NG ENERGY INTERNATIONAL CORP.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2021

The following is management's discussion and analysis ("MD&A") of the operating and financial results of NG Energy International Corp. ("NG" or the "Company"), formerly CruzSur Energy Corp., for the three and nine months ended September 30, 2021, as well as information and expectations concerning NG's outlook based on currently available information.

This MD&A should be read in conjunction with NG's interim condensed consolidated financial statements for the three and nine months ended September 30, 2021 as well as the audited annual consolidated financial statements for the year ended December 31, 2020 (collectively, 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'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.sedar.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 24, 2021.

Non-GAAP Measures

Certain financial measures in this document may not have a standardized meaning as prescribed by IFRS, and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order 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-GAAP measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.

CORPORATE OVERVIEW AND UPDATE

NG 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 is comprised of one appraisal and two exploration natural gas assets in Colombia. Assets previously held in Argentina were disposed of in October 2020 (see below). NG's common shares are listed on the TSX Venture Exchange ("TSX-V") under the symbol "GASX".

Non-brokered Private Placement

In October 2021, the Company closed a non-brokered placement of 8,000,000 units, at a price of C$1.00 per unit, for gross proceeds of $8,000,000 Canadian Dollars ("C$"). Each unit consists of one common share and one share purchase warrant entitling the holder to purchase one additional share at a price of C$1.20 for a period of 24 months from the date of issuance, expiring on October 22, 2023, and are subject to potential accelerated expiry in the event the closing price of the common share of the Company on the TSX-V is equal to or exceeds C$2.00 for twenty consecutive trading days.

In connection with the completion of the placement, the Company has paid a C$6,000 cash commission and issued an aggregate 141,600 units, on the same terms as those issued in the financing to eligible parties who introduced subscribers.

Bought Deal Financing

In February 2021, the Company closed a bought deal private placement, pursuant to which a syndicate of underwriters purchased 7,400,000 units and exercised its option to purchase an additional 1,110,000 units, an aggregate of 8,510,000 units at a price of C$1.15 per unit for aggregate gross proceeds to the Company of $7,712,586 (C$9,786,500). Each unit consists of one common share of the Company and one-half of one common share purchase warrant, with each whole warrant entitling the holder to purchase one common share at a price of C$1.75 until February 10, 2024.

In connection with the offering, the underwriters received a cash commission equal to 6% of the gross proceeds raised and 510,600 non-transferable broker warrants equal to 6.0% of the aggregate number of units sold. Each broker warrant is exercisable into one common share at a price of C$1.15 per share for a period of 36 months from the closing of the financing. The net proceeds of the Offering will be used for working capital and general corporate purposes.

Repayment of Maria Conchita Loan by way of Non-Brokered Private Placement

In parallel with the aforementioned bought deal financing, the Company completed a non-brokered private placement offering of 429,300 units, on the same terms as those issued pursuant to the bought deal financing, for a deemed value of $388,452 (C$493,695). No fees or commissions were paid to the underwriters in connection with the private placement. The issuance of these units was completed as repayment of the outstanding balance of the Maria Conchita Loan of $350,000 plus accrued interest. Of the units issued, 224,500 units were indirectly acquired by two of the Company's directors.

Settlement of services for shares

In February 2021, pursuant to a Memorandum of Understanding with Panacol Oil and Gas Corp. ("Panacol"), the Company issued an aggregate of 4,000,000 common shares at a deemed price of C$1.49 per share. 2,800,000 common shares were issued in satisfaction of project management services provided by Panacol and 1,200,000 common shares to Landsons Investment Corporation for services provided towards obtaining the environmental and social licenses for the SN-9 project.

Appointment of New Directors

In July 2021, the Company announced the appointment of D. Jeffrey Harder and Humberto Calderton Berti as directors of the Company. At the same time, the Company announced the resignation of Mr. Frank Giustra as a director of the Company.

COVID-19 Pandemic

More than a year after being declared a global pandemic by the World Health Organization in March 2020, COVID-19 continues to impact global economic conditions. Global financial markets, and commodity prices in particular, have experienced significant volatility and uncertainty. The crisis has caused periodic delays in the Company's Colombian exploration activities planned due to temporary restrictions on exploration activities implemented by the Colombian government. The scale and duration of these developments remain uncertain but could impact the Company's operations, future net earnings, cash flows and financial condition.

Disposition of Alianza

In October 2020, the Company announced the acceptance of an offer to sell Alianza Petrolera Argentina S.A. ("Alianza"), the Argentine subsidiary through which NG operated the SRDE Asset and held interest in the Mariposa Asset.

