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DELTA REPORT

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HUSA - HOUSTON AMERICAN ENERGY C

10-K - DECEMBER 31, 2023 COMPARED TO 10-K - DECEMBER 31, 2022

The following comparison report has been automatically generated

TOTAL DELTAS	1518
CHANGES	5
DELETIONS	1452
ADDITIONS	61

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2022

☐ **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, Texas77002
(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	Trading Symbol	Name of each exchange on which registered
Common Stock, $0.001 par value	HUSA	NYSE American

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

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer	☐	Accelerated filer	☐	Non-accelerated filer	☒
Smaller reporting company	☒	Emerging growth company	☐		

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to o § 240.10D-1(b). ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2022, based on the closing sales price of the registrant's common stock on that date, was approximately $41.8 million. Shares of common stock held by each current executive officer and director and by each person known by the registrant to own 10% or more of the outstanding common stock have been excluded from this computation in that such persons may be deemed to be affiliates.

The number of shares of the registrant’s common stock, $0.001 par value, outstanding as of March 31, 2023 was 10,622,518.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s Proxy Statement for its 2022 Annual Meeting are incorporated by reference into Part III of this Report.

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FORWARD-LOOKING STATEMENTS

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

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

PART I

Item 1. Business

General

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

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

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

Properties

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

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

The following table sets forth information relating to our principal properties as of December 31, 2022:

	Net acreage	Average working interest %	Gross producing wells	Net proved reserves (boe)	2022 Net Production Oil (bbls)	2022 Net Production Natural Gas (mcf)
Texas	155	22.6 %	4	255,254	10,688	73,635
Louisiana and Oklahoma	582	23.4 %	—	—	—	—
Total U.S.	737	23.3 %	4	255,254	10,688	73,635
Colombia	91,827	10.0 %	2	—	—	—
Total	92,564	10.0 %	6	255,254	10,688	73,635

In 2022, our net acreage in the U.S. decreased as a result of lease expirations in Hockley County, Texas (730 net acres) and Yoakum County, Texas (41 net acres). In Colombia, we increased our net acreage position (up 18,038 net acres) by increasing our ownership interest in Hupecol Meta from 7.85% to approximately 18%, which was partially offset by the relinquishment of our rights in our long-disputed Serrania block. As a result, we effectively increased our interest in the underlying assets of Hupecol Meta to an approximately 16% interest in the 69,128 acre Venus Exploration Area and an approximately 8.0% interest in 570,277 additional acres in which Hupecol Meta holds a 50% interest (resulting in an increase in our interest in the CPO-11 block by 31,884 net acres; offset by the decrease in our interest in the 13,846 net acre Serrania block).

- United States Properties:

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

Texas Properties – Permian Basin

Reeves County. We hold a 18.1% average working interest in 320 gross acres in Reeves County, Texas, consisting of (1) the 160 gross acre Johnson Lease, in which we hold a 25% working interest, subject to a proportionate 5% back-in after payout, and (2) the 160 gross acre O'Brien Lease, in which we hold an average 11.2% working interest. Our Reeves County acreage lies within the Delaware sub-basin of the Permian Basin, with resource potential in the Wolfcamp, Bone Spring and Avalon formations. During 2017, we drilled and completed our initial wells on both lease blocks, the Johnson State #1H well and the O'Brien #3H well, both horizontally drilled and hydraulically fractured wells in the Wolfcamp A formation. The Johnson #1H well and O'Brien #3H well were both placed on gas lift during 2021 and were producing at December 31, 2022. For the year ended December 31, 2022, our production in Reeves County totaled 5,679 barrels of oil and 73,635 mcf of natural gas.

As of December 31, 2022, no additional development or drilling operations are planned with respect to our Reeves County acreage.

Yoakum County. We hold a 12.5% working interest, subject to a proportionate 10% back-in after payout, in an approximately 360 gross acre block in Yoakum County, Texas and hold a 100% working interest in 46.1 gross acres subject to our obligation to offer participation in that acreage to our partners in the area of mutual interest associates with our Yoakum County acreage. Our Yoakum County acreage lies within the Midland sub-basin of the Permian Basin.

During 2019, we drilled the Frost #1H well, the first well on our Yoakum County acreage. The well was horizontally drilled, hydraulically fractured in the San Andres Formation and completed and commenced production in mid-2019. A second well on our Yoakum County acreage, the Frost #2H well, was horizontally drilled, hydraulically fractured in the San Andres Formation and completed and commenced production during the third quarter of 2020. For the year ended December 31, 2022, our production in Yoakum County totaled 5,009 barrels of oil.

As of December 31, 2022, no additional development or drilling operations are planned with respect to our Yoakum County acreage.

Louisiana Properties

Our principal producing and exploration properties in Louisiana consist of a 23.437% mineral interest in 2,485 gross acres in East Baton Rouge Parish.

There are no present wells, or plans to conduct drilling operations, on our Louisiana acreage.

- Colombian Properties:

At December 31, 2022, we held interests in multiple prospects, all operated by Hupecol Operating and affiliates, in Colombia covering 920,841 gross acres. We identify our Colombian prospects by the concessions operated.

The following table sets forth information relating to our interests in prospects in Colombia at December 31, 2022:

Property	**Operator**	**Ownership Interest(1)**	**Total Gross Acres**	**Total Gross Developed Acres**	**Gross Productive Wells**
CPO-11 – Venus Exploration Area	Hupecol	16.0 %	69,128	320	2
CPO-11	Hupecol	8.0 %	570,277	—	—
Los Picachos	Hupecol	12.5 %	86,235	—	—
Macaya	Hupecol	12.5 %	195,201	—	—
Total			920,841	320	2

(1) In 2022, we increased our ownership interest Hupecol Meta, resulting in an increase in our interest in the CPO-11 block with our ownership interest in the Venus Exploration Area increasing to approximately 18% and our ownership interest in the remainder of the block increasing to approximately 8%.

At December 31, 2022, we held interests in three concessions operated by Hupecol Operating Co. related entities in Colombia. The CPO-11 concession, including the Venus Exploration Area, is located in the Llanos Basin and is owned and operated by Hupecol Meta. The Loc Picachos and Macaya concessions are located in the Caguan Putumayo Basin of Colombia. The concessions cover an aggregate area of 920,841 gross acres.

CPO-11

During 2019, we acquired a two percent ownership interest in Hupecol Meta, LLC (“Hupecol Meta”). Hupecol Meta owns the 639,405 gross acre CPO-11 block in the Llanos Basin in Colombia. The CPO-11 block is comprised of the 69,128 acre Venus Exploration area and 570,277 acres which was 50% farmed out by Hupecol to Parex Resources. In 2021, Hupecol Meta increased its ownership interest in the CPO-11 block and we agreed to contribute $99,716. In 2022, we acquired additional interests in Hupecol Meta for an aggregate of $657,638. As a result of our acquisition of additional interests in 2021 and 2022, our ownership interest in Hupecol Meta was approximately 18% at December 31, 2022. Through our ownership interest in Hupecol Meta, at December 31, 2022, we hold an approximately 16% interest in the Venus Exploration Area and an approximately 8% interest in the remainder of the CPO-11 block.

The CPO-11 block covers almost 1,000 square miles with multiple identified leads and prospects. During 2022, in the Venus Exploration Area, Hupecol Meta drilled and completed the Saturno ST1 well and drilled the Bugalu1 well. At December 31, 2022, the Saturno ST1 well and the Venus 2A legacy well, that was previously shut-in, were on production and the Bugalu 1 well was awaiting testing. All wells drilled to date in the Venus Exploration Area are vertical wells. In early 2023, a determination was made to defer testing on, and temporarily abandon, the Bugalu 1 well, in order to focus efforts and resources on drilling an initial horizontal well in the Venus Exploration Area. Drilling operations on the CPO-11 block in 2023 and beyond are expected to be focused on efforts to secure seismic data covering the Venus Exploration Area, delineating future drilling sites based on that data and, subject to market conditions and analysis of such data, drilling one or more horizontal wells, and possibly additional vertical wells, in the Venus Exploration Area.

Our investment in Hupecol Meta is accounted for using the cost method of accounting and, accordingly, this report does not include any reserves, production and operating results of Hupecol Meta.

Los Picachos and Macaya Prospects

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

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.

Drilling Activity

During 2022, we, through Hupecol Meta, drilled two wells in Colombia. The following table summarizes the number of wells drilled during 2022, 2021 and 2020, 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,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Development wells, completed as:						
Productive	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—
Total development wells	—	—	—	—	—	—
Exploratory wells, completed as:						
Productive	1	0.16	—	—	1	0.22
Non-productive	1	0.16	—	—	2	—
Total exploratory wells	2	0.32	—	—	3	0.22

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, 2022, we had no drilling operations in progress. Our Bugalu 1 well in Colombia was drilled and awaiting testing at December 31, 2022. In early 2023, a determination was made to defer testing on, and temporarily abandon, the Bugalu 1 well.

Productive Wells

Productive wells consist of producing wells and wells capable of production, including shut-in wells. A well bore with multiple completions is counted as only one well. As of December 31, 2022, we owned interests in six gross wells (including indirect interests in wells in Colombia through our equity interest in Hupecol Meta). As of December 31, 2022, we had interests in productive wells, categorized by geographic area, as follows:

	Oil Wells	Gas Wells
United States		
Gross	4	—
Net	0.68	—
Colombia		
Gross	2	—
Net	0.32	—
Total		
Gross	6	—
Net	1	—

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, including our share of sales through Hupecol Meta, of gas and oil, categorized by geographic area, for each of the three years ended December 31, 2022, 2021, and 2020:

	Year Ended December 31,		
	2022	2021	2020
Net Production:			
Gas (Mcf):			
United States	73,635	60,069	69,433
Colombia	—	—	—
Total	73,635	60,069	69,433
Oil (Bbls):			
United States	10,688	14,367	11,385
Colombia	—	—	—
Total	10,688	14,367	11,385
Average sales price:			
Gas ($ per Mcf)			
United States	$ 5.13	$ 4.13	$ 1.14
Colombia	—	—	—
Total	$ 5.13	$ 4.13	$ 1.14
Oil ($ per Bbl)			
United States	$ 93.10	$ 63.60	$ 35.63
Colombia	—	—	—
Total	$ 93.10	$ 63.60	$ 35.63
Average production costs ($ per BOE):			
United States	$ 27.48	$ 33.67	$ 16.59
Colombia	—	—	—
Total	$ 27.48	$ 33.67	$ 16.59

Natural Gas and Oil Reserves

Reserve Estimates

The following tables sets forth, by country and as of December 31, 2022, our estimated net proved oil and natural gas reserves, and the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (“PV-10”) and after future income taxes (“Standardized Measure”) of our proved reserves, each prepared in accordance with assumptions prescribed by the Securities and Exchange Commission (“SEC”).

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

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

	Reserves (1)		
	Oil	Natural Gas	Total (2)
	(bbls)	(mcf)	(boe)
Reserve category			
Proved Developed Producing			
United States	83,517	1,030,420	255,254
Colombia(3)	—	—	—
Total Proved Developed Producing Reserves	83,517	1,030,420	255,254
Proved Undeveloped			
United States	—	—	—
Colombia(3)	—	—	—
Total Proved Undeveloped Reserves	—	—	—
Total Proved Reserves	83,517	1,030,420	255,254

	Proved Developed	Proved Undeveloped	Total Proved
PV-10 (1)	$ 5,163,159	$ —	$ 5,163,159
Standardized measure (4)	$ 5,163,159	$ —	$ 5,163,159

(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, 2022. 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, 2022. The average prices utilized for purposes of estimating our proved reserves were $90.16 per barrel of oil and $5.39 per mcf of natural gas for our US properties, adjusted by property for energy content, quality, transportation fees and regional price differentials. The prices should not be interpreted as a prediction of future prices. The amounts shown do not give effect to non-property related expenses, such as corporate general administrative expenses and debt service, future income taxes or to depreciation, depletion and amortization.

