HOUSTON AMERICAN ENERGY CORP
Form 10-K
March 07, 2012

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, 2011

o 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 AMEX

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 x Non-accelerated filer o Smaller reporting company o

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, 2011, based on the closing sales price of the registrant's common stock on that date, was approximately $253 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 7, 2012 was 31,165,230.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Proxy Statement for its 2012 Annual Meeting are incorporated by reference into Part III of this Report.

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FORWARD-LOOKING STATEMENTS

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

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

PART I

Item 1. Business

General

Houston American Energy Corp is an independent oil and gas company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil properties in the U.S. 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.

Exploration Projects

Our exploration 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 exploration projects 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 exploration project ("Project Interest") represents the portion of the interest in the exploration project we share with other project partners. Because each exploration project consists of a bundle of assets that may or may not include a working interest in the project, our Project Interest simply represents our proportional ownership in the bundle of assets that constitute the exploration project. Therefore, our Project Interest in an exploration project should not be confused with the working interest that we will own when a given well is drilled. Each exploration project represents a negotiated transaction between the project partners. Our working interest may be higher or lower than our Project Interest.

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Consistent with our strategy of opportunistically divesting holdings and redeploying financial resources to grow our reserve positions, in late 2010, our indirect interests in four concessions in Colombia were sold for net proceeds, before escrow holdbacks, of $29.4 million. The interests sold accounted for 96.9% of our estimated proved oil and natural gas reserves at December 31, 2009 and 96.8% of our oil and natural gas revenues in 2010. During 2011, proceeds from that sale were redeployed principally to exploration costs associated with our CPO 4 prospect in Colombia.

The following table sets forth information relating to our principal exploration projects as of December 31, 2011:

	Net acreage	Average working interest %		Gross producing wells	Net proved reserves (boe)	2011 Net Production Oil (bbls)	2011 Net Production Natural Gas (mcf)
Oklahoma	4	2.36	%	1	1,092	—	738
Louisiana	1,451	36.90	%	3	19,437	649	8,896
Texas	42	3.81	%	2	478	443	1,204
Total U.S.	1,497	35.89	%	6	21,007	1,092	10,838
Colombia	179,978	30.41	%	14	94,619	9,924	—
Total	181,475	30.45	%	20	115,626	11,016	10,838

- 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 a 37.50% working interest in the Profit Island and North Profit Island prospects, covering 3,805 gross acres in East Baton Rouge Parish, Louisiana. In addition, we hold a 7.29% royalty interest in 2,485 royalty acres, as well as a 5.675% royalty interest in the Crown Paper #01 well.

- Plaquemines Parish — we hold a 1.80% working interest in the SL 180771 well and prospect which covers 300 gross acres. We have no present plans to drill additional wells on the South Sibley Prospect.

- Vermilion Parish — we hold a 2.25% working interest in the 830 acre La Furs, Inc. F-16 well and prospect. We have no present plans to drill additional wells on the South Sibley Prospect.

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, 2011, 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 Country — we hold a 3.50% working interest in the 779 acre Harrison Prospect in Matagorda County, Texas. We have no present plans to drill additional wells on the Harrison Prospect.

Our exploration properties in Texas at December 31, 2011 reflect our sale, during 2010, of a 2.5% working interest in 6000+ acres and a 1.25% overriding royalty interest in approximately 50,000 gross acres in Karnes County, Texas.

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- Colombian Properties:

At December 31, 2011, we held interests in multiple prospects in Colombia covering 825,657 gross acres. The majority of our holdings in Colombia are located within the Llanos and the Caguan Putumayo Basins. We identify our Colombian prospects by the prospect operator and concessions operated.

The following table sets forth information relating to our interests in prospects in Colombia at December 31, 2011:

Property	Operator	Ownership Interest		Total Gross Acres	Total Gross Developed Acres	Gross Productive Wells
La Cuerva	Hupecol	1.6	%	48,000	8,960	14
LLA 62	Hupecol	1.6	%	40,000	—	—
Los Picachos	Hupecol	12.5	%	86,235	—	—
Macaya	Hupecol	12.5	%	195,201	—	—
CPO 4	SK Innovation	37.5	%	345,452	—	—
Serrania	Hupecol	12.5	%	110,769	—	—
Total				825,657	8,960	14

Hupecol Prospects

At December 31, 2011 we held interests in five concessions operated by Hupecol. The La Cuerva and LLA 62 concessions are located in the Llanos Basin of Colombia and the Loc Picachos, Macaya and Serrania concessions are located in the Caguan Putumayo Basin of Colombia. The concessions cover an aggregate area of 480,205 acres. During 2011, Hupecol marketed the La Cuerva and LLA 62 concessions and, as of March 7, 2012, was in negotiations with a prospective buyer for those properties.

At December 31, 2011, we had interests in 14 gross wells (0.22 net wells) in the La Cuerva block operated by Hupecol. Our net daily production during December 2011 from interests operated by Hupecol was approximately 27 barrels of oil (no natural gas) per day. Well depths range from 3,000 feet to 5,000 feet.

Our interest in the Serrania Block 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 Block.

During 2010, seismic work on the Serrania Block was completed. During 2011, drilling preparation and seismic processing work was performed in connection with the planned drilling of initial test wells on the Block. The net costs incurred by Houston American Energy for the Phase 1 geological and seismic costs were approximately $390 thousand in 2009, $950 thousand in 2010 and $165 thousand in 2011.

Our working 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, 2011, approximately 1,169 mboe have been produced from four fields in La Cuerva.

For 2012, Hupecol has advised us that they plan to drill two additional wells on the La Cuerva concession, shoot seismic on the LLA 62 concession, and drill one well on the Serrania concession. Hupecol's drilling and seismic plans for 2012 are based on an anticipated sale of those concessions in 2012 and may change if a sale of those concessions does not occur. Drilling on the Serrania concession is subject to conditions in the field and may be extended into the first quarter of 2013. Houston American Energy's estimated net cost associated with drilling the initial well on the Serrania concession is approximately $625 thousand and its share of estimated costs on other wells and seismic planned to be drilled by Hupecol in 2012 on La Cuerva and LLA 62 is approximately $180 thousand.

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.

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SK Innovation Prospect

Pursuant to two Farmout Agreements and a Joint Operating Agreement, we hold an interest in the 345,452 acre CPO 4 Block located in the Western Llanos Basin and operated by SK Innovation. Under the Joint Operating Agreement, effective retroactive to May 31, 2009, SK Innovation acts as operator of the CPO 4 Block. Under the original Farmout Agreement, entered in 2009, we agreed to pay 25.0% of all past and future cost related to the CPO 4 block, as well as an additional 12.5% of the Seismic Acquisition Costs incurred during the Phase 1 Work Program, for which we received a 25.0% interest in the CPO 4 Block. Under a second Farmout Agreement, entered in 2010 and effective July 31, 2010, we acquired from SK an additional 12.5% interest in the CPO 4 Block and we agreed to pay our proportionate interest in ongoing costs plus 12.5% of certain defined costs relating to the development of the CPO 4 Block and 25% of seismic acquisition costs incurred with respect to the Phase 1 cost of the CPO 4 Block between June 18, 2009 and June 17, 2012.

As a result of the second Farmout Agreement, at December 31, 2011, we held a 37.5% interest in the CPO 4 Block.

Pursuant to the terms of, and in conjunction with, the second Farmout Agreement and the Joint Operating Agreement, we entered into a separate agreement with Gulf United Energy ("Gulf United") whereby we waived our right of first refusal under the Joint Operating Agreement for the specific purpose of permitting Gulf United to acquire a 12.5% interest in the CPO 4 Block. SK Innovation, simultaneously, entered into an agreement with Gulf United to assign a 12.5% interest in the CPO 4 Block to Gulf United conditioned upon approval of the assignment by the National Hydrocarbon Agency of Colombia (the "ANH") and the Republic of Korea. Under our agreement with Gulf United, Gulf United agreed to pay us, not later than 30 days following receipt by Gulf United of ANH approval, our 12.5% share of past costs incurred through July 31, 2010 and our 25% share of seismic acquisition costs incurred through July 31, 2010 on the CPO 4 Block.

In November 2010, we paid our proportionate interest in the past costs attributable to the additional 12.5% interest acquired in the CPO 4 Block. At December 31, 2011 and through the date of this filing, approval of the assignment to Gulf United by the ANH remained pending, as did Gulf United's obligation to reimburse us the agreed 12.5% of past costs and 25% of seismic acquisition costs.

The Phase 1 Work Program consists of reprocessing approximately 400 kilometers of existing 2-D seismic data, the acquisition, processing and interpretation of a 2-D seismic program containing approximately 620 kilometers of data and the drilling of two exploration wells. The Phase 1 Work Program was modified to allow 3-D data to be shot in place of the initial 2-D requirement. The Phase 1 seismic acquisition was completed during 2010 and the drilling of the first exploration well has ongoing at December 31, 2011. Our total expenditures on the CPO 4 Phase 1 Work Program were $8.2 million in 2010 and $13.01 million in 2011.

Drilling operations on the first well on the CPO-4 Block, the Tamandua #1 with a projected target depth of 16,300 feet, commenced in July 2011. The well was subsequently sidetracked to address drilling issues associated with high pressure and inflows of hydrocarbons and fluids into the well bore.

As of December 31, 2011, the Tamandua #1 sidetrack well had been drilled to 13,989 feet, the top of the Mirador Formation, the first of the well's four primary objective sands. Subsequently, and as of March 1, 2012, the Tamandua #1 sidetrack well had a 7 inch liner run to 13,913 feet and was drilled to total depth of 15,562 feet where Paleozoics were encountered.

While the well exhibited oil shows while drilling, and other indications of hydrocarbons such as log analysis that indicate possible productive sands, hole conditions prohibited sufficient testing of the bottom hole section. After multiple attempts to evaluate the bottom section of the well, resulting in tool failures and stuck pipe, the operator determined not to re-enter the bottom hole section. The operator, in turn, determined to come up the hole and to further evaluate the C-7 formation, where logging while drilling data showed approximately 200 feet of net resistive sands, and the C-9 formation, where logging while drilling data showed approximately 140 feet of net resistive sand (resistive sands do not necessarily mean pay).

Upon completion of further evaluation of the C-7 and C-9 formations in the Tamandua #1 sidetrack well, we anticipate that a well completion will be attempted after which we expect the rig to be moved to one of two locations on the CPO 4 block that are currently permitted and ready to receive a rig to commence drilling of a second test well on the block. The operator has identified five additional drilling locations that are in various stages of permitting, location and construction.

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Despite the information derived from the Tamandua#1 and Tamandua #1 sidetrack, there is no assurance that we will locate hydrocarbons in sufficient quantities to be commercially viable.

For 2012, SK Innovation has advised us that they plan to focus on completion of the Tamandua #1 sidetrack well and, subject to the results of such well, the drilling of up to 3 additional wells and the shooting of approximately 410 km2 of 3-D seismic on CPO 4. Our budgeted expenditures on the CPO 4 Block for 2012 are approximately $40.0 million.

Drilling Activity

During 2011, we participated in the drilling of a total of 13 gross wells, all of which were in Colombia. Of the 13 wells drilled, 11 were classified as exploratory and 2 were classified as development. Our 2011 drilling program achieved a 53.9% success rate. The following table summarizes the number of wells drilled during 2011, 2010, and 2009, 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,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	2	0.032	2	0.032	4	0.500
Non-productive	—	—	—	—	1	0.125
Total development wells	2	0.032	2	0.032	5	0.625
Exploratory wells, completed as:						
Productive	5	0.080	7	0.439	5	0.407
Non-productive	6	0.096	3	0.204	5	0.486
Total exploratory wells	11	0.176	10	0.643	10	0.893

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, 2011, we had no wells in progress or awaiting completion in the United States and one gross (0.375 net) well in progress in Colombia.

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, 2011, we owned interests in 20 gross wells. As of December 31, 2011, we had ownership interests in productive wells, categorized by geographic area, as follows:

	Oil Wells	Gas Wells
United States		
Gross	—	6
Net	—	0.20
Colombia		
Gross	14	—
Net	0.22	—

Total		
Gross	14	6
Net	0.22	0.20

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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, 2011:

	Year Ended December 31, 2011		2010	2009
Net Production:				
Gas (Mcf):				
United States	10,838		17,798	15,761
Colombia	—		—	—
Total	10,838		17,798	15,761
Oil (Bbls):				
United States	1,092		1,540	1,581
Colombia	9,924		260,239	129,782
Total	11,016		261,779	131,363
Average sales price:				
Gas ($ per Mcf)				
United States	$3.90		$5.01	$4.89
Colombia	—		—	—
Total	3.90		5.01	4.89
Oil ($ per Bbl)				
United States	97.10		76.21	59.99
Colombia	101.56		74.17	61.21
Total	101.12		74.18	61.20
Average production costs ($ per BOE):				
United States	16.05		8.50	26.01
Colombia	80.13	(1)	31.08	35.95
Total	$65.65		$30.70	$35.33

(1) The increase in production costs per BOE in Colombia during 2011 reflect reduced production volumes in 2011 following the sale of our principal producing properties in 2010 and disproportionately high fixed production costs in Colombia.