Under the terms of the offer, the purchaser acquired Alianza and assumed all rights and responsibilities relating to the oil and gas assets and general operations of Alianza. As consideration, the purchaser granted a royalty of 7% to the Company calculated on the net profit of oil production from the SRDE Asset, after applicable royalties and operating costs, up to total royalty payments of $100,000. The transaction also included the assumption by the purchaser of all responsibilities for any existing and future liabilities as well as a guarantee of indemnity for potential claims against NG and its related companies.

COLOMBIAN OIL AND NATURAL GAS PROPERTIES

NG has working interests in the Maria Conchita Block, the SN-9 Block, and the Tiburon Block. Below is a detailed description of each block:

Maria Conchita Block

The Maria Conchita Block is located 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 900 mmboe in place and currently accounts for approximately 40% of Colombia's daily natural gas output. The Chuchupa Block has been under production for over 35 years, operated by Chevron 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 in close proximity to both of Colombia's gas trunk lines, Transportadora de Gas Internacional ("TGI") and Promigas.

The 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 wholly-owned subsidiary of NG, 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. The Maria Conchita E&P Contract had an initial exploration term consisting of 6 one-year exploration phases, that 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 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.

Reserves Analysis

In March 2021, the Company announced the results of the year end 2020 reserve report for the Maria Conchita Block prepared by Petrotech Engineering Ltd. The results of this resource analysis defined a total of six prospects by using 3D seismic data and geobody mapping to detect the gas accumulation in the Miocene sands and one limestone section within the Aruchara and Tinka areas of the Maria Conchita Block with a confirmation of the best estimate Prospective Resources of 194.9 Bcf and 2P Reserves of 34.6 Bcf, exceeding management expectations and confirming the possibility to produce high gas volumes from the block. The Company decided to push towards initial production from the Aruchara-1 well at Maria Conchita, re-enter and test the Istanbul-1 well and receive final environmental approvals. The Company currently has net 27.7 Bcf of gas and 5 Mbbl of condensate of proved and probable undeveloped reserves (from gross 34.6 Bcf of gas) in the Maria Conchita Block. Once the evaluation studies have been completed and the field has been declared commercial, further studies will be performed related to extensive tests in the field for other possible re-entries and new wells to be drilled as part of a possible development plan.

Current Objectives

The Company's primary focus is establishing the necessary infrastructure to connect the Aruchara-1 well to the nearby main gas line by late 2021, with the objective of monetizing its natural gas resources, capitalizing on a premium pricing market in Colombia of over $5/MMBtu. In December 2020, the Company announced that it had entered into a Memorandum of Understanding (the "MOU") with GTX International Corp. ("GTX") pursuant to which GTX is to build and operate the production facilities and pipeline (the "Pipeline Facilities") that will extend from the Company's Maria Conchita field in Colombia to existing national gas transportation infrastructure. GTX completed a brokered offering of $10 million of senior-secured debentures (the "Debentures") that bear interest at a rate of 15% per annum, payable monthly and which mature six years from the issuance date. GTX's financing provides the necessary funding to build the infrastructure needed to begin delivering gas to the market, with expectations to commence in 2021. GTX will build, own, operate and maintain the Pipeline Facilities, which will have a capacity of 20 mmcf/d. Additionally, the MOU provides that the Company and GTX will enter into a take-or-pay agreement (the "ToP Agreement") pursuant to which NG will agree 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 per thousand cubic feet (kcf) of gas. The ToP Agreement will have a term of 18 years and the Company's Guaranteed Commitment will convert after six years into payment for only the capacity that is used.

Despite delays due to the COVID-19 pandemic and the difficulties of mobilization on Colombian roads because of the social unrest and blockades that the country is experiencing, construction of the Pipeline

Facilities continues forward. The construction of the remaining gas pipeline to the platform will be installed once the procedures for prior consultation with the local communities are completed, which have suffered delays due to the social circumstances that currently surround indigenous communities in Colombia. Furthermore, NG consultants continue to advance the studies and procedures required by Colombian government agencies to begin the production phase of the Aruchara-1 well. Once all permits have been obtained and the construction of the facilities has been completed, gas production should begin in late 2021.

