NG ENERGY INTERNATIONAL CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2023

The following is management's discussion and analysis ("MD&A") of the operating and financial results of NG Energy International Corp. ("NG Energy" or the "Company"), for the nine months ended September 30, 2023, as well as information and expectations concerning NG Energy's outlook based on currently available information.

This MD&A should be read in conjunction with NG Energy's interim condensed consolidated financial statements for the nine months ended September 30, 2023, as well as the audited annual consolidated financial statements for the year ended December 31, 2022 (the "Financial Statements") prepared in accordance with International Financial Reporting Standards ("IFRS," as defined below), together with the accompanying notes.

This MD&A contains forward-looking information about our current expectations, estimates, projections, and assumptions. See the reader advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Additional information on the Company, its Financial Statements, this MD&A, and other factors that could affect NG Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.com).

All dollar values are expressed in US dollars, unless otherwise indicated, and are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standard Board ("IASB").

This MD&A is prepared as of November 21, 2023.

Non-IFRS Measures

Certain financial measures in this document may not have a standardized meaning as prescribed by IFRS, and therefore are considered non-IFRS measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.

In addition to the above, management uses the operating netback measure. Operating netback is a benchmark common in the oil and gas industry and is calculated as revenue, net of transportation expense, less royalties, less operating expenses, calculated on a per unit basis of sales volumes. Operating netback is an important measure in evaluating operational performance as it demonstrates profitability relative to current commodity prices. Operating netback as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved, Probable and Possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgement combined with geological and engineering knowledge to assess whether specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates for natural gas liquids ("NGLs") and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of the disclosed natural gas reserves does not represent the fair market value of these reserves.

Caution Regarding Use of Barrels of Oil Equivalent (BOEs)

BOEs/boes may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Definitions

Certain terms and abbreviations used in this MD&A, but not defined or described, are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") or the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and, unless the context otherwise requires, shall have the meanings herein as in NI 51-101 or the COGE Handbook.

Resources

"**Contingent resources**" are those quantities of oil or natural gas estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe.

Contingent resources may be further categorized according to their specific project maturity sub-class, which represents the maturity of the project and sets out the associated actions required to move the project towards commercial production:

- **Development Not Viable:** This is the lowest level for contingent resources and represents a discovered accumulation for which there are contingencies resulting in there being no current plans to develop or acquire additional data at the time due to limited commercial potential.
- **Development Not Clarified**: This is the second lowest level for contingent resources and is a discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. A plan for future evaluation should exist but further study or appraisal work will be ongoing to establish the actions necessary to move the project forward to commercial maturity.
- **Development On Hold**: This is the second highest level for contingent resources and represents a discovered accumulation where project activities are on hold and where justification as a commercial development may be subject to significant delay.
- **Development Pending**: This is the highest level for contingent resources and represents a discovered accumulation where development activities are ongoing to justify commercial development in the foreseeable future.

"**Prospective resources**" are those quantities of oil or natural gas estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by applying future development projects. Prospective resources have both an associated Chance of Discovery (the chance that an exploration project will result in the discovery of oil or natural gas) and a Chance of Development (the chance that an accumulation will be commercially developed).

Prospective and contingent resources are further categorized according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity:

- **Low Estimate**: This is a conservative estimate of the quantity that will be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities recovered will equal or exceed the low estimate.
- **Best Estimate**: This is the best estimate of the quantity that will be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities recovered will equal or exceed the best estimate.
- **High Estimate**: This is an optimistic estimate of the quantity that will be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities recovered will equal or exceed the high estimate.

Prospective resources are not, and should not be confused with, reserves or contingent resources. Prospective resources are those quantities of oil or natural gas estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that the Company will produce any portion of the volumes currently classified as prospective resources. Thus, for an undiscovered accumulation the Chance of Commerciality is the product of two risk components – the Chance of Discovery and the Chance of Development.

The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. Actual prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein. The accuracy of any resources estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resources presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

The resource estimates presented in this MD&A are subject to certain risks and uncertainties, including those associated with the drilling and completion of future wells, limited available geological and geophysical data and uncertainties regarding the actual production characteristics of the reservoirs, all of which have been assumed for the preparation of the resource estimates.

Reserves

Reserves are estimated remaining quantities of commercially recoverable oil, natural gas, and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status.

"**Proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves.

"**Probable reserves**" are those additional reserves that are less certain to be recovered than Proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves.

"**Possible reserves**" are those additional reserves that are less certain to be recovered than Probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible reserves. There is a 10 percent probability that the quantities recovered will equal or exceed the sum of Proved plus Probable plus Possible reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities" (which refers to the lowest level at which reserves calculations are performed) and to "reported reserves" (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities recovered will equal or exceed the estimated Proved reserves; and
- at least a 50% probability that the quantities recovered will equal or exceed the sum of estimated Proved plus Probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, most reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Each of the reserve categories (Proved and Probable) may be divided into developed and undeveloped categories as follows:

"**Developed Producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**Undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (Proved, Probable and Possible) to which they are assigned and expected to be developed within a limited time.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped subclasses or to subdivide the developed reserves for the pool between developed producing and developed nonproducing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Interests in Reserves, Production, Wells and Properties

"**Gross**" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Net**" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

Description of Exploration and Development Wells and Costs

"**Development Costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

(c) acquire, construct, and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property.

Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

Condensate

"**Condensate**", also called condensate, gas condensate, or gas liquids, is a low-density mixture of hydrocarbon liquids that are present as gaseous components in the raw gas produced from many gas fields. Some gas species within the raw gas will condensate to a liquid state if the temperature is reduced to below the hydrocarbon dew point temperature at a set pressure. Raw gas may come from any one of three types of gas wells:

(a) **Crude Oil Wells:** Raw gas that comes from crude oil wells is called "associated gas". This gas can exist separate from crude oil in the underground formation or be dissolved in the crude oil. Condensate produced from oil wells is often referred to as "lease condensate";
(b) **Dry Gas Wells:** These wells typically produce only raw gas that contains no hydrocarbon liquids. Such gas is called "non-associated gas". Condensate from dry gas is extracted at gas processing plants and is often called "plant condensate"; and
(c) **Condensate Wells:** These wells produce raw gas along with NGLs. Such gas is also called "associated gas" and is often referred to as "wet gas".

OPERATING INCOME AND NETBACK

"Operating Income" is calculated by deducting operating expense from total revenue. Total revenue is comprised of natural gas and natural gas liquids sales, net of royalties. The Company refers to Operating Income expressed per unit of production as an "Operating Netback". "Operating Income Profit Margin" is calculated by the Company as Operating Income as a percentage of natural gas sales. A reconciliation of the measures for the three and nine months ended September 30, 2023, is as follows:

	Three months ended		Nine months ended	
	2023	2022	2023	2022
Natural Gas Sales	2,430,805	-	7,325,479	-
NGL Sales	56,186	-	73,694	-
Royalties	(428,766)	-	(1,187,533)	-
Operating Expenses	(1,086,477)	-	(2,170,681)	-
Operating Income	971,748	-	4,040,959	-
Gas Sales volume (Mcf)	476,828	-	1,445,591	-
Natural Gas Sales (per Mcf)	5.10	-	5.07	-
Royalties (per Mcf)	(0.90)	-	(0.82)	-
Operating Expenses (per Mcf)	(2.28)	-	(1.50)	-
Natural Gas Operating Netback per Mcf	1.92	-	2.75	-
Natural Gas Operating Income Profit Margin	37.6%	-	54.2%	-
NGL Sales volume (Bbls)	1,229	-	1,639	-
NGL Sales (per Bbl)	45.72	-	44.96	-

CORPORATE OVERVIEW AND UPDATE

NG Energy is an oil and gas company incorporated in Canada and is engaged in the acquisition, exploration, development, and exploitation of oil and natural gas assets in Colombia. The Company's current asset portfolio consists of one appraisal and two exploration natural gas assets in Colombia. NG Energy's common shares (each a "Common Share") are listed on the TSX Venture Exchange ("TSXV") under the symbol "GASX".

Commercialization of SN-9 Gas Production

In September 2023, the Company announced, together with its partners Clean Energy Resources S.A.S., a Colombian corporation ("Clean"), and Desarrolladora Oleum, that agreements have been reached with new local midstream partners to accelerate commercial production from the SN-9 Block. Pursuant to the terms of the agreements, 30 MMcf/d of natural gas will be brought online in Q1 2024, with an additional 10 MMcf/d of production brought online in Q3 2024, for total initial production volumes of 40 MMcf/d. The strategy to partner with midstream construction experts provides the Company with the opportunity for early monetization with minimal capital expenditures and significantly reduced construction risk, while maintaining pricing upside.

Drilling of the Aruchara-3 Well

In Q3 2023, the Company drilled the Aruchara-3 well from the same pad as the Aruchara-1 well to a total depth of 9,050 feet. The Company encountered 570 feet of net gas pay in the Jimol formation between 6,000 and 7,500 feet after experiencing gas showings throughout the 1,500 feet. The Company completed the testing of the well with 3 successful Drill Stem Tests ("DSTs"), with resulting peak gas productions rate of: 16.7 MMcf/d from DST-1; 23.5 MMcf/d from DST-2; and 25 MMcf/d from DST-3. The Company concluded that more than 1,200 feet of naturally fractured section is present, which includes the presence of gas and condensate. Aruchara-3 has now been completed and tied into production facilities, with an estimated initial production rate of 15 MMcf/d between the Aruchara-1 and Aruchara-3 well and anticipated increases to 20 MMcf/d thereafter.

Joint Operating Agreement / VMM39 Block Option

In August 2023, the Company announced the signing of a joint operating agreement with Clean which formalizes the Company's 72% working interest in the SN-9 Block. Furthermore, the Company agreed to an option to acquire a 25% working interest in the VMM39 Block, which is located in the Middle Magdalena Basin. The VMM39 Block presents potential resources for light oil with associated gas, and is located 60 km from the largest oil refinery in the country. The Company will participate in the San Diego-1X exploration well and have an option to acquire the working interest in the VMM39 Block after said project is complete, along with additional option to increase its working interest in the block after the first well is complete.

2023 Non-Brokered Private Placement

In July 2023, the Company closed a non-brokered private placement offering ("the Offering") of senior secured debenture units of the Company at a price of C$1,000 per debenture unit for total aggregate gross proceeds C$35,000,000. Each debenture unit will consist of one 10% convertible senior secured debenture with a principal amount of C$1,000 and 1,000 common share purchase warrants of the Company. Each warrant will entitle the holder thereof to purchase one common share at an exercise price equal to C$0.90 for a period of three years from the closing date of the Offering.

The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares prior to the earlier of (i) the close of business on July 31, 2026; and (ii) the business day immediately preceding the date specified by the Company for redemption of the convertible debentures upon a change of control at a conversion price equal to C$0.70 per share. In connection with the Offering, the Company paid a finder's fee of C$200,500 to certain finders.

