004	90,004
Total	58,020,518	57,809,666
Accumulated depletion, depreciation, amortization, and impairment	(55,563,591)	(54,676,723)
PROPERTY AND EQUIPMENT, NET	2,456,927	3,132,943
Other assets	3,167	3,167
TOTAL ASSETS	$2,945,016	$5,559,903
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$50,122	$23,195
Accrued expenses	11,005	16,315
TOTAL CURRENT LIABILITIES	61,127	39,510
LONG-TERM LIABILITIES		
Reserve for plugging and abandonment costs	27,444	25,262
TOTAL LIABILITIES	88,571	64,772
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Preferred stock, par value $0.001; 10,000,000 shares authorized, 0 shares issued and outstanding	—	—
Common stock, par value $0.001; 150,000,000 shares authorized 52,169,945 shares issued	52,170	52,170
Additional paid-in capital	66,158,593	66,019,681
Treasury shares, at cost; 892,557 and 190,000 shares, respectively	(174,125)	(38,152)
Accumulated deficit	(63,180,193)	(60,538,568)
TOTAL SHAREHOLDERS' EQUITY	2,856,445	5,495,131
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$2,945,016	$5,559,903

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

HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

FOR THE YEARS ENDED DECEMBER 31, 2016 AND 2015

	2016			2015		
OIL AND GAS REVENUE	$	165,910		$	429,435	
EXPENSES OF OPERATIONS						
Lease operating expense and severance tax		97,203			148,067	
Depreciation and depletion		302,782			756,757	
Impairment of oil and gas properties		584,086			1,718,088	
General and administrative expense		1,830,670			1,541,294	
Total operating expenses		2,814,741			4,164,206	
Loss from operations		(2,648,831	)		(3,734,771	)
OTHER INCOME (EXPENSE)						
Interest income		7,206			20,533	
Currency valuation loss		—			(97,103	)
Total other income (expense)		7,206			(392,654	)
Loss before taxes		(2,641,625	)		(3,811,341	)
Income tax expense (benefit)		—			18,865	
Net loss	$	(2,641,625	)	$	(3,830,206	)
Basic and diluted net loss per common share outstanding	$	(0.05	)	$	(0.07	)
		51,472,124			52,159,726	

Basic and diluted
weighted average
number of common
shares outstanding

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

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HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2016 and 2015

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings (Deficit)	Total
Balance at December 31, 2014	52,169,945	$52,170	$65,928,056	—	$—	$(56,708,362)	$9,271,864
Stock-based compensation	—	—	91,625	—	—	—	91,625
Acquisition of treasury stock	—	—	—	190,000	(38,152)	—	(38,152)
Net loss	—	—	—	—	—	(3,830,206)	(3,830,206)
Balance at December 31, 2015	52,169,945	52,170	66,019,681	190,000	(38,152)	(60,538,568)	5,495,131
Stock-based compensation	—	—	138,912	—	—	—	138,912
Acquisition of treasury shares	—	—	—	702,557	(135,973)	—	(135,973)
Net loss	—	—	—	—	—	(2,641,625)	(2,641,625)
Balance at December 31, 2016	52,169,945	$52,170	$66,158,593	892,557	$(174,125)	$(63,180,193)	$2,856,445

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, 2016 AND 2015

	2016	2015
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	$(2,641,625)	$(3,830,206)
Adjustments to reconcile net loss to net cash provided by (used in) operations		
Depreciation and depletion	302,782	756,757
Impairment of oil and gas properties	584,086	1,718,088
Stock-based compensation	138,912	91,625
Accretion of asset retirement obligation	552	1,329
Bad debt expense	262,016	—
Change in operating assets and liabilities:		
Increase (decrease) in insurance receivable	—	8,612,681
Decrease in prepaid expense and other current assets	34,507	86,703
Decrease in accounts payable and accrued expenses	21,617	(552,273)
Increase (decrease) in settlement payable	—	(7,000,000)
Increase (decrease) in accrued legal fees	—	(1,722,681)
Net cash used in operations	(1,297,153)	(1,837,977)
CASH FLOW FROM INVESTING ACTIVITIES		
Payments for acquisition and development of oil and gas properties and assets	(209,222)	(168,680)
Proceeds from sale of mineral interest	—	56,705
Proceeds from escrow receivable, net	—	59,412
Net cash used in investing activities	(209,222)	(52,563)
CASH FLOW FROM FINANCING ACTIVITIES		
Payment for acquisition of treasury shares	(135,973)	(38,512)
Net cash used in financing activities	(135,973)	(38,512)
INCREASE (DECREASE) IN CASH	(1,642,348)	(1,928,692)
Cash, beginning of year	2,123,520	4,052,212
Cash, end of year	$481,172	$2,123,520
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid	$—	$—
Taxes paid	$—	$18,865
SUPPLEMENTAL NON-CASH INVESTING AND FINANCING ACTIVITIES		
Net change in estimate of asset retirement obligation	$1,630	$4,214