Exploration Activities

The current Evaluation Program for the Maria Conchita Block consists of geological and geophysical studies and an evaluation of re-entries on the existing wells and will expire in March 2022 with the option to present a development plan of the field later during the 2022 year. In early 2021, the Company decided to complete a feasibility study on the covered Istanbul-1 well prospective area, evaluating the following aspects: condition of environmental licensing, social aspects of the area of direct influence of the project, mechanical integrity, integral costs of intervention and new wells to be drilled to sustain a production capacity close to 20 mmcf/d. Based on the results of this study, in May 2021, the Company re-entered the Istanbul-1 well and preliminary testing in several zones encountered gas that was tested for flow rates. The purpose of the re-entry of the Istanbul-1 well was to repair wellbore damage, evaluate the potential extension of the Aruchara-1 well producing zones, and define the production potential of new identified gas zones.

The existence of gas was tested in all the evaluated zones, with presence of water, and it was established that the intervals 8,396 to 8,416 feet and 8,426 to 8,438 feet present good gas production potential, expanding the prospects of the area. Based on the above, it was decided by management to complete the well temporarily, while identifying the best procedure to prevent water from influencing gas production. With this objective, existing technologies are being analyzed and the best mechanism is being defined to put the well into continuous production as soon as possible. NG has engaged professional consultants to design the re-entry (without rig) of the Istanbul-1 well and deploy de-watering capillary technology to deal with water that exists downhole. The Company and its contractors are in the final stages of defining procedures for a ten-day program, including all required governmental approvals, and anticipate completion before the end of the year. The objectives of the program are designed to determine the effectiveness of the technology to remove water and to estimate the real capacity and potential of the gas production from the well without the liquid load. The Company is advancing conversations to begin selling the gas production from the field following assembly of all GTX production facilities. This production would be transported via truck ahead of the pipeline being completed. The Company is also in the process of signing an agreement with TGI for the tie-in of the Maria Conchita pipeline, enabling the Company to transport the gas produced from the Aruchara-1 well and subsequent wells in the Maria Conchita Block through TGI's main pipeline and sell it in central consumption centers within Colombia. The remaining flow lines are expected to be laid and tied into the TGI main line by the end of the year.

The Istanbul-1 well re-entry is part of the ongoing evaluation program of the Maria Conchita field after the successful re-entry in the Aruchara-1 well (drilled by Texaco in 1980) and on the recent geological evaluation of prospective resources as required by the ANH. The re-entry of the Aruchara-1 well was completed in August 2020 as a result of implementing the work program approved by the ANH to 1) repair a gas leak detected during 2020 which was duly reported to the National Authority of Environmental Licences ("ANLA"), and 2) confirm the gas accumulation tested in the year 1980. After drilling the cement plugs and controlling the well, Drill Stem Tests ("DSTs") were carried out to determine the origin, pressure, and volume of natural gas to repair, complete, and secure the well. As previously mentioned, the Aruchara-1 well was drilled by Texaco in 1980 to a total depth of 9,715 feet and tested gas between 8,111 and 8,121 feet and between 8,051 and 8,061 feet varying from 3.4 to 9.8 mmcf/d from these two zones at that time. As part of the re-entry program, three DST procedures of this well were conducted by NG. The first DST procedure occurred between 8,052 and 8,062 feet measured depth with a maximum rate of 7.75 mmcf/d through a 48/64" choke at a pressure of 2,075 psig and a final shut-in pressure of 3,505 psig. The second DST procedure occurred between 8,111 and 8,121 feet measured depth with a maximum rate of 10.98 mmcf/d through a 48/64" choke at a pressure of 2,437 psig and a final shut-in pressure of 3,547 psig. The third DST procedure occurred between 8,088 to 8,094 feet and from 8,111 to 8,121 feet measured depth, with a maximum rate of 10.420 mmcf/d through a 48/64" choke at a pressure of 2,271 psig and a final shut-in pressure of 3,521 psig. The absolute open flow potential was estimated at 19.0 mmcf/d and a potential of 14.3 mmcf/d with a 50% drawdown. DST results were reviewed by John Yu, P. Eng. as an independent Qualified Reserves Evaluator and Auditor as defined in NI 51-101 Standards of Disclosure for Oil & Gas Activities, obtaining the following results: proved undeveloped reserves of 15,670 mmcf and probable undeveloped reserves of 18,912 mmcf for a total proved + probable reserves of 34,582 mmcf. Subsequent to testing results, the well was completed and secured, ready to produce once all necessary permits and building the required production and transportation facilities has been completed.