Natural Gas and Oil Reserves

Reserve Estimates

The following tables sets forth, by country and as of December 31, 2011, 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.

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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	6,540	86,800	21,007
Colombia	30,846	—	30,846
Total Proved Developed Reserves	37,386	86,800	51,853
Proved Undeveloped			
United States	—	—	—
Colombia	63,774	—	63,774
Total Proved Undeveloped Reserves	63,774	—	63,774
Total Proved Reserves	101,160	86,800	115,627

	Proved Developed	Proved Undeveloped	Total Proved
PV-10 (1)	$ 1,463,350	$ 2,425,009	$ 3,888,359
Standardized measure (3)	$ 1,148,984	$ 1,904,054	$ 3,053,038

(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, 2011. 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, 2011. The average prices utilized for purposes of estimating our proved reserves were $100.82 per barrel of oil and $4.77 per mcf of natural gas for our US properties and $95.78 per barrel of oil for our Colombian 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.

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

Our year-end reserve report is prepared by Lonquist & Co. based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geosciences and engineering data, and other information provided to them by our management team and by the various Hupecol entities that operated all of our proved properties in Colombia at December 31, 2011. Lonquist & Co. also prepares reserve estimates for the various Hupecol entities. This information is reviewed by knowledgeable members of our Company to ensure accuracy and completeness of the data, as it pertains to our Company, prior to submission to Lonquist & Co. 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 Senior Vice President of Exploration, a degreed geophysicist with over 25 years oil and gas industry experience, and our President for completeness of the data presented and 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 has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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, 2011, our proved undeveloped reserves totaled 63.8 mbbls of oil and 0 mcf of natural gas, for a total of 63.8 mbbls compared to 43.9 mbbls of oil and 0.0 mcf of natural gas, for a total of 43.9 mbbls as of December 31, 2010.

PUD Locations

All of our proved undeveloped reserves at December 31, 2011 were associated with our properties in Colombia operated by Hupecol.

Changes in Proved Undeveloped ("PUD") Reserves

Changes in PUD Reserves that occurred during 2011 were due to positive revisions of 19.825 mboe in PUD reserves due to Hupecol's on-going drilling program and subsequent changes in subsurface mapping.

Development Cost

Estimated future development costs relating to the development of proved undeveloped reserves are projected to be $486 thousand for 2012 and $124 thousand thereafter.

Drilling Plans

All proved undeveloped locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2016. None of our proved undeveloped locations have been booked for longer than five years.

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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, 2011:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States	2,409	70	3,805	1,427
Colombia	8,960	143	816,697	179,835
Total	11,369	213	820,502	181,262

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, 2011, the expiration periods of the gross and net acres that are subject to leases or concessions summarized in the above table of undeveloped acreage.

	Undeveloped Acres Expiring	
Twelve Months Ending:	Gross	Net
December 31, 2012	749	281
December 31, 2013	122	46
December 31, 2014	2,185	819
December 31, 2015	749	281
December 31, 2016 and later	816,697	179,835
Total	820,502	181,262

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, 2011, we had no contractual agreements to sell our gas and oil production and all production was sold on spot markets.

Employees

As of March 1, 2012, we had 4 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.

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Competition

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

Regulatory Matters

Regulation of Oil and Gas Production, Sales and Transportation

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

Environmental Regulation

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

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

- Clean Air Act, and its amendments, which govern air emissions;
- Clean Water Act, which governs discharges into waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as “Superfund”);
- Resource Conservation and Recovery Act, which governs the management of solid waste;
-

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

- Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

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

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

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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.

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.

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Item 1A. Risk Factors

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

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

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

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

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.

We may be affected by general economic conditions

The disruption experienced in U.S. and global financial and credit markets, and the accompanying economic contraction, during second half of 2008 and continuing through 2009 resulted in projected decreases in demand for oil and natural gas, resulting in a sharp drop in energy prices, and affected the availability and cost of capital. While the U.S. and global economies have experienced a slow recovery from the deep recessionary conditions that prevailed in late 2008 and much of 2009 and commodity prices have recovered a portion of the decline experienced over that period, uncertainty that continues to exist with respect to the pace and sustainability of the economic recovery continues to be a risk to oil and natural gas operators and other businesses. Global economic growth drives demand for energy from all sources, including fossil fuels. Should the U.S. and global economies experience further weakness, 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 Houston American Energy, 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.

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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 and 2010 that both provided large 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. Typically, our reserves, production, operating cash flows and operating profitability has grown as properties have been drilled and developed and fall following strategic asset divestitures when we are incurring costs to drill and develop properties. As a result of drilling and other risks, there can be no assurance that our reserve and production growth strategy will allow us to continue 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 financial resources to new resource plays or 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 of such concentration of holdings, 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 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. At December 31, 2011, drilling operations were ongoing on the Tamandua #1 sidetrack well on the CPO 4 prospect. The ultimate results of the Tamandua #1 sidetrack well have yet to be determined. Given our focus on development of the CPO 4 prospect, including the commitment of substantial financial resources, and the limited current production levels from our other prospects, failure to complete the Tamandua #1 sidetrack well as a commercial well would have a material adverse effect on our financial position and operating outlook.

A substantial percentage of our properties are undeveloped; therefore the cost of 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 or proved undeveloped, we require significant capital to prove and develop such properties before they may become productive. At December 31, 2011, approximately 99% of our net acreage was unproven and 63% of our proved reserves were undeveloped. Further, because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be developed to the extent that they result in positive cash flow. Even if we are successful in our development efforts, it could take several years for a significant portion of our undeveloped properties to be converted to positive cash flow.

While our development costs were funded during 2011 with funds on hand and cash flow from our other producing properties, our funds on hand at December 31, 2011 and anticipated cash flow from operations in 2012 are not sufficient to fund our 2012 drilling budget. Accordingly, unless we are able to secure additional financing or substantially increase our operating cash flow, we may be required to curtail our drilling plans. We do not presently have any commitments to provide additional financing to support our 2012 drilling budget. If we are unable to secure additional financing, we may be unable to meet certain contractual commitments regarding the development of our properties and, as a result, may incur penalties or risk losing some or all of our interest in properties for which we fail to satisfy our funding commitments.

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

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

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

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. It requires 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. During the years ended December 31, 2009 and 2010, revisions to prior estimates resulted in positive revisions in 2009 and 2010. Positive revisions during fiscal year 2009 amounted to 46.8% of prior year-end gas reserves and 8.2% of prior year-end proved oil reserves. Positive revisions during fiscal year 2010 amounted to 42.5% of prior year-end gas reserves and 2.6% of prior year-end proved oil reserves.

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

We 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.

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 have periodically inquired 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 FCPA 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.

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. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional 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. This risk may be enhanced in our situation, due to the fact that approximately 55.2% of our reserves are currently proved undeveloped. 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 you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

We may incur substantial 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. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

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

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

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

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;

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- 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. See “Business — Regulatory Matters.”

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.

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.

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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 ANH and Ecopetrol 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 Hupecol and our interest in the assets and operations of Hupecol represent a substantial portion of our current operating assets in Colombia. During 2008 and 2010, respectively, Hupecol sold its interest in a concession and in two 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 2011, Hupecol marketed additional interests including our principal producing property in Colombia. 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.

In addition to Hupecol's control of decisions regarding properties operated by Hupecol in Colombia, as minority owners, we are subject to substantial control of other properties in Colombia in which we hold interests that are operated by SK Innovation. Our Colombian assets consist exclusively of minority, non-operator project interests in certain Colombian assets owned and operated by Hupecol, LLC and a 37.5% non-operated working interest in certain Colombian assets owned and operated by SK Innovation. 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 Hupecol and SK Innovation.

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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.

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 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.

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 have several adverse affects, 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.

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We expect to need additional financing to fund our 2012 drilling budget and may need additional financing to support operations and future capital commitments.

While our operating cash flows and funds on hand supported our drilling budget and operations during 2011, including funding drilling costs on our Tamandua #1 well, delays in drilling and completion of the Tamandua #1 well and the resulting delay in bringing that well on line have resulted in our cash position declining below levels anticipated prior to commencement of drilling of the Tamandua #1 well. While we believe that our funds on hand are sufficient to support our existing operations, including completion of drilling operations on the Tamandua #1 well, they are not sufficient to support our 2012 drilling budget or to support investments in additional properties. In order to fully fund our 2012 drilling budget we expect that we will need to secure additional financing. We have no commitments to provide any additional financing, if needed, and may be limited in our ability to obtain the capital necessary to support operations, complete development, exploitation and exploration programs or carry out new acquisition or drilling programs. We have not thoroughly investigated whether this capital would be available, who would provide it, and on what terms. If we are unable, on acceptable terms, to raise the required capital, our business may be seriously harmed.

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.

The price of our common stock may fluctuate significantly, and this may make it difficult for you to resell common stock when you want or at prices you find attractive.

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

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

- quarterly variations in our operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance;
- announcements by us, our partners or our competitors of leasing and drilling activities;
- the operating and securities price performance of other companies that investors believe are comparable to us;
- future sales of our equity or equity-related securities;

- changes in general conditions in our industry and in the economy, the financial markets and the domestic or international political situation;
- fluctuations in oil and gas prices;
- departures of key personnel; and
- regulatory considerations.

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.

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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 March 1, 2012, our directors and executive officers owned approximately 39.1% 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.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

We currently lease approximately 4,739 square feet of office space in Houston, Texas as our executive offices. Management anticipates that our space will be sufficient for the foreseeable future. The average monthly rental under the lease, which expires on May 31, 2017, is $7,701. A description of our interests in oil and gas properties is included in “Item 1. Business.”

Item 3. Legal Proceedings

We may from time to time be a party to lawsuits incidental to our business. As of March 1, 2012, we were not aware of any current, pending, or threatened litigation or proceedings that could have a material adverse effect on our results of operations, cash flows or financial condition.

Item 4. (Removed and Reserved)

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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 Amex ("AMEX") under the symbol "HUSA." Prior to July 27, 2010, our common stock traded on the Nasdaq Global Market also under the symbol "HUSA". The following table sets forth the range of high and low closing sale prices of our common stock, and cash dividends declared, for each quarter during the past two fiscal years.

		High	Low	Dividend
Calendar Year 2011	Fourth Quarter	$17.05	$10.06	$0.000
	Third Quarter	20.90	12.50	0.000
	Second Quarter	18.45	13.55	0.000
	First Quarter	19.14	13.06	0.000
Calendar Year 2010	Fourth Quarter	$18.52	$10.40	$0.205
	Third Quarter	10.99	8.50	0.005
	Second Quarter	20.35	9.30	0.005
	First Quarter	18.55	6.39	0.005

At March 1, 2012, the closing price of the common stock on AMEX was $7.00 per share.

Holders

As of March 1, 2012, there were approximately 884 shareholders of record of our common stock, excluding holders in street name.

Dividends

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, 2011 with respect to the shares of our common stock that may be issued under our existing equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities

				reflected in column (a))
Equity compensation plans approved by security holders (1)	1,833,582	$	7.02	734,752
Equity compensation plans not approved by security holders	—		—	—
Total	1,833,582	$	7.02	734,752

(1) Consists of 500,000 shares reserved for issuance under the Houston American Energy Corp. 2005 Stock Option Plan and 2,200,000 shares reserved for issuance under the Houston American Energy 2008 Equity Incentive Plan.