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

(3) Under the cost method of accounting, we do not report any reserves attributable to our investment in Hupecol Meta.

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

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

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 and Standard Measure estimates, set forth above were prepared by Russell K. Hall & Associates, Inc. for our Permian Basin, Texas reserves.

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

Our year-end reserve reports are prepared by reserve engineering firms based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geosciences and engineering data, and other information provided to them by our management team. Upon analysis and evaluation of data provided, the reserve engineering firms issue a preliminary appraisal report of our reserves. The preliminary appraisal report and changes in our reserves are reviewed by our President and board for reasonableness of the results obtained. Once any questions have been addressed, the reserve engineering firms issue final appraisal reports, reflecting their conclusions.

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

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

Our reserve engineering firm 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

We had no proved undeveloped reserves at either December 31, 2021 or December 31, 2022.

Developed and Undeveloped Acreage

The following table sets forth the gross and net developed and undeveloped acreage (including both leases and concessions, but excluding acreage in which we hold a royalty interest but no working interest), categorized by geographical area, which we held as of December 31, 2022:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States	640	109	2,531	629
Colombia	320	51	920,521	91,775
Total	960	160	923,052	92,404

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well and acreage in which we hold a mineral interest with no potential development related lease expirations. 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.

The leases and concessions comprising the U.S. undeveloped acreage set forth in the table above relate primarily to our Yoakum County, Texas acreage and our Louisiana acreage. The Yoakum County, Texas acreage lease will expire in 2023 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.

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, 2022, we had no contractual agreements to sell our gas and oil production and all production was sold on spot markets.

Human Capital

As of December 31, 2022, we had 2 full-time employees and no part time employees. The employees are not covered by a collective bargaining agreement, and we do not anticipate that any of our future employees will be covered by such agreements.

Competition

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

Regulatory Matters

Regulation of Oil and Gas Production, Sales and Transportation

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

Environmental Regulation

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

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

- Clean Air Act, and its amendments, which govern air emissions;
- Clean Water Act, which governs discharges into waters of the United States;
- Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as “Superfund”);
- Resource Conservation and Recovery Act, which governs the management of solid waste;
- Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;
- Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;
- Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

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

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

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

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

Hydraulic Fracturing Regulation

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

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

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

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

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

Climate Change Legislation and Greenhouse Gas Regulation

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

Moreover, 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.

Since taking office in 2021, the Biden presidential administration has signaled a commitment to cutting greenhouse gases, and an accompanying commitment to moving the U.S. away from fossil fuels and to so-called green or renewable energy sources. Among the steps taken by the Biden Administration are rejoining the Paris Agreement on climate change, a stated commitment to cut U.S. greenhouse gas emissions by 2030 to roughly half of 2005 levels, limitations on land available for oil and gas leasing, the United States Methane Emissions Reduction Action Plan and certain Clean Air Act rules and various executive orders and certain provisions of the 2022 Inflation Reduction Act, each of which imposes costs, burdens, restrictions or otherwise is designed to discourage the use of oil and gas and, accordingly, is potentially harmful to the U.S. oil and gas industry.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the regulatory response is designed to reduce demand for, and use of, our products, oil and gas, in favor of alternative forms of energy. We cannot presently predict the ultimate impact of existing or future climate change initiatives on our company or our industry although we do anticipate that, at a minimum, we will incur additional operating and other costs to respond to such initiatives.

Web Site Access to Reports

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Item 1A. Risk Factors

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

Company and Organization Risks

We have experienced recurring operating losses and may not attain profitability; attainment of profitability will require successful drilling and development operations to support substantial increases in production and revenues.

We have incurred losses from operations in each year since 2011 and, at December 31, 2022, had an accumulated deficit of $73,787,720. While we have implemented cost control initiatives that have brought down our cash overhead in recent years and have brought additional wells onto production in 2022, our ability to attain profitability is substantially dependent upon increasing our production and production revenues while continuing to control costs. In order to increase production and revenues, we will need to successfully drill new wells on our existing, or future acquired, acreage at a pace, and with results, significantly greater than in recent years. If, for any reason, we are unable to substantially increase our production and revenues, while controlling drilling costs and overhead, we may never attain, or sustain, profitability. Our ability to so increase production and revenues and attain profitability is subject to all of the other risks of oil and gas operations as well as our ability to fund our share of drilling and development operations.

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

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production 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, including changes in demand resulting from general and specific economic conditions relating to the business cycle and other factors (e.g., global health pandemics such as COVID-19);
- 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, including renewable energy initiatives that result in energy consumption transitioning away from fossil fuels; and
- the price and availability of alternative fuels.

Global economic growth drives demand for energy from all sources, including fossil fuels. Should the U.S. and global economies experience weakness, demand for energy may decline. Similarly, should growth in global energy production outstrip demand, excess supplies may arise. Declines in demand and excess supplies may result in accompanying declines in commodity prices and deterioration of our financial position along with our ability to operate profitably and our ability to obtain financing to support operations.

With respect to our business, we have experienced periodic declines in demand thought to be associated with slowing economic growth in certain markets, including the effects of the COVID-19 pandemic, coupled with new oil and gas supplies coming on line and other circumstances beyond our control that resulted in oil and gas supply exceeding global demand which, in turn, resulted in steep declines in prices of oil and natural gas.

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

Supply chain challenges arising in the wake of the COVID-19 pandemic may adversely affect our operations.

Supply and demand imbalances arising from the COVID-19 pandemic resulted in shortages, backlogs and delayed deliveries of a wide array of products and services, including products and services critical to oil and gas operations. As a result of such supply chain challenges, we may experience unavailability, or delay in delivery, of products and services that are critical to our well operations. Any such delays may result in deferral or reduction of revenues and increased costs, any of which could materially adversely affect our profitability.

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

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

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

Our financial resources are limited and may not be adequate to fully drill and develop our acreage or to consummate any meaningful acquisition. While our available funds as of March 2023 are expected to be adequate to fund our share of well costs on wells expected to be drilled, as of that date, during 2023, our funds on hand are not expected to be adequate to support a long-term drilling and development plan with respect to our existing acreage holdings, should such a plan be implemented.

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

Our ability to utilize our common stock to finance future capital needs, or for other purposes, is limited by our authorized shares available for issuance.

As of March 2023, we had authority to issue a total of 12 million shares of common stock, of which approximately 10,622,518 shares had been issued and 1,038,577 shares were reserved for issuance pursuant to outstanding stock options and warrants. Absent an increase in authorized shares of common stock, we only have approximately 338,905 shares of common stock available for issuance to raise capital or to support additional stock option grants and for other uses.

We have historically utilized “at-the-market” sales of our common stock to provide financing to support growth and operations. With the limited shares of common stock presently available for issuance, our ability to secure additional funding through the sale of common stock is limited. Absent an increase in the shares of common stock authorized to be issued, we will be limited to other financing structures in the event additional financing is required. Such alternative structures may be less favorable or unavailable in which case we may be forced to forego opportunities or required to downsize operations due to lack of funding.

In 2021 and 2022, we recommended that our shareholders approve an amendment to our certificate of incorporation to increase authorize shares to support potential future capital requirements. While an overwhelming majority of shares voted approved such increase, the vote was insufficient to implement the amendment. There can be no assurance that we will be able to secure the necessary shareholder vote to increase our authorized shares of common stock and, therefore, we may continue to be limited in the shares of common stock we may issue.

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

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

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

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

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.

Oil and Gas Operating Risks

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

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

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

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

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

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

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

Decisions made by our operators may be different than those we would make reflecting priorities different than our priorities and may materially adversely affect our operating results and financial position, including potential declines in production and revenues from properties, declines in value of properties and lease expirations, among other potential consequences.

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

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

Our operations are expected to involve use of horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

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

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

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

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

Horizontal drilling in emerging areas with little or no history of use of such techniques is more uncertain than drilling in areas that are more developed and have a longer history of established horizontal drilling operations. If our horizontal drilling fail to adequately address the risks described, we may incur costs overruns, underperformance by wells or non-productive wells.

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

Shortages or the high cost of drilling rigs, equipment, supplies or personnel, including shortages or unavailability of personnel, supplies and equipment arising from the COVID-19 pandemic, could delay or adversely affect our development and exploration operations. If the price of oil and natural gas increases, the demand for production equipment and personnel will likely also increase, potentially resulting, at least in the near-term, in shortages of equipment and personnel. In addition, larger producers may be more likely to secure access to such equipment by virtue of offering drilling companies more lucrative terms. In particular, high levels of horizontal drilling and hydraulic fracturing operations in the Permian Basin have, from time to time, created increased demand, and higher costs, for associated drilling and completion services, water supply, handling and disposal and access to production handling and transportation infrastructure, each of which have resulted in higher than anticipated prices with respect to our initial Reeves County wells. If we are unable to acquire access to such resources, or can obtain access only at higher prices, not only would this potentially delay our ability to convert our reserves into cash flow but could also significantly increase the cost of producing those reserves, thereby negatively impacting anticipated net income.

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

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

The amount of oil and gas that can be produced is subject to limitations in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. Curtailments arising from these and similar circumstances may last from a few days to several months, resulting in lost or curtailed production and revenues.

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

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

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

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

We have historically been focused on development of a small number of geographically concentrated prospects. Accordingly, we lack diversification with respect to the nature and geographic location of our holdings. As a result, we are exposed to higher dependence on individual resource plays and may experience substantial losses should a single individual prospect prove unsuccessful. At December 31, 2022, we owned interests in 738 net acres and 0.68 net wells in the United States and, through properties owned and/or operated by Hupecol entities, 91,826 net acres and 0.32 net wells in Colombia. While we continually evaluate potential prospects in operations in diverse regions, our production, revenues and profitability for the foreseeable future are expected to be highly dependent upon the results of existing and future wells we may drill in the Permian Basis and the CPO-11 block in Colombia. In order grow our revenues and improve profitability, we must continue to drill productive wells. If existing wells, or future wells we may drill, perform below expectations, we may experience flat or declining production and revenues and may be unable to attain profitability.

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

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

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

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

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

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

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

- personal injuries and death; and
- natural disasters.

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

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.

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 written down the carrying value of our oil and natural gas properties periodically and may be required to further write down the carrying value of oil and gas properties in the future. A write-down would constitute a non-cash charge to earnings. It is likely the cumulative effect of a write-down could also negatively impact the trading price of our securities.

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

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

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

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

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

Our operations will be subject to environmental and other government laws, regulations and policies that are costly, could potentially subject us to substantial liabilities and potentially result in decreased demand for products.

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

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

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

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

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

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

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

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

In addition, many countries as well as several states and regions of the U.S. have agreed to regulate emissions of “greenhouse gases” and have adopted policies to actively promote alternative energy “green energy” sources that are specifically designed to replace fossil fuels. 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 “green energy” initiatives could substantially reduce demand for our products in the future.