The Company originally drilled the Istanbul-1 well in Q1 2018 and reached a total depth of 8,740 feet measured depth ("MD"). Based on the interpretation of the open hole logs and mud log, 12 separate intervals covering a total thickness of 62.4 feet were selected and perforated for testing between 7,912 feet MD and 8,608 feet MD. The well was tested with gas and water produced to surface. Although steady state conditions were never achieved, the well was flowed for a period of 7 hours at an average rate of 350,000 cubic feet of gas per day and 2,100 barrels of water per day. A production log ("PLT") confirmed that the majority of water and gas production was coming from 26 feet of perforations in the upper sand package. The PLT also confirmed that the other potential gas bearing zones (eight zones with 36.4 feet of perforations) were not contributing materially to the observed flow, being impeded by the weight of the water column in the wellbore, which severely limited the ability to achieve sufficient drawdown to initiate gas flow from these zones. NG subsequently filed a technical discovery notice for Istanbul-1, and an Evaluation Program covering an area of 32,518 acres was declared around the well in which the reserves and prospective resources exist and are covered by the existing 3D seismic.

Given the PLT results of the Istanbul-1 well were inconclusive, it was decided to perform an in-depth re-evaluation of the 3D seismic for the area and the amplitude versus offset (AVO) anomalies based on the new geological interpretation results. The new interpretation indicated the possibility that significant gas resources could exist for sustained development of the field. To confirm these volumes, it was necessary to carry out a sustained test in the Aruchara-1 well through a re-entry project to 1) repair a gas leak detected during 2020, and 2) confirm the accumulation tested in the year 1980. Based on the results of this testing, the re-entry in the Istanbul-1 well and the opportunities afforded by the dewatering capillary technology, the Company is considering a subsequent work program which might include the drilling of 3 additional exploration wells in this area. This same analysis is anticipated to also be carried out in the area near the Tinka-1 well (drilled in 1988 by Ecopetrol, S.A.) in 2022 to define the maximum commercial capacity of the field and the possibility of drilling 2 more wells in the Tinka area.

SN-9 Block

The SN-9 Block is located 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. 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 Cienaga de Oro formation at a depth of approximately 4,250 ft. 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 acquiring 125 km^2 of 3D seismic and drilling one exploration well.

Reserves Analysis

In March 2021, the Company announced the results of the year end 2020 resource reports for the SN-9 Block prepared by Petrotech Engineering Ltd. The Company confirmed best estimate contingent resources of 51.4 Bcf, best prospective resources of 836.4 Bcf for prospects and 637.4 Bcf for leads at the SN-9 Block. The 51.4 Bcf contingent resources are based on the results of the tests made on Hechizo-1 well drilled by Ecopetrol in 1992 and the two drill stem tests from 4,056 to 4,080 feet and from 4,182 to 4,196 feet in the Cienaga de Oro Formation with total combined flow rates close to 10 mmcf/d. Twelve prospects in the Porquero, Top Cienaga de Oro and Intra Cienaga de Oro with five leads have been identified using 2D seismic data, in order to upgrade the leads to prospects. The Company intends to start a 4-well exploration drilling program, subject to receiving the required environmental permits, in Q4 2021.

The Company was also very encouraged by the discovery of more than 400 feet of prospective gas zones in the Cienaga de Oro Formation by Canacol Energy in the Aguas Vivas-1 well which tested high gas production (as reported in Canacol's news release dated June 3, 2021). The Agua Vivas-1 well is located in the VIM 21 Block of the Lower Magdalena Valley Basin and is approximately 10 km from the Hechizo prospect in the SN-9 Block of the Sinu San Jacinto Basin. The confirmation of discovery of commercial gas in the Arrecife-3 well by Hocol S.A. (as reported in Hocol's news release dated June 1, 2021) in the region south of the SN-9 Block was also very promising to NG.

Current Objectives

The Company is in the process of carrying out the exploration activities in stages which will satisfy the minimum work obligations. The first stage consisted of the finalization of the environmental impact study and prior consulting processes in order to obtain the necessary environmental licenses to be able to drill. This is to be followed by the drilling of two exploration wells in the Magico and Mago areas. The second stage will focus on evaluating the Hechicero and Hechizo areas, including drilling two additional exploration wells and acquiring 3D seismic for the development of the field. However, due to the ongoing COVID-19 outbreak, activities related to the environmental license have been delayed. As such, Clean (the field operator) requested a 12-month extension of the Phase 1 exploration commitment, which was approved by the ANH. An additional extension could be requested if deemed necessary. The Company expects to have drilling rigs on site by the end of 2021 to commence the initial drilling plan outlined previously, pending environmental permits.

