HOUSTON AMERICAN ENERGY CORP
Form 10-K
March 14, 2014

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, 2013

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

For the transition period from to

Commission File No. 1-32955

HOUSTON AMERICAN ENERGY CORP.
(Exact name of registrant specified in its charter)

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

801 Travis Street, Suite 1425, Houston, Texas 77002
(Address of principal executive offices)(Zip code)

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

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

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

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 o

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 o Accelerated filer o Non-accelerated filer o 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 o No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2013, based on the closing sales price of the registrant's common stock on that date, was approximately $10.9 million. Shares of common stock held by each current executive officer and director and by each person known by the registrant to own 5% 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 3, 2014 was 52,169,945.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for its 2014 Annual Meeting are incorporated by reference into Part III of this Report.

TABLE OF CONTENTS

Table of Contents

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. Gulf Coast region and in South America. Our oil and gas reserves and operations are concentrated primarily in the South American country of Colombia and in the onshore Gulf Coast region, particularly Texas and Louisiana.

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 South America and the U.S. Gulf Coast. We typically seek to partner with 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, 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 South America, particularly Colombia, and in the onshore Texas Gulf Coast region and Louisiana.

Each of our properties differs 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 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.

Table of Contents

The following table sets forth information relating to our principal properties as of December 31, 2013:

					2013 Net Production	
	Net acreage	Average working interest %	Gross producing wells	Net proved reserves (boe)	Oil (bbls)	Natural Gas (mcf)
Oklahoma	4	2.4 %	1	1,293	8.67	709.20
Louisiana	679	13.2 %	3	15,562	2,849.09	8,111.50
Texas	59	4.4 %	2	430	105.45	638.05
Total U.S.	742	11.1 %	6	17,285	2,963.21	9,458.75
Colombia	49,025	12.5 %	—	—	—	—
Total	49,767	12.4 %	6	17,285	2,963.21	9,458.75

- United States Properties:

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

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 1,300+ net acre lease block on which a 11,000 foot test of the Bol Mex and Nonioin Struma 1, 2, 3, 4 and 5 sands was drilled in early 2014 and is awaiting completion.

Plaquemines Parish — we hold a 1.8% working interest in the SL 180771 well and prospect which covers 300 gross acres.

Vermilion Parish — we hold a 1.5% working interest in a 450+ net acre lease block on which a 15,000 foot test of the Discorbis 1, 2, 3, 4 and 5 sands in planned for the first half of 2014.

Iberville Parish — we hold a 3% working interest in a 618 acre lease block in Iberville Parish, Louisiana. A 13,500 foot test of the Cib Haz Sands was successfully drilled and completed as a producer and was tested in January 2014 with production expected to commence upon construction of production facilities.

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 well drilled in February 2014 testing the Cris H stringer and Cris H sand in Jefferson Davis Parish, Louisiana.

Texas Properties

Our principal exploration properties in Texas consist of the following:

Jim Hogg County — we hold a 4.375% working interest in the 340 acre Hog Heaven Prospect in Jim Hogg County, Texas. At December 31, 2013, the Hog Heaven Prospect produced gas from a single 6,200-foot well. We have no present plans to drill additional wells on the Hog Heaven Prospect.

Matagorda County — we hold a 2.71% working interest in the 779 acre Harrison Prospect in Matagorda County, Texas. We have no present plans to drill on the Harrison Prospect.

South Texas — we hold a 25% working interest in a 40 acre lease block in South Texas supported by 3-D seismic data. A 5,700 foot test of the Pettus and Yegua Sands was drilled in early 2014 and is awaiting testing and completion.

Jasper County — in February 2014, we acquired a 13.33% working interest before the casing point and a 10% working interest after the casing point in a 320 acre Prospect in Jasper County, Texas. A 11,950 foot test of the Wilcox 3 and 4 Sands is planned for early 2014.

Table of Contents

- Colombian Properties:

At December 31, 2013, 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, 2013:

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, 2013 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, 2013, no production had taken place on any of the fields in our then existing concessions in Colombia.

For 2014, Hupecol has advised us that they plan to drill the first two wells on the Serrania concession as well as begin seismic on the Los Picachos and Macaya concessions. Hupecol had previously advised that those same planned operations would take place during 2013. Hupecol’s drilling and seismic plans for 2014 may change based on field conditions and other factors beyond our control or the control of Hupecol. Our estimated net cost associated with drilling the first two wells on the Serrania concession as well as our portion of the seismic expenses related to the Los Picachos and Macaya concessions is approximately $2.5 million.

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.

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.

Los Picachos and Macaya Prospects

Our Los Picachos and Macaya prospects adjoin our Serrania concession. Hupecol has advised us that they plan to begin seismic on the Los Picachos and Macaya concessions during 2014, subject to conditions in the area allowing operations. The ANH has granted extensions of required development commitments, including seismic acquisition, until conditions in the area allow operations.

Table of Contents

Drilling Activity

During 2013, we participated in the drilling of a total of one gross well, which well was in the United States. The well was classified as exploratory. Our 2013 drilling program achieved a 100% success rate. The following table summarizes the number of wells drilled during 2013, 2012, and 2011, 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,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	—	—	2(1)	0.032	2	0.032
Non-productive	—	—	—	—	—	—
Total development wells	—	—	2	0.032	2	0.032
Exploratory wells, completed as:						
Productive	1	0.03	—	—	5	0.080
Non-productive	—	—	3	1.125	6	0.096
Total exploratory wells	1	0.03	3	1.125	11	0.176

(1) Consists of wells drilled on the La Cuerva prospect, which were sold along with the prospect during 2012.

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, 2013, we had no wells in progress or awaiting completion.

In addition to the well drilled, during 2013, the operator of the Crown Paper #1 well in East Baton Rouge Parish, Louisiana successfully carried out a recompletion of the well.

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, 2013, we owned interests in 6 gross wells. As of December 31, 2013, we had ownership interests in productive wells, categorized by geographic area, as follows:

	Oil Wells	Gas Wells
United States		
Gross	1	5
Net	0.03	0.15
Colombia		
Gross	—	—
Net	—	—
Total		
Gross	1	5
Net	0.03	0.15

Table of Contents

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, 2013:

	Year Ended December 31,		
	2013	2012	2011
Net Production:			
Gas (Mcf):			
United States	9,459	12,066	10,838
Colombia	—	—	—
Total	9,459	12,066	10,838
Oil (Bbls):			
United States	2,963	1,032	1,092
Colombia	—	1,755	9,924
Total	2,963	2,787	11,016
Average sales price:			
Gas ($ per Mcf)			
United States	$4.32	$3.22	$3.90
Colombia	—	—	—
Total	4.32	3.22	3.90
Oil ($ per Bbl)			
United States	103.36	105.91	97.10
Colombia	—	110.36	101.56
Total	103.36	108.71	101.12
Average production costs ($ per BOE):			
United States	18.01	25.00	16.05
Colombia	—	68.00	80.13
Total	$18.01	$40.72	$65.65

Natural Gas and Oil Reserves

Reserve Estimates

The following tables sets forth, by country and as of December 31, 2013, 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.

7

Table of Contents

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

	Reserves [1]		
	Oil (bbls)	Natural Gas (mcf)	Total [2] (boe)
Reserve category			
Proved Developed			
United States	11,150	36,810	17,285
Colombia	—	—	—
Total Proved Developed Reserves	11,150	36,810	17,285
Proved Undeveloped			
United States	—	—	—
Colombia	—	—	—
Total Proved Undeveloped Reserves	—	—	—
Total Proved Reserves	11,150	36,810	17,285

	Proved Developed	Proved Undeveloped	Total Proved
PV-10 [1]	$ 733,560	$ —	$ 733,560
Standardized measure [3]	$ 719,035	$ —	$ 719,035

(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, 2013. 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, 2013. The average prices utilized for purposes of estimating our proved reserves were $104.80 per barrel of oil and $3.98 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.

Table of Contents

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, 2013 and 2012, 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, 2013:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States	13,317	646	1,979	96
Colombia	—	—	392,205	49,025
Total	13,317	646	394,184	49,121

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, 2013, the expiration periods of the gross and net acres that are subject to leases or concessions summarized in the above table of undeveloped acreage.

Table of Contents

Twelve Months Ending:	Undeveloped Acres Expiring Gross	Net
December 31, 2014	—	—
December 31, 2015	—	—
December 31, 2016	1,979	96
December 31, 2017 and later	392,205	49,025
Total	394,184	49,121

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, 2013, 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, 2013, we had 2 full-time employees and no part time employees. The employees are not covered by a collective bargaining agreement, and we do not anticipate that any of our future employees will be covered by such agreements.

Competition

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

Regulatory Matters

Regulation of Oil and Gas Production, Sales and Transportation

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

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents
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 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.

Table of Contents

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.

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;

Table of Contents

reductions in oil and natural gas prices;

title problems; and

limitations in the market for oil and natural gas.

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

We 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.

Table of Contents

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. As 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.

We may need additional financing to support operations and future capital commitments.

At December 31, 2013, our estimated drilling budget for 2014 was approximately $4.7 million, principally relating to the drilling of two test wells on the Serrania prospect, shooting seismic on the Los Picachos and Macaya Concessions and funding our estimated share of drilling costs on domestic prospects. While we believe that our cash on hand at December 31, 2013 will support or drilling budget and overhead during 2014, there is no assurance that we will not require additional financing to support drilling operations and other cash requirements during 2014 or in future years. 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 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 2014 drilling budget and to support future acquisitions and development activities.

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. 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.

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;

Table of Contents

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.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices will also negatively impact the value of our proved reserves. A substantial or 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.

Global economic growth drives demand for energy from all sources, including fossil fuels. Should the U.S. and global economies experience weakness, such as that experienced during the global financial crisis of 2008-2009, demand for energy and accompanying commodity prices may decline and our financial position may deteriorate along with our ability to operate profitably and our ability to obtain financing to support operations and the cost and terms of the same, is unclear. With respect to our business, the crisis experienced during the 2008-2009 period resulted in a steep decline in the price of oil and natural gas, a marked decline in the value of our reserves, a determination in March 2009 to temporarily shut-in production from our Colombian wells and reduced revenues and profitability.

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

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have and may be required to further write down the carrying value of our oil and natural gas properties. 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.

Table of Contents

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

Our operations in Colombia are subject to 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 will 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. In the event of a significant negative change in the political or economic climate in Colombia, we may be forced to abandon or suspend our operations in Colombia.

A 40-year armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups—both funded by the drug trade—continues in Colombia. Insurgents continue to attack civilians and violent guerilla activity continues in many parts of the country. While our operators take measures to protect our assets, operations and personnel from guerilla activity, continuing attempts to reduce or prevent guerilla activity may not be successful and guerilla activity may disrupt our operations in the future. 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.

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 counternarcotics agreements may result in any of the following:

all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended;

the Export-Import Bank of the United States and the Overseas Private Investment Corporation would not approve financing for new projects in Colombia;

United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes; and

the President of the United States and Congress would retain the right to apply future 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. The United States may impose sanctions on Colombia in the future, and we cannot predict the effect in Colombia that these sanctions might cause.