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

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

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

International Operations Risks

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

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

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

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

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

Inflation rates in Colombia have increased in recent years, including by over 10% in 2022. A variety of factors, including a recent increase in the minimum wage, have contributed to this increase. The situation does not meet the definition of highly inflationary, but in the event it does meet that definition, we may experience financial loss associated with the related increase in operating expenses.

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

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

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

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

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

Our Colombian properties are developed under financial arrangements with various joint interest partners. In 2022, we acquired a portion of a joint interest partner's interest in the CPO-11 block when the joint interest partner was unable to fund its portion of development costs. As a result of such acquisition, while we did increase our ownership interest in the prospect, we assumed an increased portion of the prospect's development costs. If other joint interest partners are unable, or unwilling, to satisfy their various obligations relating to prospects, we may be required to pay a proportionately higher share of development costs on those prospects or the prospect may be inadequately capitalized to achieve optimal results.

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

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

- each party has not and will not offer or make payments to any person, including a government official, that would violate the laws of the country of operations, the country of formation of any of the partners or the principals described in the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions; and
- each party will maintain adequate internal controls, properly record and report all transactions and comply with the laws applicable to the transaction.

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

Stock Related Risks

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

The price of our common stock constantly changes. We expect that the market price of our common stock will continue to fluctuate. Our stock price may fluctuate as a result of a variety of factors, many of which are beyond our control. These factors include:

- quarterly variations in our operating results;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance;
- announcements by us, our partners or our competitors of leasing and drilling activities;
- the operating and securities price performance of other companies that investors believe are comparable to us;
- future sales of our equity or equity-related securities;
- changes in general conditions in our industry and in the economy, the financial markets and the domestic or international political situation;
- fluctuations in oil and gas prices;
- departures of key personnel; and
- regulatory considerations.

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

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

We currently lease approximately 3,080 square feet of office space in Houston, Texas as our executive offices. Management anticipates that our space will be sufficient for the foreseeable future. The average monthly rental under the lease, which expires on October 31, 2025, is approximately $7,200. 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 29, 2023, we were not aware of any current, pending or threatened litigation or proceedings that could have a material adverse effect on our results of operations, cash flows or financial condition.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

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

Holders

As of March 31 2023, there were approximately 873 shareholders of record of our common stock.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2022 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)]	944,177	$ 2.41	181,333
Equity compensation plans not approved by security holders	—	—	—
	944,177	$ 2.41	181,333

(1) Consists of shares (a) reserved for issuance pursuant to outstanding options granted and (b) shares remaining available for future issuance; under the Houston American Energy Corp. 2021 Equity Incentive Plan.

Item 6. Selected Financial Data

Not applicable.

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

General

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

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

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

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

Recent Developments

Lease Activity

Colombia. In 2019, we acquired a 2% interest in Hupecol Meta, LLC ("Hupecol Meta") (the "Hupecol Meta Acquisition"). Pursuant to the terms of the Hupecol Meta Acquisition, we paid total consideration of approximately $197,000. During 2020, we invested an additional $63,405 in Hupecol Meta. In 2021, we contributed an additional $99,716 to Hupecol Meta, increasing our ownership interest to 7.85%. In 2022, we acquired additional interests in Hupecol Meta from other investors, for aggregate consideration of $657,638, increasing our ownership interest to approximately 18%.

Hupecol Meta holds a working interest in the 639,405 gross acre CPO-11 block in the Llanos Basin in Colombia, comprised of the 69,128 acre Venus Exploration Area and 570,277 acres, which was 50% farmed out by Hupecol Meta. At December 31, 2022, through our ownership interest in Hupecol Meta, we hold an approximately 16% interest in the Venus Exploration Area and an approximately 8% interest in the remainder of the block.

During 2022, we experienced lease expirations in Yoakum County, Texas (41 net acres) and Hockley County, Texas (730 net acres) and relinquished our interest in the Serrania block in Colombia (13,846 net acres).

Drilling Activity and Well Operations

During 2022, Hupecol Meta drilled 3 vertical wells (the Saturno ST1, the Bugalu 1 and Caonabo) in the Venus Exploration Area of the CPO-11 block. In order to handle disposal of produced water from wells, in November 2022, Hupecol Meta secured a water injection permit allowing injection of produced water in an old well. The Saturno ST1 well and the Venus 2A well, a legacy well that was previously shut-in, were brought on production in November 2022. The Bugalu 1 well was temporarily abandoned in early 2023. The Caonabo well was determined to be a dry hole.

Capital Investments

During 2022, our capital investment expenditures for acreage acquisitions, drilling, completion and related operations, as well as investments relating to Hupecol Meta, totaled $1,661,405, principally relating to acquisitions of additional interests in Hupecol Meta ($657,638), direct investments in Hupecol Meta ($988,722) and plugging and abandonment of our Lou Brock well ($15,045).

Financing Activities

In November 2022, we entered into a Sales Agreement with Univest Securities, LLC ("Univest") pursuant to which we could sell, at our option, up to an aggregate of $3,500,000 in shares of common stock through Univest, as sales agent. Sales of shares under the Sales Agreement (the "2022 ATM Offering") were made, in accordance with placement notices delivered to Univest, which notices set parameters under which shares could be sold. The 2022 ATM Offering was made pursuant to a shelf registration statement by methods deemed to be "at the market," as defined in Rule 415 promulgated under the Securities Act of 1933. We agreed to pay Univest a commission in cash equal to 3% of the gross proceeds from the sale of shares in the 2022 ATM Offering. Additionally, we reimbursed Univest for $25,000 of expenses incurred in connection with the 2022 ATM Offering. As of December 31 2022, $2 million remained available to raise from the 2022 ATM offering.

During 2022, we sold an aggregate of 394,678 shares in the 2022 ATM Offering and received proceeds, net of commissions, of $1,543,000. After December 31, 2022, through the date of this report, we sold an additional 294,872 shares in the 2022 ATM Offering and received proceeds, net of commissions, of $874,309.

Proceeds from the 2022 ATM Offering were used to support our acquisition of additional interest in Hupecol Meta and to support our future financial commitments relating to anticipated drilling operations on the CPO-11 block.

Colombian Election

In June 2022, Colombia elected as its President, leftist candidate, Gustavo Petro. President-elect Petro has publicly vowed to wind down fossil fuel production in Colombia and end fracking in Colombia as part of a plan to transition to renewable green energy. While the President-elect's proclamations are openly hostile to the oil and gas industry and appear to bar grants of future oil and gas contracts, those proclamations appear to honor existing oil and gas contracts. Moreover, the President-elect's proclamations do not appear to be supported by the Colombian lawmakers which may make it difficult for the President-elect to effectively carry out his proclamations. Nonetheless, hostility from the executive branch may make the climate for drilling wells on existing acreage more challenging than is already the case.

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, 2022. The capitalized costs of oil and gas properties, plus estimated future development costs relating to proved reserves, are amortized on a units-of-production method over the estimated productive life of the reserves. Unevaluated oil and gas properties are excluded from this calculation. The capitalized oil and gas property costs, less accumulated amortization, are limited to an amount (the ceiling limitation) equal to the sum of: (a) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, calculated using the average oil and natural gas sales price received by the company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) and a discount factor of 10%; (b) the cost of unproved and unevaluated properties excluded from the costs being amortized; (c) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (d) related income tax effects. Costs in excess of this ceiling are charged to proved properties impairment expense.

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

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

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

Revenues are recognized for the sale of our net share of production volumes.

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

Unevaluated oil and gas properties not subject to amortization include the following at December 31, 2022 and 2021:

	At December 31, 2022	At December 31, 2021
Acquisition costs	$ 143,847	$ 143,847
Evaluation costs	2,199,279	2,199,279
Total	$ 2,343,126	$ 2,343,126

The carrying value of unevaluated oil and gas prospects includes $2,343,126 expended for properties in South America at December 31, 2022 and 2021. We are maintaining our interest in these properties.

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

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, 2022. 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.

Results of Operations

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Oil and Gas Revenues. Total oil and gas revenues increased 23% to $1,638,841 in 2022 from $1,330,198 in 2021.

The increase in revenues was attributable to (i) improved commodity pricing, including 46% and 24% increases in crude oil prices and natural gas prices, respectively, realized during 2022 compared to 2021, and (ii) a 23% increases in natural gas production volumes during 2022 compared to 2021; partially offset by a 26% decline in crude oil production.

The following table sets forth the gross and net producing wells, net oil and gas production volumes and average hydrocarbon sales prices for 2022 and 2021 (excluding information pertaining to cost method investments):

	2022	2021
Gross producing wells	4	4
Net producing wells	0.68	0.68
Net oil production (Bbls)	10,688	14,367
Net gas production (Mcf)	73,635	60,069
Oil—Average sales price per barrel	$ 93.10	$ 63.60
Gas—Average sales price per mcf	$ 5.13	$ 4.13

The change in production volumes reflects domestically, increased production from our Reeves County wells after being put on gas lift in late 2021, partially offset by natural production declines.

The change in average sales prices realized reflects a spike in global energy prices in early- to mid-2022 accompanying uncertainty associated with the Russian invasion of Ukraine.

All oil and gas sales revenues for 2022 and 2021, by region, were as follows:

	Colombia	U.S.	Total
2022			
Oil sales	$ —	$ 995,083	$ 995,083
Gas sales	$ —	$ 377,534	$ 377,534
2021			
Oil sales	$ —	$ 913,809	$ 913,809
Gas sales	$ —	$ 416,389	$ 416,389

Lease Operating Expenses. Lease operating expenses, excluding expenses attributable to our cost method investment in Colombia, decreased 12.3% to $531,675 in 2022 from $606,210 in 2021.

Lease operating expense, by region, for 2022 and 2021, were as follows:

	Colombia	U.S.	Total
2022	$ —	$ 631,033	$ 631,033
2021	$ —	$ 626,210	$ 626,210

The change in lease operating expenses was principally attributable to a decrease in non-recurring water disposal and operating costs incurred on the Lou Brock well during testing in 2021, which well was ultimately plugged and abandoned.

Depreciation and Depletion Expense. Depreciation and depletion expense decreased by 16% to $205,458 in 2022 from $245,606 in 2021. The decrease in depreciation and depletion during 2022 was attributable to the decrease in oil production during 2022.

General and Administrative Expenses (Excluding Stock-Based Compensation). General and administrative expense increased by 18% to $1,374,060 in 2022 from $1,168,969 in 2021. The change in general and administrative expense was primarily attributable to a bonus payment to our CEO of $200,000 and increase in the base salary of our CEO from $120,000 to $180,000 annually, effective September 1, 2022.

Stock-Based Compensation. Stock-based compensation decreased to $206,210 in 2022 from $323,611 in 2021. The decrease in stock-based compensation was attributable to vesting during 2021 of prior year option grants.

Other Income (Expense). Other income/expense, net, totaled $33,641 of income during 2022, compared to $12,668 of income during 2021. Other income consisted of interest earned on cash balances. The increase in other income was attributable to higher interest rates earned on cash balances.

Financial Condition

Liquidity and Capital Resources. At December 31, 2022, we had a cash balance of $4,547,210 and working capital of $4,601,168, compared to a cash balance of $4,894,577 and working capital of $5,052,685 at December 31, 2021.

Cash Flows. Operating activities used cash of $228,962 during 2022, compared to $680,691 used during 2021. The change in cash flows from operating activities was attributable to increased revenues and a resulting lower loss incurred during 2022.