Of the C$35,000,000 in proceeds from the Offering, C$11,000,000 had been received in prior months of 2023 in the form of simple agreements for future equity ("SAFE") advances carrying an interest rate of 10% until the time of the completion of the Offering.

Changes to the Board of Directors

In August 2023, the Company announced changes to the board of directors with Mr. Brian Paes-Braga joining the Board as the Company's Non-Executive Chairman and Mr. Don Sewell and Mr. Brian O'Neill joining the Board as directors. Mr. Gordon Keep and Mr. Jeffrey Harder retired from the Board.

Cease Trade Order

On May 10, 2023, NG Energy was issued a cease trade order by the British Columbia Securities Commission, due to the delay in filing its audited financial statements and corresponding management discussion and analysis for the year ended December 31, 2022; these materials were subsequently filed and the cease trade order was lifted on July 10, 2023.

Drilling of the Brujo-1 Well

In October 2022, the Company announced the successful drilling of the Brujo-1X well, at a final total depth of 8,019 feet (7,200 feet true vertical depth) in the Lower Magdalena Basin, located within the SN-9 Block, encountering 680 feet of net gas bearing zone in the Cienega de Oro ("CDO") formation and 103 feet in the Porquero formation, for a total of 783 feet of net gas pay. Subsequently, in November 2022, the Company announced the completion of testing of the well with 3 successful DSTs in the intermediate and upper section of the CDO formation. A total of 276.5 feet (out of a total of 389 feet of thickness in this formation) were perforated with resulting gas production rate of: 11.2 MMcf/d from DST-2; 18.2 MMcf/d from DST-3; and 21.2 MMcf/d from DST-4. Based on the successful tests in the CDO formation, the Company has decided to analyze the best way to complete the well and test the remaining prospective zones, including 103 feet of thickness in the Porquero formation, to achieve the maximum possible production from the three zones.

Commencement of Gas Production from Aruchara-1 Well

In August 2022, the Company announced the initiation of gas production from the area of the Maria Conchita Block where the Aruchara-1 and the Istanbul-1 wells are connected ("Istanbul Platform"). With the completion of the connection point to the Colombian National Gas Transportation System ("SNTE") through the gas trunk line of Transportadora de Gas Internacional ("TGI"), delivery of early-stage gas production commenced in late September while the surface plant continued the stabilization process of current gas flow that was injected into the SNTE from the Aruchara-1 well. Refer to the Discussion of Operating results below for more details.

Magico-1 Well Gas Discovery

In July 2022, the Company announced the discovery of significant gas within the CDO sandstone formation from the newly drilled Magico-1 well located in the SN-9 Block. Upon reaching target depth, the Company conducted two successful DSTs and a comingled test within three prospective zones in the Magico-1 well, realizing over 15 MMcf/d of dry gas with no water from the sandstone formation between 3,572 feet and 3,754 feet measured depth ("MD") with a combined net pay of 76 feet. Other identified prospective zones will be tested in the future.

2022 Non-Brokered Private Placement

In November 2022, the Company closed a non-brokered private placement ("November 2022 Offering") of 35,000 convertible debenture units of the Company at a price of C$1,000 per convertible debenture unit for total gross proceeds of C$35,000,000. Each convertible debenture unit consisted of one 10.0% senior secured convertible debenture of the Company in the principal amount of C$1,000 and 1,000 Common Share purchase warrants of the Company. Each warrant entitles the holder thereof to purchase one Common Share at an exercise price of C$1.08 until November 30, 2025.

The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares at a price equal to C$0.90 per Common Share.

2022 Prospectus Offering of Convertible Debentures

In May 2022, the Company closed a best-efforts, fully marketed prospectus offering ("May 2022 Offering") of 17,147 convertible debenture units of the Company at a price of C$1,000 per convertible debenture unit for total gross proceeds of C$17,147,000. Each convertible debenture unit consisted of one 8.0% unsecured convertible debenture of the Company in the principal amount of C$1,000 and 400 Common Share purchase warrants of the Company. Each warrant entitles the holder thereof to purchase one Common Share at an exercise price equal to C$1.40 until May 20, 2027.

The convertible debentures bear interest at a rate of 8.0% per annum from the date of issue, payable monthly in arrears on the last day of each month. The convertible debentures will mature on May 20, 2027. An amount equal to the interest payable under the convertible debentures from May 20, 2022, until May 20, 2023, was placed in escrow upon closing of the May 2022 Offering and shall be paid out to holders of the convertible debentures monthly. Interest thereafter shall be paid out of the Company's cash flow.

The principal amount of each convertible debenture is convertible, for no additional consideration, at the option of the holder in whole or in part at any time into Common Shares prior to the earlier of: (i) the close of business on May 20, 2027, and (ii) the business day immediately preceding the date specified by the Company for redemption of the convertible debentures upon a change of control, at a conversion price equal to C$1.20 per Common Share, subject to adjustment in certain events.

In connection with the offering, the underwriters received cash commissions of C$662,585 on gross proceeds raised.

The Company is entitled, at its sole option at any time after the second anniversary of the closing date of the offering to accelerate the expiry date of all of the outstanding warrants on not less than 30 days nor more than 60 days' notice, if the volume weighted average trading price of the Common Shares on the TSXV is greater than C$2.00 for the ten consecutive trading days preceding the notice. The convertible debentures and warrants were listed on the TSXV under the symbols "GASX.DB" and "GASX.WT.A," respectively, and began trading on June 2, 2022.

SN-9 Loan Conversion to Royalty

In August 2022, debt holders of the SN-9 loan exercised the conversion option to convert the loan principal and cumulative interest payable to the additional 3.0% overriding royalty on NG Energy's working interest in the gross production of the SN-9 Block. Due to the conversion, the Company no longer has an outstanding balance owed to the SN-9 debt holders.

Strategic Alliance with COX Energy America S.A.B. de C.V.

In December 2022, the Company announced that it had entered a strategic alliance with COX Energy America S.A.B. de C.V. ("COX Energy"), a regional Latin America developer, operator, and producer of renewable energy with more than 2,400-megawatt peak of solar energy products in its portfolio. With this strategic alliance, the Company and COX Energy will explore opportunities to develop, build and own solar power plants in Colombia. The Company, in collaboration with COX Energy, is expected to launch a new renewable energy division to decarbonize and minimize the environmental impact of its operations and contribute to Colombia's emission reduction commitment.

COLOMBIAN OIL AND NATURAL GAS PROPERTIES

The Company is engaged in the acquisition, exploration, development and exploitation of oil and natural gas assets in Colombia. The Company's current asset portfolio consists of one appraisal and two exploration natural gas assets in Colombia. NG Energy has working interests in the Maria Conchita Block, the SN-9 Block and the Tiburon Block.

The Company has a Colombian-based management team with significant in-country experience, strong technical experience within the Colombian basin, and strong capital markets expertise having led large public resource companies in the past.

Maria Conchita Block

The Maria Conchita Block is in the Department of La Guajira, Colombia, and neighbors the Chuchupa Block to its north, which is one of Colombia's largest gas fields with an initial 103 GBtu in place and accounts for approximately 10% of Colombia's daily natural gas output. The Chuchupa Block has been under production for over 35 years, operated by Chevron Corp. in association with Ecopetrol, S.A. Production from the Chuchupa Block has been decreasing over the last several years, creating a need for new natural gas discoveries to replace it. The Maria Conchita Block is near both of Colombia's gas trunk lines, TGI and Promigas.

The Exploration & Production ("E&P") contract for the Maria Conchita Block (the "Maria Conchita E&P Contract") is a 2009 contract between the Agencia Nacional de Hidrocarburos ("ANH") of Colombia and MKMS Enerji Sucursal Colombia ("MKMS"), a Colombian branch of MKMS Enerji AS (BVI), a wholly owned subsidiary of NG Energy, for the exploration and production of conventional hydrocarbons in the Maria Conchita area. The Company maintains an 80% working interest in the Maria Conchita Block with 20% being held by private joint operation partners. MKMS is the operator of the Maria Conchita Block. The Maria Conchita E&P Contract had an initial exploration term consisting of 6 one-year exploration phases, which are followed by a 24-year production period from the date when commerciality is declared. Phase 1 was completed with the acquisition, processing, and interpretation of 120 km^2 of 3D seismic. The Phase 2 commitment was fulfilled with the drilling of the Istanbul-1 well (see below). In late 2018, NG Energy notified the ANH of its intention not to proceed to Phase 3 of the exploration program and to relinquish the areas of the Maria Conchita Block not covered by the ongoing evaluation program. The Maria Conchita Block originally covered an area of approximately 60,076 acres. Subsequent to the relinquishment, the Company maintains 32,518 acres under the evaluation program.

Over the course of the year ended December 31, 2022, the Company put in place the necessary surface infrastructure required to commence gas production. In March 2022, the Company received an amended environmental license from the National Authority of Environmental Licenses ("ANLA"), which expires at the time the Company enters the commercialization phase at the Aruchara-1 well. This amended license was crucial for the Company, as it permitted production from the Aruchara-1 well and allowed the Company to lay the remaining 40 meters of flow line, which connected the Istanbul Platform to GTX International Corp.'s ("GTX") gas plant located within the Maria Conchita Block. Additionally, it allowed the Company to complete the connection point to the SNTE, which was completed in August 2022, through TGI, and was necessary to transport gas from the Maria Conchita Block to market. Furthermore, in August 2022, the Company entered into a Build-Own-Operate-Maintain-Transfer agreement ("BOOMT Agreement") with GTX. Pursuant to the BOOMT Agreement, GTX operates the Pipeline Facilities, which have a capacity of 20 MMcf/d. The Guaranteed Commitment (as herein defined) under the BOOMT Agreement expires after six years and ownership of the Pipeline Facilities will transfer to the Company following the expiry of the ten-year term of the BOOMT Agreement (for more information concerning the BOOMT Agreement see Contractual Commitments – Gas Transportation Services). Lastly, in December 2022, Surenergy SAS ESP ("Surenergy") completed the delivery of the third gas compressor, thereby allowing Surenergy to provide daily gas compression services to the Company.

On September 24, 2022, the Company initiated gas delivery from the Istanbul Platform, which allowed the Company to begin monetizing its gas delivery agreements. During the initial period, the quantity of gas flow from the Aruchara-1 well was initially 3.5 MMcf/d, so as to not stress the future performance of the well and to allow the Company to maximize its long-term operations. By the end of 2022, the quantity of gas flow had increased to 5.2 MMcf/d. For the year-to-date 2023 period, gas flow has averaged 6.85 MMcf/d.

With the commencement of gas delivery from the Maria Conchita Block, the Company has sought new partners to increase revenue generation. In October 2022, the Company entered a binding letter of intent ("Binding LOI") with Plus+ SAS for the purchase and sale of natural gas produced from the Aruchara-1 well and subsequent future wells located within the Maria Conchita Block. The Binding LOI is for the acquisition of up to 8,000 MMbtu per day on a firm volume purchase agreement, or the equivalent volume corresponding to the Company's 80% working interest in the Maria Conchita Block's production. The Binding LOI has a term of three years, with gas delivery expected between November 2023 and February

2026, with a set price of $6.50 per MMbtu (or Mcf/d). A gas delivery contract will be entered into once the Company is able to steadily fulfill the obligations of a full contract.