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 a substantial portion 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.

Table of Contents

In addition to the control exercised by Hupecol with respect to the properties it operates, as minority owners, we are, or may be, subject to substantial control of other properties in Colombia in which we hold interests that are operated by third party operators, other than Hupecol. Our Colombian assets presently consist, and in the future are expected to continue to consist, exclusively of minority, non-operator project interests in certain Colombian assets owned and operated by third party operators. Our passive investments in such Colombian assets constitute our principal assets, and as a result, our financial results are directly affected by the independent strategies and decisions of the operators of those properties.

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

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

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

Our Colombian assets constitute our principal assets and consist exclusively of minority, non-operator project interests. 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.

Table of Contents

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.

Table of Contents

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The Obama Administration has proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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 management team and other key personnel, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to attract and retain our management and non-management employees, including engineers, geoscientists and other technical and professional staff and, in particular, our President, John Terwilliger, who is principally responsible for sourcing our resource plays. We will depend, to a large extent, on the efforts, technical expertise and continued employment of such personnel and members of our management team. If members of our management team 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;

Table of Contents

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 is conducting an investigation of our company.

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.

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.

Our management owns a significant amount of our common stock, giving them influence or control in corporate transactions and other matters, and their interests could differ from those of other shareholders.

At December 31, 2013, our directors and executive officers owned approximately 22% of our outstanding common stock. As a result, our current directors and executive officers are in a position to significantly influence or control the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of incorporation or bylaws, and the approval of mergers and other significant corporate transactions. Such level of control of the Company may delay or prevent a change of control on terms favorable to the other shareholders and may adversely affect the voting and other rights of other shareholders.

Table of Contents

We may incur costs and be subject to sanctions and uncertainties relating to the ongoing investigation of our company by the SEC.

We are the subject of an ongoing formal investigation by the SEC. Pursuant to the investigation, we received subpoenas issued by the SEC calling for the testimony of our principal officers and the delivery of certain documents. The subpoenas were issued pursuant to a nonpublic formal order of private investigation issued by the SEC on March 1, 2011, which followed a nonpublic informal inquiry commenced by the SEC in October 2010. After investigation by the SEC of possible violations of the federal securities laws, in August 2013, we, and our CEO, received a so-called “Wells” notice advising that the staff of the SEC has made a preliminary recommendation to initiate an enforcement action and providing the opportunity to provide reasons of law, policy or fact why the proposed enforcement action should not be filed. The commencement of an enforcement action and an ultimate finding that we have violated the U.S. securities laws would likely have a material adverse effect on our consolidated financial position, results of operations or cash flows.

We could be negatively impacted by securities class action complaints.

On April 27, 2012, a purported class action lawsuit was filed in the U.S. District Court for the Southern District of Texas against us and certain of our executive officers, which we refer to as the Silverman litigation. The complaint generally alleges that, between March 29, 2010 and April 18, 2012, all of the defendants violated Sections 10(b) of the Securities Exchange Act of 1934 and SEC Rule 10b-5 and the individual defendants violated Section 20(a) of the Exchange Act in making materially false and misleading statements including certain statements related to the status and viability of the first test well on the CPO 4 prospect. The complaint seeks unspecified damages, interest, attorneys’ fees, and other costs. In August 2013, our motion to dismiss the Silverman litigation was granted after which the plaintiffs filed an appeal of such motion. The case remains pending on appeal. It will take time and money to defend against this suit and may distract us from more productive activities. We may not be successful in defending this litigation, and insurance proceeds may not be sufficient to cover any liability under such claims. If the plaintiffs in the Silverman litigation, or the plaintiffs in any other class action litigation, are successful in their litigation, the payment by us of damages, interest, attorneys’ fees and costs would have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

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.”

Table of Contents
Item 3. Legal Proceedings

On April 27, 2012, a purported class action lawsuit was filed in the U.S. District Court for the Southern District of Texas against us and certain of our executive officers: Steve Silverman v. Houston American Energy Corp. et al., Case No. 4:12-CV-1332. The complaint generally alleges that, between March 29, 2010 and April 18, 2012, all of the defendants violated Sections 10(b) of the Securities Exchange Act of 1934 and SEC Rule 10b-5 and the individual defendants violated Section 20(a) of the Exchange Act in making materially false and misleading statements including certain statements related to the status and viability of the Tamandua #1 well. Two additional class action lawsuits were filed against us in May 2012. The complaints seek unspecified damages, interest, attorneys' fees, and other costs. On September 20, 2012, the court consolidated the class action lawsuits and appointed a lead plaintiff and on November 15, 2012 the lead plaintiffs filed an amended complaint. On January 14, 2013, we filed a motion to dismiss and, on August 22, 2013, the court granted our motion and dismissed the complaint. The plaintiffs have since filed a Notice of Appeal of the dismissal of the complaint and the appeal is presently pending before the U.S. Court of Appeals for the Fifth Circuit. We believe all of the claims in the consolidated class action lawsuits are without merit and intend to vigorously defend against these claims. It is not possible at this time to predict the timing or outcome of the class action lawsuits that have or may be filed.

On July 19, 2012, a purported derivative cause of action was filed in the U.S. District Court for the Southern District of Texas against certain of our directors and officers and Houston American Energy, as nominal defendant: E. Howard King, Jr., derivatively, on behalf of Houston American Energy Corp., v. John F. Terwilliger, John P. Boylan, Orrie Lee Tawes III, Stephen Hartzell, James J. Jacobs, Kenneth A. Jeffers, defendants, and Houston American Energy Corp., as nominal defendant, Case No. 4:12-CV-02182. The complaint asserts a cause of action by a shareholder on behalf of Houston American against certain of our directors and senior executive officers in connection with the June 11, 2012 approval of payment of certain bonuses, increases in salary, grant of certain stock options and entry into certain Change in Control Agreements. The complaint alleges that the approval of such matters constituted breach of fiduciary duty and corporate waste and seeks injunctive relief to bar each of the actions in question and seeks restitution. No damages have been or, by the nature of the derivative cause of action, are expected to be alleged against us. On February 26, 2013, an order was entered granting a motion by the Company to dismiss the lawsuit and providing leave to the plaintiff to amend its complaint to cure pleading deficiencies. The Plaintiff's allotted time to amend its complaint by the Court expired on March 26, 2013, and no amendment was made by the Plaintiff, effectively ending the lawsuit.

At December 31, 2013, the Company was the subject of a formal investigation being conducted by the Securities and Exchange Commission (the "SEC"). Pursuant to the investigation, the Company received subpoenas issued by the SEC. The subpoenas called for the testimony of certain of the Company's officers and the delivery of certain documents. The subpoenas were issued pursuant to a nonpublic formal order of private investigation issued by the SEC on March 1, 2011, which followed a nonpublic informal inquiry commenced by the SEC in October 2010. The Company received a copy of the nonpublic formal order of private investigation on February 10, 2012 in connection with a subpoena issued by the SEC. The SEC is investigating whether there have been any violations of the federal securities laws and has focused on matters relating to disclosures in the late 2009 and early 2010 time period regarding resource potential for the CPO 4 prospect. The Company has presented information supporting its disclosure relative to resource potential on the CPO 4 prospect. On August 29, 2013, the Company and John Terwilliger received a "Wells" notice advising them that the staff of the SEC has made a preliminary recommendation to initiate an enforcement action and providing them an opportunity to provide reasons of law, policy or fact why the proposed enforcement action should not be filed. The Company has cooperated fully, and is committed to continuing to cooperate fully, with the SEC in this matter. It is not possible at this time to predict the timing or outcome of the SEC investigation, including whether or when any proceedings might be initiated, when these matters may be resolved or what, if any, penalties or other remedies may be imposed, and whether any such penalties or remedies would have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

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 (“NYSE”) 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 2013	Fourth Quarter	$0.35	$0.23
	Third Quarter	0.39	0.24
	Second Quarter	0.48	0.18
	First Quarter	0.36	0.20
Calendar Year 2012	Fourth Quarter	$1.06	$0.19
	Third Quarter	1.65	0.78
	Second Quarter	5.35	0.75
	First Quarter	14.73	5.02

At March 3, 2014, the closing price of the common stock on NYSE MKT was $0.38 per share.

Holders

As of March 3, 2014, there were approximately 3,029 shareholders of record of our common stock.

Dividends

No dividends were paid during calendar years 2012 or 2013. 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, 2013 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	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans

	rights (a)			(excluding securities reflected in column (a))
Equity compensation plans approved by security holders [1]	2,592,832	$	4.07	3,907,168
Equity compensation plans not approved by security holders	—		—	—
	2,592,832		4.07	3,907,168

(1) Consists of 500,000 shares reserved for issuance 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.

Table of Contents

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. Gulf Coast region and in South America. Our oil and gas reserves and operations are concentrated primarily in the South American country of Colombia and in the onshore Gulf Coast region, particularly Texas and Louisiana.

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 South America and the U.S. Gulf Coast. We 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

Drilling Activity

During 2013, we drilled one well in Iberville Parish, Louisiana. The well was successfully completed in December 2013, tested in January 2014 and is awaiting hook up with production expected to commence in the second quarter of 2014.

At December 31, 2013, we had no wells drilling.

Subsequent to December 31, 2013, we (1) successfully drilled and completed a 7,000 foot test well in Jefferson Davis Parish, Louisiana with the well awaiting testing and hook up before anticipated commencement of production; (2) successfully drilled an 11,000 foot test well in East Baton Rouge Parish, Louisiana with the well awaiting testing and completion; (3) successfully drilled a 5,700 foot test well in South Texas with the well undergoing testing and awaiting completion; and (4) drilled a 4,000 foot dry hole in South Texas.

Sale of La Cuerva and LLA 62 Blocks

During the first quarter of 2012, we sold all of our interest in Hupecol Cuerva, LLC ("HC, LLC"), which holds interests in the La Cuerva block and, pending approval of the Colombian authorities, the LLA 62 block, together covering approximately 90,000 acres in the Llanos Basin in Colombia.

HC, LLC sold for $75 million, adjusted for working capital. 13.3% of the sales price of HC, LLC were placed in escrow to fund potential claims arising from the sale. Pursuant to our 1.6% ownership interest in HC, LLC, we received 1.6% in the net sale proceeds after deduction of commissions, overriding royalty interest, and transaction expenses; subject to the escrow holdback and a further contingency holdback by Hupecol of 1.3% of the sales price. Following completion of the sale of HC, LLC, we have no continuing interest in the La Cuerva and LLA 62 blocks.