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Performance Graph

The following performance graph and related information shall not be deemed “soliciting material” or to be “filed” with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following performance graph compares the change in the cumulative total return of Houston American Energy’s common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2011. The graph assumes that $100 was invested in the Company’s common stock and each index on December 31, 2006, and that dividends were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN AMONG
HOUSTON AMERICAN ENERGY CORPORATION, THE S&P 500 INDEX
AND DJ U.S. EXPL & PROD. INDEX

	December 31,					
	2006	2007	2008	2009	2010	2011
Houston American Energy Corporation	$100	$41	$46	$84	$247	$170
S&P 500 Index	$100	$105	$67	$84	$97	$99
DJ U.S. Expl. & Prod. Index	$100	$144	$86	$121	$141	$135

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Item 6. Selected Financial Data

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2011. This information is derived from our Financial Statements and the notes thereto. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31, 2011	2010	2009	2008	2007
Statement of Operations Data:					
Revenue:					
Oil and gas revenue	$ 1,156,178	$ 19,508,894	$ 8,116,275	$ 10,622,050	$ 4,977,172
Expenses of operations:					
Lease operating expense and severance tax	854,319	8,142,444	4,746,295	3,366,740	1,841,119
Joint venture expense	13,930	156,686	172,890	183,510	149,200
Depreciation and depletion	185,931	3,161,366	1,900,631	5,816,691	1,099,826
Impairment of oil and gas properties	—	—	—	5,621,106	348,019
General and administrative expense	4,952,560	4,896,955	2,768,195	3,152,930	1,568,228
Total operating expenses	6,006,740	16,357,451	9,588,011	18,140,977	5,006,392
Loss (gain) on sale of oil and gas properties	1,026,608	(27,159,114)	—	(7,615,236)	—
Income (loss) from operations	(5,877,170)	30,310,557	(1,471,736)	96,309	(29,220)
Other income (expense):					
Interest income	66,852	65,155	64,882	295,375	649,742
Other income (expense)	(95,872)	8,092	—	—	—
Total other income (expense)	(29,020)	73,247	64,882	295,375	649,742
Net income (loss) before income taxes	(5,906,190)	30,383,804	(1,406,854)	391,684	620,522
Income tax expense (benefit)	(1,570,816)	9,353,864	(737,406)	(73,261)	127,116
Net income (loss)	$ (4,335,374)	$ 21,029,940	$ (669,448)	$ 464,945	$ 493,406
Basic net income (loss) per share	$ (0.14)	$ 0.68	$ (0.02)	$ 0.02	$ 0.02
Diluted net income (loss) per share	$ (0.14)	$ 0.66	$ (0.02)	$ 0.02	$ 0.02
Cash dividends paid per share	$ 0.00	$ 0.22	$ 0.04	$ 0.04	$ —
Cash Flow Data:					
Cash flow from operating activities	$ (4,633,032)	$ 8,290,671	$ (484,677)	$ 1,452,054	$ 1,801,481
Cash flow from investing activities	(11,930,534)	12,660,487	(9,239,263)	8,787,853	(1,792,672)
Cash flow from financing activities	(162,600)	6,267,845	11,786,383	(747,031)	—
Balance Sheet Data (at end of period):					
Working capital	$ 19,636,540	$ 34,255,206	$ 16,365,490	$ 10,536,834	$ 10,358,502
Property, plant and equipment, net	23,795,880	10,691,421	11,356,255	5,263,131	10,017,045
Total assets	48,657,936	55,476,428	34,062,829	22,637,054	20,714,797
Long-term debt, less current portion	45,039	26,761	332,912	205,524	135,267
Total stockholders' equity	48,315,926	50,364,637	33,245,312	21,048,248	20,243,447

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

General

We are an independent energy company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil properties in the U.S. 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

Production Levels, Revenues and Profitability – Sale of HDC, LLC and HL, LLC

Our production levels, revenues and profitability during 2011, as compared to 2010, were adversely affected by the sale, in late 2010, of our interest in certain prospects and producing properties located in Colombia.

In December 2010, Hupecol Dorotea & Cabiona Holdings, LLC ("Hupecol D&C Holdings") and Hupecol Llanos Holdings, LLC ("Hupecol Llanos Holdings") sold all of their interests in Hupecol Dorotea and Cabiona, LLC ("HDC, LLC") and Hupecol Llanos, LLC ("HL, LLC"). We own 12.5% interests in each of Hupecol D&C Holdings and Hupecol Llanos Holdings and, in turn, held indirect equivalent interests in each of HDC, LLC and HL, LLC, which companies hold interests in the Dorotea, Cabiona, Leona and Las Garzas blocks and related assets in Colombia.

HDC, LLC sold for $200 million and HL, LLC sold for $81 million, each subject to certain closing adjustments based on operations between the June 1, 2010 effective date and the closing date. Fifteen percent of the sales price of each of HDC, LLC and HL, LLC was held in escrow to fund potential claims arising from the sale, with escrowed amounts to be released over a three year period based on amounts remaining in escrow after any claims. In addition to the fifteen percent escrowed, Hupecol LLC ("Hupecol") withheld 5% of the proceeds in escrow for any contingencies that may arise from the transactions. During 2011, we received a partial payment of $516,392 from Hupecol for the 5% contingency withheld related to HL, LLC. Pursuant to our 12.5% ownership interest in each of Hupecol D&C Holdings and Hupecol Llanos Holdings, we received 12.5% in the net sale proceeds after deduction of commissions and transaction expenses from each sale and subject to the escrow hold back. Following completion of the sale of HDC, LLC and HL, LLC, we had no continuing interest in the Dorotea, Cabiona, Leona and Las Garzas blocks.

During 2010, respectively, the Dorotea, Cabiona, Leona and Las Garzas blocks accounted for approximately 254,785 barrels of oil (net to our interest) produced, or 98% of our total production, and $18,880,298 of revenues.

During 2011, proceeds from the 2010 sale were redeployed principally to exploration costs associated with our CPO 4 prospect in Colombia and, to a lesser extent, other Hupecol operated prospects. We are substantially dependent upon the results of our ongoing drilling program in Colombia, particularly our CPO 4 prospect, to replace, and grow, the reserves, production and revenues attributable to the prospects sold in 2010.

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The following table presents pro forma data that reflects revenue and income from continuing operations for 2010 as if the HDC, LLC and HL, LLC sale had occurred at January 1, 2010.

Pro-Forma Information	2010
Oil and gas revenue	$628,596
Income (loss) from operations	(3,213,162)

Drilling Activity

During 2011, we drilled 13 international wells in Colombia, as follows:

- 13 wells were drilled on concessions in which we hold a 1.6% working interest, of which 7 were completed and in production at December 31, 2011 and 6 were dry holes.

At December 31, 2011, drilling operations were ongoing on our CPO 4 prospect in Colombia. See "CPO 4 Development" below.

During 2011, no domestic wells were drilled and, at December 31, 2011, no domestic drilling operations were ongoing.

CPO 4 Development

During 2011, our capital expenditures relating to development of our CPO 4 prospect totaled $13,010,000 and related principally to drilling preparation and seismic processing and commencement of our first test well.

Drilling operations on the Company's first well on the CPO-4 block in Colombia, the Tamandua #1, with a projected target depth of 16,300 feet, commenced in July 2011 and was subsequently sidetracked to address drilling issues associated with high pressure and inflows of hydrocarbons and fluids into the well bore. As of December 31, 2011, the sidetrack well had been drilled to 13,989 feet and efforts were ongoing to control the well bore while continuing drilling to the target depth.

Subsequently, and as of March 1, 2012, the Tamandua #1 sidetrack well had a 7 inch liner run to 13,913 feet and was drilled to total depth ("TD") at 15,562 feet. Upon drilling the well to TD, the well encountered Paleozoics which was a clear indication that the TD had been reached.

While the well exhibited oil shows while drilling, and other indications of hydrocarbons such as log analysis that indicate possible productive sands, hole conditions have prohibited sufficient testing on the bottom hole sections. There have been many attempts to evaluate the well resulting in tool failures and stuck pipe, and current conditions are such that the operator has made the decision not to try to reenter the bottom hole sections. As a result of these developments, the decision has been made that without the ability to effectively test the lower zones, the most prudent course of action is to plug back the well and to further evaluate the C-7 and C-9 Formations. As indicated by the Logging While Drilling data, the well encountered approximately 200 feet of net resistive sands in the C-7 formation and approximately 140 feet of net resistive sands in the C-9 formation (resistive sands do not necessarily mean pay).

After attempting to complete the well, the rig is expected to be moved to one of two locations that are currently permitted and ready to receive the rig. In addition, the operator has five additional locations that are in various stages of permitting, location and construction.

We anticipate completion of the Tamandua #1 well during the first quarter of 2012 with well testing and, as appropriate, completion of the well to follow. Drilling of a second test well on the CPO 4 prospect is expected to commence shortly after completion of the Tamandua #1 well.

Serrania Development

During 2011, our capital expenditures relating to development of our Serrania prospect totaled $165,500 and related principally to drilling preparation and seismic processing. For 2012, Hupecol has advised us that they plan to drill one well on the Serrania concession. Drilling on the Serrania concession will be subject to conditions in the field and may be extended into the first quarter of 2013. Houston American Energy's estimated net cost associated with drilling the initial well on the Serrania concession is approximately $625 thousand.

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Leasehold Activity

During 2011, our Macaya and Los Picachos Technical Evaluation Agreements were converted to exploration and production contracts. Subject to final ANH approval of our interest in each contract, we hold a 12.5% interest in each of the Macaya prospect and the Los Picachos prospect.

Asset Sales

In addition to the above described 2010 sale of our indirect interests in the Dorotea, Cabiona, Leona and Las Garzas blocks in Colombia, during 2010, we divested our direct interest in acreage in Karnes County, Texas.

As a result of the 2010 sales, we realized a gain on the sale of oil and gas properties of $27,159,114 during 2010. As a result of post-closing adjustments relating to our 2010 sale of Colombian assets, we realized a loss on sale of assets of $1,026,608 during 2011.

Hupecol, the operator of our Colombian assets, other than CPO 4, continues to periodically undertake efforts to divest prospects in an opportunistic manner where it believes that proceeds from such divestitures can be redeployed on a more favorable basis. During 2011, Hupecol engaged an advisor to market the La Cuerva and LLA 62 prospects in Colombia. Hupecol is currently in negotiations with a prospective buyer of those properties, and it is anticipated that a sale will take place during 2012.

Compensation Expense

In June 2011, our board of directors approved, and we paid, cash bonuses totaling $526,000, and granted an aggregate of 45,000 shares of restricted stock with a fair value of $743,400, to our senior management team to vest over three years and, effective July 1, 2011, we increased the base salary of members of our senior management team by 5%. In June 2010, our board of directors approved, and we paid, cash bonuses to our senior management team totaling $637,500 and, effective June 15, 2010, we increased the base salary of members of our senior management team by 10%. In August 2010, we expanded our management team with the appointment of a then-consultant to serve as Senior Vice President of Exploration.

In June 2010, we modified the non-cash compensation arrangements for our non-employee directors to provide for annual grants of stock options to purchase 25,000 shares of common stock. Pursuant to such revised compensation arrangements, we granted 100,000 stock options to non-employee directors on June 15, 2010 and granted 25,000 stock options to a newly appointed non-employee director in July 2010. In August 2010, we granted 150,000 stock options to the newly appointed member of our management team. As a result of these 2010 option grants and the amortization of the cost associated with options granted in prior years that remain subject to vesting, we recognized non-cash compensation expense for 2010 totaling $2,357,230.

During 2011, we granted stock options to our non-employee directors to purchase an aggregate of 106,250 shares of common stock with 25,000 options vesting immediately and 81,250 options vesting 20% on date of grant and 80% on March 13, 2012. During 2011, we recognized non-cash compensation expense associated with grants of restricted stock and stock options totaling $2,342,892.

As of December 31, 2011, there was $731,925 of total unrecognized compensation cost related to unvested restricted stock and $2,574,620 of total unrecognized compensation cost related to unvested stock options. The cost of the unvested restricted stock is expected to be recognized over a weighted average period of approximately 2.45 years and the cost of the unvested stock options is expected to be recognized over a weighted average period of 2.07 years.

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Critical Accounting Policies

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

Full Cost Method of Accounting for Oil and Gas Activities. We follow the full cost method of accounting for oil and gas property acquisition, exploration and development activities. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisition, geological and geophysical work, delay rentals, costs of drilling, completing and equipping successful and unsuccessful oil and gas wells and related internal costs that can be directly identified with acquisition, exploration and development activities, but does not include any cost related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized unless significant amounts of oil and gas reserves are involved. No corporate overhead has been capitalized as of December 31, 2011. 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, 2011 and 2010:

	At December 31, 2011	At December 31, 2010
Acquisition costs	$ 5,325,369	$ 2,795,439
Evaluation costs	17,565,575	7,463,541
Total	$ 22,890,944	$ 10,258,980

The carrying value of unevaluated oil and gas prospects includes $22,028,895 and $9,647,632 expended for properties in South America at December 31, 2011 and December 31, 2010, 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 (“forfeitures”). 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.

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Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Oil and Gas Revenues. Total oil and gas revenues decreased 94%, to $1,156,178, in 2011 from $19,508,894 in 2010.

The decrease in revenue was due to the 2010 sale of our indirect interests in the Dorotea, Cabiona, Leona and Las Garzas blocks, partially offset by (1) higher average sales prices for oil during 2011 and (2) oil production from 7 new wells brought onto production during 2011.

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2011 and 2010:

	2011	2010 (1)
Gross producing wells	20	34
Net producing wells	0.42	2.704
Net oil production (Bbls)	11,016	261,779
Net gas production (Mcf)	10,838	17,798
Oil—Average sales price per barrel	$101.12	$74.18
Gas—Average sales price per mcf	$3.90	$5.01

(1) As noted elsewhere, we sold our indirect interest in four Colombian concessions in December 2010. Of the wells and production shown in 2010, the concessions sold in December 31, 2010 account for 19 gross wells, 2.375 net wells and 254,785 bbls of net oil production.

The change in gross and net producing wells reflects the 2010 sale of our interest in wells associated with the Dorotea, Cabiona, Leona and Las Garzas blocks and the drilling and completion of 7 gross (.112 net) wells in 2011. In addition, two of our gross well (.018 net wells) went off-line in 2011.

The change in average sales prices realized reflects a rise in global oil prices and declining domestic natural gas prices.

Oil and gas sales revenues for 2011 and 2010 by region were as follows:

	Colombia	U.S.	Total
2011			
Oil sales	$1,007,912	$106,037	$1,113,949
Gas sales	$—	$42,229	$42,229
2010			
Oil sales	$19,302,303	$117,360	$19,419,663
Gas sales	$—	$89,231	$89,231

Lease Operating Expenses. Lease operating expenses, excluding joint venture expenses relating to our Colombian operations discussed below, decreased 90% to $854,319 in 2011 from $8,142,444 in 2010.