On February 27, 2023, the Company, entered into a gas supply contract ("Natural Gas Contract") with Plus+ SAS, whereby MKMS has agreed to deliver gas up to 3,600 MMbtu per day from the Aruchara-1 well to Plus+ SAS, and Plus+ SAS has agreed to receive, pay and allocate such gas in accordance with the terms of the Natural Gas Contract. The Natural Gas Contract has a term of eighteen (18) months, during which time the gas price is set at $5.08 per MMbtu, less a fee of $0.25 per MMbtu ("Gas Price"). In the event Plus+ SAS sells the gas above $5.08; the Gas Price will increase by the value corresponding to 50% of the difference between the final price at which Plus+ SAS has sold the gas and the Gas Price. In April 2023, the Company entered into another contract with Gases del Caribe to sell additional Maria Conchita gas production until November 30, 2023. Condensate liquids that are derived from gas production at Maria Conchita is being sold separately from natural gas sales as produced.

Reserves Analysis

In June 2023, the Company filed its Form 51-101F1 - *Statement of Reserves Data and Other Oil and Gas Information*, for the fiscal year ended December 31, 2022, which was prepared with Sproule International Limited in accordance with the COGE Handbook and has an effective date of December 31, 2022, ("2022 51-101F1"). The reserves and resources attributed to the H1A, H1A1, H1B, H2, H2B and LM2 zones have been included in the 2022 51-101F1. The Company reported Company gross Proved plus Probable plus Possible reserves of 7.8 MMboe (46.9 Bcf (58.5 Bcf project gross) of gas and 73 Mbbl of condensate) for a before-tax NPV10 of $50.1 million. This represents a 71% year-over-year increase in Proved plus Probable plus Possible reserves, which can be broken down as follows:

- Company gross Proved reserves of 3.6 MMboe (21.5 Bcf of gas and 47 Mbbl of condensate), which represents a 74% year-over-year increase in Proved reserves;
- Company gross Probable reserves of 2.9 MMboe (17.5 Bcf of gas and 15 Mbbl of condensate), which represents a 16% year-over-year increase in Probable reserves; and
- Company gross initial Possible reserves of 1.3 MMboe (7.9 Bcf and 11 Mbbl of condensate).

It is important to note that Possible reserves are those additional reserves that are less certain to be recovered than Probable reserves. There is a 10% probability that the quantities recovered will equal or exceed the sum of Proved plus Probable plus Possible reserves.

Resources Analysis

In the 2022 51-101F1, the Company further reported Company gross unrisked best estimate contingent resources (development pending) of 11.1 MMboe (65.8 Bcf (82.2 Bcf project gross) and 136 Mbbl of condensate) for before-tax NPV_{10} of $49.7 million. The Company's contingent resources in the Maria Conchita Block are petroleum and gas classified as "development pending" and are attributed a chance of development risk factor of 0.73. However, the Company believes the unrisked best estimate contingent resources provides the most appropriate indication of volumes that will become Proved plus Probable reserves.

It is important to note that there is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Current Objectives

The Company's primary focus on the Maria Conchita Block is the monetization of gas production and capitalizing on a premium pricing market in Colombia. In Q3 2023, the Company drilled the Aruchara-3 well from the same pad as the Aruchara-1 well to a total depth of 9,050 feet. The Company encountered 570 feet of net gas pay in the Jimol formation between 6,000 and 7,500 feet after experiencing gas showings throughout the 1,500 feet. The Company completed the testing of the well with 3 successful DSTs, with resulting gas production rate of: 16.7 MMcf/d from DST-1; 23.5 MMcf/d from DST-2; and 25 MMcf/d from DST-3. The Company concluded that more than 1,200 feet of naturally fractured section is present, which includes the presence of gas and condensate. Aruchara-3 has now been completed and tied into production facilities, with an estimated initial production rate of 15 MMcf/d between the Aruchara-1 and Aruchara-3 well and anticipated increases to 20 MMcf/d thereafter that will utilize the full capacity of the existing facilities and pipeline.

SN-9 Block

The SN-9 Block is in the Lower Magdalena Valley, 75 km from Colombia's Caribbean coast. The SN-9 Block, which covers an area of approximately 311,353 acres in the Department of Córdoba, Colombia, has a 6-year exploration period, divided in two phases of three years each, followed with a 24-year production period from the date when commerciality is declared. The SN-9 Block is adjacent to blocks held by Canacol Energy Ltd and Hocol S.A. The area has excellent infrastructure with good roads and access to the northern gas trunk line. In previous years, the Hechizo well was drilled on the block by Ecopetrol, S.A. in 1992 and tested gas in the CDO formation at a depth of approximately 4,250 feet. The SN-9 Block has 730 km of 2D seismic.

The E&P contract for the SN-9 Block (the "SN-9 E&P Contract"), dated October 2014, was entered into between the ANH and Clean Energy Resources S.A.S., a Colombian corporation ("Clean"). The SN-9 E&P Contract is currently in the first phase of the exploration program which includes a minimum work obligation of drilling two exploration wells. The current deadline of January 2023 was approved by the ANH after an extension request was made by Clean Energy. Subsequently, Clean has requested a further extension of Phase 1, which is still under consideration by the ANH. The Company's working interest is 72%.

In September 2021, the Company received the necessary environmental license from the ANLA required to commence exploratory drilling in the SN-9 Block, including the construction of civil works, production infrastructure and the construction of up to eleven locations for a total of twenty-two wells to be developed. The ANLA license shall expire at the time that the Company enters the commercialization phase at the Mágico-1 or Brujo-1 well.

During the fiscal year ended December 31, 2022, the Company and its contractors completed the drilling of two wells in the SN-9 Block: the Magico-1X well, which was completed in July 2022, and the Brujo-1X well, which was completed in November 2022. Significant gas was encountered in both the Magico-1X well and the Brujo-1X well and further testing was undertaken throughout the course of the year. The results of such testing are outlined and discussed below under "Exploration Activities".

In September 2023, the Company announced, together with its partners Clean and Desarrolladora Oleum, that agreements have been reached with new local midstream partners to accelerate commercial production from the SN-9 Block. Pursuant to the terms of the agreements, 30 MMcf/d of natural gas will be brought online in Q1 2024, with an additional 10 MMcf/d of production brought online in Q3 2024, for total initial production volumes of 40 MMcf/d. The strategy to partner with midstream construction experts provides the Company with the opportunity for early monetization with minimal capital expenditures and significantly reduced construction risk, while maintaining pricing upside.

Resources Analysis

In June 2023, the Company filed the 2022 51-101F1. Resources attributed to the Hechizo, Brujo, Magico, Mago, Hechicero, Encanto, Milagroso, Porquero, Embrujo, Ensalmo and Sortilegio zones have been included in the 2022 51-101F1. The Company reported Company gross unrisked best estimate contingent resources (development pending) of 249.5 Bcf for a before-tax NPV10 of $294.4 million. The Company's contingent resources in the SN-9 Block are petroleum and gas classified as "development pending" and are attributed to a chance of development risk of 80%. However, the Company believes the unrisked best estimate contingent resources provides the most appropriate indication of volumes that will become Proved plus Probable reserves.

It is important to note that there is no certainty that it will be commercially viable to produce any portion of the contingent resources until further development of the SN-9 Block has occurred.

Current Objectives

The development of the SN-9 Block is a major focus for the Company in 2023. The Company's objectives for the SN-9 for the fiscal year ended December 31, 2023, are as follows:

- secure a large-scale pipeline partner for the construction of infrastructure within the SN-9 Block;
- secure a long-term production agreement for gas and oil produced within the SN-9 Block;
- evaluate options and commence early production from successfully completed wells within the SN-9 Block; and
- secure permits to evaluate oil prospects located in the western region of the SN-9 Block.

Exploration Activities

In May 2022, the Company completed the construction of the pad at the Magico-1X well and commenced drilling. The well was drilled to a true vertical depth of 3,918 feet in three phases using a 1,500-horsepower hydraulic rig. The Company identified three intervals to be tested, with the CDO sandstone reservoir being the primary objective. The Company encountered gas within the well in the lower first structure, which measured 50 feet in the CDO sandstone reservoir. The Company further identified several prospective gas bearing zones through well logs at a depth of between 3,200 – 3,350 feet for a total gross pay of 150 feet and net pay of 100 feet. As a result, in July 2022, the Company conducted two successful DST procedures and one comingled test, with the well completed, within the three prospective zones. The first DST procedure occurred at a measured depth of between 3,694 – 3,724 feet and produced 4.0983 MMcf of gas with no water. The specific gravity of the gas from this test was 0.5579. The second DST procedure occurred at a measured depth of between 3,572 – 3,582 feet and 3,632 – 3,640 feet and produced 5.0997 MMcf of gas and no water. The specific gravity of the gas from this test was 0.5576. The comingled test occurred at a measured depth of between 3,572 – 3,582 feet, 3,632 – 3,640 feet and 3,694 – 3,724 feet and produced 4.0347 MMcf of gas and no water. The specific gravity of the gas from this test was 0.5576.

The total amount of gas produced from these three tests was 13.2326 MMcf with no water. The Magico-1X well tested over 15 MMcf/d of dry gas with no water on a comingled production completion from the three prospective zones located within the CDO sandstone reservoir between 3,572 – 3,724 feet with a combined net pay of 76 feet. It is important to note that, based on the seismic survey, the Magico area has deeper zones to be drilled and tested. It is also important to note that the above data should be considered preliminary until pressure transient analysis or well-test interpretation has been conducted. Therefore, the above test results are not necessarily indicative of long-term performance or of ultimate recovery.

In November 2022, the Company completed drilling at the Brujo-1X well to a true vertical depth of 7,200 ft in three phases using a 1,500-horsepower hydraulic rig. The Company had identified several intervals of interest using geological and geophysical evidence, with the CDO sandstone reservoir as the primary target. The Company encountered 680 ft of net gas bearing zones in the CDO sandstone reservoir and 103 feet in the Porquero formation, for a total of 783 feet of net gas pay. As a result, in November 2022, the Company conducted 4 DST procedures, with 3 successful DST procedures in the intermediate and upper section of the CDO formation. The first DST procedure occurred between a measured depth of 6,127 – 6,789 feet, however this test was unsuccessful. The second DST procedure occurred between a measure depth of 5,055 – 5,365 feet and produced 3.1306 MMcf of gas and no water over a period of 11.3 hours. The specific gravity of the gas from this test was 0.56044. The third DST procedure occurred between a measured depth of 4,563.5 – 4,910 feet and produced 6.2279 MMcf of gas with no water over a period of 15.1 hours. The specific gravity of the gas from this test was 0.56044. The fourth DST procedure occurred between a measured depth of 4,086 – 4,530 feet and produced 5.442 MMcf of gas with no water over a period of 13.6 hours. The gas-bearing thickness in the CDO formation was perforated for these tests with gas production rates of 11.2 MMcf/d from the second DST procedure, 18.2 MMcf/d from the third DST procedure and 21.2 MMcf/d from the fourth DST procedure. It is important to note that the above data should be considered preliminary until pressure transient analysis or well-test interpretation has been conducted. Therefore, the above test results are not necessarily indicative of long-term performance or of ultimate recovery.