Exploration Activities

During December 2020, the Company announced that it had received a binding commercial offer from CPVEN (the "Binding Offer") to execute the planned drilling program. Under the Binding Offer, the companies will enter into a market pricing-based preferred supply agreement for drilling and gas well services activities for all phases of the SN-9 exploration program. CPVEN has initially committed to construct and complete four gas wells, including mobilization, demobilization, engineering, drilling and completion, for an aggregate cost of $27.2 million. CPVEN has developed its own technology and has the managerial and technical personnel capable of executing complex operations, utilizing state-of-the-art infrastructure and equipment design.

The Company is in the process of negotiating with other service providers who will build the civil infrastructure required to carry on the drilling and testing activities.

In relation to the SN-9 permitting process, the Environmental Impact Study for the exploratory drilling area was delivered to ANLA in December 2020 with the follow up requirements being attended to in May 2021. It is estimated that the governmental authority will issue the administrative environmental licensing act before the end of 2021. Progress is being made in the environmental and drilling areas which will allow the start of civil works for the road access and site construction to start drilling the Magico-1X well in late 2021, pending environmental permits. Magico-1X is the first of four wells to be drilled in the SN-9 Block, including one well in the Hechizo prospect. The primary focus of the exploration program is the Cienaga de Oro Formation, similar to the Aguas Vivas-1 well and other producing wells in the area.

Existing Agreements

The terms of the original agreement between the Company and Clean regarding the Company's acquisition from Clean of 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 share of Net Profit Interest and Overriding Royalties (as defined in the SN-9 PSA) related to this additional 5% working interest will be the obligation of Clean and not carried by the Company.

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 into 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 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 the 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 2D seismic in the Bahia Honda area within the Tiburon Block, which is equivalent to the current Phase 3 commitment of the E&P Contract of 69.75 km^2 of 3D seismic.

The previous request to change the phase commitment of 2D seismic in the Bahia Honda area is based on the technical study carried out on the area of the Tiburon Block, as well as on the analysis of its geological model. Through the study and re-interpretation of the existing information, the Company has concluded that the Bahia Honda area (La Guajira) shows a higher level of perspectivity, being able to determine structures, leads and geological prospects of interest, with possible resources estimated between 2 and 4 TCF. In addition, there exists less uncertainty regarding social acceptance and the completion of the requisite “prior consultation” process in this area. This will ultimately allow the Company to execute the exploration activities and commitments of the E&P Contract with a higher probability of success.

Due to the ongoing COVID-19 outbreak, the Company requested from the ANH a one-year extension of the exploration commitment. This request was not approved as the phase commitments are still currently suspended due to the aforementioned pre-existing community issues that are impeding any progress in the area. The Company will comply with the phase 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 intends to start environmental and social analyses to execute the seismic activities, pending the outcome of the ongoing COVID-19 outbreak and the resolution of the local community conflicts that are impeding any progress in the area.

Existing Agreements

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

- 10% working interest on the completion of the Phase 3 3D seismic commitment
- An additional 15% working interest on the drilling and testing of one exploration well
- A further 15% working interest on the drilling and testing of a second exploration well

After completing the seismic commitment, NG is not obligated to drill any of the exploration wells and can exit the contract with no further commitments but will lose the original $0.3 million performance guarantee currently held in deposit with the ANH. Alternatively, NG 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 if the Company is still participating in the block when the ANH performance guarantee is returned at the end of the Phase 3 commitment. In the event that NG does not fulfill the Phase 3 commitment, except for reasons beyond its control, NG 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 continues to move forward with its planned exploration program in the Maria Conchita and SN-9 Block as was mentioned above. The Company believes the SN-9 Block could be an important new source of natural gas in Colombia. Through a phased approach, NG expects to increase reserves and provide a stable supply of natural gas in the country. The Company currently expects exploration activities to begin in late 2021, pending sufficient resolution of the ongoing COVID-19 outbreak which is causing delays on necessary environmental license activities. The Company anticipates that the environmental license should be granted before the end of 2021 and drilling activities will commence thereafter.

Furthermore, the aforementioned 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 re-entry project of the Aruchara-1 well is assisting to confirm the size of the accumulation of natural gas in the Aruchara area, which is allowing the Company to build the best development project for this area of the field and to establish production and transportation facilities. Extended tests of prospective gas zones are expected to take place by the end of 2021. After the re-entry of Istanbul-1 well in 2021, re-entry of the Tinka-1 at a future date could test several prospective zones based on new geological and seismic re-interpretation and the results of the capillary dewatering technology deployment at the Istanbul-1 well.