Investing activities used cash of $1,661,405 during 2022, compared to $238,180 used during 2021. The increase in cash used in investing activities is primarily attributable to the acquisition of additional interests in Hupecol Meta ($657,638) and direct investments in Hupecol Meta ($988,722).

Financing activities provided cash of $1,543,000 during 2022, compared to $4,570,888 provided during 2021. During 2022, cash provided by financing activities was attributable to funds received from the sale of common stock under our 2022 ATM Offering. During 2021, cash provided by financing activities was attributable to funds received from the sale of common stock ($6,575,889) under our 2021 ATM Offering and 2021 Supplemental ATM Offering, partially offset by the payment of dividends on preferred stock ($37,201) and redemption of all remaining outstanding shares of preferred stock ($1,967,800). As of December 31, 2022, $2 million was still available under the 2022 ATM offering.

Long-Term Liabilities. At December 31, 2022, we had long-term liabilities of $219,148, compared to $279,953 at December 31, 2021. Long-term liabilities, as of December 31, 2022, consisted of a reserve for plugging costs of $72,789 and a lease liability of $146,359.

Capital and Exploration Expenditures and Commitments. Our principal capital and exploration expenditures relate to ongoing efforts to acquire, drill and complete prospects, in particular our Colombian acreage held through Hupecol Meta. During 2022, capital expenditures relating to Hupecol Meta increased sharply with our acquisition of additional interests in Hupecol Meta and our investments in Hupecol Meta to fund our share of costs associated with the initial wells drilled on the CPO-11 block. Based on discussions with Hupecol Meta, we anticipate that additional expenditures will be made to acquire seismic data and to support additional drilling operations on the CPO-11 block in 2023 and beyond with an initial focus on drilling a horizontal well in the Venus Exploration Area. There are no present plans to conduct additional drilling operations on our U.S. properties. The actual timing and number of well operations undertaken will be principally controlled by the operators of our acreage based on a number of factors, including but not limited to availability of financing, performance of existing wells on the subject acreage, energy prices and industry condition and outlook, costs of drilling and completion services and equipment and other factors beyond our control or that of our operators.

In addition to possible operations on our existing acreage holdings, we continue to evaluate drilling prospects in which we may acquire an interest and participate.

As our allocable share of well costs will vary depending on the timing and number of wells drilled as well as our working interest in each such well and the level of participation of other interest owners, we have not established a drilling budget but will budget on a well-by-well basis as our operators propose wells.

We believe that we have the ability, through our cash on-hand, to fund operations and our cost for all planned seismic expenditures and wells expected to be drilled during 2023 and for the twelve months following the issuance of these financial statements.

In the event that we pursue additional acreage acquisitions or expand our drilling plans, we may be required to secure additional funding beyond our resources on hand. While we may, among other efforts, seek additional funding from “at-the-market” sales of common stock, and private sales of equity and debt securities, we presently have, as of December 31, 2022, less than 600,000 authorized shares of common stock available for issuance to support equity capital raises and we have no commitments to provide additional funding, and there can be no assurance that we can secure the necessary capital to fund our share of drilling, acquisition or other costs on acceptable terms or at all. If, for any reason, we are unable to fund our share of drilling and completion costs and fail to satisfy commitments relative to our interest in our acreage, we may be subject to penalties or to the possible loss of some of our rights and interests in prospects with respect to which we fail to satisfy funding commitments and we may be required to curtail operations and forego opportunities.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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

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

Item 8. Financial Statements and Supplementary Data

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

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

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive who also serves as our principal financial officer, we conducted an evaluation as of December 31, 2022 of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer concluded that our disclosure controls and procedures were not effective as of December 31, 2022.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of management, including our principal executive officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the 2013 framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework, management concluded that our internal control over financial reporting was not effective as of December 31, 2022. Such conclusion reflects our chief executive officer's assumption of duties of the principal financial officer and the resulting lack of segregation of duties. Until we are able to remedy this material weakness, we are relying on third party consultants to assist with financial reporting.

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

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fourth quarter of 2022 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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

Executive Officers

Our executive officers as of December 31, 2022, and their ages and positions as of that date, are as follows:

Name	Age	Position
John Terwilliger	75	President and Chief Executive Officer

John Terwilliger has served as our President and CEO, and as a director, since December 2020. Mr. Terwilliger is the company's founder and served as its President, Chief Executive Officer and Chairman of the Board from 2001 to 2015 and continued, in a non-executive role, to provide oil and gas prospect and operations services to the company from 2015 until his appointment as an officer in 2020. Mr. Terwilliger has more than 40 years' experience in oil and gas management and operations.

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

Item 11. Executive Compensation

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

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

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

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

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

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

Item 14. Principal Accountant Fees and Services

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

PART IV

Item 15. Exhibits and Financial Statement Schedules

1. Financial statements. See “Index to Financial Statements” on page F-1.

2. Exhibits

		Incorporated by Reference			
Exhibit Number	**Exhibit Description**	**Form**	**Date**	**Number**	**Filed Herewith**
1.1	At-the-Market Issuance Sales Agreement, dated November 18, 2022, by and between Houston American Energy Corp. and Univest Securities, LLC	8-K	11/18/22	1.1	
3.1	Certificate of Incorporation of Houston American Energy Corp. filed April 2, 2001	SB-2	08/03/01	3.1	
3.2	Amended and Restated Bylaws of Houston American Energy Corp. adopted November 26, 2007	8-K	11/29/07	3.1	
3.3	Certificate of Amendment to the Certificate of Incorporation of Houston American Energy Corp. filed September 25, 2001	SB-2	10/01/01	3.4	
3.4	Certificate of Amendment to the Certificate of Incorporation of Houston American Energy Corp. filed July 21, 2020	8-K	07/17/20	3.1	
4.1	Text of Common Stock Certificate of Houston American Energy Corp.	SB-2	08/03/01	4.1	
10.1	Form of 2019 Warrant	8-K	09/20/19	10.3	
10.2	Houston American Energy Corp. 2017 Equity Incentive Plan*	Sch 14A	07/24/17	Ex A	
10.3	Houston American Energy Corp. 2021 Equity Incentive Plan*	Sch 14A	04/28/21	Ex B	
10.4	Form of Change in Control Agreement, dated June 11, 2012*	8-K	06/14/12	10.1	
10.5	Production Incentive Compensation Plan*	10-Q	08/14/13	10.1	
14.1	Code of Ethics for CEO and Senior Financial Officers	10-KSB	03/26/04	14.1	
23.1	Consent of Marcum, LLP				X
23.2	Consent of Russell K. Hall & Associates, Inc.				X
31.1	Section 302 Certification of CEO and CFO				X

32.1	Section 906 Certification of CEO and CFO	X

99.1	Code of Business Ethics	8-K	07/07/06	99.1		
99.2	Report of Russell K. Hall & Associates, Inc.				X	
101.INS	Inline XBRL Instance Document					X
101.SCH	Inline XBRL Taxonomy Extension Schema Document					X
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document					X
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)					X

* Compensatory plan or arrangement.

Item 16. Form 10-K Summary

Not applicable

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 31, 2023

By: */s/ John Terwilliger*

John 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 Terwilliger **John Terwilliger**	Chief Executive Officer, President and Director (Principal Executive Officer and Principal Financial Officer)	March 31, 2023
/s/ James Schoonover **James Schoonover**	Director	March 31, 2023
/s/ Stephen Hartzell **Stephen Hartzell**	Director	March 31, 2023
/s/ Keith Grimes **Keith Grimes**	Director	March 31, 2023

HOUSTON AMERICAN ENERGY CORP.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Houston American Energy Corp. (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of operations, shareholders' equity and cash flows for each of the years ended December 31, 2022 and 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the years ended December 31, 2022 and 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depreciation, depletion and amortization and impairment of oil and gas properties

At December 31, 2022, the net carrying value of the Company's oil and gas properties was $65.1 million, depreciation, depletion and amortization ("DD&A") expense was $0.2 million, and impairment expense was $0 million for the year then ended. As described in Note 1, the Company follows the full cost method of accounting for its oil and gas properties. DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method based on proved oil and gas reserves, as estimated by the Company's internal and external reservoir engineers. Under the full cost method, a ceiling test is performed each quarter. 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 DD&A, impairment, and the related deferred income taxes, may not exceed the estimated future net cash flows from proved oil and gas reserves. If capitalized costs exceed this limit, the capitalized cost is reduced to fair value.

Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and natural gas liquids, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Additionally, the expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes from estimated oil and gas reserves. Significant judgment is required by the Company's internal and external reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital costs assumptions, and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to prepare the proved oil and gas reserve estimates for select properties as of December 31, 2022.

Auditing the Company's DD&A and impairment calculations is complex because of the use of the work of the internal reservoir engineers and the independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating oil and gas reserves. We obtained an understanding of the Company's controls over its process to calculate DD&A and impairment, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent petroleum engineers primarily responsible for the preparation of the reserve estimates for select properties. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating oil and gas reserves by agreeing them to source documentation, and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's development plan and the availability of capital relative to the development plan. We also tested the mathematical accuracy of the DD&A and impairment calculations, including comparing the oil and gas reserve amounts used in the calculations to the Company's reserve reports.

/s/ Marcum LLP

Marcum LLP

We have served as the Company's auditor since 2010

New York, New York
March 31, 2023

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

	December 31, 2022	December 31, 2021
ASSETS		
CURRENT ASSETS		
Cash	$ 4,547,210	$ 4,894,577
Accounts receivable – oil and gas sales	164,575	214,662
Prepaid expenses and other current assets	84,544	85,403
TOTAL CURRENT ASSETS	4,796,329	5,194,642
PROPERTY AND EQUIPMENT		
Oil and gas properties, full cost method		
Costs subject to amortization	62,786,267	62,771,222
Costs not being amortized	2,343,126	2,343,126
Office equipment	90,004	90,004
Total	65,219,397	65,204,352
Accumulated depletion, depreciation, amortization, and impairment	(60,602,051)	(60,396,594)
PROPERTY AND EQUIPMENT, NET	4,617,346	4,807,758
Cost method investment	2,102,139	455,779
Right of use asset	212,202	272,507
Other assets	3,167	3,167
TOTAL ASSETS	$ 11,731,183	$ 10,733,853
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 113,741	$ 69,607
Accrued expenses	16,035	15,176
Short-term lease liability	65,385	57,174
TOTAL CURRENT LIABILITIES	195,161	141,957
LONG-TERM LIABILITIES		
Lease liability, net of current portion	146,359	211,744
Reserve for plugging and abandonment costs	72,789	68,209
TOTAL LONG-TERM LIABILITIES	219,148	279,953
TOTAL LIABILITIES	414,309	421,910
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Preferred stock, par value $0.001; 10,000,000 shares authorized		

Series A Convertible Redeemable Preferred Stock, Par value $0.001; 2,000 shares authorized; 0 and 0 shares issued and outstanding, respectively	—	—
Series B Convertible Redeemable Preferred Stock, Par value $0.001; 1,000 shares authorized; 0 and 0 shares issued and outstanding, respectively	—	—
Common stock, par value $0.001; 12,000,000 shares authorized 10,327,646 and 9,928,338 shares issued and outstanding	10,328	9,928
Additional paid-in capital	85,094,266	83,345,456
Accumulated deficit	(73,787,720)	(73,043,441)
TOTAL SHAREHOLDERS' EQUITY	11,316,874	10,311,943
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 11,731,183	$ 10,733,853