The decrease in total lease operating expenses was attributable to the 2010 sale of our interests in the Dorotea, Cabiona, Leona and Las Garzas blocks.

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

	Colombia	U.S.	Total
2011	$795,247	$59,072	$854,319
2010	$8,088,230	$54,214	$8,142,444

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, either on our continuing Hupecol blocks or our CPO 4 block not operated by Hupecol.

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Joint Venture Expenses. Joint venture expenses totaled $13,930 in 2011 compared to $156,686 in 2010. The 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 December 2010 divestiture of assets operated by Hupecol.

Depreciation and Depletion Expense. Depreciation and depletion expense decreased by 94% to $185,931 in 2011 from $3,161,366 in 2010. The decrease in depreciation and depletion was due to the 2010 sale of assets discussed above.

Gain (Loss) on sale of oil and gas properties. The sale of our indirect interests in Hupecol Dorotea and Cabiona, LLC and Hupecol Llanos, LLC resulted in a gain of $25,397,048, and the sale of our Karnes County, Texas interests resulted in a gain of $1,762,066 during 2010. Post-closing purchase price adjustments relating to our 2010 sale of Colombian assets and our prior 2008 sale of Colombian assets resulted in a loss on sale of oil and gas properties of $1,026,608 in 2011.

General and Administrative Expenses. General and administrative expense increased by 1% to $4,952,560 in 2011 from $4,896,955 in 2010. The increase in general and administrative expense was primarily attributable to an increase in salary attributable to the hiring of an additional executive in late 2010 and increases in base salary in 2010 and 2011 and a restricted stock grant in 2011, partially offset by higher bonuses and stock option grants during 2010 and the imposition during 2011 of a vesting schedule on director option grants which resulted in the deferral of recognition of $190,489 compensation expense relating to such grants until 2012.

Other Income (Expense). Other income (expense) consists of interest earned on cash balances net of other bank fees. Net other expense totaled $29,020 in 2011 as compared to net other income of $73,247 in 2010. The change was attributable to fees incurred during 2011 attributable to our Standby Letter of Credit and operations in Colombia.

Income Tax Expense/Benefit. We reported an income tax benefit of approximately $1.6 million in 2011 as compared to an income tax expense of approximately $9.4 million in 2010. The current year benefit consists of the $1.2 million benefit as discussed in Note 3 – Income Taxes as well as a federal income tax refund of $505,874 received during the tax year. The decrease in income tax expense in 2011 was attributable to decreased revenues and profitability of our Colombian operations following our 2010 sale of assets discussed above.

The income tax expense during 2010 was entirely attributable to operations in Colombia and reflects increased sales and profitability in Colombia, as well as the taxes applicable to the proceeds received on sale of oil and gas properties discussed above.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Oil and Gas Revenues. Total oil and gas revenues increased 140.37%, to $19,508,894 in 2010 from $8,116,275 in 2009.

The increase in revenue is principally due to (1) higher average sales prices for oil and gas during 2010 reflecting increased commodity pricing due to improved global macroeconomic conditions compared to 2009 and (2) increased oil production due to new wells brought onto production and production from our Colombian properties for the full period in 2010 as compared to 2009, when production was temporarily shut-in for 52 days due to market conditions, partially offset by the sale, in December 2010, of our indirect interest in the entities holding four concessions in Colombia.

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2010 and 2009:

	2010 (1)	2009
Gross producing wells	34	26
Net producing wells	2.704	2.31
Net oil production (Bbls)	261,779	131,363
Net gas production (Mcf)	17,798	15,761
Oil—Average sales price per barrel	$74.18	$61.20
Gas—Average sales price per mcf	$5.01	$4.89

(1) As noted elsewhere, we sold our indirect interest in four Colombian concessions in December 2010. Of the wells and production shown in 2010, the concessions sold in December 31, 2010 account for 19 gross wells, 2.375 net wells and 254,785 bbls of net oil production.

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As noted, production volumes were less then what they otherwise would have been in 2009 due to the cessation of production and sales from the majority of our Colombian properties for 52 days in early 2009 as a result of unfavorable commodity prices.

Oil and gas sales revenues for 2010 and 2009 by region were as follows:

	Colombia	U.S.	Total
2010			
Oil sales	$19,302,303	$117,360	$19,419,663
Gas sales	$—	$89,231	$89,231
2009			
Oil sales	$7,944,353	$94,839	$8,039,192
Gas sales	$—	$77,083	$77,083

Lease Operating Expenses. Lease operating expenses, excluding joint venture expenses relating to our Colombian operations discussed below, increased 71.5% to $8,142,444 in 2010 from $4,746,295 in 2009.

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

	Colombia	U.S.	Total
2010	$8,088,230	$54,214	$8,142,444
2009	$4,665,578	$80,717	$4,746,295

The increase in total lease operating expenses was attributable to an increase in production and the number of net wells producing. The decrease in lease operating expenses as a percentage of revenues, from 58% of revenues in 2009 to 42% of revenues in 2010, was attributable to the temporary cessation of production from the majority of our Colombian properties during the 2009 period and increased production and improved commodity prices during 2010.

Joint Venture Expenses. Joint venture expenses totaled $156,686 in 2010 compared to $172,890 in 2009. The joint venture expenses represent our allocable share of the indirect field operating and region administrative expenses billed by Hupecol.

Depreciation and Depletion Expense. Depreciation and depletion expense increased by 66% to $3,161,366 in 2010 from $1,900,631 in 2009. The increase in depreciation and depletion was due to an increase in production volumes during 2010.

Gain on sale of oil and gas properties. The sale of our indirect interests in Hupecol Dorotea and Cabiona, LLC and Hupecol Llanos, LLC resulted in a gain of $25,397,048, and the sale of our Karnes County, Texas interests resulted in a gain of $1,762,066 during 2010.

General and Administrative Expenses. General and administrative expense increased by 77% to $4,896,955 in 2010 from $2,768,195 in 2009. The increase in general and administrative expense was primarily attributable to increases in employee compensation, principally related to the payment of $637,500 of cash bonuses, a 10% increase in base salaries effective June 15, 2010, the hiring of an additional executive and a $1,277,100 increase in stock-based compensation in 2010 versus 2009 associated with options granted to directors and officers during 2010.

Other Income. Other income consists primarily of interest earned on cash balances. Other income totaled $73,247 in 2010 as compared to $64,882 in 2009. The increase in other income resulted primarily from an increase in larger average interest earning cash balances.

Income Tax Expense/Benefit. We reported an income tax expense of approximately $9.4 million in 2010 as compared to a benefit of $737,406 in 2009.

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The income tax expense during 2010 was entirely attributable to operations in Colombia and reflects increased sales and profitability in Colombia, as well as the taxes applicable to the proceeds received on sale of oil and gas properties discussed above.

The income tax benefit during 2009 was primarily attributable to net operating losses generated in Colombia and the United States and the refund during 2009 of approximately $548,000 of Colombian taxes. The income tax benefit during 2009 was attributable $402,663 to the U.S. and $334,743 to Colombia.

At December 31, 2010, we had no foreign tax credit carryovers.

Financial Condition

Liquidity and Capital Resources. At December 31, 2011, we had a cash balance of $9,930,284 and working capital of $19,636,540 compared to a cash balance of $26,656,450 and working capital of $34,255,206 at December 31, 2010. The decrease in cash and working capital during 2011 was primarily attributable to the payment of U.S. federal income taxes, the decline in profitability following the 2010 sale of assets discussed above and the payment of our proportionate share of costs relating to the drilling and related work on the CPO 4 prospect and drilling preparations on the Serrania prospect.

Cash Flows. Operating activities used $4,633,032 of cash during 2011 compared to $8,290,671 of cash provided during 2010. The decrease in cash flows from operations was primarily attributable to the decline in profitability during 2011 following the 2010 asset sale discussed above as well changes in receivables and payables.

Investing activities used $11,930,534 of cash during 2011 as compared to $12,660,487 of cash provided during 2010. Funds used in investing activities during 2011 principally reflect investments in oil and gas properties and assets of $13,280,858, payment of a deposit of $54,856 and purchase of securities $601,074 partially offset by proceeds from escrow receivable of $2,006,254. Funds provided by investing activities during 2010 reflect the receipt of proceeds from the sale of our Karnes County, Texas property and our indirect interest in four Colombian concessions which provided, in the aggregate, approximately $25,942,822 of net proceeds. The funds provided by investing activities during 2010 were partially offset by investments in oil and gas properties and assets and property plant and equipment of $8,740,642 and payments of $3,951,370 of costs associated with the CPO 4 prospect that are reimbursable by Gulf United and recorded as accounts receivable - other.

We had cash used in financing activities during 2011 of $162,600 of stock offering costs associated with stock issued in 2009. Financing activities used $6,267,845 of cash during 2010. Funds used by financing activities during 2010 consisted of cash dividends paid of $6,837,845, partially offset by warrant exercise proceeds received of $570,000.

Long-Term Liabilities. At December 31, 2011, we had long-term liabilities of $45,039 as compared to $26,761 at December 31, 2010. Long-term liabilities at December 31, 2011 and December 31, 2010 consisted of a reserve for plugging costs and deferred rent liability.

Capital and Exploration Expenditures and Commitments. Our principal capital and exploration expenditures relate to our ongoing efforts to acquire, drill and complete prospects.

During 2011, we invested $13,280,858 for the acquisition and development of oil and gas properties, which included expenses related to (1) drilling of 13 wells in Colombia ($9,683,739), including $9,042,364 million of drilling costs on the Tamandua #1 test well on our CPO 4 prospect, (2) seismic and geological costs in Colombia ($1,067,187), (3) leasehold costs on U.S. properties ($250,702), and (4) acquisition and evaluation costs in Colombia ($2,279,230).

At December 31, 2011, our only material contractual obligation requiring determinable future payments on our part was our lease relating to our executive offices.

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The following table details our contractual obligations as of December 31, 2011:

	Payments due by period				
	Total	< 1 year	1-3 years	3-5 years	> 5 years
Operating leases	$498,592	$87,672	$180,486	$189,955	$40,479
Total	$498,592	$87,672	$180,486	$189,955	$40,479

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.

Planned Drilling, Leasehold and Other Activities. As of December 31, 2011, our acquisition and drilling budget for 2012 totaled approximately $40.8 million and related principally to (1) drilling 2 wells in Colombia on existing Hupecol prospects; (2) drilling 1 well on the Serrania Block; (3) completion of the first test well on the CPO 4 Block and drilling 3 additional wells on the CPO 4 Block, and (4) shooting approximately 410 km2 of 3-D seismic on CPO 4. Additional wells may be drilled at locations to be determined based on the results of the planned drilling projects. Our acquisition and drilling budget has historically been subject to substantial fluctuation over the course of a year based upon successes and failures in drilling and completion of prospects and the identification of additional prospects during the course of a year.

Due to delays in drilling the Tamandua #1 well and the subsequent delays in putting the well online, we anticipate that we will require additional financing to fully fund our 2012 drilling budget and our ongoing efforts to acquire additional prospects. The amount of additional financing we may require, and the timing on which we may require such financing, is dependent upon the ultimate results of the Tamandua #1 well and the timing of planned operations which, in each instance, are controlled by the operators of our various properties. If we are unable to fully fund our 2012 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 2012 drilling budget and to support future acquisitions and development activities.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2011.

Inflation

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

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

Item 8. Financial Statements and Supplementary Data

Our financial statements appear immediately after the signature page of this report. See "Index to Financial Statements" on page 40 of this report.

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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, 2011 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 effective as of December 31, 2011.

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 effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by GBH CPAs, PC, an independent registered public accounting firm who audited our consolidated financial statements as of and for the year ended December 31, 2011, as stated in their report, which is included herein.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fourth quarter of 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable

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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, 2011, and their ages and positions as of that date, are as follows:

Name	Age	Position
John F. Terwilliger	64	President, Chief Executive Officer and Chairman
James J. Jacobs	34	Chief Financial Officer
Kenneth Jeffers	51	Senior Vice President of Exploration

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

James J. Jacobs has served as our Chief Financial Officer since July 2006. From April 2003 until joining the Company, Mr. Jacobs served as an Associate and as Vice President—Energy Investment Banking at Sanders Morris Harris, Inc., an investment banking firm, where he specialized in energy sector financing and transactions. Previously, Mr. Jacobs was an Energy Finance Analyst at Duke Capital Partners, LLC from June 2001 to April 2003 and a Tax Consultant at Deloitte & Touché, LLP. Mr. Jacobs holds a Masters of Professional Accounting and a Bachelor of Business Administration from the University of Texas.

Kenneth Jeffers has served as our Senior Vice President of Exploration since August 2010. Prior to his appointment as an officer, Mr. Jeffers served as a consultant to Houston American for six months focused on identification of prospects on the Company's Colombian acreage. Previously, Mr. Jeffers served as Vice President, Geophysics for Goodrich Petroleum Corporation from 2004 to 2007. Mr. Jeffers' experience includes serving as an exploration geophysicist with Mobil Oil and later serving as a staff geophysicist and senior geophysicist with Anadarko Petroleum, Pennzoil, Hunt Oil and Goodrich Petroleum.