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

DISCUSSION OF OPERATING RESULTS

General and Administrative Expenses

General and administrative expenses (“G&A”) for the nine months ended September 30, 2021 totaled $2,168,586 (2020 comparative period - $1,334,951). The G&A expenses relate to the normal course of the Company’s operations, and are constituted as follows:

USD $	Q3 2021	Q3 2020	Q2 2021	Q1 2021	Q4 2020
Wages & Salaries	122,675	20,172	51,095	51,790	59,973
Professional Fees	173,368	153,046	428,034	335,278	360,628
Fees, Rent, Investor Relations and Other	324,953	474,401	301,540	379,853	166,091
Total	**620,996**	**647,619**	**780,669**	**766,921**	**586,692**

Professional fees are comprised 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

In July 2021, The Company granted 2,250,000 options to acquire common shares to certain directors, officers, employees and consultants of the Company and certain charitable organizations at a price of C$0.91 per common share. The options were for a ten-year term, expiring on July 15, 2031. All options granted vested immediately on the date of grant.

In July 2021, the Company passed a resolution to re-price 125,000 outstanding options to acquire common shares at a price of C$8.00 per common share to a modified price of C$0.91 per common share. All other terms for these options (vesting periods, expiry etc.) were not modified as part of the re-pricing. As such the amended option had a weighted average expiry term of 6.07 years as of the date of the re-pricing.

The value of the stock options vesting in the nine months ended September 30, 2021, equated to $1,298,396 (2020 comparative period - $270,078), which was expensed as share-based payments.

Finance Income and Expense

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

USD $	Q3 2021	Q3 2020	Q2 2021	Q1 2021	Q4 2020
Interest income	(18,319)	(27,783)	(18,786)	(22,665)	(16,745)
Interest expenses and bank charges	169,281	142,966	152,662	144,650	88,905
Commitment fee	-	29,000	2,250	25,333	41,708
Accretion on decommissioning obligation	1,380	2,822	1,376	1,374	3,211
Accretion on liability component of converible debentures	-	4,710	-	-	-
Amoritzation of transaction costs on Loans	11,926	6,754	11,270	11,444	13,532
Net finance expenses	**164,268**	**158,469**	**168,772**	**160,136**	**130,611**

Foreign Exchange

The Company incurred a foreign exchange loss of $618,832 for the nine months ended September 30, 2021 (2020 comparative period – $743,469). Foreign exchange losses are due to the decrease in the value of the US dollar when compared to the Canadian dollar and the Colombian peso in the period. Conversely, foreign exchange gains are due to an increase in the value of the US dollar in comparison to these other currencies.

Cash used in Continuing Operations

For the nine months ended September 30, 2021, the Company used cash in continuing operations of $3,150,114 (2020 comparative period - $1,546,685). The cash used in operations is primarily comprised of G&A expenses and business development expenses incurred during the period.

DISCONTINUED OPERATIONS

Upon closing the divestitures outlined above, the Company ceased operations in Argentina. As such, the Company reclassified its entire Argentine segment to discontinued operations. Income and expenses allocated to net income from discontinued operations for the periods ended September 30 are as follows:

	Three months ended		Nine months ended	
	2021	**2020**	**2021**	**2020**
Revenue				
Oil and natural gas revenue	-	171,636	-	171,636
Net revenue on carried working interest	-	102,665	-	312,009
Royalty expense	-	(26,423)	-	(26,423)
	-	247,878	-	457,222
Expenses				
Operating expenses	-	145,213	-	145,213
Inventory revaluation	-	-	-	266,085
General and administrative	-	68,603	-	302,472
Depletion and depreciation	-	82,291	-	267,390
Impairment loss	-	1,175,063	-	1,175,063
Net finance expense	-	2,614	-	8,949
Foreign exchange loss (gain)	-	6,288	-	(16,587)
	-	1,480,072	-	2,148,585
Net loss from discontinued operations	**-**	**(1,232,194)**	**-**	**(1,691,363)**

Cash flows related to discontinued operations for the periods ended September 30 are as follows:

	Three months ended		Nine months ended	
	2021	2020	2021	2020
Loss from discontinued operations	-	(1,232,194)	-	(1,691,363)
Depletion and depreciation	-	82,291	-	267,390
Unrealized foreign exchange loss (gain)	-	3,982	-	(22,216)
Impairment loss	-	1,175,063	-	1,175,063
Net finance expense	-	2,614	-	8,949
Change in non-cash working capital	-	36,933	-	168,919
Operating activities of discontinued operations	**-**	**68,689**	**-**	**(93,258)**
Changes in non-cash working capital	-	137,196	-	-
Investing activities of discontinued operations	**-**	**137,196**	**-**	**-**
Net financing expense paid	-	(2,152)	-	(7,575)
Financing activities of discontinued operations	**-**	**(2,152)**	**-**	**(7,575)**

CAPITAL ADDITIONS

For the nine months ended September 30, 2021, the Company had additions (prior to recognition of any impairments, disposals or revisions of estimates) of $4.9 million relating to exploration and evaluation assets and $2,959 relating to property, plant and equipment. Additions to exploration and evaluation assets relate primarily to 1) on-going capital activities for the Aruchara well and the Istanbul-1 well re-entry; and 2) SN-9 community relations and environmental license compliance work.

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 makes adjustments to 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 nine months ended September 30 2021, the Company recognized loss from continuing operations of $4.6 million and used $3.1 million of cash flow in its operating activities for continuing operations. As at September 30, 2021 the Company had a working capital deficit of $5.3 million, which would suggest that the Company has limited ability to fund its operational and capital commitment amounts that exist for the upcoming period and beyond. Currently, the Company has contractually committed exploration and development amounts of $25.3 million as outlined further below in the "Commitment Summary Update" section. These commitments could leave the Company potentially cash deficient depending on the outcome of the Company's ongoing operations. As a result, these conditions give rise to a material uncertainty that creates significant doubt on the Company's ability to continue as a going concern.

The Company will continue to utilize its financial resources to fund existing operations and capital commitments. There is uncertainty as to the future operating and development ability of the Company as it will be contingent upon the Company's ability to successfully identify and procure necessary financing and develop oil and gas operations that generate positive cash flows. The Financial Statements have been prepared on a going concern basis, which assumes that the Company will be able to discharge its obligations and realize its assets in the normal course of operations for the foreseeable future.

Management believes that the going concern assumption is appropriate for the Financial Statements and that the Company will be able to meet its budgeted capital and operational costs as well as its other potential capital commitments during the upcoming year and beyond. There is no guarantee that the Company will be successful in its exploration and development activities 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 significant.

The Company's Colombian oil and gas interests are in the 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 in order 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.

Aruchara Loan

In December 2019, the Company entered into a loan in the amount of $1.6 million, secured by the assets of the Company. The loan is denominated in US dollars, matures on December 5, 2021, and bears interest at the rate of 15% per annum. The proceeds of the loan were utilized for the costs of the re-entry project of the Aruchara well in the Maria Conchita Block. Under the terms of the loan agreement, the lenders have also been granted a 2.5% overriding royalty derived from the production of the Maria Conchita Block. Total interest and principal is payable at the maturity date, although the lenders have an option to convert the loan principal and interest into another 2.5% overriding royalty from the Maria Conchita Block at the lenders' discretion at any point prior to the maturity date. Currently, no value has been attributed to the 2.5% overriding royalty or the conversion option for an additional 2.5% overriding royalty as this is contingent upon the successful realization of commercially viable operations within the Maria Conchita Block.

Of the principal amount of the Aruchara loan, $0.5 million of the principal of the Aruchara loan has been accounted for as a "drawdown" facility given this funding had been made available to the Company for purposes of covering expenditures on the Aruchara-1 well as necessary, in contrast to the other $1.1 million of the principal being provided as cash funds to the Company on the date of issuance. As of the date of this MD&A, the full extent of this drawdown facility has been utilized by the Company. As such, the full balance of the $1.6 million Aruchara loan is recognized as a debt balance.

Maria Conchita Loan

In July 2020, the Company entered into a loan in the amount of $350,000. The loan is denominated in US dollars and bears interest at the rate of 20% per annum. The loan maturity date was set as the earlier of six months from the advance date or such time as proceeds to the Company from gross production in the Maria Conchita Block totaled or exceeded the principal amount plus accrued interest. In February 2021, the full balance of the loan plus accrued interest was repaid by way of the 429,300 units issued under the non-brokered private placement mentioned previously.