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

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

	2022	2021
REVENUES		
Oil and gas revenue	$ 1,638,841	$ 1,330,198
Total operating revenue	1,638,841	1,330,198
EXPENSES OF OPERATIONS		
Lease operating expense and severance tax	631,033	626,210
General and administrative expense	1,580,270	1,492,580
Depreciation and depletion	205,458	245,606
Total operating expenses	2,416,761	2,364,396
Loss from operations	(777,920)	(1,034,198)
OTHER INCOME		
Interest income	33,641	12,964
Interest expense	—	(296)
Total other income, net	33,641	12,668
Loss before taxes	(744,279)	(1,021,530)
Income tax expense (benefit)	—	—
Net loss	(744,279)	(1,021,530)
Dividends to Series A and B Preferred shareholders	—	(37,201)
Net loss attributable to common shareholders	$ (744,279)	$ (1,058,731)
Basic and diluted net loss per common share outstanding	$ (0.07)	$ (0.11)
Basic and diluted weighted average number of common shares outstanding	9,961,253	9,671,909

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

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2022 and 2021

	Preferred Stock		Common Stock		Additional Paid-in	Retained Earnings	
	Shares	Amount	Shares	Amount	Capital	(Deficit)	Total
Balance at December 31, 2020	1,920	$ 2	6,977,718	$ 6,977	$ 78,453,906	$ (72,021,911)	$ 6,438,974
Issuance of common stock for cash, net	—	—	2,921,620	2,922	6,572,967	—	6,575,889
Stock-based compensation	—	—	5,000	5	323,606	—	323,611
Conversion of Series A Preferred Stock to common stock	(60)	—	24,000	24	(24)	—	—
Redemption of Series A and Series B Preferred Stock	(1,860)	(2)	—	—	(1,967,798)	—	(1,967,800)
Series A and Series B Preferred Stock dividends paid	—	—	—	—	(37,201)	—	(37,201)
Net loss	—	—	—	—	—	(1,021,530)	(1,021,530)
Balance at December 31, 2021	—	—	9,928,338	9,928	83,345,456	(73,043,441)	10,311,943
Issuance of common stock for cash, net	—	—	394,678	395	1,542,605	—	1,543,000
Issuance of common stock on cashless exercise of option	—	—	4,630	5	(5)	—	—
Stock-based compensation	—	—	—	—	206,210	—	206,210
Net loss	—	—	—	—	—	(744,279)	(744,279)
December 31, 2022	—	$ —	10,327,646	$ 10,328	$ 85,094,266	$ (73,787,720)	$ 11,316,874

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

HOUSTON AMERICAN ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

	2022	2021
CASH FLOW FROM OPERATING ACTIVITIES		
Net loss	$ (744,279)	$ (1,021,530)
Adjustments to reconcile net loss to net cash used in operations		
Depreciation and depletion	205,458	245,606
Accretion of plugging and abandonment costs	4,580	4,280
Stock-based compensation	206,210	323,611
Amortization of right of use asset	60,305	74,037
Change in operating assets and liabilities:		
Decrease/(Increase) in accounts receivable	50,087	(118,899)
Decrease/(Increase) in prepaid expense and other current assets	855	(49,558)
Increase/(Decrease) in accounts payable and accrued expenses	53,203	(89,699)
Decrease in operating lease liability	(65,385)	(48,539)
Net cash used in operating activities	(228,962)	(680,691)
CASH FLOW FROM INVESTING ACTIVITIES		
Payments for the acquisition and development of oil and gas properties	(15,045)	(42,806)
Payments for the acquisition of cost method investment	(1,646,360)	(195,374)
Net cash used in investing activities	(1,661,405)	(238,180)
CASH FLOW FROM FINANCING ACTIVITIES		
Proceeds from issuance of common stock for cash, net of offering costs	1,543,000	6,575,889
Redemption of Series A and Series B Preferred Stock	—	(1,967,800)
Payment of preferred stock dividends	—	(37,201)
Net cash provided by financing activities	1,543,000	4,570,888
(DECREASE)/INCREASE IN CASH	(347,367)	3,652,017
Cash, beginning of year	4,894,577	1,242,560
Cash, end of year	$ 4,547,210	$ 4,894,577
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid	$ —	$ —
Taxes paid	$ —	$ —
SUPPLEMENTAL NON-CASH INVESTING AND FINANCING ACTIVITIES		
Change in asset retirement obligations, net	$ —	$ 17,082
Cashless exercise of stock options	$ 5	$ —
Conversion of Series A Preferred Stock to common stock	$ —	$ (24)

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

HOUSTON AMERICAN ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

General

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

Consolidation

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

Liquidity and Capital Requirements

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business for the twelve-month period following the issuance date of these consolidated financial statements. The Company has incurred continuing losses since 2011, including a loss of $744,279 for the year ended December 31, 2022. As a result of the steep global economic slowdown that began in March 2020 as the coronavirus pandemic ("COVID-19") spread, oil and gas demand and prices realized from oil and gas sales declined sharply. While the COVID-19 crisis has subsided and the global economy and oil and gas prices have recovered, future spikes in COVID-19 infection rates could result in declines in global economic activity and oil and gas prices. Any such future declines in prices would adversely affect the Company's revenues and profitability.

During 2021 and 2022, the Company raised $6.6 million and $1.5 million, net of offering costs, from the sale of common stock. With those funds, the Company believes that it has the ability to fund, from cash on hand, its operating costs and anticipated drilling operations for at least the next twelve months following the issuance of these financial statements.

The actual timing and number of wells drilled during 2023 will be principally controlled by the operators of the Company's acreage, based on a number of factors, including but not limited to availability of financing, performance of existing wells on the subject acreage, energy prices and industry condition and outlook, costs of drilling and completion services and equipment and other factors beyond the Company's control or that of its operators.

In the event that the Company pursues additional acreage acquisitions or expands its drilling plans, the Company may be required to secure additional funding beyond our resources on hand. While the Company may, among other efforts, seek additional funding from "at-the-market" sales of common stock, and private sales of equity and debt securities, it presently has limited shares of common stock authorized for issuance to support sales of such shares and does not have any commitments to provide additional funding, and there can be no assurance that the Company can secure the necessary capital to fund its share of drilling, acquisition or other costs on acceptable terms or at all. As of December 31, 2022, the Company had $2 million remaining available from the 2022 ATM offering. If, for any reason, the Company is unable to fund its share of drilling and completion costs, it would forego participation in one or more of such wells. In such event, the Company may be subject to penalties or to the possible loss of some of its rights and interests in prospects with respect to which it fails to satisfy funding obligations and it may be required to curtail operations and forego opportunities.

General Principles and Use of Estimates

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

Cash and Cash Equivalents

Cash and cash equivalents consist of demand deposits and cash investments with initial maturity dates of less than three months when purchased. As of December 31, 2022 and 2021, the Company had no cash equivalents outstanding.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash, cash equivalents and marketable securities (if any). The Company had cash deposits of $4.3 million in excess of the FDIC's current insured limit of $250,000 at December 31, 2022 for interest bearing accounts. The Company also had cash deposits of $3,665 in Colombian banks at December 31, 2022 that are not insured by the FDIC. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Revenue Recognition

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

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

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

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

Loss per Share

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

For the years ended December 31, 2022 and 2021, the following warrants and options to purchase shares of common stock were excluded from the computation of diluted net loss per share, as the inclusion of such shares would be anti-dilutive:

	Year Ended December 31,	
	2022	2021
Stock warrants	94,400	98,400
Stock options	944,177	990,177
Totals	1,038,577	1,088,577

Accounts Receivable

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

Allowance for Accounts Receivable

The Company regularly reviews outstanding receivables and provides for estimated losses through an allowance for doubtful accounts when necessary. In evaluating the need for an allowance, the Company makes judgments regarding its customers' ability to make required payments, economic events and other factors. As the financial condition of these parties change, circumstances develop or additional information becomes available, an allowance for doubtful accounts may be required. When the Company determines that a customer may not be able to make required payments, the Company increases the allowance through a charge to income in the period in which that determination is made. As of December 31, 2022 and 2021, the Company evaluated their receivables and determined that no allowance was necessary.

Oil and Gas Properties

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

The Company categorizes its full cost pools as costs subject to amortization and costs not being amortized. The sum of net capitalized costs subject to amortization, including estimated future development and abandonment costs, are amortized using the unit-of-production method. Depletion and amortization for oil and gas properties was $194,392 and $245,606 for the years ended December 31, 2022 and 2021, respectively, and accumulated amortization, depreciation and impairment was $60,501,999 and $60,306,590 at December 31, 2022 and 2021, 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 2022 and 2021 using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) with consideration of price change only to the extent provided by contractual arrangement, discounted at 10%, net of related tax effects. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional accumulated DD&A. During 2022 and 2021, the Company recorded no impairments of oil and gas properties.

Furniture and Equipment

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

Office equipment having an original cost basis of $90,004 was fully depreciated as of January 1, 2020. Therefore, accumulated depreciation was $90,004 and $90,004 at December 31, 2022 and 2021, respectively.

Cost Method

Businesses not accounted for under either the consolidation method or equity method of accounting are accounted for under the cost method of accounting and are further discussed in Note 3, “Oil and Gas Properties.” The Company’s share of the earnings and/or losses of cost method businesses is not included in the Consolidated Statements of Operations. Income from cost method investments is only realized if and when distributions are made from the cost method business to its investors. However, impairment charges related to cost method businesses are recognized in the company’s Consolidated Statements of Operations. If circumstances suggest that the value of a cost method business with respect to which an impairment charge has been made has subsequently recovered, that recovery is not recorded. The carrying values of the company’s cost method businesses are reflected in the line item “Cost method investment” in the Company’s Consolidated Balance Sheets.

Asset Retirement Obligations

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

Joint Venture Expense

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

Income Taxes

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

Uncertain Tax Positions

The Company evaluates uncertain tax positions to recognize a tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. Those tax positions failing to qualify for initial recognition are recognized in the first interim period in which they meet the more likely than not standard or are resolved through negotiation or litigation with the taxing authority, or upon expiration of the statute of limitations. De-recognition of a tax position that was previously recognized occurs when an entity subsequently determines that a tax position no longer meets the more likely than not threshold of being sustained.

The Company is subject to ongoing tax exposures, examinations and assessments in various jurisdictions. Accordingly, the Company may incur additional tax expense based upon the outcomes of such matters, including any interest or penalties. In addition, when applicable, the Company will adjust tax expense to reflect the Company’s ongoing assessments of such matters, which require judgment and can materially increase or decrease its effective rate as well as impact operating results. There were no liabilities recorded for uncertain tax positions at December 31, 2022 and 2021.

Stock-Based Compensation

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

Concentration of Risk

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

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

The Company's Permian Basin, Texas properties accounted for all of the Company's drilling operations and substantially all of its oil and gas investments in 2022 and 2021. In the event of a significant negative change in operations or operating outlook pertaining to the Company's Permian Basin properties, the Company may be forced to abandon or suspend such operations, which abandonment or suspension could be materially harmful to the Company.

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

For 2022, the Company's oil production from the its mineral interests was sold to U.S. oil marketing companies based on the highest bid. The gas production is sold to U.S. natural gas marketing companies based on the highest bid. No purchaser accounted for more than 10% of our oil and gas sales.

The Company reviews accounts receivable balances when circumstances indicate a balance may not be collectible. Based upon the Company's review, no allowance for uncollectible accounts was deemed necessary at December 31, 2022 and 2021, respectively.