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 on April 2, 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 located principally in the Texas Permian Basin and Gulf Coast areas of the United States and international locations with proven production, which to date has focused on Colombia, South America.

Going Concern

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 date of these consolidated financial statements. The Company has incurred continuing losses, negative operating cash flow and declining cash balances since 2011, including negative operating cash flow of $1,297,153 for the year ended December 31, 2016. These conditions, together with continued low oil and natural gas prices and financial commitments the Company has made relative to its Permian Basin and Colombian properties, raise substantial doubt as to the Company's ability to continue as a going concern for the next twelve months following the filing date of these financial statements. These financial statements do not include any adjustments that might be necessary if the Company is unable to continue as a going concern.

To address these concerns, the Company may seek additional financing or may consider divestiture of certain assets. There can be no assurance that the Company will be successful in its efforts.

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.

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.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash and cash equivalents. The Company had cash deposits of approximately $158,000 in excess of the FDIC’s current insured limit of $250,000 at December 31, 2016 for interest bearing accounts. The Company has not experienced any losses on its deposits of cash and cash equivalents.

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, 2016, the Company evaluated their receivables and determined an allowance of $262,016 related to its escrow receivable was necessary.

Oil and Gas Revenues

The Company recognizes sales revenues, net of royalties and net profits interests, based on the amount of gas, oil, and condensate sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when production has been delivered to a pipeline. The Company follows the sales method to account for natural gas imbalances. Sales may result in more or less of the Company's share of pro-rata production from certain wells. When natural gas sales volumes exceeds the Company's entitled share and the accumulated overproduced balance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company will record a liability. Historically, sales volumes have not materially differed from the Company's entitled share of natural gas production and the Company did not have a material imbalance position in terms of volumes or values at December 31, 2016 or 2015.

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 $301,786 and $754,892 for the years ended December 31, 2016 and 2015, respectively and accumulated amortization, depreciation and impairment was $55,473,698 and $54,587,826 at December 31, 2016 and 2015, 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 2016 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 2016 and 2015, the Company impaired oil and gas properties in the amount of $584,086 and $1,718,088, respectively.

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 $996 and $1,865 for 2016 and 2015, respectively, and accumulated depreciation was $89,893 and $88,897 at December 31, 2016 and 2015, 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.

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 share-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.

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. No shares of preferred stock had been issued as of December 31, 2016.

Net Loss Per Share

Basic net loss per share is computed by dividing the net loss attributable to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted net loss per share is computed by dividing the net loss attributable to common shareholders by the weighted-average number of common and common equivalent shares outstanding during the period. Common share equivalents included in the diluted computation represent shares issuable upon assumed exercise of stock options and warrants using the treasury stock and “if converted” method. For periods in which net losses are incurred, weighted average shares outstanding is the same for basic and diluted loss per share calculations, as the inclusion of common share equivalents would have an anti-dilutive effect.

For the years ended December 31, 2016 and 2015, outstanding options to purchase 5,232,165 shares of common stock and 4,432,165 shares of common stock, respectively, were excluded from the calculation of diluted net loss per share because they were anti-dilutive.

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 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.

At December 31, 2016, 89% of the Company’s net oil and gas property investment, and 0% of its revenue for the year ended December 31, 2016, was with or derived from interests operated in Colombia.

For 2016, 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, 2016 and 2015, respectively.

Subsequent Events

The Company evaluated subsequent events for disclosure from December 31, 2016 through the date the consolidated financial statements were issued.

Recent Accounting Developments

No accounting standards or interpretations issued recently are expected to a have a material impact on our consolidated financial position, operations or cash flows.