At December 31, 2011, our estimated proved reserves associated with the La Cuerva and LLA 62 blocks totaled 94,619 barrels of oil, which represented 82% of our estimated proved oil and natural gas reserves. Sales of oil and gas properties under the full cost method of accounting are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and reserves. Since the sale of these oil and gas properties would significantly alter the relationship, we recognized a gain on the sale of $315,119 during 2012, computed as follows:

Table of Contents

Sales price	$1,224,393
Add: Transfer of asset retirement and other obligations	34,471
Less: Transaction costs	(30,330)
Less: Prepaid deposits	(54,857)
Less: Carrying value of oil and gas properties, net	(858,558)
Net gain on sale	$315,119

The following table presents pro forma data that reflects revenue, income from continuing operations, net loss and loss per common share for 2012 as if the HC, LLC sale had occurred at the beginning of each period and excludes the gain on sale.

Pro-Forma Information:	2012
Oil and gas revenue	$148,163
Loss from operations	$(56,566,181)
Net loss	$(56,847,211)
Basic and diluted loss per common share	$(1.47)

CPO 4 Termination

During 2013, we made no capital expenditures with respect to the CPO 4 prospect in Colombia but entered into a Settlement Agreement with SK Innovation, operator and principal owner of the CPO 4 prospect. Pursuant to the terms of the Settlement Agreement, we terminated, and agreed to convey to SK Innovation, our entire interest in the CPO 4 prospect and we and SK Innovation agreed to release any and all claims each may have against the other under the Operating Agreement with respect to the CPO 4 prospect. We were relieved of any and all obligations under past, present and future capital calls relating to the CPO 4 prospect, including accrued cash calls at December 31, 2012 of $3,219,128. Our balance sheet reflects a reduction in the cash call obligation and an increase in accumulated depletion, depreciation, amortization and impairment, each in the amount of $3,219,128. In conjunction with the termination of our interest in the CPO 4 Block, during 2013, we terminated a standby letter of credit obligation and $3,056,250 of funds posted as collateral to secure a standby letter of credit and previously recorded as restricted cash was returned to us.

Colombian Developments – Serrania, Los Picachos and Macaya

During 2013, our capital investment expenditures in Colombia related to the preparation and evaluation of our three concessions in Colombia, which amount totaled $172,252. During 2014, we anticipate drilling two test wells on the Serrania concession, and have budgeted approximately $2.0 million as our share of capital costs in connection with these activities.

In addition, we anticipate shooting approximately 83.6 kilometers of 2-D seismic on the Los Picachos concession and approximately 201.9 kilometers of 2-D seismic on the Macaya Concession during 2014. In connection with these seismic acquisitions, we have budgeted approximately $1.2 million as our share of costs in connection with the planned seismic shoots. The budget for all 3 blocks is contingent on conditions in the areas allowing operations.

Domestic Developments

With the termination of our interest in the CPO 4 prospect and improving economics in the U.S. energy sector, during the first half of 2013, we began actively evaluating opportunities to invest and participate in domestic oil and gas prospects. Our management team, led by our CEO, has evaluated numerous opportunities and is sourcing and evaluating additional domestic opportunities.

During 2013, we drilled and completed one domestic well, a 13,500’ test of the Cib Haz Sands in Iberville Parish, Louisiana. The well was successfully drilled and completed and, in January 2014, tested at 384 barrels of oil, 565 mcf of natural gas and no water. We own a 3% working interest in the well and 618 acre lease block.

Table of Contents

As of December 31, 2013, we had agreed to participate in 5 additional prospects, each of which has commenced drilling, or is expected to commence drilling during 2014, as follows:

In South Texas, a 4,000’ test of the Lower Hockley Sand was drilled as a dry hole. The prospect is within a 179 acre lease block supported by 3-D seismic. A second similar prospect has been identified on the lease block. We will own a 7.2% working interest in the well and acreage.

In Jefferson Davis Parish, Louisiana, a 7,000’ test of the Cris H stringer and Cris H sand was drilled and completed with the objective of gaining structure on existing productive oil wells. We will own a 10.9% working interest in the well before payout and a 9.375% working interest after payout.

In Vermilion Parish, Louisiana, a 15,000' test of the Discorbis 1, 2, 3, 4 and 5 sands is planned in a double upthrown fault closure. We will own a 1.5% working interest in the test well and 450+ net acre lease block.

In East Baton Rouge Parish, Louisiana, a 11,000' test of the Bol Mex and Nonion Struma 1, 2, 3, 4 and 5 sands was drilled in a downthrown fault closure and is awaiting completion. The well was planned to test by-passed pay as well as untested sands in the fault block which produce in nearby fields. We will hold a 5% working interest in the test well and 1,300+ net acre lease block.

In South Texas, a 5,700' test of the Pettus and Yegua Sands on a 40 acre lease was drilled based on 3D seismic data and is awaiting testing and completion. We will hold a 25% working interest in the test well. Nearby wells produce oil and/or natural gas from these zones.

Our costs for the above test wells are expected to total approximately $1.5 million. As of December 31, 2013, we had incurred $776,738 of drilling costs associated with the planned test wells.

In February 2014, we acquired a 13.33% working interest before the casing point and a 10% working interest after the casing point in a 320 acre prospect in Jasper County, Texas. A 11,950 foot test of the Wilcox 3 and 4 Sands is planned for early 2014. Our acquisition and dry hole costs for the test well are estimated at $400,000.

During the second quarter of 2013, the operator of the Crown Paper #1 well in the Profit Island Field in East Baton Rouge Parish, Louisiana successfully carried out a recompletion of the well. We hold a 3.5475% royalty interest in the well. As a result of the recompletion, production from the well was down for the first half of 2013 but has increased since the middle of the second quarter of 2013. During 2013, our royalties attributable to the well increased to $320,686 from $103,131 during the 2012. As of December 31, 3013, the well had achieved pay out.

Colombian Tax

During 2012, we engaged our tax advisors in Colombia to evaluate certain tax and other filings made in Colombia by them and other advisors for 2009, 2010 and 2011. Our advisors identified inconsistencies between tax and non-tax filings with respect to equity investments made by us in Colombia. Based on guidance from our advisors, during 2012 we recorded a one-time foreign tax liability of $1,883,266 of which $1,693,085 was paid during 2013 and the remaining balance is expected to be paid over the next twelve months, relating primarily to a newly enacted Colombian equity tax measure based on the equity of our Colombian branch as of January 1, 2011.

Tax Refund

During 2013, we received a U.S. income tax refund of approximately $3.3 million attributable to the amendment of our 2010 federal tax return to carry back net operating losses from 2011 and 2012.

Management Changes

In July 2013, our chief financial officer resigned to pursue other opportunities and we determined not to renew the employment agreement of our Senior Vice President of Exploration on its expiration in August 2013. Until a replacement is hired to fill the chief financial officer position, the functions of our chief financial officer will be handled by other employees and consultants. The Senior Vice President of Exploration position is not expected to be filled at this time as that position was focused on the CPO 4 prospect in which we no longer hold an interest.

Table of Contents

Compensation Expense

In June 2013, our shareholders approved an increase in the shares reserved for issuance under our 2008 Equity Incentive Plan.

With approval of the increase in shares reserved under the 2008 Equity Incentive Plan, 915,525 options granted during 2012 became exercisable. In addition, in June 2013, we granted 1,200,000 stock options to employees and 100,000 stock options to non-employee directors. As a result of such grants and approval of the increase in shares reserved under the plan and resulting exercisability of 2012 option grants, we recognized $482,969 of compensation expense during 2013, in addition to stock compensation expense attributable to the amortization of unrecognized stock-based compensation from prior year grants.

As a result of the changes in management noted above, our overhead is expected to decrease by more than $500,000 annually. Additionally, 5,000 shares of restricted stock held by each of those officers was forfeited as of the date of termination of employment. Similarly, unvested stock option grants to purchase an aggregate of 150,000 shares of common stock each terminated as of the date of termination of employment.

Production Incentive Compensation Plan

In August 2013, our 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 our company participation in attractive oil and gas opportunities.

Under the Production Incentive Compensation 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 our 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 our 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 our 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 our 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 Houston American. In no event may the percentage assigned to our 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 we continue to be derive revenues 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 our 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 our compensation committee which shall consult with our 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.

Table of Contents

Legal Proceedings

At December 31, 2013, we were the subject of a formal investigation being conducted by the Securities and Exchange Commission (the "SEC"). Pursuant to the investigation, we received subpoenas issued by the SEC. The subpoenas called for the testimony of certain of our officers and the delivery of certain documents. The subpoenas were issued pursuant to a nonpublic formal order of private investigation issued by the SEC on March 1, 2011, which followed a nonpublic informal inquiry commenced by the SEC in October 2010. We received a copy of the nonpublic formal order of private investigation on February 10, 2012 in connection with a subpoena issued by the SEC. The SEC is investigating whether there have been any violations of the federal securities laws and has focused on matters relating to disclosures in the late 2009 and early 2010 time period regarding resource potential for the CPO 4 prospect. We have presented information supporting our disclosure relative to resource potential on the CPO 4 prospect. On August 29, 2013, we, and John Terwilliger, received a "Wells" notice advising that the staff of the SEC has made a preliminary recommendation to initiate an enforcement action and providing them an opportunity to provide reasons of law, policy or fact why the proposed enforcement action should not be filed. We have cooperated fully, and are committed to continuing to cooperate fully, with the SEC in this matter. It is not possible at this time to predict the timing or outcome of the SEC investigation, including whether or when any proceedings might be initiated, when these matters may be resolved or what, if any, penalties or other remedies may be imposed, and whether any such penalties or remedies would have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

In connection with the ongoing investigation being conducted by the SEC and indemnification provisions contained in an engagement agreement with Global Hunter Securities, LLC relating to our 2009 equity offering, in July 2012, we entered into an agreement with Global Hunter to settle any and all claims by Global Hunter related to reimbursement of attorney's fees under the indemnity provision. During 2012, we paid a total of $490,850 to Global Hunter and in exchange for the payments, we were granted a full release by Global Hunter Securities of any future claims or liabilities asserted by Global Hunter in connection with the offering. The payment to Global Hunter Securities was recorded as a charge to additional paid in capital and is listed under the Cash Flow from Financing Activities in the statement of cash flows as Cost of capital.

On April 27, 2012, a purported class action lawsuit was filed in the U.S. District Court for the Southern District of Texas against us and certain of our executive officers: Steve Silverman v. Houston American Energy Corp. et al., Case No. 4:12-CV-1332. The complaint generally alleges that, between March 29, 2010 and April 18, 2012, all of the defendants violated Sections 10(b) of the Securities Exchange Act of 1934 and SEC Rule 10b-5 and the individual defendants violated Section 20(a) of the Exchange Act in making materially false and misleading statements including certain statements related to the status and viability of the Tamandua #1 well. Two additional class action lawsuits were filed against us in May 2012. The complaints seek unspecified damages, interest, attorneys' fees, and other costs. On September 20, 2012, the court consolidated the class action lawsuits and appointed a lead plaintiff. On January 14, 2013, we filed a motion to dismiss and, on August 22, 2013, the court granted our motion and dismissed the complaint. The plaintiffs have since filed a Notice of Appeal of the dismissal of the complaint and the appeal is presently pending before the U.S. Court of Appeals for the Fifth Circuit. We believe all of the claims in the consolidated class action lawsuits are without merit and intend to vigorously defend against these claims. It is not possible at this time to predict the timing or outcome of the class action lawsuits that have or may be filed. We expect to incur costs and to devote management time and resources to defending such lawsuits.