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.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

1. Financial statements. See “Index to Financial Statements” on page 40 of this report.

2. Exhibits

		Incorporated by Reference			
Exhibit Number	Exhibit Description	Form	Date	Number	Filed Herewith
3.1	Certificate of Incorporation of Houston American Energy Corp. filed April 2, 2001	SB-2	8/3/01	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	8/3/01	4.1	
10.1	Houston American Energy Corp. 2005 Stock Option Plan*	8-K	8/16/05	10.1	
10.2	Form of Director Stock Option Agreement*	8-K	8/16/05	10.2	
10.3	Houston American Energy Corp. 2008 Equity Incentive Plan*	Sch 14A	4/28/08	Ex A	
10.4	Form of Subscription Agreement, dated November 2009 relating to the sale of shares of common stock	8-K	12/03/09	10.1	
10.5	Employment Agreement of Kenneth Jeffers*	10-K	03/15/11	10.6	
14.1	Code of Ethics for CEO and Senior Financial Officers	10-KSB	3/26/04	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				X
31.2	Section 302 Certification of CFO				X

32.1	Section 906 Certification of CEO				X
32.2	Section 906 Certification of CFO				X
99.1	Code of Business Ethics	8-K	7/7/06	99.1	
99.2	Report of Lonquist & Co., LLC				X

* Compensatory plan or arrangement.

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SIGNATURES

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

	HOUSTON AMERICAN ENERGY CORP.	
Dated: March 7, 2012		
	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)	March 7, 2012
/s/ O. Lee Tawes III O. Lee Tawes, III	Director	March 7, 2012
/s/ Stephen Hartzell Stephen Hartzell	Director	March 7, 2012
/s/ John P. Boylan John P. Boylan	Director	March 7, 2012
/s/ Richard Howe Richard Howe	Director	March 7, 2012
/s/ James J. Jacobs James J. Jacobs	Chief Financial Officer (Principal Accounting and Financial Officer)	March 7, 2012

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HOUSTON AMERICAN ENERGY CORP.

INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Houston American Energy Corp.
Houston, Texas

We have audited Houston American Energy Corp.'s (the "Company") internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based upon our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers, or persons performing similar functions, and effected by the Company's board of directors, management, and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Houston American Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based upon the COSO Criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Houston American Energy Corp. as of December 31, 2011 and 2010, and the related consolidated statements of operations and comprehensive income, changes in shareholders' equity, and cash flows for the years ended December 31, 2011, 2010 and 2009, and our report dated March 7, 2012 expressed an unqualified opinion thereon.

/s/ GBH CPAs, PC

GBH CPAs, PC
www.gbhcpas.com
Houston, Texas

March 7, 2012

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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, 2011 and 2010, and the related consolidated statements of operations and comprehensive income, changes in shareholders' equity, and cash flows for the years ended December 31, 2011, 2010 and 2009. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes 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, 2011 and 2010, and the results of their operations and their cash flows for the years ended December 31, 2011, 2010 and 2009, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Houston American Energy Corp.'s internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 7, 2012 expressed an unqualified opinion thereon.

/s/ GBH CPAs, PC

GBH CPAs, PC
www.gbhcpas.com
Houston, Texas

March 7, 2012

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HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash	$9,930,284	$26,656,450
Restricted cash – letter of credit	3,056,250	3,056,250
Accounts receivable – oil and gas sales	40,502	1,226,341
Accounts receivable – other	4,322,063	3,951,370
Escrow receivable – current	1,863,332	4,440,953
Marketable securities – available for sale	707,445	—
Prepaid expenses and other current assets	13,635	8,872
TOTAL CURRENT ASSETS	19,933,511	39,340,236
PROPERTY, PLANT AND EQUIPMENT		
Oil and gas properties, full cost method		
Costs subject to amortization	2,490,164	1,831,738
Costs not being amortized	22,890,944	10,258,980
Office equipment	90,004	90,004
Total	25,471,112	12,180,722
Accumulated depletion, depreciation, amortization, and impairment	(1,675,232)	(1,489,301)
PROPERTY, PLANT AND EQUIPMENT, NET	23,795,880	10,691,421
Deferred tax asset	3,195,583	1,997,079
Escrow receivable	1,664,581	3,434,167
Other assets	68,381	13,525
TOTAL ASSETS	$48,657,936	$55,476,428
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$84,300	$122,536
Accrued expenses	185,597	11,963
Income taxes payable	27,074	4,950,531
TOTAL CURRENT LIABILITIES	296,971	5,085,030
LONG-TERM DEBT		
Reserve for plugging and abandonment costs	41,419	15,441
Deferred rent obligation	3,620	11,320
TOTAL LONG-TERM DEBT	45,039	26,761
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;100,000,000 shares authorized, 31,165,230 and 31,080,772 shares issued and outstanding, respectively	31,165	31,081
Additional paid-in capital	40,602,643	38,422,435
Retained earnings	7,575,747	11,911,121
Accumulated other comprehensive income	106,371	—
TOTAL SHAREHOLDERS' EQUITY	48,315,926	50,364,637
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$48,657,936	$55,476,428

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

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HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	2011	2010	2009
OIL AND GAS REVENUE	$1,156,178	$19,508,894	$8,116,275
EXPENSES OF OPERATIONS			
Lease operating expense and severance tax	854,319	8,142,444	4,746,295
Joint venture expense	13,930	156,686	172,890
Depreciation and depletion	185,931	3,161,366	1,900,631
General and administrative expense	4,952,560	4,896,955	2,768,195
Total operating expenses	6,006,740	16,357,451	9,588,011
(Gain) loss on sale of oil and gas properties	1,026,608	(27,159,114)	—
Income (loss) from operations	(5,877,170)	30,310,557	(1,471,736)
OTHER INCOME (EXPENSE)			
Interest income	66,852	65,155	64,882
Other income (expense)	(95,872)	8,092	—
Total other income (expense)	(29,020)	73,247	64,882
Net income (loss) before taxes	(5,906,190)	30,383,804	(1,406,854)
Income tax expense (benefit)	(1,570,816)	9,353,864	(737,406)
Net income (loss)	$(4,335,374)	$21,029,940	$(669,448)
Basic net income (loss) per share	$(0.14)	$0.68	$(0.02)
Diluted net income (loss) per share	$(0.14)	$0.66	$(0.02)
Basic weighted average shares	31,138,470	31,070,101	28,214,553
Diluted weighted average shares	31,138,470	31,958,073	28,214,553
COMPREHENSIVE INCOME (LOSS)			
Net loss	$(4,335,374)	$21,029,940	$(669,448)
Unrealized gain on marketable securities	106,371	—	—
Net comprehensive income (loss)	$(4,229,003)	$21,029,940	$(669,448)

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

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HOUSTON AMERICAN ENERGY CORP.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 and 2009

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total
Balance at December 31, 2008	28,000,772	$28,001	$22,631,773	$(1,611,526)	$ —	$21,048,248
Stock issued for -						
Cash, net of offering costs of $758,760	2,890,000	2,890	12,763,550	—	—	12,766,440
Options issued to directors	—	—	38,174	—	—	38,174
Options issued to employees	—	—	1,041,955	—	—	1,041,955
Dividends paid	—	—	(980,057)	—	—	(980,057)
Net loss	—	—	—	(669,448)	—	(669,448)
Balance at December 31, 2009	30,890,772	30,891	35,495,395	(2,280,974)	—	33,245,312
Stock issued for -						
Warrant exercise	190,000	190	569,810	—	—	570,000
Options issued to directors	—	—	1,177,783	—	—	1,177,783
Options issued to employees	—	—	1,179,447	—	—	1,179,447
Dividends paid	—	—	—	(6,837,845)	—	(6,837,845)
Net income	—	—	—	21,029,940	—	21,029,940
Balance at December 31, 2010	31,080,772	31,081	38,422,435	11,911,121	—	50,364,637
Stock issued for -						
Employees	45,000	45	135,630	—	—	135,675
Option exercise	39,458	39	(39)	—	—	—
Options issued to directors	—	—	965,551	—	—	965,551
Options issued to employees	—	—	1,241,666	—	—	1,241,666
Offering costs	—	—	(162,600)	—	—	(162,600)
Other comprehensive income	—	—	—	—	106,371	106,371
Net loss	—	—	—	(4,335,374)	—	(4,335,374)
Balance at December 31, 2011	31,165,230	$31,165	$40,602,643	$7,575,747	$ 106,371	$48,315,926

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

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HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

	2011	2010	2009
CASH FLOW FROM OPERATING ACTIVITIES			
Net income (loss)	$ (4,335,374)	$ 21,029,940	$ (669,448)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operations			
Depreciation and depletion	185,931	3,161,366	1,900,631
Stock-based compensation	2,342,892	2,357,230	1,080,129
Deferred tax expense (benefit)	(1,704,378)	3,682,947	(402,672)
Accretion of asset retirement obligation	16,446	24,272	13,038
Amortization of deferred rent	(7,700)	(5,332)	(2,962)
(Gain) loss on sale of oil and gas properties	1,026,608	(27,159,114)	—
Change in operating assets and liabilities:			
Decrease (increase) in accounts receivable	1,691,660	605,333	(1,516,043)
Decrease (increase) in prepaid expense	(4,763)	41	11,327
(Decrease) increase in accounts payable and accrued liability	(3,844,354)	4,593,988	(898,677)
Net cash provided by (used in) operations	(4,633,032)	8,290,671	(484,677)
CASH FLOW FROM INVESTING ACTIVITIES			
Restricted cash held for letter of credit	—	(1,018,750)	(2,037,500)
Payments for accounts receivable - other	—	(3,951,370)	—
Payments for issuance of note receivable	—	—	(125,000)
Proceeds from payment of note receivable	—	125,000	—
Payments for acquisition and development of oil and gas properties and assets	(13,280,858)	(8,662,516)	(8,273,5450)
Proceeds from sale of Colombian properties, net of expenses	—	22,289,653	—
Proceeds from sale of US properties, net of expenses	—	3,653,169	397,102
Payments for property, plant, and equipment	—	(78,126)	—
Payments for deposits	(54,856)	(10,357)	—
Purchase of marketable securities	(601,074)	—	—
Proceeds from escrow receivable, net	2,006,254	313,784	799,680
Net cash provided by (used in) investing activities	(11,930,534)	12,660,487	(9,239,263)
CASH FLOW FROM FINANCING ACTIVITIES			
Sale of common stock	—	—	13,525,200
Common stock offering costs	(162,600)	—	(758,760)
Exercise of warrants	—	570,000	—

Dividends paid		—			(6,837,845	)		(980,057)
Net cash provided by (used in) financing activities		(162,600	)		(6,267,845	)		11,786,383
INCREASE (DECREASE) IN CASH		(16,726,166	)		14,683,313			2,062,443
Cash, beginning of year		26,656,450			11,973,137			9,910,694
Cash, end of year	$	9,930,284		$	26,656,450		$	11,973,137
SUPPLEMENTAL CASH FLOW INFORMATION:								
Interest paid	$	—		$	4,772		$	—
Taxes paid	$	3,914,135		$	720,512		$	224,261
SUPPLEMENTAL NON-CASH INVESTING AND FINANCING ACTIVITIES								
Net change in asset retirement obligation	$	9,532		$	3,142		$	117,312
Change in escrow receivable for expenses paid on the Company's behalf	$	1,114,779		$	—		$	—
Reclassification of escrow receivable to accounts receivable - other	$	370,640		$	—		$	—
Cash proceeds from sale of oil and gas properties placed in escrow	$	—		$	7,315,033		$	—
Cashless exercise of stock option	$	39		$	—		$	—
Unrealized gain on available for sale securities	$	106,371		$	—		$	—

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

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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, 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 $12,630,785 in excess of the FDIC's current insured limit of $250,000 at December 31, 2011 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.

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Allowance for Accounts Receivable

HUSA regularly reviews outstanding receivables and provides for estimated losses through an allowance for doubtful accounts when necessary. In evaluating the need for an allowance, HUSA 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 HUSA determines that a customer may not be able to make required payments, HUSA increases the allowance through a charge to income in the period in which that determination is made. As of December 31, 2010, HUSA 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 than the Company's share of pro-rata production from certain wells. When natural gas sales volumes exceed 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, 2011 or 2010.

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 $168,351, $3,145,915 and $1,900,631 for the years ended December 31, 2011, 2010 and 2009, respectively and accumulated amortization, depreciation and impairment was $1,630,323 and $1,461,972 at December 31, 2011 and 2010, 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 2011 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.

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Unevaluated oil and gas properties not subject to amortization at December 31, 2011 included the following:

	North America	South America	Total
Leasehold acquisition costs	$ 861,169	$ 4,464,200	$ 5,325,369
Geological, geophysical, screening and evaluation costs	880	17,564,695	17,565,575
Total	$ 862,049	$ 22,028,895	$ 22,890,944

Unevaluated oil and gas properties not subject to amortization at December 31, 2010 included the following:

	North America	South America	Total
Leasehold acquisition costs	$610,468	$2,184,971	$2,795,439
Geological, geophysical, screening and evaluation costs	880	7,462,661	7,463,541
Total	$611,348	$9,647,632	$10,258,980

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 $17,580, $15,451 and $0 for 2011, 2010 and 2009, respectively, and accumulated depreciation was $44,909 and $27,329 at December 31, 2011 and 2010, 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.