Existing Agreements

The terms of the original agreement between the Company and Clean regarding the Company's acquisition from Clean of an economic beneficial interest in the SN-9 Block are as follows:

- The Company's participation interest is 72%. Clean's participation in the SN-9 Block will be 13%, and will comprise two components:
  - First component - carried working interest of 8%
  - Second component - Clean will acquire an additional 5% by one of two options:
    - Option 1 - payment of $1.2 million to the Company if Clean chooses to only participate in the first phase of the exploration program.
    - Option 2 - payment of $2.9 million to the Company if Clean chooses to participate in both phases of the exploration program.

Payment to the Company for either option will be received through the sale of 62.5% of Clean's production on the SN-9 Block corresponding to this 5% interest. Furthermore, the Common Share of Net Profit Interest and Overriding Royalties (as defined in the SN-9 purchase and sale agreement) related to this additional 5% working interest will be the obligation of Clean and not carried by the Company.

In November 2023, Clean filed the application to the ANH for the official transfer of 51% participation interest in the SN-9 E&P Contract to MKMS. Upon completion of the Phase 2 commitments of the SN-9 E&P Contract, Clean will formally transfer of the remaining 21% participation interest to MKMS.

Tiburon Block

The Tiburon Block currently covers an area of approximately 245,850 acres in the Department of La Guajira, Colombia. The E&P Contract for the Tiburon Block (the "Tiburon E&P Contract") is a contract for the exploration and production of conventional hydrocarbons, dated June 2006 and entered between the ANH and Omimex de Colombia Ltd., which later changed its name to ColPan Oil & Gas Ltda. ("ColPan").

The Tiburon E&P Contract initially provided for an exploration period divided into six phases of twelve months each. The Tiburon E&P contract is currently in Phase 3 of the exploration period with an existing minimum work obligation to acquire, process, and interpret 69.75 km^2 of 3D seismic. The Phase 3 commitment is currently suspended due to "Force Majeure and Third-Party Acts" due to local community issues within the region outside the control of the Company.

Exploration Activities

In light of the force majeure situation, the Company has carried out technical studies of the area in order to present for the consideration of the ANH a request to change the identified area within the Tiburon Block where the current minimum work obligation of 3D seismic is to be completed, and alternatively, complete the acquisition, processing and interpretation of 112 km of 2D seismic in the Bahia Honda area within the Tiburon Block, which is equivalent to the current Phase 3 commitment of the Tiburon E&P Contract of 69.75 km^2 of 3D seismic.

On September 16, 2016, the Tiburon E&P Contract was suspended due to the pre-existing community issues that are impeding any progress in the area. The Company will comply with the Phase 3 commitments of the Tiburon E&P Contract once the community conflicts existing in the area have been resolved. The timing of any conflict resolution is unknown at this time.

Meanwhile, the Company is developing environmental and social analyses to execute seismic activities and work with Colombia’s Ministry of Interior to find resolutions to the community conflicts.

Existing Agreements

The terms of the original agreement between the Company and ColPan outlining the Company's acquisition from ColPan of an economic beneficial interest in the Tiburon Block are based on the execution of the following work program:

- Ten percent working interest upon the completion of the Phase 3 3D seismic commitment.
- An additional 15% working interest upon the drilling and testing of one exploration well.
- A further 15% working interest upon the drilling and testing of a second exploration well.

After completing the seismic commitment, NG Energy is not obligated to drill any of the exploration wells and can exit the contract with no further commitments but will lose the original $300,000 performance guarantee currently held on deposit with the ANH. Alternatively, NG Energy may elect to stay in the license with a 10% working interest. $120,000 of management fees paid by the Company will be returned to NG Energy if the Company is still participating in the block when the ANH performance guarantee is returned at the end of the Phase 3 commitment. If NG Energy does not fulfill the Phase 3 commitment, except for reasons beyond its control, NG Energy will cede a 1.5% carried working interest in the SN-9 Block to ColPan and forfeit the aforementioned $120,000 payment.

OUTLOOK

The Company's primary focus in the short-term is the monetization of its natural gas resources and capitalizing on a premium pricing market in Colombia. The connection of the Aruchara-1 well to the SNTE has turned the Company into a revenue producing entity. With the tie-in of the Aruchara-3 well in Q4 2023, the Company expects to be able to realize potential production levels of up to 20 MMcf/d with the Company's current pipeline facilities capacity. Given the current shortage of gas in Colombia and the high probability of an El Niño phenomenon coming in the next months, the Company has a reasonable expectation that any gas that it produces will be purchased. The commencement of this revenue stream will assist the Company with improving its working capital position and service debt payments for interest payable on its convertible debentures.

The Company's consistent joint efforts with joint venture partners to accelerate the commercial production from the SN-9 Block provide favorable outlook for continued growth of natural gas revenue. As mentioned, pursuant to new agreements with midstream partners, 30 MMcf/d of natural gas will be brought online in Q1 2024, with an additional 10 MMcf/d of production brought online in Q3 2024, for total initial production volumes of 40 MMcf/d. This direction provides opportunity for early monetization with minimal capital expenditures and significantly reduced construction risk, while maintaining pricing upside.

The Company continues to move forward with its planned exploration and development program in the Maria Conchita Block and SN-9 Block, as discussed above. The Company believes the SN-9 Block could be an important new source of natural gas in Colombia. Through a phased approach, NG Energy expects to increase reserves and provide a stable supply of natural gas in Colombia. The evaluation program is underway in the Maria Conchita Block to define total resources and determine the most appropriate development plan for the Uitpa and Jimol formations.

The Company continues to pursue asset prioritization strategies, additional and alternative production and exploration opportunities, and the development of its reserves. The Company may choose to delay development, depending on several circumstances including the existence of higher priority expenditures, prevailing commodity prices and the availability of funds.

DISCUSSION OF OPERATING RESULTS

Sales Revenue

	YTD 2023	YTD 2022	Q3 2023	Q2 2023	Q1 2023
Natural gas sales	7,325,479	-	2,430,805	2,797,821	2,096,853
Natural gas volume (Mcf/d)	5,295.2	-	5,182.9	5,673.5	4,513.2
Natural gas realized price ($/Mcf)	5.07	-	5.10	5.12	5.16
NGL sales	73,694	-	56,186	17,508	-
NGL volume (Bbls)	1,639	-	1,229	410	-
NGL realized price ($/Bbl)	44.96	-	45.72	42.70	-

For the three and nine months ended September 30, 2023, the Company averaged 5,182.9 Mcf/d and 5,295.2 Mcf/d respectively, which resulted in gross natural gas sales for the three and nine months ended of $2,430,805 and $7,325,479, respectively. The realized sales price for natural gas per Mcf for the three and nine months ended was $5.10 and $5.07, respectively. In Q2 2023, the Company began selling Natural gas liquids having now sold 1,639 Bbls of NGL volumes resulting in gross NGL revenue of $73,694 and a realized sales price of $44.96/Bbl. The presented results are due to the commencement of production from the Maria Conchita block in Q4 2022.

Royalties

	YTD 2023	YTD 2022	Q3 2023	Q2 2023	Q1 2023
Total royalties	1,187,533	-	428,766	365,425	393,342
Total royalties (% of sales)	16.21%	-	17.64%	12.96%	18.76%
Total royalties ($/Mcf)	0.82	-	0.90	0.71	0.97

Royalties as a percentage of total natural gas sales are highly sensitive to commodity prices. Thus, royalty rates can fluctuate from quarter-to-quarter and year-to-year. Royalties as a percentage of revenues for the three and nine months ended September 30, 2023, were 17.64% and 16.21%, respectively. The royalties paid in the three and nine months ended September 30, 2023, consisted of royalties paid to the Colombia government in the amount of $161,431 and $448,260, gross overriding royalties to partners of $119,481 and $338,712, and royalties paid in conjunction with the settlement of the Aruchara loan in the amount of $147,744 and $439,621.

Operating Expenses

	YTD 2023	YTD 2022	Q3 2023	Q2 2023	Q1 2023
Total operating expenses	2,170,681	-	1,086,477	517,599	566,605
Total operating expenses ($/Mcf)	1.50	-	2.28	1.00	1.39

Operating costs for three and nine months ended September 30, 2023, were $1,086,477 and $2,170,681 respectively and include commercialization fees, lifting costs, gas compression services and other municipal taxes that are incurred to operate the well, gather and treat production volumes and to perform well and facility repairs and maintenance. The presented results are due to the commencement of production from the Maria Conchita block in Q4 2022.

General and Administrative Expenses

General and administrative ("G&A") expenses for the three and nine months ended September 30, 2023, totaled $1,608,804 and $4,464,501 respectively (2022 comparative period - $806,611 and $2,722,357). The G&A expenses relate to the normal course of the Company's operations, and are constituted as follows:

	YTD 2023	YTD 2022	Q3 2023	Q2 2023	Q1 2023
Wages & Salaries	1,578,690	614,846	554,325	537,758	486,607
Professional Fees	2,255,977	815,589	804,869	739,598	711,510
Other	629,833	1,291,922	249,609	182,612	176,089
Total	**4,464,500**	**2,722,357**	**1,608,803**	**1,459,968**	**1,374,206**

Professional fees are composed of legal, audit, tax, and other fees that have been incurred by the Company for operations. Wages and salaries are amounts paid to employees of the Company. Other expenses comprise the normal operations of the Company and include office rent, public relations, insurance, travel, and other general and administrative expenses.

Share-Based Payments

During the nine months ended September 30, 2023, the Company issued 2,850,000 stock options. The value of the stock options vesting in the nine months ended September 30, 2023, equated to $2,716 (2022 comparative periods - $1,860,743).

Restricted share units ("RSUs"), deferred share units ("DSUs") and performance share units ("PSU's") were issued during the nine months ended September 30, 2023. The value of vesting of these compensation units for the nine months ended September 30, 2023 was $18,924 (2022 comparative periods - $nil).