On July 19, 2012, a purported derivative cause of action was filed in the U.S. District Court for the Southern District of Texas against certain of our directors and officers and Houston American Energy, as nominal defendant: E. Howard King, Jr., derivatively, on behalf of Houston American Energy Corp., v. John F. Terwilliger, John P. Boylan, Orrie Lee Tawes III, Stephen Hartzell, James J. Jacobs, Kenneth A. Jeffers, defendants, and Houston American Energy Corp., as nominal defendant, Case No. 4:12-CV-02182. The complaint asserts a cause of action by a shareholder on behalf of Houston American against certain of our directors and senior executive officers in connection with the June 11, 2012 approval of payment of certain bonuses, increases in salary, grant of certain stock options and entry into certain Change in Control Agreements. The complaint alleges that the approval of such matters constituted breach of fiduciary duty and corporate waste and seeks injunctive relief to bar each of the actions in question and seeks restitution. No damages have been or, by the nature of the derivative cause of action, are expected to be alleged against us. We may, however, incur certain costs and demands on management time and resources in connection with the lawsuit. On February 26, 2013, an order was entered granting a motion by the company to dismiss the lawsuit and providing leave to the plaintiff to amend its complaint to cure pleading deficiencies.

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.

Table of Contents

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, 2013. 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, 2013 and 2012:

	At December 31, 2013	At December 31, 2012
Acquisition costs	$1,366,222	$972,885
Evaluation costs	2,435,820	4,836,412
Total	$3,802,042	$5,809,297

The carrying value of unevaluated oil and gas prospects includes $1,789,536 and $4,836,412 expended for properties in South America at December 31, 2013 and December 31, 2012, respectively. We are maintaining our interest in these properties and development has or is anticipated to commence within the next twelve months.

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, 2013 Compared to Year Ended December 31, 2012

Oil and Gas Revenues. Total oil and gas revenues decreased 16%, to $347,139, in 2013, from $411,349, in 2012.

The decrease in revenue was due to the 2012 sale of our interest in the La Cuerva block partially offset by increased royalties following recompletion of the Crown Paper #1 well.

Table of Contents

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2013 and 2012:

	2013	2012
Gross producing wells	6	6
Net producing wells	0.18	0.19
Net oil production (Bbls)	2,963	2,787
Net gas production (Mcf)	9,459	12,066
Oil—Average sales price per barrel	$103.36	$108.71
Gas—Average sales price per mcf	$4.32	$3.22

The change in gross and net producing wells and production reflects the sale, during the first quarter of 2012, of our interest in wells associated with the La Cuerva block.

The change in average sales prices realized reflects fluctuations in global commodity prices.

Oil and gas sales revenues for 2013 and 2012 by region were as follows:

	Colombia	U.S.	Total
2013			
Oil sales	$—	$306,278	$306,278
Gas sales	$—	$40,861	$40,861
2012			
Oil sales	$263,185	$109,298	$372,483
Gas sales	$—	$38,865	$38,865

Lease Operating Expenses. Lease operating expenses, excluding joint venture expenses relating to our Colombian operations discussed below, decreased 58.1% to $81,774 in 2013 from $195,381 in 2012.

The decrease in total lease operating expenses was attributable to the 2012 sale of our interest in the La Cuerva block partially offset by higher severance taxes and compression fees following recompletion of the Crown Paper #1 well.

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

	Colombia	U.S.	Total
2013	$—	$81,774	$81,774
2012	$118,788	$76,593	$195,381

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.

Joint Venture Expenses. Joint venture expenses totaled $0 in 2013 compared to $3,244 in 2012. Joint venture expenses represent our allocable share of the indirect field operating and region administrative expenses billed by Hupecol. The decrease in joint venture expenses was attributable to reduced allocated administrative costs following the March 2012 divestiture of assets operated by Hupecol.

Depreciation and Depletion Expense. Depreciation and depletion expense decreased by 63% to $24,954 in 2013 from $66,971 in 2012. The decrease in depreciation and depletion was due to the 2012 sale of assets discussed above.

Gain (Loss) on Sale of Oil and Gas Properties. The sale of our indirect interests in Hupecol Cuerva, LLC and post-closing price adjustments related to the sale resulted in a gain of $387,314 during 2012 and a gain of $45,475 during 2013.

Impairment Expense. Termination of our testing and completion efforts on, and abandonment of, three test wells on our CPO 4 block resulted in impairment expense of $46,235,574 during 2012.

Table of Contents

General and Administrative Expenses. General and administrative expense decreased by 32% to $3,417,292 in 2013 from $5,027,024 in 2012. The change in general and administrative expense reflects a combination of (1) a decrease in non-cash stock based compensation (down $509,396) reflecting lower stock price and a resulting lower value of equity grants, and (2) decreased cash compensation (down $553,213) attributable to elimination of bonuses paid during 2013 and the termination of two officers.

Bad Debt Expense. Bad debt expense decreased to $86,507 in 2013 from $3,951,370 in 2012. Bad debt expense in 2013 related to our inability to obtain reimbursement of expenses disbursed by Hupecol, from an escrow held on our behalf, to pay certain operating expenses of the purchaser of HDC, LLC. Bad debt expense in 2012 related to Gulf United Energy's delinquency in satisfying its financial obligations with respect to the CPO 4 prospect.

Foreign Equity Tax. During 2012, we recorded a one-time foreign equity tax expense of $1,689,039 relating to a newly enacted Colombian equity tax measure based on the equity of our Colombian branch as of January 1, 2011.

Other Income (Expense). Other income (expense) consists of interest earned on cash balances net of other bank fees. Net other expense totaled ($32,158) in 2013 as compared to $73,319 in 2012. The change was attributable to reduced interest income during 2013 reflecting lower interest rates and lower cash holdings, partially offset by interest received on tax refunds.

Income Tax Expense/Benefit. We reported income tax benefit of $(12,274) in 2013 as compared to income tax expense of $216,923 in 2012. The change in income tax expense was attributable to lower tax obligations in 2013.

Financial Condition

Liquidity and Capital Resources. At December 31, 2013, we had a cash balance of $7,578,730 and working capital of $9,316,486 compared to a cash balance of $5,626,345 and working capital of $9,144,869 at December 31, 2012. The increase in cash during 2013 was attributable to the receipt of a tax refund and release of restricted cash partially offset by operating losses incurred during 2013 and investments to support planned drilling operations. The increase in working capital was attributable to our settlement with SK Innovation terminating our interest in the CPO 4 prospect and release of our cash call commitment obligation totaling $3,219,128 at December 31, 2012.

Cash Flows. Operating activities used $103,434 of cash during 2013 compared to $2,620,837 of cash used during 2012. The decrease in cash used in operations was primarily attributable to tax refunds received during 2013 totaling approximately $3.3 million and a reduced operating loss.

Investing activities provided $2,055,819 of cash during 2013 as compared to $23,041,556 of cash used during 2012. Funds provided by investing activities during 2013 reflects the release, following termination of our interest in the CPO 4 block, of restricted cash in the amount of $3,056,250 securing a standby letter of credit obligation to secure performance relative to the CPO 4 block, partially offset by investments in oil and gas properties. Funds used in investing activities during 2012 principally reflect investments in oil and gas properties and assets of $26,033,065 and purchases of marketable securities of $156,817 partially offset by proceeds from sale of securities of $660,625, escrow receivable of $1,460,633 and proceeds from the sale of our interest in Hupecol Cuerva, LLC of $1,027,068.

Financing activities provided $21,358,454 of cash during 2012 from our May 2012 and October 2012 offerings of common stock and warrants.

Long-Term Liabilities. At December 31, 2013, we had long-term liabilities of $8,424 as compared to $201,270 at December 31, 2012. Long-term liabilities at December 31, 2013 consisted of a reserve for plugging costs.

Capital and Exploration Expenditures. During 2013, we invested $1,219,917 for the development of oil and gas properties, consisting of (1) preparation and evaluation costs in Colombia of $172,252, and (2) costs on U.S. properties of $1,047,665. Of the amount invested, we capitalized $8,044 to oil and gas properties subject to amortization, and $1,211,873 to oil and gas properties not subject to amortization, primarily attributable to preparation and evaluation cost in Colombia of $172,252 and leasehold cost in the U.S. of $262,883, drilling cost of $762,451 and lease equipment of $14,287.

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.

Table of Contents

Our estimated capital expenditure budget for 2014 is approximately $5.1 million and relates to the anticipated drilling of two test wells on the Serrania concession ($2.0 million), seismic shoots on the Los Picachos and Macaya concessions ($1.2 million) and drilling of test wells on six domestic concessions ($1.9 million). Drilling and seismic plans for 2014 may change based on field conditions and other factors beyond our control or the control of the operators of our prospects and, as such, there can be no assurance as to the timing of these operations or the amount actually spent on such operations.

We anticipate that our cash on hand will be adequate to fully fund our operations during 2014, including our capital expenditure budget. However, depending on the ultimate cost and results of our drilling operations, it is possible that we will require additional capital to fully fund our future drilling budget and operations. If, for any reason, we are unable to fully fund our drilling budget and fail to satisfy commitments reflected therein, we may be subject to penalties or to the possible loss of some of our rights and interests in prospects with respect to which we fail to satisfy funding commitments. We have no commitments to provide any additional financing should we require and seek such financing and there is no guarantee that we will be able to secure additional financing on acceptable terms, or at all, to fully fund our drilling budget and to support future acquisitions and development activities.

Contractual Obligations. At December 31, 2013, 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, 2013:

	Payments due by period				
	Total	< 1 year	1-3 years	3-5 years	> 5 years
Operating leases	$312,866	$91,432	$230,434	$ —	$ —
Total	$312,866	$91,432	$230,434	$ —	$ —

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 John Terwilliger and O. Lee Tawes, III.

Additionally, during 2013, we adopted our Production Incentive Compensation Plan pursuant to which up to 2% of our share of revenues from qualifying domestic properties may be paid as compensation to recipients of award grants under the plan.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2013.

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.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Our financial statements appear immediately after the signature page of this report. See “Index to Financial Statements.”.

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, 2013 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 and our principal financial officer concluded that our disclosure controls and procedures were not effective as of December 31, 2013.

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 and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the 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, 2013. Such conclusion reflects the departure of our chief financial officer and assumption of duties of the principal financial officer by our chief executive officer and the resulting lack of accounting experience of our now principal financial officer and a 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 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable

Table of Contents

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, 2013, and their ages and positions as of that date, are as follows:

Name	Age	Position
John F. Terwilliger	66	President, Chief Executive Officer and Chairman

John F. Terwilliger has served as our President, CEO and Chairman since our inception in April 2001.

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.