NOTE 2—ESCROW RECEIVABLE

At December 31, 2016 and December 31, 2015, the Company's balance sheet reflected the following escrow receivables relating to various oil and gas properties previously sold by the Company:

	December 31, 2016	December 31, 2015
HDC LLC and HL LLC 15% Escrow	$ —	$ 251,125
HDC LLC and HL LLC 5% Contingency	—	10,891
Total	$ —	$ 262,016

During 2016, the Company evaluated its outstanding escrow receivable and determined that an allowance for accounts receivable of $262,016 was necessary.

NOTE 3—OIL AND GAS PROPERTIES

Evaluated Oil and Gas Properties

Evaluated oil and gas properties subject to amortization at December 31, 2016 included the following:

	United States	South America	Total
Evaluated properties being amortized	$6,184,631	$49,454,702	$55,639,333
Accumulated depreciation, depletion, amortization and impairment	(6,018,996)	(49,454,702)	(55,473,698)
Net capitalized costs	$165,635	$—	$165,635

Evaluated oil and gas properties subject to amortization at December 31, 2015 included the following:

	United States	South America	Total
Evaluated properties being amortized	$5,385,898	$49,454,702	$54,840,600
Accumulated depreciation, depletion, amortization and impairment	(5,133,124)	(49,454,702)	(54,587,826)
Net capitalized costs	$252,774	$—	$252,774

Unevaluated Oil and Gas Properties

Unevaluated oil and gas properties not subject to amortization at December 31, 2016 included the following:

	United States	South America	Total
Leasehold acquisition costs	$—	$141,318	$141,318
Geological, geophysical, screening and evaluation costs	6,994	2,142,869	2,149,863
Total	$6,994	$2,284,187	$2,291,181

Unevaluated oil and gas properties not subject to amortization at December 31, 2015 included the following:

	United States	South America	Total
Leasehold acquisition costs	$761,545	$141,319	$902,864
Geological, geophysical, screening and evaluation costs	4,143	1,972,056	1,976,199
Total	$765,688	$2,133,375	$2,876,199

NOTE 4—Asset Retirement Obligations

The following table describes changes in our asset retirement liability during each of the years ended December 31, 2016 and 2015.

	2016	2015
ARO liability at January 1	$25,262	$28,147
Accretion expense	552	1,329
Changes in estimates	1,630	(4,214)
ARO liability at December 31	$27,444	$25,262

NOTE 5—STOCK-BASED COMPENSATION

On August 12, 2005, the Company's Board of Directors adopted the Houston American Energy Corp. 2005 Stock Option Plan (the "2005 Plan"). The terms of the 2005 Plan allow for the issuance of up to 500,000 options to purchase 500,000 shares of the Company's common stock.

In 2008, the Company's Board of Directors adopted the Houston American Energy Corp. 2008 Equity Incentive Plan (the "2008 Plan" and, together with the 2005 Plan, the "Plans"). 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. Persons eligible to participate in the Plans are key employees, consultants and directors of the Company.

Stock Option Activity

In 2015, options to purchase an aggregate of 8,333 shares were granted to a new non-employee director, options to purchase an aggregate of 900,000 shares were granted to a new officer and options to purchase an aggregate of 200,000 shares were granted to non-employee directors.

The 8,333 options granted to a new non-employee director vested 20% on the grant date and vest as to the remaining 80% nine months from the grant date, have a ten-year life and have an exercise price of $0.2158 per share. The option grant to the non-employee director was valued on the date of grant at $805 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.36%, (2) expected life in years of 4.98, and (3) expected stock volatility of 106%. The Company determined the option qualifies as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

The 900,000 options granted to an employee have a ten year life and an exercise price of $0.2158 per share and vest 1/3 on each of the first three anniversaries of the grant date, subject to acceleration of vesting in the event of certain changes in control or (i) the receipt of $10 million or more in aggregate gross proceeds from the sale of equity securities or securities convertible into equity securities, or (ii) the acquisition by the Company of $10 million or more in aggregate purchase price of oil and gas properties. The option grant to the employee was valued on the date of grant at $82,000 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of1.36%, (2) expected life in years of 4.98, and (3) expected stock volatility of 106%. The Company determined the option qualifies as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

The 200,000 options granted to non-employee directors vested 20% on the grant date and vest as to the remaining 80% nine months from the grant date, have a ten-year life and have an exercise price of $0.2028 per share. The option grants to non-employee directors were valued on the date of grant at $17,370 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.73% (2) expected life in years of 5.01, and (3) expected stock volatility of 105%. The Company determined the options qualify as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In March 2016, options to purchase an aggregate of 20,000 shares were granted to non-employee directors. The options were granted in connection with service on an ad hoc board committee and vest on the earlier of August 15, 2016, the termination of the committee or termination of service on the committee due to death or disability. The options have a five-year life and an exercise price of $0.1982 per share. The options were valued on the date of grant at $2,896 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.49%; (2) expected life in years of 4.99; (3) expected stock volatility of 106.95%; (4) expected dividend yield of 0%; and (5) forfeiture rate of 15.22%. The Company determined the options qualify as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