Finance Income and Expense

The Company's finance-related income and expenses for each of the reporting periods are as follows:

	YTD 2023	YTD 2022	Q3 2023	Q2 2023	Q1 2023
Interest income	(502,479)	(168,657)	(220,351)	(143,828)	(138,300)
Interest expenses and bank charges	3,481,592	695,359	1,516,751	1,014,089	950,752
Accretion on decommissioning obligation	71,973	13,358	24,057	24,071	23,845
Accretion on liability component of convertible debentures	1,331,390	197,140	558,089	395,891	377,410
Interest expense on lease liabilities	2,877,603	62,734	936,960	967,498	973,145
Amortization of transaction costs on loans	-	20,205	-	-	-
Total net finance expense	**7,260,079**	**820,139**	**2,815,506**	**2,257,721**	**2,186,852**

Foreign Exchange

The Company incurred a foreign exchange gain of $24,669 and $277,926 for the three and nine months ended September 30, 2023, respectively (2022 comparative period losses of $875,142 and $1,470,060, respectively). Foreign exchange gains are due to the increase in the value of the Canadian dollar and the

Colombian peso when compared to the US dollar in the period. Conversely, foreign exchange losses are due to a decrease in the value of these other currencies in comparison to the US dollar.

Cash used in Operating Activities

For the nine months ended September 30, 2023, the Company used cash in operating activities of $2,331,464 (2022 comparative period - $3,932,005). The cash used in operations is primarily comprised of G&A expenses and business development expenses incurred during the period.

CAPITAL ADDITIONS

For the nine months ended September 30, 2023, the Company had additions (prior to recognition of any impairments, disposals, or revisions of estimates) of $5.9 million relating to exploration and evaluation assets, and $8.9 million related to oil and gas assets. Additions to exploration and evaluation assets relate primarily to the acquisition of the option to acquire a 25% working interest in the VMM39 Block as well as the ongoing SN-9 drilling and testing program, community relations and environmental license compliance work. Additions to oil and gas assets relate to the drilling of the Aruchara 3 well in the Maria Conchita block and civil works provided to prepare the site for drilling. During the year ended December 31, 2022, the Company asserted commercial viability related to the Maria Conchita Block and accordingly, all additions to oil and gas assets relate to development costs associated with the Maria Conchita Block.

LIQUIDITY AND CAPITAL RESOURCES AND GOING CONCERN

The Company's capital management objective is to have sufficient capital to be able to execute its business plan. The Company manages its capital structure and adjusts it in the light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The continued development of the Company's oil and natural gas assets is dependent on the ability of the Company to secure sufficient funds through operations, credit facilities and other sources. Such funds may not be available on acceptable terms or at all.

During the three and nine months ended September 30, 2023, the Company recognized a net loss of $4.9 million and $11.6 million, respectively, and cash used in operating activities of $1.1 million and $2.3 million, respectively. As of September 30, 2023, the Company had working capital of $6.9 million, including cash and cash equivalents of $12.0 million. For 2023, the Company has contractually committed exploration and development amounts of $3.0 million and $6.6 million for lease obligations. Although in 2022, the Company commenced early-stage gas production on the Maria Conchita Block, current gas flow is only stabilizing, and production volumes are still below expectations such that the Company is anticipating that cash will continue to be used in operations. As such, the Company will need to obtain capital to fund the Company's ongoing operations, commitments, and the ultimate continued development of the Company's exploration and evaluation assets.

As such, there remains a material uncertainty surrounding the Company's ability to obtain sufficient capital to meet its operational requirements and commitments. These conditions noted above indicate a material uncertainty exists that may cast significant doubt with respect to the Company's ability to continue as a going concern.

Management believes that the going concern assumption is appropriate for the Financial Statements and that the Company will be able to meet its operational requirements and commitments during the upcoming year and beyond. There is no guarantee that the Company will be successful in its endeavors and no certainty as to the timing of the Company's impending exploration commitments. Should the going concern assumption not be appropriate and the Company is not able to realize its assets and settle its liabilities, the Financial Statements would require adjustments to the amounts and classifications of assets and liabilities, and these adjustments could be material.

The Company's Colombian oil and gas interests are in the early development or exploration stage and the Company has yet to establish operations to achieve sustainable production from its oil and gas assets. Accordingly, the recoverability of amounts recorded as oil and natural gas properties is dependent upon successful development of its assets to put them into production and then achieve future profitable production, the ability of the Company to secure adequate sources of financing to continue to fund the development of its assets and the political stability of Colombia. The outcome of these matters cannot be predicted with certainty at this time.

Convertible Debentures

As previously mentioned, in May and November 2022, and August 2023 the Company completed the separate offerings of convertible debenture units for aggregate proceeds of $13.4 million (C$17.1 million), $25.9 million (C$35.0 million) and $26.6 million (C$35.0 million) respectively.

In July 2023, the Company completed a private placement offering of convertible debentures for aggregate proceeds of $26.6 million (C$35 million). Each convertible debenture unit is denominated in Canadian dollars and consisted of: (i) one 10% convertible unsecured debenture in the principal amount of $1,000 maturing on July 31, 2026; and (ii) 1,000 common share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one common share of the Company at an exercise price of C$0.90 per share for a period of three years ending July 31, 2026. Under the terms of the debentures, the lenders may at any time prior to the maturity date convert any or all the principal amount of the debentures into shares of the Company at a conversion price of C$0.70 per share.

In the May 2022 Offering, each convertible debenture unit is denominated in Canadian dollars and consisted of: (i) one 8% convertible unsecured debenture in the principal amount of $1,000 maturing on May 20, 2027; and (ii) 400 Common Share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one Common Share at an exercise price of C$1.40 per Common Share for a period of five years ending May 20, 2027. Under the terms of the convertible debentures, the lenders may at any time prior to the maturity date convert any or all the principal amount of the debentures into Common Shares of the Company at a conversion price of C$1.20 per Common Share.

In the November 2022 Offering, each convertible debenture unit is denominated in Canadian dollars and consists of: (i) one 10.0% convertible senior secured debenture with a principal amount of $1,000 maturing on November 30, 2025; and (ii) 1,000 Common Share purchase warrants of the Company, with each warrant entitling the holder thereof to purchase one Common Share at an exercise price of C$1.08 per Common Share for a period of three years ending November 30, 2025. The principal amount of each convertible debenture will be convertible, for no additional consideration, at the option of the holder, in whole or in part, at any time and from time to time, into Common Shares at a conversion price equal to C$0.90 per Common Share.

Interest on the debentures is payable monthly in arrears on the last day of each month. An amount equal to the interest payable for the first year under each of the debentures was placed in escrow upon closing of each of the May 2022 and November 2022 Offerings and the August 2023 Offering and shall be paid out to holders of debentures monthly. Interest thereafter shall be paid out of the Company's cash flow.

In August 2022, certain convertible debenture holders from the May 2022 Offering elected to convert C$350,000 face value of their debentures to Common Shares of the Company at the conversion price of C$1.20 per Common Share, resulting in the issuance of 291,666 Common Shares.

In September 2023, certain convertible debenture holders from the November 2022 Offering elected to convert C$210,000 face value of their debentures to Common Shares of the Company at the conversion price of C$0.90 per Common Share, resulting in the issuance of 233,333 Common Shares.

In October 2023, a certain debenture holder from the November 2022 Offering elected to convert C$250,000 face value of their debentures to Common Shares of the Company at the conversion price of C$0.90 per Common Share, resulting in the issuance of 277,777 Common Shares.

Restricted Cash

As of September 30, 2023, funds totaling $2,464,680 (December 31, 2022 - $1,968,873) were classified as restricted cash. The composition of this amount is as follows:

	2023	**2022**
SN-9 ANH Guarantee	2,036,943	1,704,618
Tiburon ANH Guarantee	427,737	264,255
	2,464,680	**1,968,873**

Term deposits of $2.4 million and $0.3 million were originally established to secure performance guarantees required by the Colombian National Hydrocarbon Agency ("ANH") under the Exploration and Production ("E&P") Contracts for the SN-9 and Tiburon Block. The SN-9 and Tiburon deposits amounts were defined in US dollars by the ANH but are held in Colombian pesos with Colombian banks and are subject to foreign currency fluctuation risks in relation to the US dollar, which may result in additional funding towards these term deposits from time to time at the discretion of the ANH. These deposits are to be released to the Company once current phase commitments under each E&P Contract are completed.

LONG-TERM INCENTIVE COMPENSATION

The long-term incentive compensation includes RSUs, PSUs and DSUs. Each of these compensation units are expected to be settled by way of the issuance of NG common shares when settled. As such, they are recognized as contributed surplus on a graded vesting basis over the vesting term of each grant. Stock-based compensation relating to RSUs, PSUs and DSUs of $18,924 (2022 - $nil) was expensed during the three and nine months ended September 30, 2023, respectively.

The number of outstanding RSUs, PSUs and DSUs as at September 30, 2023 were as follows:

	RSUs	PSUs	DSUs	Total
Balance at December 31, 2022	-	-	-	-
Granted	2,525,000	2,635,000	4,540,000	9,700,000
Balance at September 30, 2023	2,525,000	2,635,000	4,540,000	9,700,000

Deferred Share Units

On September 29, 2023, the Company granted a total of 4,540,000 DSUs to directors of the Company. The DSUs vest in two equal tranches over two years from the grant date and are expected to be settled in common shares of the Company. For the nine months ended September 30, 2023, no DSUs were settled by the Company.

Restricted Share Units

On September 29, 2023, the Company granted a total of 2,525,000 RSUs to officers, employees, and consultants of the Company. The RSUs vest in two equal tranches over two years from the grant date and are expected to be settled in common shares of the Company. For the nine months ended September 30, 2023, no RSUs were settled by the Company.

Performance Share Units

On September 29, 2023, the Company granted a total of 2,635,000 PSUs to officers and employees of the Company. The PSUs vest in three equal tranches, with the vesting conditions of each tranche related to the successful realization of specific operational milestones that the Company expects to be achieved over the foreseeable future. At a minimum, each tranche can only vest after a minimum of one year has transpired since the date of grant. For the nine months ended September 30, 2023, no PSUs were settled by the Company.

SHARE CAPITAL

Common shares

As of September 30, 2023, the Company was authorized to issue an unlimited number of Common Shares, with no par value, with holders of Common Shares entitled to one vote per Common Share and to dividends, if declared. Outstanding Common Shares as of September 30, 2023, are as follows:

	Common shares	Amount ($)
Balance, December 31, 2021	119,930,155	103,572,805
Shares issued through warrant exercise	5,011,111	1,205,561
Shares issued through option exercise	30,000	11,108
Conversion of debentures	291,666	198,245
Shares cancelled through share buyback	(140,800)	(106,279)
Balance, December 31, 2022	**125,122,132**	**104,881,440**
Shares issued through warrant exercise	4,610,500	5,160,346
Shares issued through option exercise	450,000	189,575
Shares issued on acquisition of new blocks	6,592,000	4,002,135
Conversion of debentures	233,333	147,085
Balance, September 30, 2023	**137,007,965**	**114,380,581**

Stock Options

The Company's stock option plan provides for the issue of stock options to directors, officers, employees, charities, and consultants. The plan provides that stock options may be granted up to a number equal to 10% of the Company's outstanding Common Shares. Vesting terms are determined by the Board of Directors as they are granted and currently include periods ranging from immediately to one-third on each anniversary date over three years. The options' maximum term is ten years.