Recent Accounting Developments

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

Subsequent Events

The Company evaluated subsequent events for disclosure from December 31, 2022 through the date the consolidated financial statements were issued.

NOTE 2—REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregation of Revenue from Contracts with Customers

The following table disaggregates revenue by significant product type for the years ended December 31, 2022 and 2021:

	Year Ended December 31,	
	2022	**2021**
Oil sales	$ 995,083	$ 913,809
Natural gas sales	377,534	247,992
Natural gas liquids sales	266,224	168,397
Total revenue from customers	$ 1,638,841	$ 1,330,198

There were no significant contract liabilities or transaction price allocations to any remaining performance obligations as of December 31, 2022 or 2021.

NOTE 3—OIL AND GAS PROPERTIES

Evaluated Oil and Gas Properties

Evaluated oil and gas properties subject to amortization at December 31, 2022 included the following:

	United States	**South America**	**Total**
Evaluated properties being amortized	$ 13,331,565	$ 49,444,654	$ 62,776,219
Accumulated depreciation, depletion, amortization and impairment	(11,057,345)	(49,444,654)	(60,501,999)
Net capitalized costs	$ 2,274,220	$ —	$ 2,274,220

Evaluated oil and gas properties subject to amortization at December 31, 2021 included the following:

	United States	**South America**	**Total**
Evaluated properties being amortized	$ 13,326,568	$ 49,444,654	$ 62,771,222
Accumulated depreciation, depletion, amortization and impairment	(10,861,936)	(49,444,654)	(60,306,590)
Net capitalized costs	$ 2,464,632	$ —	$ 2,464,632

Unevaluated Oil and Gas Properties

Unevaluated oil and gas properties not subject to amortization at December 31, 2022 included the following:

	United States	**South America**	**Total**
Leasehold acquisition costs	$ —	$ 143,847	$ 143,847
Geological, geophysical, screening and evaluation costs	—	2,199,279	2,199,279
Total	$ —	$ 2,343,126	$ 2,343,126

Unevaluated oil and gas properties not subject to amortization at December 31, 2021 included the following:

	United States	**South America**	**Total**
Leasehold acquisition costs	$ —	$ 143,847	$ 143,847
Geological, geophysical, screening and evaluation costs	—	2,199,279	2,199,279
Total	$ —	$ 2,343,126	$ 2,343,126

During 2022, the Company invested $1,661,405 for the acquisition and development of oil and gas properties, consisting of (1) drilling and development operations in the U.S. Permian Basin ($15,045) which have been classified as oil and gas properties subject to amortization, and (2) acquisition of additional interest in Hupecol Meta LLC ("Hupecol Meta") ($657,638) and direct investments in Hupecol Meta relating to drilling operations in Colombia ($988,722). Of the amount invested, we capitalized $15,045 to oil and gas properties subject to amortization and capitalized $1,646,360 as additional investment in Hupecol Meta, reflected in the cost method investment on the Company's balance sheet. During 2021, the Company capitalized $42,806 to oil and gas properties subject to amortization. See Note 4—Cost Method Investment for additional information on the Company's investment in Hupecol Meta.

NOTE 4—Cost Method Investment

The Company's carrying value of its holdings in cost method investment was $2.1 million and $0.5 million as of December 31, 2022 and 2021, respectively, as reflected in the line item "Cost method investment" in the company's Consolidated Balance Sheets.

During the year ended December 31, 2022, the Company paid $657,638 to increase its ownership interest in Hupecol Meta, to approximately 18%. During 2022, the Company also made direct investments in Hupecol Meta of $988,722 for required capital contributions.

During the year ended December 31, 2021, the Company contributed $99,716 to Hupecol Meta, increasing its ownership interest to 7.85%. During 2021, the Company also made direct investments in Hupecol Meta of $195,374 for required capital contributions.

Impairments

The Company performs annual business reviews of its cost method investments to determine whether the carrying value in that investment is impaired. The Company determined its carrying value in its cost method business was not impaired during the years ended December 31, 2022 and 2021.

NOTE 5—ASSET RETIREMENT OBLIGATIONS

The following table describes changes in our asset retirement liability ("ARO") during each of the years ended December 31, 2022 and 2021.

	2022	2021
ARO liability at January 1	$ 68,209	$ 63,929
Additions from new drilling	—	—
Dispositions from sales of oil and gas properties	—	—
Changes in estimates	—	—
Accretion expense	4,580	4,280
ARO liability at December 31	$ 72,879	$ 68,209

NOTE 6—STOCK-BASED COMPENSATION

In 2008, the Company adopted the Houston American Energy Corp. 2008 Equity Incentive Plan (the "2008 Plan"). The terms of the 2008 Plan, as amended in 2012 and 2013, allow for the issuance of up to 480,000 shares of the Company's common stock pursuant to the grant of stock options and restricted stock.

In 2017, the Company adopted the Houston American Energy Corp. 2017 Equity Incentive Plan (the "2017 Plan"). The terms of the 2017 Plan allow for the issuance of up to 400,000 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.

In 2021, the Company adopted the Houston American Energy 2021 Equity Incentive Plan (the "2021 Plan" and, together with the 2008 Plan and the 2017 Plan, the "Plans"). The terms of the 2021 Plan allow for the issuance of up to 500,000 shares of the Company's common stock pursuant to the grant of stock options and restricted stock. Persons eligible to participate in the Plans are key employees, consultants and directors of the Company.

Stock Option Activity

In June 2021, options to purchase an aggregate of 210,000 shares of the Company's common stock were granted to the Company's directors and sole officer. The options have a ten-year life and are exercisable at $1.77 per share. The 60,000 aggregate options granted to directors vest 20% on the date of grant and 80% ten months from the date of grant. The 150,000 options granted to the Company's sole officer vest one year from the date of grant. The grant date fair value of these stock options was $340,308 based on the Black-Scholes Option Pricing model based on the following assumptions: market value of common stock on grant date – $1.77; risk free interest rate based on the applicable US Treasury bill rate – 1.27%; dividend yield – 0%; volatility factor based on the trading history of the Company – 107.2%; weighted average expected life in years – 10; and expected forfeiture rate – 0%.

Additionally, in June 2021, options to purchase 54,000 shares of the Company's common stock, granted in November 2020 subject to shareholder approval of the Company's 2021 Plan, received the requisite approval of shareholders and are treated as granted during 2021. The options have a ten-year life, are exercisable at $1.45 per share and vested in full on shareholder approval of the 2021 Plan. The grant date fair value of these stock options was $70,279 based on the Black-Scholes Option Pricing model based on the following assumptions: market value of common stock on grant date – $1.45; risk free interest rate based on the applicable US Treasury bill rate - 0%; dividend yield – 0%; volatility factor based on the trading history of the Company – 103.3%; weighted average expected life in years – 10; and expected forfeiture rate – 0%.

In September 2022, options to purchase an aggregate of 60,000 shares of common stock were granted to the Company's directors. The options have a ten-year life and are exercisable at $3.91 per share. The options vest 20% on the date of grant and 80% nine months from the date of grant. The grant date fair value of these stock options was $216,326 based on the Black-Scholes Option Pricing model with the following parameters: (1) risk-free interest rate of 0% based on the applicable US Treasury bill rate; (2) expected life in years of 10; (3) expected stock volatility of 121% based on the trading history of the Company; and (4) expected dividend yield of 0%. The

Company determined the options qualified as ‘plain vanilla’ under the provisions of SAB 107 and the simplified method was used to estimate the expected option life.

Option activity during 2022 and 2021 was as follows:

	Options		Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in Years)		Aggregate Intrinsic Value
Outstanding at December 31, 2020	730,973	$	5.07			
Granted[(1)]	264,000	$	1.70			
Forfeited	(4,800)	$	167.81			
Outstanding at December 31, 2021	990,177		3.38			
Granted	60,000		3.91			
Exercised	(48,000)		3.84			
Forfeited	(58,000)		20.43			
Outstanding at December 31, 2022	944,177	$	2.08	7.85	$	1,025,655
Exercisable at December 31, 2022	896,177	$	1.92	7.68	$	1,025,655

(1) 54,000 options granted in November 2020 under the Company's 2021 Plan pending shareholder approval were excluded from grants during 2020 and included in grants during 2021 when the 2021 Plan was approved by shareholders.

During 2022 and 2021, the Company recognized $206,210 and $323,611, respectively, of stock-based compensation expense attributable to a stock grant and outstanding stock option grants, including current period grants and unamortized expense associated with prior period grants.

As of December 31, 2022, non-vested options totaled 48,000 and total unrecognized stock-based compensation expense related to non-vested stock options was $163,735. The related unrecognized expense is expected to be recognized over a weighted average period of 2.08 years. The weighted average remaining contractual term of the outstanding options and exercisable options at December 31, 2022 is 7.85 years and 7.68 years, respectively.

As of December 31, 2022, there were 181,333 shares of common stock available for issuance pursuant to future stock or option grants under the Plans.

During the year ended December 31, 2022, stock options covering 48,000 shares of common stock were issued pursuant to a cashless exercise resulting in the issuance of 4,630 shares of common stock.

Stock-Based Compensation Expense

During 2021, a non-executive employee was granted 5,000 shares of the Company's common stock as compensation for services with a grant date fair value of $10,825 based on the market price of the Company's common stock on the grant date.

The following table reflects stock-based compensation recorded by the Company for 2022 and 2021:

		2021		2021
Stock-based compensation expense from stock options and common stock included in general and administrative expense	$	206,210	$	32
Earnings per share effect of stock-based compensation expense	$	(0.02)	$	

NOTE 7—CAPITAL STOCK

Common Stock - At-the-Market Offerings

In January 2021, the Company entered into an At-the-Market Issuance Sales Agreement (the "Sales Agreement") with Univest Securities, LLC ("Univest") pursuant to which the Company could sell (the "2021 ATM Offering"), at its option, up to an aggregate of $4.768 million in shares of its common stock through Univest, as sales agent. Sales of shares under the Sales Agreement (the "2021 ATM Offering") were made, in accordance with placement notices delivered to Univest, which notices set parameters under which shares could be sold. The 2021 ATM Offering was made pursuant to a shelf registration statement by methods deemed to be "at the market," as defined in Rule 415 promulgated under the Securities Act of 1933. The Company paid Univest a commission in cash equal to 3% of the gross proceeds from the sale of shares in the 2021 ATM Offering. The Company reimbursed Univest for $18,000 of expenses incurred in connection with the 2021 ATM Offering.

In January 2021, the Company sold an aggregate of 2,108,520 shares in connection with the 2021 ATM Offering and received proceeds, net of commissions and expenses, of $4.6 million.

In February 2021, the Company entered into another Sales Agreement with Univest pursuant to which the Company could sell (the “2021 Supplemental ATM Offering”), at its option, up to an aggregate of $2.03 million in shares of its common stock through Univest, as sales agent. Sales of shares under the Sales Agreement (the “2021 Supplemental ATM Offering”) were made, in accordance with placement notices delivered to Univest, which notices set parameters under which shares could be sold. The 2021 Supplemental ATM Offering was made pursuant to a shelf registration statement by methods deemed to be “at the market,” as defined in Rule 415 promulgated under the Securities Act of 1933. The Company paid Univest a commission in cash equal to 3% of the gross proceeds from the sale of shares in the 2021 Supplemental ATM Offering. The Company reimbursed Univest for $18,000 of expenses incurred in connection with the 2021 Supplemental ATM Offering.