Table of Contents

PART IV

Item 15. Exhibits and Financial Statement Schedules

1. Financial statements. See "Index to Financial Statements."

2. Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date	Number	Filed Herewith
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	Form of Common Stock Purchase Warrant, dated May 8, 2012	8-K	05/03/12	4.1	
4.3	Form of Class A Common Stock Purchase Warrant, dated October 4, 2012	8-K	10/03/12	4.1	
4.4	Form of Class B Common Stock Purchase Warrant, dated October 4, 2012	8-K	10/03/12	4.2	
10.1	Houston American Energy Corp. 2005 Stock Option Plan*	8-K	08/16/05	10.1	
10.2	Form of Director Stock Option Agreement*	8-K	08/16/05	10.2	
10.3	Houston American Energy Corp. 2008 Equity Incentive Plan*	Sch 14A	04/28/08	Ex A	
10.4	Employment Agreement of Kenneth Jeffers*	10-K	03/15/11	10.6	
10.5	Form of Change in Control Agreement, dated June 11, 2012*	8-K	06/14/12	10.1	
10.6	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.

Table of Contents
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.

HOUSTON AMERICAN ENERGY CORP.

Dated: March 14, 2014

By: /s/ John F. Terwilliger
John F. Terwilliger
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 F. Terwilliger John F. Terwilliger	Chairman, Chief Executive Officer, President and Director (Principal Executive Officer and Principal Financial Officer)	March 14, 2014
/s/ O. Lee Tawes, III O. Lee Tawes, III	Director	March 14, 2014
/s/ Stephen Hartzell Stephen Hartzell	Director	March 14, 2014
/s/ John P. Boylan John P. Boylan	Director	March 14, 2014
/s/ Keith Grimes Keith Grimes	Director	March 14, 2014

Table of Contents

HOUSTON AMERICAN ENERGY CORP.
INDEX TO FINANCIAL STATEMENTS

Table of Contents

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, 2013 and 2012, and the related consolidated statements of operations and comprehensive income, changes in shareholders' equity, and cash flows for the years ended December 31, 2013 and 2012. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We 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, 2013 and 2012, and the results of their operations and their cash flows for the years ended December 31, 2013 and 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ GBH CPAs, PC
www.gbhcpas.com
Houston, Texas
March 14, 2014

Table of Contents

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	2012
ASSETS		
CURRENT ASSETS		
Cash	$7,578,730	$5,626,345
Restricted cash – letter of credit	—	3,056,250
Accounts receivable – other	—	3,436,305
Escrow receivable – current	1,921,217	2,095,228
Prepaid expenses and other current assets	46,175	36,539
TOTAL CURRENT ASSETS	9,546,122	14,250,667
PROPERTY AND EQUIPMENT		
Oil and gas properties, full cost method		
Costs subject to amortization	50,320,591	47,093,419
Costs not being amortized	3,802,042	5,809,297
Office equipment	90,004	90,004
Total	54,212,637	52,992,720
Accumulated depletion, depreciation, amortization, and impairment	(50,349,833)	(47,105,751)
PROPERTY AND EQUIPMENT, NET	3,862,804	5,886,969
Other assets	3,167	3,167
TOTAL ASSETS	$13,412,093	$20,140,803
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$8,119	$84,740
Accrued cash call to operator	—	3,219,128
Accrued expenses	31,336	90,923
Taxes payable	190,181	1,711,007
TOTAL CURRENT LIABILITIES	229,636	5,105,798
LONG-TERM LIABILITIES		
Reserve for plugging and abandonment costs	8,424	7,872
Taxes Payable long-term	—	193,398
TOTAL LONG-TERM LIABILITIES	8,424	201,270
TOTAL LIABILITIES	238,060	5,307,068
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Preferred stock, par value $0.001; 10,000,000 shares authorized, 0 shares issued and outstanding, respectively	—	—
Common stock, par value $0.001; 150,000,000 shares authorized, 52,169,945 and 52,180,045 shares issued and outstanding, respectively	52,170	52,180
Additional paid-in capital	65,477,046	63,963,257
Accumulated deficit	(52,355,183)	(49,181,702)
TOTAL SHAREHOLDERS' EQUITY	13,174,033	14,833,735
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$13,412,093	$20,140,803

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

Table of Contents

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
FOR THE YEARS ENDED DECEMBER 31, 2013 AND 2012

	2013	2012
OIL AND GAS REVENUE	$347,139	$411,349
EXPENSES OF OPERATIONS		
Lease operating expense and severance tax	81,774	195,381
Joint venture expense	—	3,244
Depreciation and depletion	24,954	66,971
Impairment of oil and gas properties	—	46,235,574
Bad debt expense	86,507	3,951,370
Foreign Equity Tax	—	1,689,039
Loss on sale of securities	—	97,267
General and administrative expense	3,417,292	5,027,024
Total operating expenses	3,610,527	57,265,870
Gain on sale of oil and gas properties	45,475	387,314
Loss from operations	(3,217,913)	(56,467,207)
OTHER INCOME (EXPENSE)		
Interest income	33,238	10,844
Other expense	(1,080)	(84,163)
Total other income (expense)	32,158	(73,319)
Net loss before taxes	(3,185,755)	(56,540,526)
Income tax expense (benefit)	(12,274)	216,923
Net loss	$(3,173,481)	$(56,757,449)
Basic and diluted net loss per common share outstanding	$(0.06)	$(1.46)
Basic and diluted weighted average number of common shares outstanding	52,175,677	38,799,434
COMPREHENSIVE LOSS		
Net loss	$(3,173,481)	$(56,757,449)
Unrealized gain on marketable securities	—	(106,371)
Net comprehensive loss	$(3,173,481)	$(56,863,820)

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

Table of Contents

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2013 and 2012

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total
Balance at December 31, 2011	31,165,230	$31,165	$40,602,643	$7,575,747	$ 106,371	$48,315,926
Stock issued for -						
May 2012 offering	6,200,000	6,200	13,137,800	—	—	13,144,000
October 2012 offering	14,814,815	14,815	9,985,185	—	—	10,000,000
Offering costs	—	—	(1,785,546)	—	—	(1,785,546)
Options issued to directors	—	—	312,286	—	—	312,286
Options issued to employees	—	—	1,463,467	—	—	1,463,467
Restricted stock issued to employees	—	—	247,422	—	—	247,422
Other comprehensive income	—	—	—	—	(106,371)	(106,371)
Net loss	—	—	—	(56,757,449)	—	(56,757,449)
Balance at December 31, 2012	52,180,045	52,180	63,963,257	(49,181,702)	0	14,833,735
Options issued to directors	—	—	72,399	—	—	72,399
Options issued to employees	—	—	1,284,240	—	—	1,284,240
Restricted stock issued to employees	—	—	157,140	—	—	157,140
Restricted stock cancelled	(10,100)	(10)	10	—	—	—
Net loss	—	—	—	(3,173,481)	—	(3,173,481)
Balance at December 31, 2013	52,169,945	$52,170	$65,477,046	$(52,355,183)	$ 0	$13,174,033

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

Table of Contents

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2013 AND 2012

	2013	2012
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	$(3,173,481)	$(56,757,449)
Adjustments to reconcile net loss to net cash provided by (used in) operations		
Depreciation and depletion	24,954	66,971
Stock-based compensation	1,513,779	2,023,175
Deferred tax expense (benefit)	—	3,195,583
Accretion of asset retirement obligation	552	924
Amortization of deferred rent	—	(3,620)
Gain on sale of oil and gas properties	(45,475)	(387,314)
Impairment of oil and gas properties	—	46,235,574
Bad debt expense	86,507	3,951,370
Loss on sale of securities	—	97,267
Change in operating assets and liabilities:		
Decrease in accounts receivable	—	319,016
Increase in income tax refund receivable	3,349,798	(3,344,126)
Increase in prepaid expense and other current assets	(9,636)	(12,547)
(Decrease) increase in accounts payable and accrued expenses	(136,208)	117,008
Foreign equity taxes payable	(1,714,224)	1,877,331
Net cash used in operations	(103,434)	(2,620,837)
CASH FLOW FROM INVESTING ACTIVITIES		
Release of restricted cash	3,056,250	—
Payments for acquisition and development of oil and gas properties and assets	(1,219,917)	(26,033,065)
Proceeds from sale of Colombian properties, net of expenses	45,475	1,027,068
Proceeds from sale of securities	—	660,625
Purchase of marketable securities	—	(156,817)
Proceeds from escrow receivable, net	174,011	1,460,633
Net cash provided by (used in) investing activities	2,055,819	(23,041,556)
CASH FLOW FROM FINANCING ACTIVITIES		
Sale of common stock and warrants	—	23,144,000
Common stock offering costs	—	(1,785,546)
Net cash provided by financing activities	—	21,358,454
INCREASE (DECREASE) IN CASH	1,952,385	(4,303,939)
Cash, beginning of year	5,626,345	9,930,284
Cash, end of year	$7,578,730	$5,626,345
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid	$—	$—
Taxes paid	$1,726,498	$—
SUPPLEMENTAL NON-CASH INVESTING AND FINANCING ACTIVITIES		
Accrued oil and gas development costs	$(3,219,128)	$3,219,128,

Sales price of oil and gas properties placed in escrow	—	166,995
Unrealized gain (loss) on available for sale securities	—	(106,371)
Cancellation of stock	(10)	—

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

Table of Contents
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 Gulf Coast area of the United States and international locations with proven production, which to date has focused on Colombia, South America.

Consolidation

The accompanying consolidated financial statements include all accounts of HUSA and its subsidiaries (HAEC Louisiana 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 $7.3 million in excess of the FDIC's current insured limit of $250,000 at December 31, 2013 for interest bearing accounts. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Marketable Securities – Available for Sale

Management determines the appropriate classification of its investments in marketable securities at the time of purchase and reevaluates such determination at each balance sheet date. Equity securities not classified as trading securities are classified as available-for-sale. Available-for-sale securities are reported at fair value and unrealized gains and losses are included in stockholders' equity. Management determines fair value of its investments based on quoted market prices at each balance sheet date.

Accounts Receivable

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

Table of Contents

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, 2013, the Company evaluated their receivables and determined an allowance was not required.

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, 2013 or 2012.

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 $12,111 and $49,391 for the years ended December 31, 2013 and 2012, respectively and accumulated amortization, depreciation and impairment was $50,274,501 and $47,043,262 at December 31, 2013 and 2012, 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 2013 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.

Table of Contents

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 $12,843 and $17,580 for 2013 and 2012, respectively, and accumulated depreciation was $75,332 and $62,489 at December 31, 2013 and 2012, 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 have been issued.

Table of Contents

Net Income (Loss) Per Share

Basic net income (loss) per share is computed by dividing the net income (loss) attributable to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted net income (loss) per share is computed by dividing the net income (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 year ended December 31, 2013, outstanding options to purchase 2,592,832 shares of common stock were excluded from the calculation of diluted net loss per share because they were dilutive. For the year ended December 31, 2012, outstanding options to purchase 2,443,057 shares of common stock were excluded from the calculation of diluted net loss per share because they were anti-dilutive.