In June 2016, options to purchase an aggregate of 800,000 shares were granted to non-employee directors. The options, which included a one-time supplemental grant to purchase an aggregate of 600,000 shares, were granted in connection with service on the board of directors. 200,000 of the options granted to non-employee directors vested 20% on the grant date and vest as to the remaining 80% nine months from the grant date, have a ten-year life and have an exercise price of $0.2201 per share. Those option grants were valued on the date of grant at $32,640 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.26%; (2) expected life in years of 5.28; (3) expected stock volatility of 108.5%; (4) expected dividend yield of 0%; and (5) forfeiture rate of 15.01%. 600,000 of the options granted to non-employee directors vest (i) 50% on the earlier of June 7, 2017 or the day preceding the next annual shareholders meeting at which directors are elected, (ii) 50% on the earlier of June 7, 2018 or the day preceding the second annual shareholders meeting (after the grant date) at which directors are to be elected, and (iii) in the event that the Company consummates a transaction(s) (after the option grant date) in the nature of a sale of shares of equity securities for cash or assets resulting in a net addition(s) to the Company’s stockholders’ equity of not less than $2 million, all unvested options vest in full. Those options have a ten-year life and have an exercise price of $0.2201 per share. Those option grants were valued on the date of grant at $83,421 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.26% (2) expected life in years of 5.28, and (3) expected stock volatility of 108.5%. The Company determined the option qualifies as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

Option activity during 2016 and 2015 was as follows:

	Options	Weighted	Weighted	**Aggregate**
		Average	Average	**Intrinsic**

		Exercise Price	Remaining Contractual Term (in Years)	**Value**
Outstanding at December 31, 2014	3,392,832	$ 3.21		
Granted	1,108,333	$ 0.21		
Exercised	—	$ —		
Forfeited	(69,000)	$ 2.55		
Outstanding at December 31, 2015	4,432,165	$ 2.47		
Granted	820,000	$ 0.22		
Exercised	—	$ —		
Forfeited	(20,000)	$ 4.10		
Outstanding at December 31, 2016	5,232,165	$ 2.11	6.35	$ —

During 2016 and 2015, the Company recognized $138,912 and $91,625, 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, 2016, non-vested options totaled 1,310,000 and total unrecognized stock-based compensation expense related to non-vested stock options was $120,687. The unrecognized expense is expected to be recognized over a weighted average period of 1.23 years. The weighted average remaining contractual term of the outstanding options and exercisable options at December 31, 2016 is 6.35 years and 5.50 years, respectively.

As of December 31, 2016, there were 767,835 shares of common stock available for issuance pursuant to future stock or option grants under the Plans.

Share-Based Compensation Expense

The following table reflects share-based compensation recorded by the Company for 2016 and 2015:

	2016	2015
Share-based compensation expense included in general and administrative expense	$138,911	$91,625
Earnings per share effect of share-based compensation expense	$(0.00)	$(0.00)

Treasury Stock

We account for repurchases of common stock using the cost method with common stock in treasury classified in the consolidated balance sheets as a reduction of shareholders' equity. During the years ending December 31, 2016 and 2015, the Company acquired 702,557 and 190,000 shares of common stock, respectively, for $135,973 and $38,152, respectively.

NOTE 6—TAXES

The following table sets forth a reconciliation of the statutory federal income tax for the years ending December 31, 2016 and 2015.

	2016	2015

Income (loss) before income taxes	$(2,641,625)	$(3,811,341)
Income tax expense (benefit) computed at statutory rates	$(924,569)	$(1,333,969)
Permanent differences, nondeductible expenses	514	501
Increase (decrease) in valuation allowance	874,987	635,888
Return to accrual items	—	(764)
Other adjustment	49,068	717,209
NOL adjustment	—	—
Tax provision	$—	$18,865
Total provision		
Foreign	$—	$18,865
Total provision (benefit)	$—	$18,865

At December 31, 2016 the Company has a federal tax loss carry forward of $48,205,895 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, 2016 and 2015 are set out below.