In February 2021, the Company sold an aggregate of 813,100 shares in connection with the 2021 Supplemental ATM Offering and received proceeds, net of commissions and expenses, of $2.0 million.

In November 2022, the Company entered into another Sales Agreement with Univest pursuant to which the Company could sell (the “2022 ATM Offering”), at its option, up to an aggregate of $3.5 million in shares of its common stock through Univest, as sales agent. Sales of shares under the Sales Agreement (the “2022 Supplemental ATM Offering”) were made, in accordance with placement notices delivered to Univest, which notices set parameters under which shares could be sold. The 2022 ATM Offering was made pursuant to a shelf registration statement by methods deemed to be “at the market,” as defined in Rule 415 promulgated under the Securities Act of 1933. The Company paid Univest a commission in cash equal to 3% of the gross proceeds from the sale of shares in the 2022 ATM Offering. The Company reimbursed Univest for $25,000 of expenses incurred in connection with the 2022 ATM Offering.

In December 2022, the Company sold an aggregate of 394,678 shares in connection with the 2022 ATM Offering and received proceeds, net of commissions and expenses, of $1.5 million.

Preferred Stock

The Company has authorized 10,000,000 shares of preferred stock with a par value of $0.001. The Board of Directors shall determine the designations, rights, preferences, privileges and voting rights of the preferred stock as well as any restrictions and qualifications thereon. As of December 31, 2022, the Company had no shares of preferred stock issued and outstanding.

Series A Convertible Preferred Stock

In January 2017, the Company issued 1,200 shares of 12% Series A Convertible Preferred Stock (the “Series A Preferred Stock”) for aggregate gross proceeds of $1.2 million. The Series A Preferred Stock (i) accrued a cumulative dividend, commencing July 1, 2017, at 12% payable, if and when declared, quarterly; (ii) was convertible at the option of the holder into shares of common stock at a conversion price of $2.50 per share, (iii) had a liquidation preference of $1,000 per share plus accrued and unpaid dividends; and (iv) was redeemable at the Company’s option, commencing on the second anniversary of the issue date, at a premium to issue price, which premium decreases from 12% to 0% following the fifth anniversary of the issue date, plus accrued and unpaid dividends.

During 2022 and 2021, respectively, the Company paid $0 and $21,501 of dividends on its Series A Preferred Stock.

In February 2021, 60 shares of Series A Preferred Stock were converted into 24,000 shares of common stock, and the Company redeemed all outstanding shares of Series A Preferred Stock for cash paid of $1.07 million plus accrued dividends totaling $21,501.

Series B Convertible Preferred Stock

In May 2017, the Company received $909,600 from the sale of 909.6 Units (the "Units"), each Unit consisting of one share of 12.0% Series B Convertible Preferred Stock (the "Series B Preferred Stock") and a Warrant (the "Series B Warrant"). The Series B Preferred Stock (i) accrued a cumulative dividend at 12% payable, if and when declared, quarterly; (ii) was convertible at the option of the holder into shares of common stock at a conversion price of $4.50 per share, (iii) had a liquidation preference of $1,000 per share plus accrued and unpaid dividends; and (iv) was redeemable at the Company's option, commencing on the second anniversary of the issue date, at a premium to issue price, which premium decreases from 12% to 0% following the fifth anniversary of the issue date, plus accrued and unpaid dividends.

During 2022 and 2021, respectively, the Company paid $0 and $16,700 of dividends on its Series B Preferred Stock.

In February 2021, the Company redeemed all outstanding shares of Series B Preferred Stock for cash paid of $0.9 million plus accrued dividends of $16,700.

Warrants

Consultant Warrants. In September 2017, the Company issued warrants (the "Consultant Warrants") to a consultant. The Consultant Warrants were exercisable to purchase 4,000 shares of common stock at $6.875 per share and expired on December 31, 2021. The relative value of the warrants were valued on the date of grant at $16,132 using the Black-Scholes option-pricing model with the following parameters: (1) risk-free interest rate of 1.63% based on the applicable US Treasury bill rate; (2) expected life in years of 4.32; (3) expected stock volatility of 99.75% based on the trading history of the Company; and (4) expected dividend yield of 0%. The Company recognized $0 of stock-based compensation expense related to the vesting of the Consultant Warrants during each of the years ended December 31, 2022 and 2021.

Bridge Loan Warrants. In September 2019, the Company issued the warrants in conjunction with a bridge loan. The Bridge Loan Warrants are exercisable, for a period of ten years, expiring September 18, 2029, to purchase an aggregate of 94,400 shares of common stock of the Company at $2.50 per share. The relative fair value of the warrants was determined on the date of grant at $144,948 using the Black Scholes option-pricing model with the following parameters: (1) risk free interest rate of 1.80% based on the applicable US Treasury bill rate; (2) expected life in years of 10.0; (3) expected stock volatility of 82.9% based on the trading history of the Company; and (4) expected dividend yield of 0%. The relative fair value of the warrants was recorded as debt discount on the Bridge Loan Notes and was amortized as additional interest expense over the term of the notes.

A summary of warrant activity and related information for 2022 and 2021 is presented below:

	Warrants	Weighted-Average Exercise Price	Aggregate Intrinsic Value
Outstanding at December 31, 2020	98,400	$ 2.63	
Issued	—	—	
Exercised	—	—	
Expired	4,000	$ 6.88	
Outstanding at December 31, 2021	94,400	$ 2.50	
Issued	—	—	
Exercised	—	—	
Expired	—	—	
Outstanding at December 31, 2022	94,400	$ 2.50	$ —
Exercisable at December 31, 2022	94,400	$ 2.50	$ —

NOTE 8—TAXES

The following table sets forth a reconciliation of the statutory federal income tax for the years ended December 31, 2022 and 2021.

	2022	2021
Income (loss) before income taxes	$ (744,279)	$ (1,02
Income tax expense (benefit) computed at statutory rates	$ (156,299)	$ (21
Permanent differences, nondeductible expenses	10,439	1
Increase (decrease) in valuation allowance	(189,914)	(7
State and Local Taxes	3,003	
Other adjustment	369,680	22
Deferred True-Up	(33,082)	4
ASC 842 lease standard adoption	—	
Tax provision	$ 3,827	$
Total provision		
Foreign	$ —	$
Total provision (benefit)	$ 3,827	$

At December 31, 2022 the Company has a federal tax loss carry forward of $11,889,216 and a foreign tax credit carry forward of $27,745, both of which have been fully reserved.

The tax effects of the temporary differences between financial statement income and taxable income are recognized as a deferred tax asset and liabilities. Significant components of the deferred tax asset and liability as of December 31, 2022 and 2021 are set out below.

	2022	2021
Non-Current Deferred tax assets:		
Net operating loss carry forward	$ 11,912,710	$ 11,81
Foreign tax credit carry forward	27,745	39
Deferred state tax	—	
Stock compensation	425,860	43
Book in excess of tax depreciation, depletion and capitalization methods on oil and gas properties	(3,458)	(3
Other	(174,401)	(22
ASC 842 lease standard – building lease	(4)	
Pass-through investment	—	
Total Non-Current Deferred tax assets	12,188,452	12,37
Valuation Allowance	(12,188,452)	(12,37
Net deferred tax asset	$ —	$

Schedule of Net Operating Loss Carryforwards

The Company is currently subject to a three-year statute of limitation for federal tax purposes and, in general, three to four-year statute of limitation for state tax purposes. State NOL expiration will occur beginning in 2033 and Federal NOL expiration will begin in 2032.

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

The provisions were subsequently amended further under the Coronavirus Aid, Relief, and Economic Security Act ("CARES Act") on March 27, 2020. The CARES Act amended the net operating loss provisions in the 2017 Tax Cuts and Jobs Act ("TCJA") and allows for the carryback of NOL's arising in the taxable years ending December 31, 2017 and before January 1, 2021, to each of the five taxable years preceding the taxable year of the loss. Additionally, the 80% limitation related to application of NOL's towards current federal taxable income has been removed for taxable years prior to January 1, 2021; thereby allowing 100% of the NOL to be applied to federal taxable income.

To the best of the Company’s knowledge, Hupecol Meta has made all requisite filings relative to its operations, including those in Colombia, and that there are no known or expected tax issues, payments due, or judgments related to Hupecol Meta that would adversely impact the Company’s cost method investment therein.

NOTE 9—COMMITMENTS AND CONTINGENCIES

Lease Commitment

The Company leases office facilities under an operating lease agreement that expires October 31, 2025. During the year ended December 31, 2022, the operating cash outflows related to operating lease liabilities were $86,373 and the expense for the amortization of the right of use asset for operating leases was $59,445. As of December 31, 2022, the Company's operating lease had a weighted-average remaining term of 2.8 years and a weighted average discount rate of 12%. Below is a summary of the Company's right of use assets and liabilities as of December 31, 2022:

Right of use asset	$ 212,202

Year	Amount
2023	$ 87,288
2024	88,801
2025	75,051
Total future lease payments	251,140
Less: imputed interest	39,396
Present value of future operating lease payments	211,744
Less: current portion of operating lease liabilities	(65,385)
Long-term operating lease liability	$ 146,359

During the years ended December 31, 2022 and 2021, the Company recognized operating lease expense of $86,644 and $80,998, respectively, which is included in general and administrative expenses in the Company's consolidated statements of operations. The Company does not have any capital leases or other operating lease commitments.

Legal Contingencies

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

Environmental Contingencies

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

Development Commitments

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

Production Incentive Arrangements and ORRIs

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

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

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

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

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

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

During 2022, no pools were established under the Plan.

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

ORRI Grants. All present and future prospects in Colombia are subject to a 1.5% ORRI in favor of each of our Chairman and Chief Executive Officer and a former director.

Payments made by the Company under the Plan and ORRI's totaled $17,725 and $15,081 in 2022 and 2021, respectively. As of December 31, 2022 and 2021, the Company had accrued $0 and $0, respectively, under the Plan as accounts payable.

NOTE 10—SUBSEQUENT EVENTS

Subsequent to December 31, 2022, and through the date of this report, the Company issued a total of 294,872 shares of common stock under the 2022 ATM Offering for proceeds, net of commissions and offering expenses, of $874,309.

NOTE 11—GEOGRAPHICAL INFORMATION

The Company currently has operations in two geographical areas, the United States and Colombia. Revenues for the years ended December 31, 2022 and 2021 and long-lived assets as of December 31, 2022 and 2021 attributable to each geographical area are presented below:

	2022		2021	
	Revenues	Long Lived Assets, Net	Revenues	Long Liv Assets, N
North America	$ 1,638,841	$ 2,274,220	$ 1,330,198	$ 2,46
South America	—	2,343,126	—	2,34
Total	$ 1,638,841	$ 4,617,346	$ 1,330,198	$ 4,80

NOTE 12—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:

	2022	2021
Revenues		
North America	$ 1,638,841	$ 1,330,198
South America	—	—
	$ 1,638,841	$ 1,330,198
Production Cost		
North America	$ 631,033	$ 626,210
South America	—	—
	$ 631,033	$ 626,210

Capital Costs

Capitalized costs and accumulated depletion relating to the Company's oil and gas producing activities as of December 31, 2022, all of which are onshore properties located in the United States and Colombia, South America are summarized below:

	United States	South America	Total
Unproved properties not being amortized	$ —	$ 2,343,126	$ 2,34
Proved properties being amortized	13,331,565	49,444,654	62,77
Accumulated depreciation, depletion, amortization and impairment	(11,057,345)	(49,444,654)	(60,50
Net capitalized costs	$ 2,274,220	$ 2,343,126	$ 4,61

Amortization Rate

The amortization rate per unit based on barrel of oil equivalents was $8.95 for the United States for the year ended December 31, 2022.