Concentration of Risk

The Company is dependent upon the industry skills and contacts of John F. Terwilliger, the chief executive officer, to identify potential acquisition targets in the onshore coastal Gulf of Mexico region of Texas and Louisiana and in the South American country of Colombia. Further, 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 Hupecol 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, 2013, 46.5% of the Company's net oil and gas property investment, and 0% of its revenue for the year ended December 31, 2013, was with or derived from interests operated in Colombia.

For 2013, 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, 2013 and 2012, respectively.

Subsequent Events

The Company evaluated subsequent events from December 31, 2013 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.

Table of Contents

NOTE 2—ACCOUNTS RECEIVABLE—OTHER

Gulf United Energy, Inc.

In connection with the Company's acquisition in July 2010 of an additional 12.5% interest in the approximately 345,452 acre CPO 4 Block in the Llanos Basin of Columbia and which is operated by SK Innovation Co. LTD ("SK Innovation"), the Company entered into a separate agreement with Gulf United Energy, Inc. ("Gulf United") whereby the Company waived its right of first refusal under the CPO 4 Block Joint Operating Agreement for the specific purpose of permitting Gulf United to acquire from SK Innovation a 12.5% interest in the CPO 4 Block. Under the agreement with Gulf United, as a condition of the Company's agreement to waive its preferential rights, Gulf United agreed to pay to the Company, not later than 30 days following ANH approval, (i) the Company's 12.5% share of Past Costs (as defined in the Farmout Agreement with SK Innovation) incurred through July 31, 2010, and (ii) the Company's 25% share of seismic acquisition costs incurred through July 31, 2010, or a total of $3,951,370. The amount due from Gulf United was classified as accounts receivable – other in the accompanying balance sheet as of December 31, 2012.

As a result of Gulf United Energy's delinquency in satisfying its financial obligations with respect to the CPO 4 prospect, during the year ended December 31, 2012, the Company wrote-off the receivable from Gulf United for $3,951,370 and recorded bad debt expense.

Hupecol Operating, LLC

During 2011, Hupecol Operating, LLC ("Hupecol") disbursed funds from a 5% contingency escrow established with a portion of the proceeds from the sale of Hupecol Dorotea & Cabiona Holdings, LLC ("HDC, LLC"), to pay certain operating expenses incurred on behalf of the purchaser of these entities. Hupecol sought reimbursement from the purchaser for these expenses as part of the post-closing process but to date has been unsuccessful in such efforts. The Company established a receivable from Hupecol for the Company's proportionate share of the escrow funds disbursed for these expenses of $86,507. See Note 3. As a result of the inability to recover such amounts, the amount due from Hupecol was written off as of December 31, 2013.

NOTE 3—ESCROW RECEIVABLE

At December 31, 2013 and December 31, 2012, the Company's balance sheet reflected the following escrow receivables relating to various oil and gas properties previously held by the Company:

	Balance as of December 31, 2013		
Description	Current	Noncurrent	Total
Tambaqui Escrow	$22,029	$ —	$22,029
HDC LLC and HL LLC 15% Escrow	1,827,929	—	1,827,929
HDC LLC and HL LLC 5% Contingency	57,321	—	57,321
HC LLC 5% Contingency	13,938	—	13,938
TOTAL	$1,921,217	$ —	$1,921,217

	Balance as of December 31, 2012		
Description	Current	Noncurrent	Total
Tambaqui Escrow	$22,029	$ —	$22,029
HDC LLC and HL LLC 15% Escrow	1,827,929	—	1,827,929
HDC LLC and HL LLC 5% Contingency	57,321	—	57,321
HC LLC 14.66% Escrow	151,048	—	151,048

HC LLC 5% Contingency	36,901	—	36,901
TOTAL	$2,095,228	$ —	$2,095,228

The principal escrow receivables relate to the sale of HC LLC (see Note 5 below) and the 2010 sale of HDC LLC and Hupecol Llanos LLC (“HL LLC”).

Hupecol Cuervo, LLC

Changes in escrow receivables during 2013 reflect the release of $151,048 from the HC LLC 14.66% escrow and $22,964 from the HC LLC 5% contingency.

Hupecol Dorotea and Cabiona, LLC and Hupecol Llanos, LLC Escrow

Pursuant to the terms of the sales of HDC, LLC and HL, LLC, on the closing date of the sale, a portion of the purchase price was deposited in escrow to settle post-closing adjustments under the purchase and sale agreement. The Company’s proportionate interest in the escrow deposit totaled $7,069,810, and was recorded as escrow receivable.

As of December 31, 2013 and 2012, $1,921,217 and $2,095,228 was recorded as escrow receivable – current. Subsequent to December 31, 2013, the Company collected $1,614,290 of the escrow receivable (see Note 12).

NOTE 4—MARKETABLE SECURITIES—AVAILABLE FOR SALE

During the year ended December 31, 2012, the Company purchased shares of common stock in a publicly traded company at a cost of $156,817. This investment was classified as marketable securities - available for sale and, accordingly, any unrealized changes in market values were recognized as other comprehensive income in the consolidated statements of operations. During the year ended December 31, 2012, the company sold all of its marketable securities and recognized a $97,267 loss.

NOTE 5—OIL AND GAS PROPERTIES

Sale of La Cuerva and LLA 62 Blocks

During the first quarter of 2012, the Company sold all of its interest in Hupecol Cuerva, LLC (“HC, LLC”), which holds interests in the La Cuerva block and, pending approval of the Colombian authorities, the LLA 62 block, together covering approximately 90,000 acres in the Llanos Basin in Colombia.

HC, LLC sold for $75 million, adjusted for working capital. 13.3% of the sales price of HC, LLC will be held in escrow to fund potential claims arising from the sale. Pursuant to its 1.6% ownership interest in HC, LLC, the Company received 1.6% in the net sale proceeds after deduction of commissions, overriding royalty interest, and transaction expenses; subject to the escrow holdback and a further contingency holdback by Hupecol of 1.3% of the sales price. Following completion of the sale of HC, LLC, the Company has no continuing interest in the La Cuerva and LLA 62 blocks.

At December 31, 2011, the Company’s estimated proved reserves associated with the La Cuerva and LLA 62 blocks totaled 94,619 barrels of oil, which represented 82% of the Company’s estimated proved oil and natural gas reserves. Sales of oil and gas properties under the full cost method of accounting are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and reserves. Since the sale of these oil and gas properties would significantly alter the relationship, the Company recognized a gain on the sale of $315,119 during 2012, computed as follows:

Table of Contents

Sales price	$1,224,393
Add: Transfer of asset retirement and other obligations	34,471
Less: Transaction costs	(30,330)
Less: Prepaid deposits	(54,857)
Less: Carrying value of oil and gas properties, net	(858,558)
Net gain on sale	$315,119

The following table presents pro forma data that reflects revenue, income from continuing operations, net loss and loss per common share for 2012 as if the HC, LLC sale had occurred at the beginning of each period and excludes the gain on sale.

Pro-Forma Information (unaudited):	2012
Oil and gas revenue	$148,163
Loss from operations	$(56,566,181)
Net loss	$(56,847,211)
Basic and diluted loss per common share	$(1.47)

Impairments

During 2012, the Company completed operations on three test wells on the CPO 4 block in Colombia. Each of the test wells was determined to be noncommercial and was plugged and abandoned. As a result of the determinations to plug and abandon each of those test wells, the Company included the costs related to those wells in the full cost pool for inclusion in the ceiling test. The Company recorded an impairment charge of $46,235,574 during 2012 to write off costs not being amortized that were attributable to the drilling of the test wells on the CPO 4 block as well as to write off seismic exploration and evaluation cost, general and administrative cost and environmental and governmental cost that were attributable to the test wells through December 31, 2012.

Unevaluated Oil and Gas Properties

Unevaluated oil and gas properties not subject to amortization at December 31, 2013 included the following:

	North America	South America	Total
Leasehold acquisition costs	$1,234,888	$131,335	$1,366,223
Geological, geophysical, screening and evaluation costs	777,618	1,658,201	2,435,819
Total	$2,012,506	$1,789,536	$3,802,042

Unevaluated oil and gas properties not subject to amortization at December 31, 2012 included the following:

	North America	South America	Total
Leasehold acquisition costs	$972,005	$2,015,850	$2,987,855
Geological, geophysical, screening and evaluation costs	880	2,820,562	2,821,442
Total	$972,885	$4,836,412	$5,809,297

Table of Contents

NOTE 6—Asset Retirement Obligation

The following table describes changes in our asset retirement liability during each of the years ended December 31, 2013 and 2012. The ARO liability in the table below includes amounts classified as both current and long-term at December 31, 2013 and 2012.

	North America Years Ended December 31		South America Years Ended December 31	
	2013	2012	2013	2012
ARO liability at January 1	$7,872	$7,320	$—	$34,099
Accretion expense	552	552	—	372
Liabilities incurred from drilling	—	—	—	—
Liabilities settled—assets sold	—	—	—	(34,471)
Changes in estimates	—	—	—	—
ARO liability at December 31,	$8,424	$7,872	$—	$—

NOTE 7—COMMON STOCK

May 2012 Offering

In May 2012, the Company sold to institutional investors 6,200,000 units, with each unit consisting of one of our common shares and one warrant to purchase one common share, for gross proceeds of approximately $13.14 million, before deducting placement agent fees and estimated offering expenses of $527,000 recorded as cost of capital, in a "registered direct" offering. The investors purchased the units at a purchase price of $2.12 per unit. The warrants, which represent the right to acquire an aggregate of up to 6,200,000 common shares, are exercisable at any time on or after November 9, 2012 and prior to November 9, 2015 at an exercise price of $2.68 per share, which was 120% of the closing price of our common shares on the NYSE MKT on May 2, 2012.

October 2012 Offering

In October 2012, the Company sold 14,814,815 units, with each unit consisting of one of our common shares, one Class A Warrant and one Class B Warrant, for gross proceeds of approximately $10.0 million, before deducting placement agent fees and estimated offering expenses of $828,000 recorded as cost of capital, in a "registered direct" public offering. The investors purchased the units at a purchase price of $0.675 per unit. The Class A Warrants represent the right to acquire one-half common share per warrant, or an aggregate of up to 7,407,407 common shares for a period of six months at an exercise price of $0.81 per share. The Class B Warrants represent the right to acquire one-half common share per warrant, or an aggregate of up to 7,407,407 common shares for a period of three years at an exercise price of $0.90 per share.

NOTE 8—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 allowed for the issuance of up to 2,200,000 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.

During 2012 and 2013, the Company's board of directors and shareholders adopted amendments to the Company's 2008 Equity Incentive Plan to increase the shares reserved to 6,000,000 shares.

Stock Option Activity

During 2012, the Company granted 325,000 options to non-employee directors and 1,200,000 options to employees.