As of September 30, 2023, a total of 12,976,893 (December 31, 2022 – 12,526,293) options were issued and outstanding under this plan. Options which are forfeited/expired are available for reissue. A summary of the changes in stock options is presented below:

	Stock options	Weighted average exercise price (C$)
Balance, December 31, 2021	9,915,400	0.85
Options issued	2,640,893	1.14
Options exercised	(30,000)	0.275
Balance, December 31, 2022	12,526,293	0.91
Options issued	2,850,000	1.18
Options exercised	(450,000)	0.33
Options forfeited	(1,949,400)	1.43
Balance, September 30, 2023	**12,976,893**	**0.92**

The following summarizes information about stock options outstanding as of September 30, 2023:

Exercise prices (C$)	Number of options outstanding	Weighted average term to expiry (years)	Number of options exercisable
0.275	836,000	6.73	836,000
0.275	185,000	0.83	185,000
0.45	1,675,000	5.75	1,675,000
0.45	285,000	0.83	285,000
0.91	1,325,000	7.79	1,325,000
0.91	350,000	1.08	350,000
0.91	325,000	0.83	325,000
1.00	2,350,000	7.15	2,350,000
1.00	500,000	0.83	500,000
1.00	220,000	1.08	220,000
1.00	25,000	0.17	25,000
1.14	1,745,893	8.86	1,745,893
1.14	295,000	0.83	295,000
1.18	2,850,000	5.00	-
8.00	10,000	3.86	10,000
	12,976,893	**5.71**	**10,126,893**

Subsequent to September 30, 2023, option holders exercised 150,000 options resulting in the issuance of 150,000 common shares. Based on the exercise price of options exercised, gross proceeds of C$58,750 were received by the Company.

Warrants

As of September 30, 2023, a total of 87,101,562 (December 31, 2022 – 56,712,062) Common Share purchase warrants were issued and outstanding. A summary of the change in total warrants is presented below:

	Warrants	Weighted average exercise price (C$)
Balance, December 31, 2021	25,489,373	1.13
Warrants issued with convertible debentures	41,858,800	1.13
Warrants expired	(5,625,000)	10.50
Warrants exercised	(5,011,111)	0.26
Balance, December 31, 2022	**56,712,062**	**1.20**
Warrants issued with convertible debentures	35,000,000	0.90
Warrants exercised	(4,610,500)	1.18
Balance, September 30, 2023	**87,101,562**	**1.08**

The following summarizes information about total Common Share purchase warrants outstanding as of September 30, 2023:

Exercise prices (C$)	Number of warrants outstanding	Weighted average term to expiry (years)	Number of warrants exercisable
0.90	35,000,000	2.83	35,000,000
1.08	34,100,000	2.17	34,100,000
1.15	475,600	0.36	475,600
1.20	4,431,100	0.06	4,431,100
1.40	6,858,800	3.64	6,858,800
1.50	2,036,412	0.25	2,036,412
1.75	4,199,650	0.36	4,199,650
	87,101,562	**2.30**	**87,101,562**

As of the date of this MD&A, the Company has 137,450,742 common shares, 12,826,893 stock options, and 87,101,062 warrants issued and outstanding.

COMMITMENT SUMMARY UPDATE

Capital Commitments

A summary of the Company's estimated capital commitments (in millions of dollars) are as follows:

Block	2023	2024	Total
SN-9 Block [(1)]	22.3	-	**22.3**
Tiburon Block [(2)]	3.0	-	**3.0**
Total	**25.3**	**-**	**25.3**

1) NG's ANH commitment to carry out the minimum requirement to drill two exploration wells (for which the Company will pay 100% of the costs under the terms of the SN-9 Acquisition) according to Phase 1 of the contractual exploration program. The ANH commitment was approved by the ANH in May 2022 to replace the previous minimum requirement to process and interpret 204.4 km of 2D seismic and drill one exploration well, with an extension up to August 2023 for the completion of the Phase 1 exploration program. The first exploration well (Magico-1) was completed in August 2022 and drilling of the second exploration well (Brujo-1) was completed in November 2022. With the completion of the Brujo-1 well, the Company has sought confirmation from the ANH that the Phase 1 exploration commitments have been fulfilled.

2) Relates to NG's share of the ANH commitment to carry out the minimum requirement to acquire, process, and interpret 69.75 km^2 of 3D seismic according to Phase 3 of the contractual exploration program. Currently, operations are delayed due to community disputes in the region, with 148 days to fulfil the commitment after the local disputes are resolved and the activities carried out in the previously proposed area. The Company assumes that activities related to the permits for the new seismic survey will commence in 2023 if the dispute is resolved by the Colombian Ministry of the Interior.

The expenditures provided in the above table only represent the Company's estimated cost to satisfy contractual requirements. Actual expenditures to satisfy these commitments, initiate production or create Proved plus Probable natural gas reserves may differ from these estimates. The expenditures in the above table are based on the latest possible date required per contract and may be incurred at an earlier date.

Contractual Commitments

Natural Gas Transportation Services

In August 2022, the Company entered into a Build-Own-Operate-Maintain-Transfer agreement (the "BOOMT") with GTX International Corp. ("GTX") pursuant to which GTX has built and will operate production facilities and pipeline (the "Pipeline Facilities") with capacity of 20 million cubic feet per day ("MMcf/d") that will extend from the Company's Maria Conchita Block in Colombia to existing national infrastructure. The BOOMT Agreement outlines the take-or-pay arrangement ("ToP") pursuant to which NG has agreed to transport, or pay for, 16 MMcf/d through the Pipeline Facilities for a period of six years (the "Guaranteed Commitment") at a tariff of $0.90/Mcf of gas, which commenced on September 23, 2022. Following the end of the term of the Guaranteed Commitment, the Company will no longer be required to pay for the full capacity of 16 MMcf/d but rather will only pay for that capacity which is used. The BOOMT Agreement has a term of ten years, after which ownership of the Pipeline Facilities will transfer to the Company. The BOOMT Agreement was reviewed as per guidelines in IFRS 16 to determine if it was for financial reporting purposes considered a right-of-use asset and lease liability. It was determined that the agreement met the criteria to be accounted for as a right-of-use asset and lease liability within the Company's Financial Statements.

Natural Gas Compression Services

In November 2021, the Company entered into a take-or-pay service contract with Surenergy SAS ESP ("Surenergy") for the compression of natural gas production derived from the Maria Conchita Block. Under the terms of the contract, Surenergy will install and maintain necessary infrastructure and equipment required to provide daily natural gas compression services for a natural gas production capacity of 20 MMcf/d, for a period of six years from the commencement of commercial natural gas production within the Maria Conchita Block. For these services, the Company will pay Surenergy a monthly service fee of $96,240 plus tax, annually adjusted to the Consumer Price Index, regardless of whether the Company fully utilizes the daily stipulated natural gas compression capacity. In December 2022, Surenergy completed the delivery of the third gas compressor, thereby satisfying the last outstanding condition required to turn the Surenergy Agreement into a binding obligation on the Company. The agreement with Surenergy was reviewed as per guidelines in IFRS 16 to determine if it was for financial reporting purposes considered a right-of-use asset and lease liability. It was determined that the agreement met the criteria to be accounted for as a right-of-use asset and lease liability within the Company's Financial Statements.

RELATED PARTIES

During the three and nine months ended September 30, 2023 and 2022, there were separate related party transactions as follows:

I. The Company paid a monthly advisory fee to a firm affiliated with a former director of NG. The relationship between the firm and NG ended in August 2023 with the director's departure. For the three and nine months ended September 30, 2023, as per the consulting agreement, NG paid the firm $16,350 and $65,398 respectively, (for the three and nine months ended September 30, 2022 - $25,276 and $77,175, respectively). As at September 30, 2023, a payables balance of $nil was owed to the firm.

II. For the three and nine months ended September 30, 2023, the Company incurred expenditures of $92,300 and $274,723, respectively (three and nine months ended September 30, 2022 - $nil and $nil) in royalty payments paid to directors and firms that are affiliated with directors of NG.

III. For the three and nine months ended September 30, 2023, the Company incurred expenditures of $8,496 and $23,620, respectively (three and nine months ended September 30, 2022 - $18,058 and $58,990, respectively), in office rental costs in Colombia. The related office space was rented from an entity affiliated with a certain director of the Company. As at September 30, 2023, a payables balance of $4,281 was owed to the lessor entity.

IV. In July 2023, the Company completed a non-brokered private placement of convertible debentures of 35,000 debenture units at $1,000 per unit, with 1,000 common share purchase warrants issued per unit. Of the units issued, 6,100 units were issued for subscriptions by directors and key personnel of the Company.

V. In November 2022, the Company completed a non-brokered private placement of convertible debentures of 35,000 debenture units at $1,000 per unit, with 1,000 common share purchase warrants issued per unit. Of the units issued, 3,250 units were issued for subscriptions by directors of the Company or investors related to directors of the Company.

VI. In May 2022, the Company completed a prospectus offering of convertible debentures of 17,147 debenture units at $1,000 per unit, with 400 common share purchase warrants issued per unit. Of the units issued, 7,135 units were issued for subscriptions by directors of the Company or investors related to directors of the Company.

SELECTED QUARTERLY INFORMATION

The following table sets out selected quarterly financial information of NG Energy and is derived from unaudited quarterly financial data prepared by management in accordance with IFRS.

	Q3 2023	Q2 2023	Q1 2023	Q4 2022
Net loss	(4,919,241)	(2,922,760)	(3,795,008)	(3,468,820)
Comprehensive loss	(3,996,929)	(3,718,115)	(3,743,149)	(3,673,960)
Net loss per share (basic & diluted):	(0.04)	(0.02)	(0.03)	(0.03)

	Q3 2022	Q2 2022	Q1 2022	Q4 2021
Net loss	(3,844,417)	(1,856,666)	(798,255)	(2,128,480)
Comprehensive loss	(3,362,029)	(1,730,924)	(826,278)	(2,297,814)
Net loss per share (basic & diluted):	(0.03)	(0.02)	(0.01)	(0.02)

Over the past eight quarters, trends in the net losses have been impacted significantly which has caused fluctuations on a quarter-over-quarter basis due to such factors as G&A expenses, share-based compensation expense, fair value results on derivative liabilities, and fluctuations in exchange rates.

The following outlines the significant events over the past eight quarters:

In the third quarter of 2023, the Company had gross natural gas revenue of $2,430,805, NGL revenue of $56,186, royalties of $428,766 and operating costs of $1,086,477. Increases to depletion and depreciation expenses, G&A and finance expenses also contributed to the quarterly net loss. The Company incurred G&A expenses of $1,608,804, depletion and depreciation expenses of $1,467,066 and net finance expenses of $2,815,505. The increase to G&A from the last quarter was primarily due to increases in wages and salaries and professional fees partially offset by decreases to Fees, Rent, Investor Relations, and other expenses. Increased finance expenses are primarily due to the interest expense incurred in relation to the convertible debentures and the lease liabilities that commenced in the prior year as well as an increase on decommissioning obligations.