	2016	2015
Non-Current Deferred tax assets:		
Net operating loss carry forward	$ 16,872,064	$ 16,255,870
Foreign tax credit carry forward	505,745	505,745
Deferred state tax	23,277	23,277
Stock compensation	3,090,907	3,091,356
Book in excess of tax depreciation, depletion and capitalization methods on oil and gas properties	(454,590)	(713,832)
Other	(327,600)	(327,600)
Colombia future tax obligations	—	—
Total Non-Current Deferred tax assets	19,709,803	18,834,816
Valuation Allowance	(19,709,803)	(18,834,816)
Net deferred tax asset	$ —	$ —

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 2016 and 2015, we recorded foreign tax expense of $0 and $18,865, respectively.

NOTE 7—RELATED PARTIES

In conjunction with the Company's efforts to secure oil and gas prospects, financing and services, in lieu of salary or other forms of compensation, during 2005, the Company granted to John F. Terwilliger, a principal shareholder and then Chief Executive Officer, and Orrie L. Tawes, a principal shareholder and Director, overriding royalty interests (ORRI) in select mineral properties of the Company, including all current and future properties in Colombia in which Messrs. Terwilliger and Tawes each hold a 1.5% ORRI. During 2016 and 2015, Mr. Terwilliger received royalty payments relating to those properties totaling $0 and $919, respectively, and Mr. Tawes received royalty payments relating to those properties totaling $0 and $919, respectively.

NOTE 8—COMMITMENTS AND CONTINGENCIES

Lease Commitment

The Company leases office facilities under an operating lease agreement that expires May 31, 2017. The lease agreement requires future payments as follows:

Year	**Amount**
2017	$40,479
Total	$40,479

Total rental expense was $107,620 and $95,711 in 2016 and 2015, 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.

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 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 2016, no grants were made under the plan.

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. The obligation associated with the plan totaled $0 at December 31, 2016.

NOTE 9—SUBSEQUENT EVENTS

In January 2017, we executed an agreement to acquire a 25% working interest, subject to a proportionate 5% back-in after prospect payout, in two lease blocks in Reeves County, Texas. In February 2017, we completed the acquisition of a working interest in 717 acres in Reeves County, Texas at a price of $986,000. The acreage lay in the Delaware Basin region of the larger Permian Basin. Founders Oil & Gas, our operator anticipates drilling an initial well on the acreage commencing on or about the first week of May 2017 and drilling a second well before year-end 2017. Our share of drilling cost for the initial well is estimated at $1.7 million. The well is expected to target the Wolfcamp A shale formation.

In order to fund our acquisition of the Reeves County, Texas acreage, in January 2017, we issued 1,200 shares of 12% Series A Convertible Preferred Stock for aggregate gross proceeds of $1.2 million. The Series A Convertible 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 our 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.

NOTE 10—GEOGRAPHICAL INFORMATION

The Company currently has operations in two geographical areas, the United States and Colombia. Revenues for the years ended December 31, 2016 and 2015 and long-lived assets as of December 31, 2016 and 2015 attributable to each geographical area are presented below:

	2016		2015	
	Revenues	**Long Lived Assets, Net**	Revenues	**Long Lived Assets, Net**
North America	$165,910	$260,110	$429,435	$1,019,569
South America	—	2,284,187	—	2,113,374
Total	$165,910	$2,544,297	$429,435	$3,132,943

NOTE 11—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:

	2016	2015
Revenues		
North America	$165,910	$429,435
South America	—	—
	$165,910	$429,435
Production Cost		
North America	$97,203	$148,067
South America	—	—
	$97,203	$148,067

Capital Costs

Capitalized costs and accumulated depletion relating to the Company's oil and gas producing activities as of December 31, 2016, 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	$ 6,994	$ 2,284,187	$ 2,291,181
Proved properties being amortized	6,184,631	49,454,702	55,639,333
Accumulated depreciation, depletion, amortization and impairment	(6,018,996)	(49,454,702)	(55,473,698)
Net capitalized costs	$ 172,629	$ 2,284,187	$ 2,456,816

Amortization Rate

The amortization rate per unit based on barrel of oil equivalents was $48.57 for the United States and $0 for South America for the year ended December 31, 2016.