Table of Contents

300,000 of the options granted to non-employee directors vested 20% on the grant date and vested as to the remaining 80% nine months from the grant date, have a ten year life and have an exercise price of $1.65 per share. Of those options, 155,475 were exercisable commencing 6 months from the date of grant and 144,525 were exercisable on and after shareholder approval of the amendment to the Company's 2008 Equity Incentive Plan to increase the shares reserved under the plan to facilitate exercise. The option grants to non-employee directors, excluding grants that were subject to shareholder approval of amendment to the 2008 Equity Incentive Plan, were valued on the date of grant at $128,328 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 0.35%, (2) expected life in years of 2.83, (3) expected stock volatility of 84.6%, and (4) expected dividend yield of 1.21%.

25,000 of the options granted to non-employee directors were granted to a new non-employee director, vested 20% on the grant date and vested as to the remaining 80% nine months from the grant date, have a ten year life and have an exercise price of $1.18 per share. Those options have a fair value of $19,375 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 0.82%, (2) expected life in years of 5.835, (3) expected stock volatility of 91.70%, and (4) expected dividend yield of 1.70%.

The 1,200,000 options granted to employees vested on the grant date, have a ten-year life and have an exercise price of $1.65 per share. Of those options, 429,000 were exercisable commencing 6 months from the date of grant and 771,000 were exercisable on and after shareholder approval of the amendment to the Company's 2008 Equity Incentive Plan to increase the shares reserved under the plan to facilitate exercise. The option grants to employees, excluding grants that were subject to shareholder approval of amendment to the 2008 Equity Incentive Plan, were valued on the date of grant at $354,098 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 0.35%, (2) expected life in years of 2.83, (3) expected stock volatility of 84.6%, and (4) expected dividend yield of 1.21%.

In June 2013, the Company's shareholders approved the amendment to the Company's 2008 Equity Incentive Plan to increase the shares reserved thereunder, resulting in the vesting of options to purchase 915,525 shares of common stock. The options were valued on the date of shareholder approval at $164,377 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 5.6, (3) expected stock volatility of 105%, and (4) expected dividend yield of 0%. 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.

During 2013, options to purchase an aggregate of 100,000 shares were granted to non-employee directors and options to purchase an aggregate of 1,200,000 shares were granted to employees.

The 100,000 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 $0.3075 per share. The option grants to non-employee directors were valued on the date of grant at $24,507using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.26%, (2) expected life in years of 5.6, (3) expected stock volatility of 105%, and (4) expected dividend yield of 0%. 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.

The 1,200,000 options granted to employees vested 50% on the grant date and vest as to the remaining 50% on the first anniversary of the grant date, have a ten year life and have an exercise price of $0.3075 per share. The option grants to employees were valued on the date of grant at $294,085 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 5.6, (3) expected stock volatility of 105%, and (4) expected dividend yield of 0%. 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 July and August, 2013, respectively, the employment of two officers terminated. As a result of such terminations, the unvested options granted those officers during 2013, covering 150,000 shares each, terminated and the same were forfeited. The remaining options held by those officers, all of which were out-of-the-money, covering an aggregate of 1,520,000 shares, expired three months following the respective termination dates.

Table of Contents

Option activity during 2013 and 2012 was as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2011	1,833,582	$ 7.02		
Granted	609,475	$ 1.63		
Exercised	—	$ —		
Forfeited	—	$ —		
Outstanding at December 31, 2012	2,443,057	$ 5.68		
Granted (1)	2,215,525	$ 0.86		
Exercised	—	$ —		
Forfeited	(2,065,750)	$ 2.53		
Outstanding at December 31, 2013	2,592,832	$ 4.07	6.97	$ —

(1) Includes 915,525 options granted in 2012, the exercise of which was subject to shareholder approval of an amendment to the Company's 2008 Equity Incentive Plan to increase the shares reserved for issuance thereunder, which approval was obtained during 2013.

During 2013 and 2012, the Company recognized $1,513,779 and $1,775,753, respectively, of stock compensation expense attributable to outstanding stock option grants, including current period grants and unamortized expense associated with prior period grants.

As of December 31, 2013, non-vested options totaled 530,000 and total unrecognized stock-based compensation expense related to non-vested stock options was $353,555. The unrecognized expense is expected to be recognized over a weighted average period of 0.45 years. The weighted average remaining contractual term of the outstanding options and exercisable options at December 31, 2013 is 6.97 years and 7.24 years, respectively.

As of December 31, 2013, there were 3,907,168 shares of common stock available for issuance pursuant to future stock or option grants under the Plans.

Restricted Stock Activity

During 2011, the Company granted to officers an aggregate of 45,000 shares of restricted stock, which shares vest over a period of three years. The fair value of $743,400 was determined based on the fair market value of the shares on the date of grant. This value is being amortized over the vesting period, and during 2013 and 2012, $157,140 and $247,422 was amortized to expense respectively. As a result of the termination of two officers, 5,000 shares of restricted stock were forfeited and cancelled during 2013 with respect to each of the terminated officers. As of December 31, 2013, there was $37,001 of unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately 0.45 years.

Share-Based Compensation Expense

The following table reflects share-based compensation recorded by the Company for 2013 and 2012:

	2013	2012
Share-based compensation expense included in general and administrative expense	$1,513,779	$2,023,175
Earnings per share effect of share-based compensation expense	$(0.03)	$(0.05)

Table of Contents

NOTE 9—TAXES

The following table sets forth a reconciliation of the statutory federal income tax for the years ending December 31, 2013 and 2012.

	2013	2012
Income (loss) before income taxes	$(3,185,755)	$(56,540,526)
Income tax expense (benefit) computed at statutory rates	$(1,115,014)	$(19,223,779)
Permanent differences, nondeductible expenses	(1,177,769)	282,547
Current Colombian tax expense	8,880	216,923
Increase (decrease) in valuation allowance	(902,498)	22,026,880
Valuation allowance (decrease) related to carryback	—	(3,345,683)
Change in tax rate	(79,409)	—
Return to accrual items	127,913	—
Foreign tax credit	3,649,259	—
Other adjustment	(21,156)	260,035
NOL adjustment	(502,480)	—
State (net of federal benefit)	—	—
Tax provision (benefit)	$(12,274)	$216,923
Total Provision		
Current Federal	$—	$(3,195,583)
Current State	—	—
Deferred Federal	—	3,195,583
Deferred State	—	—
Permanent True-up	(21,154)	—
Foreign	8,880	216,923
Total provision (benefit)	$(12,274)	$216,923

At December 31, 2013 the Company has a federal tax loss carry forward of $48,582,039 and a foreign tax credit carry forward of $484,697, 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, 2013 and 2012 are set out below.

	2013	2012
Non-Current Deferred tax assets:		
Net operating loss carry forwards	$17,003,714	$12,964,068
Foreign tax credit carry forwards	484,697	4,133,956
Deferred state tax	23,277	66,505
Stock compensation	3,618,643	3,000,568
Book in excess of tax depreciation, depletion, and capitalization methods on oil and gas properties	(2,151,329)	(271,419)
Other	(83,560)	(95,738)
Colombia future tax obligations	—	—
Total Non-Current Deferred tax assets	18,895,442	19,797,940

Valuation Allowance	(18,895,442)	(19,797,940)
Net deferred tax asset	$—	$—

F-16

Table of Contents

Foreign Income Taxes

The Company owns direct ownership in several properties in Colombia operated by Hupecol and SK Innovation. Colombia's current income tax rate is 33%. During 2013 and 2012, we recorded foreign tax expense of $8,880 and $216,923, respectively.

Foreign Equity Tax

During 2012, we recorded a one-time foreign equity tax expense of $1,689,039 relating to a newly enacted Colombian equity tax measure based on the equity of our Colombian branch as of January 1, 2011. For U.S. GAAP purposes, the equity tax is not considered an income tax.

NOTE 10—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, 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 2013 and 2012, Mr. Terwilliger received royalty payments relating to those properties totaling $20,305 and $16,594, respectively, and Mr. Tawes received royalty payments relating to those properties totaling $20,305 and $16,594, respectively.

NOTE 11—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
2014	91,432
2015	93,793
2016	96,162
2017	40,479
Total	321,866

Total rental expense was $97,220 and $90,194 in 2013 and 2012, respectively. The Company does not have any capital leases or other operating lease commitments.

Standby Letter of Credit – CPO 4 Block

On November 5, 2009, JP Morgan Chase issued a Letter of Credit to Banco de Bogota S.A. for $2,037,500. Banco de Bogota then in turn issued a Stand by Letter of Credit to the Agency De National Hydrocarbons to guaranty the Company's compliance and proper execution of the work obligations relating to the phase one (1) work program of the CPO-4 block for the Company's 25% interest in the Block. Per the Standby Letter of Credit issued between JP Morgan Chase and Banco de Bogota, the Company was required to keep on deposit with JP Morgan Chase $2,037,500. In addition, the Company was required by JP Morgan Chase to pay fees associated with the Standby Letter of Credit equal to 1.0% per year of the amount, equal to $20,375.

On December 2, 2010, JP Morgan Chase amended the Letter of Credit to Banco de Bogota S.A. to increase the total amount of the Letter of Credit to $3,056,250. Banco de Bogota then in turn issued an amended Stand by Letter of Credit to the Agency de National Hydrocarbons to guaranty the Company's compliance and proper execution of the work obligations relating to the phase one (1) work program for the CPO-4 block for the Company's 37.5% interest in the Block. Per the amended Standby Letter of Credit issued between JP Morgan Chase and Banco de Bogota, the date of expiration was extended until April 1, 2013 and the Company is required to keep on deposit with JP Morgan Chase $3,056,250. This increase in deposits was related to the Company increasing its interest in the CPO 4 block from 25.0% to 37.5%. All other terms and conditions of the Letter of Credit remained unchanged. The Company paid JP Morgan fees associated with the Standby Letter of Credit equal to 1.0% per year of the amount, equal to $32,070. The deposit with JP Morgan Chase was classified as Restricted cash – letter of credit in the accompanying balance sheet as of December 31, 2012. Due to the settlement agreement with SK Innovation in which the Company assigned its 37.5% interest in the CPO-4 prospect, the Company did not renew the Letter of Credit and, during 2013, funds securing the Letter of Credit, in the amount of $3,056,250, were released to the Company.

Table of Contents

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.

At December 31, 2013, the Company was the subject of a formal investigation being conducted by the Securities and Exchange Commission (the “SEC”). Pursuant to the investigation, the Company received subpoenas issued by the SEC. The subpoenas called for the testimony of certain of the Company’s officers and the delivery of certain documents. The subpoenas were issued pursuant to a nonpublic formal order of private investigation issued by the SEC on March 1, 2011, which followed a nonpublic informal inquiry commenced by the SEC in October 2010. The Company received a copy of the nonpublic formal order of private investigation on February 10, 2012 in connection with a subpoena issued by the SEC. The SEC is investigating whether there have been any violations of the federal securities laws and has focused on matters relating to disclosures in the late 2009 and early 2010 time period regarding resource potential for the CPO 4 prospect. The Company has presented information supporting its disclosure relative to resource potential on the CPO 4 prospect. On August 29, 2013, the Company and John Terwilliger received a “Wells” notice advising them that the staff of the SEC has made a preliminary recommendation to initiate an enforcement action and providing them an opportunity to provide reasons of law, policy or fact why the proposed enforcement action should not be filed. The Company has cooperated fully, and is committed to continuing to cooperate fully, with the SEC in this matter. It is not possible at this time to predict the timing or outcome of the SEC investigation, including whether or when any proceedings might be initiated, when these matters may be resolved or what, if any, penalties or other remedies may be imposed, and whether any such penalties or remedies would have a material adverse effect on the Company’s consolidated financial position, results of operations, or cash flows.