In the second quarter of 2023, the Company had gross natural gas revenue of $2,797,821, NGL revenue of $17,508, royalties of $365,425 and operating costs of $517,599. Increases to depletion and depreciation expenses, G&A and finance expenses also contributed to the quarterly net loss. The Company incurred G&A expenses of $1,459,968, depletion and depreciation expenses of $1,381,924 and net finance expenses of $2,257,721. The increase to G&A from the last quarter was primarily due to increases in wages and salaries and professional fees partially offset by decreases to Fees, Rent, Investor Relations, and other expenses. Increased finance expenses are primarily due to the interest expense incurred in relation to the convertible debentures and the lease liabilities that commenced in the prior year as well as an increase on decommissioning obligations.

In the first quarter of 2023, the Company had gross natural gas revenue of $2,096,853, royalties of $393,342 and operating costs of $566,605. Increases to depletion and depreciation expenses, G&A and finance expenses also contributed to the quarterly net loss. The Company incurred G&A expenses of $1,395,729, depletion and depreciation expenses of $1,262,589 and net finance expenses of $2,558,552. The increase to G&A from the last quarter was primarily due to increases in wages and salaries partially offset by decreases to Fees, Rent, Investor Relations, and other expenses. Increased finance expenses are primarily due to the interest expense incurred in relation to the convertible debentures and the lease liabilities that commenced in the prior year as well as an increase on decommissioning obligations.

In the fourth quarter of 2022, increased G&A expenses of $1,213,887, increased finance expenses of $1,500,889, foreign exchange losses of $916,355, and depletion and depreciation expenses of $945,343 contributed to the quarterly net loss. Increases in professional fees were the primary cause of the overall G&A expense increase quarter over quarter. Increased finance expenses were due to additional interest expense incurred in Q4 2022 in relation to the convertible debentures as well as the GTX and Surenergy lease liabilities that have commenced. Also, in Q4 2022, production of natural gas resulted in gross revenue of $1,766,325 less royalties of $315,289 and operating costs of $511,248. As there were assets transferred from E&E to D&P, Q4 saw a significant increase in the depletion and depreciation expenses, this is due to the right-of-use asset depreciation for the full quarter as well depletion on the producing assets that were transferred from E&E.

In the third quarter of 2022, G&A expenses of $806,611, increased finance expenses of $462,954, share-based compensation expense of $1,860,743, and foreign exchange losses of $875,142 contributed to the quarterly net loss. Reductions in professional services rendered to the Company during Q3 2022 when compared to these same expenses in Q2 2022 was the primary cause of the reduction in G&A expenses, quarter to quarter. Increased finance expenses were due to the additional interest expense incurred in Q3 2022 in relation to the convertible debentures as well as the GTX lease liability that commenced September 23, 2022.

In the second quarter of 2022, G&A expenses of $867,185 as well as increased finance expenses of $265,038 and foreign exchange losses of $997,668 contributed to the quarterly net loss. Reductions in investor relation expenses during Q2 2022 when compared to these same expenses in Q1 2022 was the primary cause of the reduction in G&A expenses, quarter to quarter. Increased finance expenses were due to the additional interest expense incurred in Q2 2022 with the completion of the May 2022 Offering.

In the first quarter of 2022, the Company incurred G&A expenses of $1,048,561, partially offset by foreign exchange gains of $402,750. The decreased G&A expenses are due to reduced expenses for professional services rendered to the Company in the quarter in comparison to Q4 2021.

In the fourth quarter of 2021, the Company experienced foreign exchanges losses of $182,944 as well as increased G&A expenses of $1,615,679. The increased G&A expenses are due to increased growth and activity of the Company in anticipation of revenue-generating operations in 2022.

USE OF ESTIMATES AND JUDGMENTS

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of the financial statements are outlined below.

Critical Judgments in Applying Accounting Policies

The following are the critical judgments that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in the Financial Statements:

i) *Identification of cash-generating units*
Natural gas assets and processing facilities are grouped into cash generating units ("CGUs") identified as having largely independent cash inflows and are geographically integrated. The determination of the CGUs was based on management's interpretation and judgment. The recoverability of development and production asset carrying values is assessed at the CGU level. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

ii) *Impairment of property, plant and equipment and exploration and evaluation assets*
Judgments are required to assess when impairment indicators, or reversal indicators, exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land, transaction values and other relevant assumptions.

iii) *Exploration and evaluation assets*
The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing economic and technical feasibility.

iv) *Income taxes*
The Company conducts business internationally and therefore is required to comply with tax laws and regulations in various tax jurisdictions. Significant judgment, such as the interpretation of tax laws and regulations in each tax jurisdiction are required by management in determining the income tax balances and disclosures. The Company engages independent third-party tax specialists to assist with the interpretation of international tax laws and regulations.

Additionally, judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

v) *VAT recoverability*
Judgment is required by management in evaluating the likelihood of whether or not value added tax ("VAT") on purchases is recoverable from the Colombian government.

Key Sources of Estimation Uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, which have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

i) *Reserves and resource assessment*
The assessment of reported recoverable quantities of Proved plus Probable natural gas reserves and prospective resource estimates include estimates regarding forecasted production volumes, natural gas commodity prices, operating costs, royalty costs and future development costs. Additional estimates are made in relation to geological and geophysical models in anticipated recoveries. The economical, geological, and technical factors used to estimate Proved plus Probable natural gas reserves and prospective resources may change from period to period. Changes in reported Proved plus Probable natural gas reserves and prospective resources can impact the carrying values of the Company's natural gas properties and exploration and evaluation assets and equipment, the calculation of depletion and depreciation, the provision for decommissioning obligations, and the recognition of deferred tax assets due to changes in expected future cash flows.

The Company's Proved plus Probable natural gas reserves, if any, represent the estimated quantities of natural gas and natural gas liquids which geological, geophysical, and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially viable. Such Proved plus Probable natural gas reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Proved plus Probable natural gas reserves may only be considered proven and probable if the ability to produce is supported by either actual production or conclusive formation tests. Prospective resources are determined using an externally prepared valuation report which reflects estimated prospective resources and external pricing and costs assumptions reflective of the current market. The Company's Proved plus Probable natural gas reserves and prospective resources are determined pursuant to NI 51-101.

The Company uses estimated Proved plus Probable natural gas reserves to deplete its natural gas assets included in PP&E, to assess for indicators of impairment on the Company's CGU and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGUs and to assess E&E costs for impairment when transferred to PP&E.

ii) *Decommissioning obligations*

The Company estimates future remediation costs of production facilities, wells, and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

iii) *Share-based payments*

All equity-settled, share-based awards issued by the Company are recorded at fair value using the Black-Scholes option-pricing model. In assessing the fair value of equity-based compensation, estimates must be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate, and estimated forfeitures at the initial grant date. Share-based payments to non-employees are measured at the date when goods and services are received. Where the fair value of goods and services received cannot be reliably measured, the measure of the goods and services received and the corresponding increase in equity indirectly by reference to the fair value of the equity instruments granted, measured at the date goods are obtained or services rendered. Assessing the fair value based on services rendered are subject to measurement uncertainty given that it is dependent upon obtaining reasonable data as to the value of services rendered or good obtained based on readily available market metrics.

iv) *Tax provisions*

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in the period of the change and future periods. In periods of rate change, the Company estimates the period of anticipated reversal of the associated deferred income tax liability to determine the appropriate tax rate to apply to temporary differences. Deferred income tax assets are recognized to the extent future recovery is probable in management's judgment. Deferred income tax assets are reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the asset to be recovered. Deferred income tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods. Income tax filings are subject to audits and reassessments and changes in facts, circumstances and interpretations of the standards may result in a material increase or decrease in the Company's provision for income taxes.

Risks and Uncertainties

Exploration, development, production of oil and natural gas involves a wide variety of inherent risks because of the geological, social, and economic conditions in the various areas of operation. Therefore, the Company is subject to several financial, operational, and political risks that could have a significant impact on its profitability and levels of operating cash flows. Although the Company assesses and minimizes these risks by applying high operating standards, including careful management, and planning of its facilities, hiring qualified personnel, and developing their skills through training and development programs, these risks cannot be eliminated. Such risks include:

- risks related to the Common Shares;
- inability to obtain additional capital required to implement business plan;
- limited customer base;
- directors and officers;
- personnel;
- going concern risk;
- dilution;
- internal controls;
- Forward-Looking Statements may prove inaccurate;
- diversification;
- expansion into new activities;
- climate change;
- income taxes;
- cash from subsidiaries;
- pending or future litigation, arbitration, and other regulatory proceedings;
- climate change related litigation;
- technology;
- information technology or cybersecurity;
- breach of confidentiality;
- earnings & accounting estimates;
- Shareholder activism;
- global financial conditions;
- COVID-19 pandemic;
- Russia – Ukraine conflict;
- estimated oil resources and natural gas reserves are based on assumptions that may prove inaccurate;
- E&P Contracts;
- volatility of pricing for oil and natural gas;
- exploration, production, and general operational risk;
- replacement reserves;
- competition;

- changing investor sentiment about the oil and gas industry;
- reputational risk;
- environmental, health and safety risk;
- natural disaster and weather-related risks;
- joint venture risks;
- gathering and processing facilities and pipeline systems;
- delays in production, marketing, and transportation;
- difficulty transporting and distributing production;
- drilling costs and availability of equipment;
- drilling wells could result in liabilities;
- decommissioning costs;
- insurance;
- inflation and cost management;
- oil and gas companies in Colombia do not own any of the oil and gas reserves in the country;
- unforeseen title defects;
- seizure or expropriation of assets;
- risks of foreign operations;
- risks associated with geographically concentrated operations;
- gas industry in Colombia is less developed;
- operations in emerging market country;
- economic and political developments in Colombia;
- political uncertainty in Colombia, Canada and elsewhere;
- changes in laws or regulations;
- corruption;
- money laundering and other illegal and improper activities;
- licenses and permits;
- land, communities, prior consultation, and zoning restrictions;
- activities in areas classified as Indigenous reserves and Afro-Colombian lands;
- social disruptions and instability;
- sanctions by the United States of America on Colombia;
- Canada's relations with Colombia; and
- violence and instability in Colombia.

If any of these risks materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently aware or which it considers to be material in relation to the Company's business occur, the Company's assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects, are likely to be materially and adversely affected. In such circumstances, the prices of the Company's securities could decline, and investors may lose all or part of their investment.

Readers are encouraged to read and consider the risk factors listed above, which are more specifically described in the Company's Annual Information Form dated June 30, 2023, which is available on SEDAR+ at www.sedarplus.com. Such risk factors could materially affect the future operating results of the Company and could cause actual events to differ materially from those described in forward-looking statements relating to the Company.