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The following table describes changes in our asset retirement liability during each of the years ended December 31, 2011 and 2010. The ARO liability in the table below includes amounts classified as both current and long-term at December 31, 2011 and 2010.

	North America Years Ended December 31		South America Years Ended December 31	
	2011	2010	2011	2010
ARO liability at January 1	$5,481	$24,506	$9,960	$291,754
Accretion expense	1,839	2,568	14,607	21,704
Liabilities incurred from drilling	—	—	9,532	6,856
Liabilities settled—assets sold	—	(21,144)	—	(307,089)
Changes in estimates	—	(449)	—	(3,265)
ARO liability at December 31,	$7,320	$5,481	$34,099	$9,960

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. The Company had a deferred tax asset of $3,195,583 and $1,997,079 at December 31, 2011 and 2010, respectively.

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.

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.

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For the year ended December 31, 2011, 1,833,682 outstanding options to purchase common stock were excluded from the calculation of diluted net loss per share because they were anti-dilutive. As of December 31, 2010, 1,813,998 outstanding options to purchase common stock resulted in weighted averaged diluted shares outstanding of 31,958,073 based upon the treasury method, which resulted in $0.66 diluted earnings per share. For the year ended December 31, 2009, 1,538,998 options and 190,000 warrants to purchase 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, Ken Jeffers, and James J. Jacobs, the chief executive officer, senior vice president of exploration and chief financial officer, respectively, 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 and by SK Innovation in the South American country of Colombia, the Company is dependent on the personnel, management and resources of Hupecol and SK Innovation 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, 2011, 7.12% of the Company's net oil and gas property investment and 87% of its revenue was with or derived from interests operated by Hupecol.

For 2011, 100% of our oil production from the Company's mineral interests was sold to an international integrated oil company. The gas production is sold to U.S. natural gas marketing companies based on the highest bid. There were no other product sales of more than 10% to a single buyer.

The Company reviews accounts receivable balances when circumstances indicate a balance may not be collectible. Historically, the Company has not experienced any uncollectible accounts receivable. Based upon the Company's review, no allowance for uncollectible accounts was deemed necessary at December 31, 2011 and 2010, respectively.

Subsequent Events

The Company evaluated subsequent events through March 7, 2012, which is the date the consolidated financial statements were issued.

Recent Accounting Developments

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

NOTE 2—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 in select mineral properties of the Company. During 2011 and 2010, Mr. Terwilliger received royalty payments relating to those properties totaling $26,776 and $458,448, respectively, and Mr. Tawes received royalty payments relating to those properties totaling $26,776 and $458,448, respectively.

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NOTE 3—INCOME TAXES

The following table sets forth a reconciliation of the statutory federal income tax for the years ending December 31, 2011, 2010 and 2009.

	2011	2010	2009
Income (loss) before income taxes	$(5,906,190)	$30,383,804	$(1,406,854)
Income tax expense (benefit) computed at statutory rates	$(2,008,105)	$10,589,580	$(478,330)
Permanent differences, nondeductible expenses	9,611	4,915	2,789
Current Colombian tax expense	10,266	—	—
Increase (decrease) in valuation allowance	755,159	(1,111,932)	(220,939)
Change in tax rate	55,795	(148,245)	—
Return to accrual items	—	—	—
Foreign tax credit	—	—	—
State (net of federal benefit)	1,980	19,546	(40,926)
Tax provision (benefit)	$(1,175,294)	$9,353,864	$(737,406)
Total Provision			
Current Federal	$20,211	$3,850,927	$—
Current State	3,000	30,071	—
Deferred Federal	(1,198,505)	3,682,947	(361,737)
Deferred State	—	—	(40,926)
Foreign	—	1,789,919	(334,743)
Total provision (benefit)	$(1,175,294)	$9,353,864	$(737,406)

The 2011 income tax benefit noted above is net of a federal income tax refund of approximately $505,874.

At December 31, 2011 the Company has a federal tax loss carry forward of $2,251,250 and a foreign tax credit carry forward of $110,351, 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, 2011 and 2010 are set out below.

	2011	2010
Non-Current Deferred tax assets:		
Net operating loss carry forwards	$ 1,016,960	$ —
Foreign tax credit carry forwards	110,351	—
Asset retirement obligation	—	—
Deferred State Tax	66,505	66,505
Stock Compensation	2,312,689	1,560,696
Book in excess of tax depreciation, depletion, and capitalization methods on oil and gas properties	805,625	369,878
Other	(1,361)	—
Colombia Future Tax Obligations	—	—
Total Non-Current Deferred tax assets	4,310,769	1,997,079
Non-Current Deferred tax liabilities:		

Total Non-Current tax liabilities	—	—
Valuation Allowance	(1,115,186)	—
Net deferred tax asset	$ 3,195,583	$ 1,997,079

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Foreign Income Taxes

The Company owns an interest in various limited liability companies as well as direct ownership in several properties in Colombia operated by Hupecol, and various entities controlled by Hupecol. Additionally, the Company owns a direct interest in properties located in Colombia and operated by SK Innovation. Colombia's current income tax rate is 33%. Based on information provided by the manager of Hupecol, the Company has determined its share of the Colombian tax liability relating to the various limited liability companies it owns operated by Hupecol for 2011 will be $110,351. This amount has been accrued during the year and will be funded by withholdings from the 2011 revenue and from revenue received in 2012. The Company has determined that it has no Colombian income tax liability relating to the properties in which it holds a direct interest for 2011. The Company anticipates that it will be subject to an Equity tax for the properties in which it holds a direct interest, which amount is estimated to be between 1.0 and 6.0% of invested capital by the Company at January 1, 2011.

NOTE 4—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, which is still pending and is expected to occur in 2012, (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 $3,951,423. The amount due from Gulf United is classified as accounts receivable – other in the accompanying balance sheet.

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 is currently seeking reimbursement from the purchaser for these expenses as part of the post-closing process and expects to collect within the next twelve months. As a result of this activity, the Company has established a receivable from Hupecol for the Company's proportionate share of the escrow funds disbursed for these expenses of $370,640. See Note 11. The amount due from Hupecol is classified as accounts receivable – other in the accompanying balance sheet.

NOTE 5—MARKETABLE SECURITIES—AVAILABLE FOR SALE

During the year ended December 31, 2011, HUSA purchased shares of common stock in a publicly traded company valued at $601,074, based on the closing market price per share. This investment is classified as marketable securities - available for sale and, accordingly, any unrealized changes in market values are recognized as other comprehensive income in the consolidated statements of operations. At December 31, 2011, this investment was valued at $707,445, based on the closing market price per share. HUSA recognized other comprehensive income for the year ended December 31, 2011 of $106,371 for the unrealized income on this investment.

NOTE 6—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 allow 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.

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Stock Option Activity

During 2008, the Company granted 1,050,000 options to employees. The options granted to employees during 2008 had a ten year life and 150,000 of the options vest ratably over three years and 900,000 of the options vest ratably over six years. The options were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 3.875%, expected life in years of 6 and 6.75, respectively, expected stock volatility 73.81754%, and expected dividend yield of 0.0%. 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 total value of the options was $5,299,214. The options are being expensed over the vesting period. During 2011, 2010 and 2009, $861,662, $994,983, and $1,007,558, respectively, were amortized to expense as employee compensation for the options granted to employees during 2008.

During 2009, the Company granted 26,665 options to members of the Board of Directors and 120,000 options to employees.

The options granted to the directors during 2009 vested immediately, had a ten-year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 3.19%, expected life of 5 years, expected stock volatility 87.625%, expected future dividend yield of 0.0%. The Company determined the options qualify as 'plain vanilla' under the provisions of Staff Accounting Bulletin (SAB) 107 and the simplified method was used to estimate the expected option life. Using this model yielded a value of $38,174 which was charged to expense in 2009 for the options granted to directors during 2009.

The options granted to employees during 2009 vest ratably over three years, had a ten-year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 3.19%, expected life of 6 years, expected stock volatility 87.625%, and expected future dividend yield of 0.0%. 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 total value of the options was $182,831. The options are being expensed over the vesting period. During 2011, 2010 and 2009, $60,849, $60,943 and $34,396 were amortized to expense as employee compensation for the options granted to employees during 2009.

During 2010, the company granted 125,000 options to members of the Board of Directors and 150,000 options to employees.

The options granted to the directors during 2010 vested immediately, had a ten-year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 2.23%, expected life of 5.7 years, expected stock volatility 87.97%, and expected future dividend yield of 0.44%. 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. Using this model yielded a value of $1,177,781 which was charged to expense in 2010 for the options granted to directors during 2010. These options had a weighted average grant date fair value of $4.28 per share.

The options granted to employees during 2010 vest ratably over three years, had a ten-year life and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 1.70%, expected life of 5.8 years, expected stock volatility 87.35%, and expected future dividend yield of 0.0%. 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 total value of the options was $958,477. The options are being expensed over the vesting period. During 2011 and 2010, $319,155 and $123,421 was amortized to expense as employee compensation for the options granted to employees during 2010. These options had a weighted average grant date fair value of $3.49 per share.

During 2011, the company granted 106,250 options to members of the Board of Directors, including 25,000 options granted to a newly appointed director and 81,250 options granted pursuant to annual grants to independent directors. 86,666 options were exercised on a cashless basis by former directors, resulting in the issuance of 39,458 shares of common stock.

The 25,000 options granted to the newly appointed director vested immediately, had a ten-year life, an exercise price of $14.06 per share and were valued on the date of the grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 2.095%, expected life of 5.685 years, (3) expected stock volatility 87.549%, and expected future dividend yield of 0.142%. 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. Using this model yielded a value of $250,915 which was charged to expense in 2011. These options had a grant date fair value of $10.04 per share.

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The 81,250 options granted under the annual director grants vest 20% on the grant date and 80% on March 13, 2012. These options had a ten-year life, an exercise price of $16.07 per share and were valued on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions: risk-free interest rate 1.689%, expected life of 5.30 years, expected stock volatility 87.25%, and expected dividend yield of 0.124%. 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. Using this model yielded a value of $905,125, of which $714,636 was expensed during 2011. These options had a grant date fair value of $11.14 per share.

Option activity during 2011, 2010 and 2009 is as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2008	1,392,333	$ 6.21		
Granted	146,665	$ 2.05		
Exercised	—			
Forfeited	—			
Outstanding at December 31, 2009	1,538,998	$ 5.81		
Granted	275,000	$ 10.85		
Exercised	—			
Forfeited	—			
Outstanding at December 31, 2010	1,813,998	$ 6.57		
Granted	106,250	$ 15.60		
Exercised	(39,458)	$ 4.60		
Forfeited	(47,208)	$ 10.97		
Outstanding at December 31, 2011	1,833,582	$ 7.02	6.63	$ 9,977,732

As of December 31, 2011, 1,178,582 of the outstanding options were exercisable. The exercisable options had a weighted average exercise price of $6.47 and an intrinsic value of $6,994,632 as of December 31, 2011.

Unvested options at December 31, 2011 totaled 655,000, with a weighted average grant date fair value and exercise price per share of $5.66 and $8.02, respectively, an amortization period of 1.95 years and a weighted average remaining life of 7.2 years.

As of December 31, 2011, total unrecognized stock-based compensation expense related to non-vested stock options was $2,574,620. As of December 31, 2011, there were 734,752 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 2011, $135,675 was amortized to expense. As of December 31, 2011, there was $607,725 of unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately 2.45 years.

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Share-Based Compensation Expense

The following table reflects share-based compensation recorded by the Company for 2011, 2010 and 2009:

	2011	2010	2009
Share-based compensation expense included in general and administrative expense	$2,342,892	$2,357,230	$1,080,128
Earnings per share effect of share-based compensation expense	$(0.08)	$(0.08)	$(0.04)

NOTE 7—COMMON STOCK

2009 Registered Direct Offering

In December 2009, the Company sold to various institutional investors, in a "registered direct" offering, an aggregate of 2,890,000 shares of common stock for net proceeds after offering costs of $12,766,440. During the year ended December 31, 2011, HUSA incurred additional cost of $162,600 by the placement agent related to additional legal expenses related to the Company's 2009 private placement.

Exercise of Warrants

During 2010, the placement agent of a 2005 private placement exercised the remaining 190,000 Placement Agent Warrants and the Company issued 190,000 shares for an aggregate consideration of $570,000. At December 31, 2011, no warrants were outstanding.

Dividends

During 2011, 2010 and 2009, we declared and paid cash dividends to our shareholders of $0.00, $0.22 and $0.035, respectively, or an aggregate of $0, $6,837,845 and $980,057, respectively.

NOTE 8—COMMITMENTS AND CONTINGENCIES

Lease Commitment

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

Year	Amount
2012	87,672
2013	89,054
2014	91,432
2015	93,793
2016	96,162
2017	40,479
Total	$498,592

Total rental expense was $63,541 in 2011, $80,381 in 2010 and $99,388 in 2009. 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 Houston American Energy's compliance and proper execution of the work obligations relating to the phase one (1) work program of the CPO-4 block for Houston American Energy's 25% interest in the Block. Per the Standby Letter of Credit issued between JP Morgan Chase and Banco de Bogota, Houston American Energy was required to keep on deposit with JP Morgan Chase $2,037,500. In addition, Houston American Energy 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.