In connection with the ongoing investigation being conducted by the SEC and indemnification provisions contained in an engagement agreement with Global Hunter Securities, LLC relating to our 2009 equity offering, in July 2012, the Company entered into an agreement with Global Hunter to settle any and all claims by Global Hunter related to reimbursement of attorney’s fees under the indemnity provision. During 2012, the Company paid a total of $490,850 to Global Hunter and in exchange for the payments, the Company was granted a full release by Global Hunter Securities of any future claims or liabilities asserted by Global Hunter in connection with the offering. The payment to Global Hunter Securities was recorded as a charge to additional paid in capital and is listed under the Cash Flow from Financing Activities in the statement of cash flows as Cost of capital.

On April 27, 2012, a purported class action lawsuit was filed in the U.S. District Court for the Southern District of Texas against us and certain of our executive officers: Steve Silverman v. Houston American Energy Corp. et al., Case No. 4:12-CV-1332. The complaint generally alleges that, between March 29, 2010 and April 18, 2012, all of the defendants violated Sections 10(b) of the Securities Exchange Act of 1934 and SEC Rule 10b-5 and the individual defendants violated Section 20(a) of the Exchange Act in making materially false and misleading statements including certain statements related to the status and viability of the Tamandua #1 well. Two additional class action lawsuits were filed against us in May 2012. The complaints seek unspecified damages, interest, attorneys’ fees, and other costs. On September 20, 2012, the court consolidated the class action lawsuits and appointed a lead plaintiff and on November 15, 2012 the lead plaintiffs filed an amended complaint. On January 14, 2013, we filed a motion to dismiss and, on August 22, 2013, the court granted our motion and dismissed the complaint. The plaintiffs have since filed a Notice of Appeal of the dismissal of the complaint and the appeal is presently pending before the U.S. Court of Appeals for the Fifth Circuit. We believe all of the claims in the consolidated class action lawsuits are without merit and intend to vigorously defend against these claims. It is not possible at this time to predict the timing or outcome of the class action lawsuits that have or may be filed.

On July 19, 2012, a purported derivative cause of action was filed in the U.S. District Court for the Southern District of Texas against certain of the Company’s directors and officers and the Company, as nominal defendant: E. Howard

King, Jr., derivatively, on behalf of Houston American Energy Corp., v. John F. Terwilliger, John P. Boylan, Orrie Lee Tawes III, Stephen Hartzell, James J. Jacobs, Kenneth A. Jeffers, defendants, and Houston American Energy Corp., as nominal defendant, Case No. 4:12-CV-02182. The complaint asserts a cause of action by a shareholder on behalf of the Company against certain of its directors and senior executive officers in connection with the June 11, 2012 approval of payment of certain bonuses, increases in salary, grant of certain stock options and entry into certain Change in Control Agreements. The complaint alleges that the approval of such matters constituted breach of fiduciary duty and corporate waste and seeks injunctive relief to bar each of the actions in question and seeks restitution. No damages have been or, by the nature of the derivative cause of action, are expected to be alleged against the Company. The Company may, however, incur certain costs and demands on management time and resources in connection with the lawsuit. On February 26, 2013, an order was entered granting a motion by the company to dismiss the lawsuit and providing leave to the plaintiff to amend its complaint to cure pleading deficiencies. The Plaintiff's allotted time to amend its complaint by the Court expired on March 26, 2013, and no amendment was made by the Plaintiff, effectively ending the lawsuit.

Table of Contents

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.

Table of Contents

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.

NOTE 12—SUBSEQUENT EVENTS

Subsequent to December 31, 2013, the Company collected $1,614,290 of escrow receivables, leaving an uncollected balance of $306,927 as of March 12, 2014.

NOTE 13—GEOGRAPHICAL INFORMATION

The Company currently has operations in two geographical areas, the United States and Colombia. Revenues for the years ended December 31, 2013 and 2012 and long-lived assets as of December 31, 2013 and 2012 attributable to each geographical area are presented below:

	2013		2012	
	Revenues	Long Lived Assets, Net	Revenues	Long Lived Assets, Net
North America	347,139	2,073,268	$148,163	$1,050,557
South America	—	1,789,536	263,186	4,836,412
Total	347,139	3,862,804	$411,349	$5,886,969

NOTE 14—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:

	2013	2012
Revenues		
North America	$347,139	$148,163
South America	—	263,186
	$347,139	$411,349
Production Cost		
North America	$81,774	$76,593
South America	—	118,788
	$81,774	$195,381

Table of Contents

Capital Costs

Capitalized costs and accumulated depletion relating to the Company's oil and gas producing activities as of December 31, 2013, 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	$2,012,506	$1,789,536	$3,802,042
Proved properties being amortized	865,889	49,454,702	50,320,591
Accumulated depreciation, depletion, amortization and impairment	(819,799)	(49,454,702)	(50,274,501)
Net capitalized costs	$2,058,596	$1,789,536	$3,848,132

Amortization Rate

The amortization rate per unit based on barrel of oil equivalents was $2.67 for the United States and $0 for South America for the year ended December 31, 2013.

Acquisition, Exploration and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities as of December 31, 2013 and 2012 are summarized below:

	2013 United States	South America
Property acquisition costs:		
Proved	$8,640	84,081
Unproved	262,883	—
Exploration costs	—	88,171
Development costs	776,142	—
Total costs incurred	$1,047,665	172,252

	2012 United States	South America
Property acquisition costs:		
Proved	$—	$—
Unproved	110,836	—
Exploration costs	—	25,915,741
Development costs	6,488	—
Total costs incurred	$117,324	$25,915,741

Table of Contents

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.

Table of Contents

	United States Gas (mcf)	United States Oil (bbls)	South America Gas (mcf)	South America Oil (bbls)	Total Gas (mcf)	Total Oil (bbls)
Total proved reserves						
Balance December 31, 2011	86,800	6,540	—	94,619	86,800	101,159
Extensions and discoveries	—	—	—	—	—	—
Purchase of minerals in place	—	—	—	—	—	—
Revisions of prior estimates	10,546	662	—	253	10,546	915
Sale of minerals in place	—	—	—	(93,117)	—	(93,117)
Production	(12,066)	(1,032)	—	(1,755)	(12,066)	(2,787)
Balance December 31, 2012	85,280	6,170	—	—	85,280	6,170
Purchase of minerals in place						
Revisions to prior estimates	(39,011)	7,943	—	—	(39,011)	7,943
Sales of minerals in place			—	—		
Production	(9,459)	(2,963)	—	—	(9,459)	(2,963)
Balance December 31, 2013	36,810	11,150	—	—	36,810	11,150
Proved developed reserves						
at December 31, 2012	85,280	6,170	—	—	85,280	6,170
at December 31, 2013	36,810	11,150			36,810	11,150
Proved undeveloped reserves						
at December 31, 2012	—	—	—	—	—	—
at December 31, 2013	—	—	—	—	—	—

During 2013 and 2012, the Company recorded extensions and discoveries resulting principally from its ongoing drilling operations in Colombia. As of December 31, 2013, we had no proved undeveloped ("PUD") reserves. None of the PUD reserves as of December 31, 2012 were converted to proved developed producing reserves in 2013. All remaining PUD reserves as of December 31, 2011 were sold during 2012 in connection with the sale of our indirect 1.6% ownership in an entity holding interests in the La Cuerva and LLA 62 blocks in Colombia.

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.

Table of Contents

Standardized measure of discounted future net cash flows at December 31, 2013:

	United States	South America	Total
Future cash flows from sales of oil and gas	$1,306,020	$ —	$1,306,020
Future production cost	(357,970)	—	(357,970)
Future development cost	—	—	—
Future income tax	(14,525)	—	(14,525)
Future net cash flows	933,525	—	933,525
10% annual discount for timing of cash flow	(214,490)	—	(214,490)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$719,035	$ —	$719,035
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(265,365)	—	(265,365)
Change due to revisions in standardized variables:			
Income taxes	(14,525)	—	(14,525)
Accretion of discount	29,807	—	29,807
Net change in sales and transfer price, net of production costs	48,603	—	48,603
Previously estimated development costs incurred during the period	—	—	—
Changes in estimated future development costs	—	—	—
Revision and others	30,997	—	30,997
Discoveries	—	—	—
Sales of reserves in place	—	—	—
Changes in production rates and other	591,447	—	591,447
Net	420,965	—	420,965
Beginning of year	298,070	—	298,070
End of year	$719,035	$ —	$719,035

Table of Contents

Standardized measure of discounted future net cash flows at December 31, 2012:

	United States	South America	Total
Future cash inflows from sales of oil and gas	$921,070	$—	$921,070
Future production cost	(392,430)	—	(392,430)
Future development cost	—	—	—
Future income tax	—	—	—
	528,640		528,640
10% annual discount for timing of cash flow	(230,570)	—	(230,570)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$298,070	$—	$298,070
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(71,570)	(144,398)	(215,968)
Change due to revisions in standardized variables:			
Income taxes	(12,911)	—	(12,911)
Accretion of discount	49,238	—	49,238
Net change in sales and transfer price, net of production costs	(62,724)	—	(62,724)
Previously estimated development costs incurred during the period	—	—	—
Changes in estimated future development costs	—	—	—
Revision and others	35,781	—	35,781
Discoveries	—	—	—
Sales of reserves in place	—	(2,505,431)	(2,505,431)
Changes in production rates and other	(42,954)	—	(42,954)
Net	(105,140)	(2,649,829)	(2,754,969)
Beginning of year	403,210	2,649,829	3,053,039
End of year	$298,070	$—	$298,070

Table of Contents

NOTE 15—SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
2013				
Operating revenue	$15,032	$19,223	$170,311	$142,573
Loss from operations	(785,191)	(1,296,227)	(526,248)	(610,247)
Net loss	(806,175)	(1,266,267)	(526,464)	(574,575)
Loss per common share - basic	$(0.02)	$(0.02)	$(0.01)	$(0.01)
Loss per common share - diluted	$(0.02)	$(0.02)	$(0.01)	(0.01)
2012				
Operating revenue	$320,510	$36,347	$30,752	$23,740
Income from operations	(20,633,191)	(18,654,298)	(5,910,504)	(11,269,214)
Net income	(20,668,095)	(22,022,079)	(5,935,713)	(8,131,562)
Earnings per common share - basic	$(0.66)	$(0.63)	$(0.16)	$(0.16)
Earnings per common share - diluted	(0.66)	(0.63)	(0.16)	(0.16)