Management's Report on Internal Control over Financial Reporting

In connection with National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings ("NI 52-109") adopted by each of the securities commissions across Canada, the Chief Executive Officer and Chief Financial Officer of the Company are required to file a Venture Issuer Basic Certificate with respect to the financial information contained in the unaudited interim financial statements and the audited annual financial statements and respective accompanying Management's Discussion and Analysis. The Venture Issuer Basic Certificate does not include representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in NI 52- 109.

FINANCIAL AND OTHER INSTRUMENTS

The Company has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies, and processes for measuring and managing these risks, and the Company's management of capital. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

Credit Risk

Credit risk reflects the risk of loss if counterparties do not fulfill their contractual obligations. The carrying amount of cash and cash equivalents, deposits in escrow, accounts receivable, VAT receivable and restricted cash represent the maximum credit exposure. As of September 30, 2023, the Company had $2,464,680 (December 31, 2022 - $1,968,873) in restricted cash towards development activity and joint operations in Colombia.

As of September 30, 2023, the Company had $3,488,032 (December 31, 2022 - $920,947) in accounts receivable and prepaids. The Company does not consider any of its receivables past due.

The Company maintained a VAT receivable balance of $3,284,477 as of September 30, 2023 (December 31, 2022 - $2,354,633), which is classified as a non-current asset. The Company considers these VAT balances to be collectible in the future as such VAT amounts will be utilized to offset future VAT charged on sales realized by the Company on future oil and gas production that would otherwise be required to be paid to the Colombian tax authorities.

As of September 30, 2023, the Company held cash and cash equivalents of $11,998,276 (December 31, 2022 - $6,962,228) and deposits in escrow of $2,660,985 (December 31, 2022 - $2,788,368). The Company manages the credit exposure related to cash and cash equivalents and deposits in escrow by ensuring counterparties (e.g., banks) maintain satisfactory credit ratings and monitors all investments to ensure a stable return.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due and describes the Company's ability to access cash. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient cash resources to finance operations, fund capital expenditures, and to repay debt and other liabilities of the Company as they come due, without incurring unacceptable losses or risking harm to the Company's reputation. The Company's processes for managing liquidity risk include preparing and monitoring capital and operating budgets, coordinating, and authorizing project expenditures, and authorization of contractual agreements. The Company seeks additional financing based on the results of these processes. The budgets are updated when required as conditions change.

The following table outlines the contractual maturities of the Company's financial liabilities on September 30, 2023:

	Less than 1 year	1-3 years	Thereafter	Total
Trade accounts payable	4,273,712	-	-	4,273,712
Royalties payable	779,357	-	-	779,357
Capital payables	3,090,524	-	-	3,090,524
Lease liability payments	6,569,986	13,111,173	13,183,333	32,864,492
Convertible debentures - interest	6,155,888	9,735,962	634,995	16,526,845
Convertible debentures - principal	-	-	64,043,640	64,043,640
	20,869,467	**22,847,135**	**77,861,968**	**121,578,570**

Market Risk

Market risk is the risk or uncertainty that changes in price, such as commodity prices, foreign exchange rates, and interest rates will affect the Company's net earnings and the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. From time to time, the Company may utilize financial derivative contracts to manage market risks in accordance with the risk management policy that has been approved by the Board of Directors. There were no financial derivative contracts or embedded derivatives outstanding on September 30, 2023, nor were there any at the previous year ended December 31, 2022.

Commodity Price Risk

Commodity price risk is the risk that the fair value of the future cash flows will fluctuate because of changes in commodity prices. Commodity prices for natural gas are affected not only by the United States dollar, but also by world economic events that dictate the levels of supply and demand. The Company's natural gas revenue is derived from natural gas production on the Maria Conchita block.

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate because of changes in foreign currency exchange rates. Some of the Company's business transactions and commitments occur in currencies other than US dollars. A portion of the Company's oil and natural gas activities in Colombia transact in Colombian Peso (COP$). In addition, most of the Company's financing and a portion of the administrative costs will be based and paid in Canadian dollars and COP$. Therefore, the Company is exposed to the risk of fluctuations in foreign exchange rates between US dollars, COP$ and Canadian dollars.

As of September 30, 2023, the Company had not entered any foreign currency derivatives to manage its exposure to currency fluctuations, nor were there any foreign currency derivatives as at the previous year ended December 31, 2022.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate because of changes in prevailing market interest rates. Fluctuations of interest rates for the periods ended September 30, 2023 and 2022, would not have had a significant impact on cash and cash equivalents and short-term investments. Furthermore, the Company is not currently exposed to interest rate risk on its interest-bearing loans given these debt instruments are all subject to fixed interest rates.

READER ADVISORIES

Forward-Looking Statements

This MD&A may include forward-looking statements including opinions, assumptions, estimates and management's assessment of future plans and operations, capital expenditures and the timing and funding thereof. When used in this document, the words "anticipate," "believe," "estimate," "expect," "intent," "may," "project," "plan", "should" and similar expressions are intended to be among the statements that identify forward-looking statements. Forward-looking statements are subject to a wide range of risks and uncertainties, and although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will be realized. Any number of important factors could cause actual results to differ materially from those in the forward-looking statements including, but not limited to, risks associated with petroleum and natural gas exploration, development, exploitation, production, marketing and transportation, the volatility of petroleum and natural gas prices, currency fluctuations, the ability to implement corporate strategies, the state of domestic capital markets, the ability to obtain financing, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in petroleum and natural gas acquisition and drilling programs, delays resulting from inability to obtain required regulatory approvals, delays resulting from inability to obtain drilling rigs and other services, labor supply risks, environmental risks, competition from other producers, imprecision of reserve estimates, changes in general economic conditions, ability to execute farm-in and farm-out opportunities, and other factors, all of which are more fully described under the caption "*Risk Factors*" in the Company's Annual Information Form dated as of June 30, 2023, which is available for review on SEDAR+ at www.sedarplus.com.

Management believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct. Such forward-looking information included in this MD&A should not be unduly relied upon as the plans, assumptions, intentions, or expectations upon which it is based may not occur. Actual results or events may vary from the forward-looking information.

In particular, this MD&A may contain forward-looking information pertaining to the following:

- the resource potential of the Company's assets;
- the Company's strategy and opportunities;
- performance characteristics of the Company's oil and gas properties and estimated capital commitments and probability of success;
- gas production and recovery estimates and targets;
- the existence and size of the oil and gas reserves and resources, if any;
- the Company's drilling plans;
- capital expenditure programs and estimates, including the timing of activity;
- the Company's plans for, and results of, exploration and development, activities, and factors that may affect such activities;
- projections of market prices and costs;
- the supply and demand for natural gas and oil;
- expectations regarding the ability to raise equity and debt capital on acceptable terms and to add continually to reserves through acquisitions and development, including the ability to negotiate and complete the agreements contemplated in this MD&A;
- the timing for receipt of regulatory approvals; and
- treatment of the Company under governmental regulatory regimes and tax laws.

The purpose of providing any financial outlook in this MD&A is to illustrate how the business of the Company might develop without the benefit of specific historical financial information. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking information herein is based on certain assumptions and analysis by the management of the Company considering its experience and perception of historical trends, current conditions and expected future developments and other factors that it believes are appropriate and reasonable under the circumstances. The forward-looking information herein is based on several assumptions, including but not limited to:

- the availability on acceptable terms of funds for capital expenditures;
- the availability in a cost-efficient manner of equipment and qualified personnel when required,
- continuing favorable relations with Latin American governmental agencies;
- continuing strong demand for natural gas and oil;
- the stability of the regulatory framework governing royalties, taxes and environmental matters in Colombia and any other jurisdiction in which the Company may conduct its business in the future;
- the Company's future ability to market production of natural gas or oil successfully to customers;
- the Company's future production levels and natural gas and oil prices;
- the applicability of technologies for recovery and production of the Company's natural gas and oil reserves or resources, as applicable;
- the existence and recoverability of any oil and gas reserves;

- geological and engineering estimates in respect of the Company's resources and reserves;
- the geography of the areas in which the Company is exploring; and
- the impact of increasing competition on the Company.

The actual results, performance and achievements of the Company could differ materially from those anticipated in these forward-looking statements as a result of the risks and uncertainties set forth elsewhere in the MD&A and the risks and uncertainties more specifically described in the Company's Annual Information Form dated June 30, 2022, which is available on SEDAR+ at www.sedarplus.com.

Readers are cautioned that the foregoing lists of assumptions, risks and uncertainties are not exhaustive; there may be other factors that cause actions, events, or results not to be anticipated, estimated or intended. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement. The forward-looking information speaks only as of the date of this MD&A, and the Company does not undertake any obligation to publicly update or revise any forward-looking information if circumstances or management's estimates or opinions should change except as required by applicable securities laws.

Analogous Information

Certain information in this MD&A may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas, assets, wells, industry activity and/or operations that are in geographical proximity to or believed to be on-trend with lands held by NG Energy. This document notes specific analogous oil and gas discoveries and corresponding details of said discoveries in the Chuchupa Block as well as blocks owned by Canacol Energy Ltd. and makes certain assumptions about the Maria Conchita Block and SN-9 Block because of such analogous information and potential recovery rates as a result thereof. Such information has been obtained from public sources, government sources, regulatory agencies, or other industry participants. Management of NG Energy believes the information may be relevant to help define the reservoir characteristics within lands on which NG Energy holds an interest and such information has been presented to help demonstrate the basis for NG Energy's business plans and strategies. However, management cannot confirm whether such analogous information has been prepared in accordance with NI 51-101 and the CO GE Handbook and NG Energy is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. NG Energy has no way of verifying the accuracy of such information. There is no certainty that the results of the analogous information or inferred thereby will be achieved by NG Energy and such information should not be construed as an estimate of future production levels or the actual characteristics and quality NG Energy 's assets. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by NG Energy and there is no certainty that such information will prove to be analogous in the future. The reader is cautioned that the data relied upon by NG Energy may be in error and/or may not be analogous to such lands to be held by NG Energy.

Abbreviations

$/bbl	*dollars per barrel*
$/boe	*dollars per barrel of oil equivalent*
$/GJ	*dollars per gigajoule*
$/Mcf	*dollars per thousand cubic feet*
bbl	*barrel*
bbl/d	*barrels per day*
bcf	*billion cubic feet*
boe	*barrel of oil equivalent*
boe/d	*barrel of oil equivalent per day*
GJ	*gigajoule*
GJ/d	*gigajoules per day*
km	*kilometer*
Mcf	*thousand cubic feet*
Mcf/d	*thousand cubic feet per day*
Mbbl	*thousand barrels*
MMbbl	*million barrels*
MMboe	*million barrels of oil equivalent*
MMcf	*million cubic feet*
MMcf/d	*million cubic feet per day*
NGLs	*natural gas liquids*
API	*American Petroleum Industry gravity*
m^3	*Cubic meters*
ppm	*parts per million*
psig	*pounds per square in gauge*
NPV_{10}	*Net present value using a 10% forward discount rate*