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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 Houston American Energy's compliance and proper execution of the work obligations relating to the phase one (1) work program for the CPO-4 block for Houston American Energy'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 January 18, 2013 and Houston American Energy is required to keep on deposit with JP Morgan Chase $3,056,250. This increase in deposits was related to Houston American Energy 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. Houston American Energy 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 is classified as Restricted cash – letter of credit in the accompanying balance sheet.

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. The Company is currently not a party to any litigation.

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.

Employment Arrangements

The Company has one employment agreement with its Senior Vice President of Exploration, Ken Jeffers. Under the agreement, Mr. Jeffers receives a current base salary of $252,000 annually and is entitled to discretionary bonuses and other benefits consistent with those available to members of senior management. The Company has no other employment agreements.

NOTE 9—OIL AND GAS ACQUISITIONS

Domestic Leases

During 2009, the Company acquired interests in four prospects in Louisiana, the N. Jade and W. Jade prospects, acquired for $67,480, and the Profit Island and North Profit Island prospects, acquired for $350,644. Subsequent to purchasing its interest in the Profit and North Profit Island prospects, the Company sold down part of its interest in the Profit Island prospect. The Company still retains an interest in both of the prospects. See “Note 10 – Sale of Oil and Gas Properties – Sale of Domestic Leasehold Interests.”

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During 2009, the Company acquired (1) a 2.5% working interest in over 4,500 acres under lease within a 50,000 acre area of mutual interest (AMI) in Karnes County, Texas, for a purchase price of $75,000, and (2) a 1.25% Overriding Royalty in the same leases and all acreage within the AMI, for a purchase price of $100,000. Per the contract, the Company was carried to the completion point on the first well. Subsequent to purchasing its interests in the Karnes County Leases and AMI, during the year ended December 31, 2010, the Company sold its entire interest in the Karnes County Leases and AMI. See "Note 10 – Sale of Oil and Gas Properties – Sale of Unproved Domestic Leasehold Interests."

Colombian Leases

Serrania Contract Farmout

During 2009, the Company entered into a farmout agreement pursuant to which the Company will pay 25.0% of designated Phase 1 geological and seismic costs in return for a 12.5% interest in the Serrania Contract for Exploration and Production covering the approximately 110,769 acre Serrania Block in Colombia.

Los Picachos TEA

During 2009, the Company elected to participate at its percentage interest (12.5%) in the Los Picachos Technical Evaluation Agreement (the "Los Picachos TEA"). The Los Picachos TEA was entered into by and between the Colombian National Hydrocarbons Agency (the "ANH") and Hupecol Operating Co. LLC ("Hupecol") and encompasses an 86,235 acre region located to the west and northwest of the Serrania block, which is located in the municipalities of Uribe and La Macarena in the Department of Meta in the Republic of Colombia. As a result of the election to participate, the Company agreed to pay its proportionate share, or 12.5%, of the acquisition costs and costs for the minimum work program contained in the Los Picachos TEA.

During 2011, the Los Picachos TEA was converted to an exploration and production contract. Subject to final approval of the Company's interest in the contract, the Company holds a 12.5% interest in the Los Picachos prospect.

Macaya TEA

During 2010, the Company elected to participate for its percentage interest (12.5%) in the Macaya Technical Evaluation Agreement (the "Macaya TEA"). The Macaya TEA was entered into by and between the ANH and Hupecol, and encompasses a 195,171 acre region located to the southeast of the Serrania block, which is located in the municipalities of Uribe and La Macarena in the Department of Meta in the Republic of Colombia. As a result of the election to participate, the Company agreed to pay its proportionate share, or 12.5%, of the acquisition costs and costs for the minimum work program contained in the Macaya TEA.

During 2011, the Macaya TEA was converted to an exploration and production contract. Subject to final approval of the Company's interest in the contract, the Company holds a 12.5% interest in the Macaya prospect.

CPO 4 Farmout

During 2009, the Company announced the approval by the ANH of a Farmout Agreement and Joint Operating Agreement (the "JOA") with SK Innovation Co. LTD., a Korean multinational conglomerate ("SK"), relating to the CPO 4 Contract for Exploration and Production covering the 345,452 net acre CPO 4 Block located in the Western Llanos Basin in the Republic of Colombia.

Under the JOA, effective retroactive to May 31, 2009, SK will act as operator of the CPO 4 Block and the Company will pay 25.0% of all past and future cost related to the CPO 4 Block, as well as an additional 12.5% of the Seismic Acquisition Costs incurred during the Phase 1 Work Program, for which the Company will receive a 25.0% interest in the CPO 4 Block. The Company's share of the past costs related to its initial 25.0% farm in was $194,584. During 2010, the Company entered into a separate Farmout Agreement with SK pursuant to which SK agreed to assign to the Company an additional 12.5% interest in the CPO 4 Block, increasing the Company's current interest in the CPO 4 Block from 25% to 37.5%.

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Under the terms of the Farmout Agreement, the Company will be responsible for paying its proportionate interest in all future development and operating costs ("Ongoing Costs"). In addition to payment of its proportionate interest in Ongoing Costs, the Company will be responsible for reimbursement to SK, or payment, of (i) 12.5% of certain defined past costs relating to development of the CPO 4 Block (the "Past Costs"), and (ii) 25% of seismic acquisition costs incurred with respect to the Phase One cost of CPO 4 Block between June 18, 2009 and June 17, 2012 (the "Seismic Acquisition Costs"). The assignment of the additional interest in the CPO 4 Block was conditioned upon the approval by the ANH and the Republic of Korea by July 31, 2011 and payment of the Company's proportionate interest in Past Costs. During 2010 the Company received, and paid, an invoice for $3,939,003 for its share of the Past Costs. In December 2010 the ANH approved our additional 12.5% interest in Block CPO 4 along with the assignment from SK bringing our total interest to 37.5% in the Block.

Pursuant to the terms of, and in conjunction with, the Farmout Agreement and the JOA, 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 JOA for the specific purpose of permitting Gulf United to acquire 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 incurred through July 31, 2010, and (ii) the Company's 25% share of Seismic Acquisition Costs incurred through July 31, 2010. Upon Gulf United receiving ANH approval, it will reimburse us for the $3,951,370 invoiced by SK Innovation for Past Costs; plus any additional cost accrued under the terms of the Farmout Agreement. At December 31, 2011, the Company has recorded as accounts receivable – other the amount due from Gulf United of $3,951,370. As of December 31, 2011 and through the date of this filing, Gulf United had not yet received ANH approval.

The Phase 1 Work Program consists of reprocessing approximately 400 kilometers of existing 2-D seismic data, the acquisition, processing and interpretation of a 2-D seismic program containing approximately 620 kilometers of data and the drilling of two exploration wells. The phase 1 work program was modified to allow 3-D data to be shot in place of the initial 2-D requirement. The Phase 1 seismic acquisition was completed during 2010, the first exploration was in progress at December 31, 2011 and the entire Phase 1 Work Program is estimated to be completed by mid-2012.

For 2012, SK Innovation has advised us that they plan to focus, in addition to completion of the Tamandua #1 well, on the drilling of 3 wells on CPO 4. Our expenditures on CPO 4 during 2011 were $12,010,000 and our budgeted expenditures on the CPO 4 Block for 2012 are approximately $40.0 million.

LLA 62 Block

During 2010, the Company elected to participate for its percentage interest (1.59%) in the LLA 62 Block in Colombia (the "LLA 62 Block"). The LLA 62 Block was awarded to Hupecol by the ANH during 2010. The LLA 62 Block is adjacent to the La Cuerva Block operated by Hupecol. The award of the LLA 62 Block includes a Phase I commitment to shoot 60 square kilometers of 3D seismic on the block. As a result of the election to participate the Company agreed to pay its proportionate share (1.59%) of all costs of exploiting the block, except the 3D seismic costs, where the Company agreed to pay two times its proportional cost.

NOTE 10—SALE OF OIL AND GAS PROPERTIES

Sale of Unproven Domestic Leasehold Interests

During 2009, the Company received $353,896 from the sale of part of its interest in the Profit Island prospect. The proceeds received were recorded as a reduction of oil and gas properties. The Company still retains an interest in both of the prospects. See “Note 9 – Oil and Gas Acquisitions – Domestic Leases.”

During 2010, the Company sold its 2.5% Working Interest in 6,000+ acres, and 1.25% of 8/8’s Overriding Royalty Interest in the 50,000 gross acres AMI, in Karnes County, Texas for approximately $4.1 million in cash, less customary closing costs. The Company recorded a reduction of oil and gas properties of $2,302,299 and recognized a gain on sale of $1,762,066.

Sale of Interest in Hupecol Dorotea and Cabiona, LLC and Hupecol Llanos, LLC

In December 2010, Hupecol Dorotea & Cabiona Holdings, LLC (“Hupecol D&C Holdings”) and Hupecol Llanos Holdings, LLC (“Hupecol Llanos Holdings”) sold all of their interests in Hupecol Dorotea and Cabiona, LLC (“HDC, LLC”) and Hupecol Llanos, LLC (“HL, LLC”). The Company owns 12.5% interests in each of Hupecol D&C Holdings and Hupecol Llanos Holdings and, in turn, indirect interests in each of HDC, LLC and HL, LLC, which companies hold interests in the Dorotea, Cabiona, Leona and Las Garzas blocks and related assets in Colombia.

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HDC, LLC sold for $200 million and HL, LLC sold for $81 million, each subject to certain closing adjustments based on operations between the June 1, 2010 effective date and the closing date. Fifteen percent of the sales price of each of HDC, LLC and HL, LLC will be held in escrow to fund potential claims arising from the sale, with escrowed amounts to be released over a three year period based on amounts remaining in escrow after any claims. In addition to the fifteen percent escrowed, Hupecol withheld 5% of the proceeds in escrow for any contingencies that may arise, and it is expected that the Company will receive the 5% withheld by Hupecol in 2010. Pursuant to its 12.5% ownership interest in each of Hupecol D&C Holdings and Hupecol Llanos Holdings, the Company received 12.5% in the net sale proceeds after deduction of commissions and transaction expenses from each sale and subject to the escrow hold back. Following completion of the sale of HDC, LLC and HL, LLC, the Company had no continuing interest in the Dorotea, Cabiona, Leona and Las Garzas blocks.

At December 31, 2009, the Company's estimated proved reserves associated with the Dorotea, Cabiona, Leona and Las Garzas blocks totaled 1,178,576 barrels of oil, which represented 96.9% 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 $25,397,048 during the year ended December 31, 2010, computed as follows:

Proceeds from the sale	$ 34,503,835
Add: Transfer of asset retirement and other obligations	321,798
Less: Transaction costs	(5,439,349)
Carrying value of oil and gas properties, net	(3,989,236)
Net gain on sale	$ 25,397,048

Because the Company determined there were substantial economic differences between the properties retained and those sold, the carrying value of the properties sold was computed by allocating total capitalized costs within the non-U.S. full cost pool between properties sold and properties retained based upon the relative fair values of the properties.

During the year ended December 31, 2011, the Company incurred additional post closing costs of $1,026,608. These costs were recorded as a loss on sale of oil and gas properties.

The following table presents pro forma data that reflects revenue, income from continuing operations, net income and income per share for 2010 and 2009 as if the HDC, LLC and HL, LLC transaction had occurred at the beginning of each period and excludes the related gain on sale.

	2010	2009
Pro-Forma Information		
Oil and gas revenue	$628,595	$179,662
Loss from operations	(3,213,162)	(4,769,339)
Net loss	$(10,594,649)	$(1,761,062)
Basic loss per share	$(0.34)	$(0.06)
Diluted loss per share	$(0.34)	$(0.06)

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NOTE 11—ESCROW RECEIVABLE

At December 31, 2011 and December 31, 2010, 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, 2011		
Description	Current	Noncurrent	Total
Caracara Escrow	$ 131,021	$ —	$ 131,021
Tambaqui Escrow	31,500	—	31,500
Eagle Ford Escrow	—	—	—
HDC LLC and HL LLC 15% Escrow	1,664,581	1,664,581	3,329,162
HDC LLC and HL LLC 5% Contingency	36,230	—	36,230
TOTAL	$ 1,863,332	$ 1,664,581	$ 3,527,913

	Balance as of December 31, 2010		
Description	Current	Noncurrent	Total
Caracara Escrow	$ 267,451	$ —	$ 267,451
Tambaqui Escrow	292,637	—	292,637
Eagle Ford Escrow	245,222	—	245,222
HDC LLC and HL LLC 15% Escrow	1,717,058	3,434,167	5,151,225
HDC LLC and HL LLC 5% Contingency	1,918,585	—	1,918,585
TOTAL	$ 4,440,953	$ 3,434,167	$ 7,875,120

Changes in escrow receivables reflect the various settlements and releases relating to the previous sales of the Company's interest in the Caracara prospect and HDC LLC and HL LLC described below. Except as described, as of December 31, 2011, the Company is not aware of any other claims by the purchasers of the Caracara assets or HDC, LLC and HL, LLC that would further reduce the escrow receivable.