Acquisition, Exploration and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities as of December 31, 2016 and 2015 are summarized below:

	2016	
	United States	**South America**
Property acquisition costs:		
Proved	$—	$—
Unproved	6,994	—
Exploration costs	31,415	170,812
Development costs	—	—
Total costs incurred	$38,409	$170,812

	2015	
	United States	**South America**
Property acquisition costs:		
Proved	$16,669	$—
Unproved	—	—
Exploration costs	72,500	79,511
Development costs	—	—
Total costs incurred	$89,169	$79,511

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

In December 2009, the Company adopted revised oil and gas reserve estimation and disclosure requirements. The primary impact of the new disclosures is to conform the definition of proved reserves with the SEC Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. The accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be 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. The unaudited supplemental information on oil and gas exploration and production activities has been presented in accordance with the new reserve estimation and disclosure rules. 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 Lonquist & Co., LLC ("Lonquist"), utilizing reserve definitions and pricing requirements prescribed by the SEC. Lonquist is an independent professional engineering firm specializing in the technical and financial evaluation of oil and gas assets. 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. Lonquist and its 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, 2014	72,710	34,130	—	—	72,710	34,130
Revisions of prior estimates	17,136	(19,212)	—	—	17,136	(19,212)
Production	(32,146)	(6,068)	—	—	(32,146)	(6,068)
Balance December 31, 2015	57,700	8,850	—	—	57,700	8,850
Revisions to prior estimates	2,524	2,763	—	—	2,524	2,763
Production	(20,204)	(2,933)	—	—	(20,204)	(2,933)
Balance December 31, 2016	40,020	8,680	—	—	40,020	8,680
Proved developed reserves						
at December 31, 2015	57,700	8,850	—	—	57,700	8,850
at December 31, 2016	40,020	8,680	—	—	40,020	8,680
Proved undeveloped reserves						
at December 31, 2015	—	—	—	—	—	—
at December 31, 2016	—	—	—	—	—	—

As of December 31, 2016 and December 31, 2015, the Company had no proved undeveloped ("PUD") reserves. No PUD reserves were converted to proved developed producing reserves in 2016 or 2015.

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, 2016:

	United States	South America	Total
Future cash flows from sales of oil and gas	$460,760	$ —	$460,760
Future production cost	(264,730)	—	(264,730)
Future net cash flows	196,030	—	196,030
10% annual discount for timing of cash flow	(31,900)	—	(31,900)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$164,130	$ —	$164,130
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(68,707)	—	(68,707)
Change due to revisions in standardized variables:			
Accretion of discount	25,438	—	25,438
Net change in sales and transfer price, net of production costs	(147,362)	—	(147,362)
Revision and others	(43,109)	—	(43,109)
Changes in production rates and other	143,490	—	143,490
Net	(90,250)	—	(90,250)
Beginning of year	254,380	—	254,380
End of year	$164,130	$ —	$164,130

Standardized measure of discounted future net cash flows at December 31, 2015:

	United States	South America	Total
Future cash flows from sales of oil and gas	$611,520	$ —	$611,520
Future production cost	(308,020)	—	(308,020)
Future net cash flows	303,500	—	303,500
10% annual discount for timing of cash flow	(49,120)	—	(49,120)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$254,380	$ —	$254,380
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(281,368)	—	(285,582)
Change due to revisions in standardized variables:			
Accretion of discount	183,828	—	183,828

Net change in sales and transfer price, net of production costs	(405,129)	—	(405,129)
Revision and others	(176,014)	—	(176,014)
Changes in production rates and other	(617,498)	—	(613,285)
Net	(1,296,181)	—	(1,296,181)
Beginning of year	1,550,561	—	1,550,561
End of year	$254,380	$ —	$254,380

NOTE 12—SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
2016				
Operating revenue	$48,260	$33,887	$39,738	$44,025
Loss from operations	(343,411)	(492,202)	(371,192)	(1,442,026)
Net loss	(339,451)	(490,406)	(370,343)	(1,441,425)
Loss per common share – basic	$(0.01)	$(0.01)	$(0.01)	$(0.03)
Loss per common share – diluted	$(0.01)	$(0.01)	$(0.01)	$(0.03)
2015				
Operating revenue	$101,971	$114,122	$124,448	$88,894
Loss from operations	(1,191,769)	(339,488)	(468,332)	(1,735,182)
Net loss	(1,187,064)	(351,808)	(463,566)	(1,827,768)
Loss per common share – basic	$(0.02)	$(0.01)	$(0.01)	$(0.04)
Loss per common share – diluted	$(0.02)	$(0.01)	$(0.01)	$(0.04)