Acquisition, Exploration and Development Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities as of December 31, 2022 and 2021 are summarized below:

	2022		
	United States		South Ameri
Property acquisition costs:			
Proved	$	—	$
Unproved		—	
Exploration costs		—	
Development costs		15,045	
Total costs incurred	$	15,045	$

	2021		
	United States		South Ameri
Property acquisition costs:			
Proved	$	19,835	$
Unproved		—	
Exploration costs		—	
Development costs		22,971	
Total costs incurred	$	42,806	$

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

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

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

The reserve estimates set forth below were prepared by Russell K. Hall and Associates, Inc. ("R.K. Hall"), utilizing reserve definitions and pricing requirements prescribed by the SEC. R.K. Hall is an independent professional engineering firm specializing in the technical and financial evaluation of oil and gas assets. R.K. Hall's report was conducted under the direction of Russell K. Hall, founder and President of R.K. Hall. Mr. Hall holds a BS in Mechanical Engineering from the University of Oklahoma and is a registered professional engineer with more than 30 years of experience in reserve evaluation services. R.K. Hall and their respective employees have no interest in the Company and were objective in determining the results of the Company's reserves.

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, 2020	764,274	96,513	—	—	764,274	96,513
Revisions of prior estimates	202,713	12,405	—	—	202,713	12,405
Production	(60,069)	(14,367)	—	—	(60,069)	(14,367)
Balance December 31, 2021	906,918	94,551	—	—	906,918	94,551
Revisions to prior estimates	197,137	(346)	—	—	197,137	(346)
Production	(73,635)	(10,688)	—	—	(73,635)	(10,688)
Balance December 31, 2022	1,030,420	83,517	—	—	1,030,420	83,517
Proved developed reserves						
at December 31, 2021	906,918	94,551	—	—	906,918	94,551
at December 31, 2022	1,030,420	83,517	—	—	1,030,420	83,517
Proved undeveloped reserves						
at December 31, 2021	—	—	—	—	—	—
at December 31, 2022	—	—	—	—	—	—

As of December 31, 2022 and 2021, the Company had no proved undeveloped ("PUD") reserves.

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

Standardized measure of discounted future net cash flows at December 31, 2022:

	United States	South America	Total
Future cash flows from sales of oil and gas	$ 16,451,375	$ —	$ 16,451,375
Future production cost	(5,918,092)	—	(5,918,092)
Future development cost	—	—	—
Future net cash flows	10,533,283	—	10,533,283
10% annual discount for timing of cash flow	(5,370,124)	—	(5,370,124)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$ 5,163,159	$ —	$ 5,163,159
Changes in standardized measure:			
Change due to current year operations			
Sales, net of production costs	$ (1,007,808)	$ —	$ (1,007,808)

Change due to revisions in standardized variables:			
Accretion of discount	338,098	—	338,098
Net change in sales and transfer price, net of production costs	1,876,949	—	1,876,949
Net change in future development cost	—	—	—
Discoveries	—	—	—
Revision and others	691,609	—	691,609
Changes in production rates and other	(116,667)	—	(116,667)
Net	1,782,181	—	1,782,181
Beginning of year	3,380,978	—	3,380,978
End of year	$ 5,163,159	$ —	$ 5,163,159

Standardized measure of discounted future net cash flows at December 31, 2021:

	United States	South America	Total
Future cash flows from sales of oil and gas	$ 11,281,236	$ —	$ 11,281,236
Future production cost	(4,726,717)	—	(4,726,717)
Future development cost	—	—	—
Future net cash flows	6,554,519	—	6,554,519
10% annual discount for timing of cash flow	(3,173,541)	—	(3,173,541)
Standardized measure of discounted future net cash flow relating to proved oil and gas reserves	$ 3,380,978	$ —	$ 3,380,978
Changes in standardized measure:			
Change due to current year operations			
Sales, net of production costs	$ (678,014)	$ —	$ (678,014)
Change due to revisions in standardized variables:			
Accretion of discount	117,413	—	117,413
Net change in sales and transfer price, net of production costs	2,650,901	—	2,650,901
Net change in future development cost	—	—	—
Discoveries	—	—	—
Revision and others	786,094	—	786,094
Changes in production rates and other	(669,548)	—	(669,548)
Net	2,206,846	—	2,206,846
Beginning of year	1,174,132	—	1,174,132
End of year	$ 3,380,978	$ —	$ 3,380,978

Exhibit 23.1

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM'S CONSENT

We consent to the incorporation by reference in the Registration Statement of Houston American Energy Corp. on Form S-3 (File No. 333-228749), Form S-3 (File No. 333-220990), Form S-3 (File No. 333-267163), Form S-8 (File No. 333-220838) and Form S-8 (File No. 333-151824) and in any amendments to those Registration Statements, of our report dated April 2, 2024, with respect to our audits of the consolidated financial statements of Houston American Energy Corp. as of December 31, 2023 and 2022 and for the years ended December 31, 2023 and 2022, which report is included in this Annual Report on Form 10-K of Houston American Energy Corp. for the year ended December 31, 2023.

/s/ Marcum LLP
Marcum LLP
Houston, Texas
April 2, 2024

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of the name Russell K. Hall and Associates, Inc. and to incorporation by reference of our report dated February 23, 2023 March 8, 2024, which appears in the annual report on Form 10-K of Houston American Energy Corp. for the year ended December 31, 2022 December 31, 2023, in the Registration Statements of Houston American Energy Corp. on Form S-8 (File No. 333-258906), Form S-3 (File No. 333-228749), Form S-8 (File No. 333-220838), Form S-8 (File No. 333-206875) and Form S-8 (File No. 333-151824), and in any amendments to those Registration Statements.

/s/ Russell K. Hall

RUSSELL K. HALL AND ASSOCIATES, INC.
MIDLAND, TEXAS
March 31, 2023
/s/ Russell K. Hall

RUSSELL K. HALL AND ASSOCIATES, INC.
MIDLAND, TEXAS
April 2, 2024

Exhibit 31.1

SECTION 302
CERTIFICATION

I, John Terwilliger, certify that:

1. I have reviewed this annual report on Form 10-K of Houston American Energy Corp.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respect the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a–15(f) and 15d–15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 31, 2023 April 2, 2024	*/s/ John Terwilliger*
	John Terwilliger,
	Chief Executive Officer and
	Principal Financial Officer

Exhibit 32.1

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

I, John Terwilliger, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Annual Report of Houston American Energy Corp. on Form 10-K for the year ended December 31, 2020 December 31, 2023 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Form 10-K fairly presents in all material respects the financial condition and results of operations of Houston American Energy Corp.

By:	*/s/ John Terwilliger*
Name:	John Terwilliger
Title:	Chief Executive Officer and Chief Financial Officer
Dated:	March 31, 2023 April 2, 2024

Exhibit 99.2

Exhibit 97.1

HOUSTON AMERICAN ENERGY CORP.
Clawback Policy
Effective: March 28, 2023

1. <u>Recoupment</u>

If Houston American Energy Corp. (the “Company”) is required to undertake a Restatement, then the Board shall, unless the Company’s Compensation Committee determines it impracticable to do so, after exercising a normal due process review of all the relevant facts and circumstances, recover all Recoverable Compensation Received by any Covered Person during the Applicable Period. In addition, the Board may, in its sole discretion and in the reasonable exercise of its business judgment, determine whether and to what extent additional action is appropriate to address the circumstances surrounding such Restatement to minimize the likelihood of any recurrence and to impose such other discipline as it deems appropriate.

Subject to applicable law, the Board may seek to recoup such Recoverable Compensation by requiring any Covered Person to repay such amount to the Company; by set-off of a Covered Person’s other compensation; by reducing future compensation; or by such other means or combination of means as the Board, in its sole discretion, determines to be appropriate.

2. <u>Administration of Policy</u>

The Board shall have full authority to administer this Policy. Actions of the Board pursuant to this Policy shall be taken by the vote of a majority of its members. The Board shall, subject to the provisions of this Policy, make such determinations and interpretations and take such actions in connection with this Policy as it deems necessary, appropriate or advisable. All determinations and interpretations made by the Board shall be final, binding and conclusive.

The Board may delegate any of its powers under this Policy to the Compensation Committee of the Board or any subcommittee or delegate thereof.

3. <u>Acknowledgement by Covered Persons</u>

The Board shall provide notice and seek written acknowledgement of this Policy from each Covered Person, provided that the failure to provide such notice or obtain such acknowledgement shall have no impact on the applicability or enforceability of this Policy.

4. <u>Other Laws</u>

This Policy is in addition to (and not in lieu of) any right of repayment, forfeiture or right of offset against any Covered Person that may be available under applicable law or otherwise (regardless of whether implemented at any time prior to or following the adoption of the Policy). Notwithstanding anything to the contrary in this Policy, in no event shall the Board seek any recoupment described in this Policy if, by doing so, the Company would be in violation of any applicable state wage or other law.

5. Amendment; Termination

The Board may amend or terminate this Policy at any time.

6. Disclosures

Appropriate disclosures and other filings with respect to this Policy will be made in accordance with Rule 10D-1 of the Securities Exchange Act of 1934, as amended, and the Company's applicable exchange listing standards.

7. Definitions

For purposes of this Policy, the following terms shall have the following meanings:

Applicable Period. "Applicable Period" means the three complete fiscal years preceding the determination a Restatement is required, as determined by the Board.

Board. "Board" means the Board of Directors of the Company.

Covered Person. "Covered Person" means any person who is or was during the Applicable Period an Executive Officer of the Company or any affiliate thereof.

Executive Officer. "Executive Officer" means the Company's president, principal financial officer, principal accounting officer (or if there is no such accounting officer, the controller), any vice-president of the Company in charge of a principal business unit, division, or function (such as sales, administration, or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the Company.

Financial Reporting Measure. "Financial Reporting Measure" means a measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements (including "non-GAAP" financial measures, such as those appearing in earnings releases or MD&A), and any measure that is derived wholly or in part from such measure. Examples of Financial Reporting Measures include measures based on: revenues, net income, operating income, financial ratios, EBITDA, liquidity measures, return measures (such as return on assets), profitability of one or more segments, sales per square foot, same store sales, revenue per user, and cost per employee. Stock price and total shareholder return are also Financial Reporting Measures.

Incentive-Based Compensation. "Incentive-Based Compensation" means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure. Incentive-Based Compensation does not include any base salaries, discretionary cash bonuses and equity awards that vest solely on the passage of time.

Policy. "Policy" means this Houston American Energy Corp. Clawback Policy.

Received. Incentive-Based Compensation is deemed "Received" in the Company's fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that period.

Recoverable Compensation. "Recoverable Compensation" means the amount of any Incentive-Based Compensation (calculated on a pre-tax basis) Received by a Covered Person during the Applicable Period that is in excess of the amount that otherwise would have been Received if the calculation were based on the Restatement.

Restatement. "Restatement" means an accounting restatement of any of the Company's financial statements filed with the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended, due to the Company's material noncompliance with any financial reporting requirement under U.S. securities laws, regardless of whether company or executive officer misconduct was the cause for such restatement. "Restatement" includes any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (commonly referred to as "Big R" restatements), or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (commonly referred to as "little r" restatements).

DISCLAIMER