Caracara Escrow

In June 2008, the Company, through Hupecol Caracara LLC as owner/operator under the Caracara Association Contract, sold all of its interest in the Caracara Association Contract and related assets for a total cash consideration of $11,917,418.

Pursuant to the terms of the sale of the Caracara assets, 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 $1,673,551, and was recorded as escrow receivable. During 2009, $1,158,613 of the funds deposited in escrow was released to the Company based on post-closing adjustments. During 2011, the Company was informed by Hupecol that approximately $136,430 of the Company's funds still held in escrow related to the Caracara sale will likely be used to pay a post-closing settlement entered into between Hupecol and the purchaser of the Caracara assets. As such, during 2011, the Company charged $136,430 to loss on sale of oil and gas properties on the income statement to account for the potential payment using the escrowed funds.

As of December 31, 2011, the balance held in escrow for the sale of the Caracara assets was $131,021. These funds continue to be held pending resolution of disputes among Hupecol, the purchaser of the Caracara assets and Ecopetrol.

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.

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During 2011, the Company received a partial payment of $516,392 from Hupecol for the 5% contingency escrow related to HL, LLC, and was informed that Hupecol disbursed funds from the 5% contingency escrow set up from the proceeds of the HDC, LLC sale to pay Colombian taxes as well as certain invoices related to post closing operating costs incurred on behalf of the purchaser of these interests. Hupecol is currently seeking reimbursement from the purchaser for these expenses as part of the post-closing process. As a result of this activity, the Company has established a receivable from Hupecol for the Company's proportionate share of the escrow funds disbursed for these expenses of $370,640 (See Note 4) and has reduced the 5% contingency escrow account for HDC, LLC to reflect its current balance after payment of the taxes and post-closing expenses paid on behalf of the purchaser.

In addition, the Company received partial payments from the HL, LLC and HDC, LLC escrow accounts in the amounts of $474,786 and $508,717, respectively. The Company was also informed that Hupecol made payments from the HL, LLC and HDC, LLC 15% escrow accounts to the purchaser for post-closing expenses. As such, the Company has reduced its proportionate interest in the HL, LLC escrow by approximately $15,788 and its interest in the HDC, LLC escrow by $694,795 to reflect these payments and, during 2011, charged approximately $710,583 to loss on sale of oil and gas properties on the statement of operations.

NOTE 12—GEOGRAPHICAL INFORMATION

The Company currently has operations in two geographical areas, the United States and Colombia. Revenues for the years ended December 31, 2011, 2010 and 2009 and long-lived assets as of December 31, 2011, 2010 and 2009 attributable to each geographical area are presented below:

	2011		2010		2009	
	Revenues	Long Lived Assets, Ne	Revenues	Long Lived Assets, Net	Revenues	Long Lived Assets, Net
North America	$148,266	$603,135	$206,591	$737,066	$171,922	$2,730,667
South America	1,007,912	23,192,745	19,302,303	9,954,355	7,944,353	8,625,588
Total	$1,156,178	$23,795,880	$19,508,894	$10,691,421	$8,116,275	$11,356,255

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

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

Geographical Data

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

	2011	2010	2009
Revenues			
North America	$148,266	$206,591	$171,922
South America	1,007,912	19,302,303	7,944,353
	$1,156,178	$19,508,894	$8,116,275
Production Cost			
North America	$59,072	$54,214	$80,717
South America	795,247	8,088,230	4,665,578
	$854,319	$8,142,444	$4,746,295

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Capital Costs

Capitalized costs and accumulated depletion relating to the Company's oil and gas producing activities as of December 31, 2011, 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	$ 862,049	$ 22,028,895	$ 22,890,944
Proved properties being amortized	851,357	1,638,807	2,490,164
Accumulated depreciation, depletion, amortization and impairment	(800,531)	(829,792)	(1,630,323)
Net capitalized costs	$ 912,875	$ 22,837,910	$ 23,750,785

Amortization Rate

The amortization rate per unit based on barrel of oil equivalents was $4.22 for the United States and $15.73 for South America for the year ended December 31, 2011.

Acquisition, Exploration and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities as of December 31, 2011, 2010 and 2009 are summarized below:

	2011	
	United States	South America
Property acquisition costs:		
Proved	$—	$ —
Unproved	250,702	2,279,230
Exploration costs	—	10,109,551
Development costs	—	641,375
Total costs incurred	$250,702	$ 13,030,156

	2010	
	United States	South America
Property acquisition costs:		
Proved	$—	$ —
Unproved	312,921	—
Exploration costs	—	7,017,816
Development costs	—	1,331,779
Total costs incurred	$312,921	$ 8,349,595

	2009	
	United States	South America
Property acquisition costs:		

Proved	$106,875	$ —
Unproved	1,010,941	2,560,808
Exploration costs	335,070	2,505,497
Development	—	1,754,354
Total costs incurred	$1,452,886	$ 6,820,659

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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 & 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 29 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management. Lonquist and its employees have no interest in the Company, and were objective in determining the results of the Company's reserves. Lonquist used a combination of production performance, offset analogies, seismic data and their interpretation, subsurface geologic data and core data, along with estimated future operating and development costs as provided by the Company and based upon historical costs adjusted for known future changes in operations or development plans, to estimate our reserves. The Company does not operate any of its oil and gas properties.

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

	United States		South America		Total	
	Gas (mcf)	Oil (bbls)	Gas (mcf)	Oil (bbls)	Gas (mcf)	Oil (bbls)
Total proved reserves						
Balance December 31, 2008	18,774	1,941	—	211,475	18,774	213,416
Extensions and discoveries	15,703	44	—	1,104,041	15,703	1,104,085
Purchase of minerals in place	42,685	1,394	—	—	42,685	1,394

Revisions of prior estimates	8,772	1,100	—	16,493	8,772	17,593
Production	(15,761)	(1,581)	—	(129,782)	(15,761)	(131,363)
Balance December 31, 2009	70,173	2,898	—	1,202,227	70,173	1,205,125
Extensions and discoveries	—	—	—	129,197	—	129,197
Purchase of minerals in place	—	—	—	—	—	
Revisions of prior estimates	29,845	4,652	—	26,217	29,845	30,869
Sales of minerals in place	—	—	—	(1,036,252)	—	(1,036,252)
Production	(17,798)	(1,540)	—	(260,239)	(17,798)	(261,779)
Balance December 31, 2010	82,220	6,010	—	61,150	82,220	67,160
Extensions and discoveries	—	—	—	45,889	—	45,889
Purchase of minerals in place	—	—	—	—	—	—
Revisions of prior estimates	15,418	1,622		(2,496)	15,418	(874)
Production	(10,838)	(1,092)	—	(9,924)	(10,838)	(11,016)
Balance December 31, 2011	86,800	6,540	—	94,619	86,800	101,159
Proved developed reserves						
at December 31, 2009	70,173	2,898	—	307,993	70,173	310,891
at December 31, 2010	82,220	6,010	—	17,202	82,220	23,212
at December 31, 2011	86,800	6,540	—	30,845	86,800	37,385
Proved undeveloped reserves						
at December 31, 2009	—	—	—	894,234	—	894,234
at December 31, 2010	—	—	—	43,948	—	43,948
at December 31, 2011	—	—	—	63,774	—	63,774

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During 2011 and 2010, the Company recorded extensions and discoveries resulting principally from its ongoing drilling operations in Colombia. As of December 31, 2011, our proved undeveloped (“PUD”) reserves totaled 63,774 bbls of oil and 0 mcf of natural gas, for a total of 63,774 boe. Negative revisions of 11,805 boe in PUD reserves during 2011 were due to the ongoing drilling program and subsequent changes in subsurface mapping. None of the PUD reserves as of December 31, 2010 were converted to proved developed producing reserves in 2011. All PUD locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2016. None of our PUD locations have been booked for longer than five years.

Positive revisions of 129,197 boe in PUD reserves during 2010 were due to the on-going drilling program and subsequent changes in subsurface mapping.

Sales of reserves in place during 2010 represent the December 2010 transaction whereby entities owned 12.5% by the Company sold entities that held all of the Company’s interest in the Dorotea, Cabiona, Leona and Las Garzas 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.

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Standardized measure of discounted future net cash flows at December 31, 2011:

	United States	South America	Total
Future net cash flow	$ 1,074,280	$ 8,996,185	$ 10,070,465
Future production cost	(333,520)	(4,202,604)	(4,536,124)
Future development cost	(48,320)	(625,113)	(673,433)
Future income tax	(13,790)	(821,537)	(835,327)
10% annual discount for timing of cash flow	(275,440)	(697,102)	(972,542)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$ 403,210	$ 2,649,829	$ 3,053,039
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(89,168)	(212,666)	(301,834)
Change due to revisions in standardized variables:			
Income taxes	(13,790)	(821,537)	(835,327)
Accretion of discount	43,962	161,839	205,801
Net change in sales and transfer price, net of production costs	26,770	328,994	355,764
Previously estimated development costs incurred during the period	—	641,375	641,375
Changes in estimated future development costs	—	(494,665)	(494,665)
Revision and others	86,695	(91,917)	(5,222)
Discoveries	—	1,594,813	1,594,813
Sales of reserves in place	—	—	—
Changes in production rates and other	(90,878)	426,332	335,454
Net			1,496,159
Beginning of year			1,556,880
End of year			$ 3,053,039

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Standardized measure of discounted future net cash flows at December 31, 2010:

	United States	South America	Total
Future net cash flow	$ 900,040	$ 4,724,278	$ 5,624,318
Future production cost	(279,710)	(2,021,273)	(2,300,983)
Future development cost	-	(636,275)	(636,275)
Future income tax	-	(501,125)	(501,125)
10% annual discount for timing of cash flow	(180,710)	(448,345)	(629,055)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$ 439,620	$ 1,117,260	$ 1,556,880
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(152,377)	(11,214,073)	(11,366,450)
Change due to revisions in standardized variables:			
Income taxes	-	(392,431)	(392,431)
Accretion of discount	32,397	1,549,659	1,582,056
Net change in sales and transfer price, net of production costs	224,620	22,861,606	23,086,226
Previously estimated development costs incurred during the period	-	1,336,231	1,336,231
Changes in estimated future developments costs	-	10,235,689	10,235,689
Revision and others	14,680	1,877,525	1,892,205
Discoveries	-	728,856	728,856
Sales of reserves in place	-	(29,750,509)	(29,750,509)
Changes in production rates and other	(3,691)	(10,614,782)	(10,618,473)
Net			(13,266,600)
Beginning of year			14,823,480
End of year			$ 1,556,880

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Standardized measure of discounted future net cash flows at December 31, 2009

	United States	South America	Total
Future net cash flow	$ 455,522	$ 66,715,086	$ 67,170,608
Future production cost	(87,192)	(36,712,770)	(36,799,962)
Future development cost		(11,571,920)	(11,571,920)
Future income tax	—	(1,560,871)	(1,560,871)
10% annual discount for timing of cash flow	(44,363)	(2,370,012)	(2,414,375)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$ 323,967	$ 14,499,513	$ 14,823,480
Changes in standardized measure:			
Change due to current year operations Sales, net of production costs	(91,205)	(3,278,775)	(3,369,980)
Change due to revisions in standardized variables:			
Income taxes	—	(1,312,411)	(1,312,411)
Accretion of discount	10,361	351,301	361,662
Net change in sales and transfer price, net of production costs	(21,603)	3,899,640	3,878,037
Previously estimated development costs incurred during the period	335,070	4,259,860	4,594,930
Changes in estimated future developments costs	(335,070)	(3,526,367)	(3,861,437)
Revision and others	70,166	289,606	359,772
Discoveries	51,631	13,602,240	13,653,871
Purchase of reserves in place	189,626	—	189,626
Changes in production rates and other	35,510	(2,857,593)	(2,822,083)
Net			11,671,987
Beginning of year			3,151,493
End of year			$ 14,823,480

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NOTE 14—SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
2011				
Operating revenue	$124,303	$353,505	$319,261	$359,109
Loss from operations	(1,209,450)	(1,637,537)	(1,051,697)	(1,978,486)
Net loss	(1,231,915)	(1,702,806)	(1,088,574)	(312,079)
Loss per common share - basic	$(0.04)	$(0.05)	$(0.03)	$(0.02)
Loss per common share - diluted	(0.04)	(0.05)	(0.03)	(0.02)
2010				
Operating revenue	$4,241,395	$7,629,274	$5,354,499	$2,283,726
Income from operations	979,003	876,888	1,411,332	27,043,334
Net income	808,716	990,134	1,171,642	18,059,448
Earnings per common share - basic	$0.03	$0.03	$0.04	$0.58
Earnings per common share - diluted	0.03	0.03	0.04	0.56
2009				
Operating revenue	$445,142	$1,134,118	$2,403,996	$4,133,019
Income (loss) from operations	(1,481,351)	(576,188)	133,242	452,561
Net income (loss)	(1,478,320)	112,107	428,578	268,187
Earnings (loss) per common share - basic	$(0.05)	$0.00	$0.02	$0.01
Earnings (loss) per common share - diluted	(0.05)	0.00	0.02	0.01