SN-9 Loan

In August 2020, the Company entered into a loan in the amount of $2.5 million, secured by the assets of the Company. The loan is denominated in US dollars, matures in August 2022, and bears interest at the rate of 15% per annum. The proceeds of the loan are to be utilized for the costs of exploratory activities in the SN-9 Block. Under the terms of the loan agreement, the lenders have also been granted a 3% overriding royalty on NG's working interest in the gross production of the SN-9 Block. Total interest and principal is payable at the maturity date, although the lenders have an option to convert the loan principal and interest into another 3% overriding royalty on NG's working interest in the gross production of the SN-9 Block at the lenders' discretion at any point prior to the maturity date. Currently, no value has been attributed to the 3% overriding royalty or the conversion option for an additional 3% overriding royalty as this is contingent upon the successful realization of commercially viable operations within the SN-9 Block.

Of the principal amount of the SN-9 loan, $0.6 million of the principal of the SN-9 loan is recognized as a "drawdown" facility given this funding has been made available to the Company for purposes of covering expenditures on the SN-9 Block as necessary, in contrast to the other $1.9 million of the principal being provided as cash funds to the Company on the date of issuance. In June 2021, cash funding for the full amount of the drawdown facility was transferred to the Company, bringing the loan amount from $1.9 million to $2.5 million.

Restricted Cash

As of September 30, 2021, funds totaling $2,426,520 (December 31, 2020 - $2,706,991) were classified as restricted cash. The composition of this amount is as follows:

	2021	**2020**
SN-9 ANH Guarantee	2,114,846	2,362,822
Tiburon ANH Guarantee	311,674	344,169
	2,426,520	**2,706,991**

Term deposits of $2.4 million and $0.3 million were established to secure performance guarantees required by the ANH under the E&P Contracts for the SN-9 and Tiburon Block. The SN-9 and Tiburon deposits amounts are 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. These deposits are to be released to the Company once current phase commitments under each E&P Contract are completed. As of September 30, 2021, the balances of the SN-9 term deposit and Tiburon term deposit were $2,114,846 and $311,674 respectively.

SHARE CAPITAL

Common shares

As at September 30, 2021, 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 share and to dividends, if declared. Outstanding common shares as of September 30, 2021 are as follows:

	Common shares	Amount ($)
Balance, December 31, 2019	30,175,840	64,997,628
Shares issued through private placements (net of costs)	16,072,823	3,287,545
Conversion of debentures	21,666,659	10,657,548
Shares issued through warrant exercise	20,544,992	10,444,789
Shares issued through option exercise	330,000	173,763
Shares issued for interest payment	806,719	115,122
Balance, December 31, 2020	89,597,033	89,676,395
Shares issued through private placements (net of costs)	8,939,300	5,633,876
Shares issued to service provider	4,000,000	1,099,592
Shares issued through warrant exercise	6,467,232	2,116,569
Shares issued through option exercise	170,000	72,797
Balance, September 30, 2021	**109,173,565**	**98,599,229**

February 2021 bought deal and non-brokered private placement

In February 2021, the Company completed a bought deal private placement, pursuant to which a syndicate of underwriters purchased 7,400,000 units and exercised its option to purchase an additional 1,110,000 units, an aggregate of 8,510,000 units at a price of C$1.15 per unit for aggregate gross proceeds to the Company of $7,712,586 (C$9,786,500) before transaction costs. Each unit consists of one common share of the Company and one-half of one common share purchase warrant, with each whole warrant entitling the holder to purchase one common share at a price of C$1.75 until February 10, 2024.

In connection with the offering, the underwriters received a cash commission equal to 6% of the gross proceeds raised and 510,600 non-transferable broker warrants equal to 6.0% of the aggregate number of units sold. Each broker warrant is exercisable into one common share at a price of C$1.15 per share until February 10, 2024. The net proceeds of the offering will be used for working capital and general corporate purposes.

In parallel with the bought deal financing, the Company completed a non-brokered private placement offering of 429,300 units, on the same terms as those issued pursuant to the bought deal financing, for a deemed value of $388,452 (C$493,695). No fees or commissions were paid to the underwriters in connection with the private placement. The issuance of these units was completed as repayment of the outstanding balance of the Maria Conchita Loan of $350,000 plus accrued interest.

Settlement of services for shares

Pursuant to a Memorandum of Understanding with Panacol Oil and Gas Corp. ("Panacol") and Landsons Investment Corp. ("Landsons"), the Company formalized the definitive agreement in December 2020 to issue an aggregate of 4,000,000 common shares. In February 2021, the terms of the definitive agreement were completed as the Company issued 2,800,000 common shares to Panacol in satisfaction of project management services provided and 1,200,000 common shares to Landsons for services provided towards obtaining the environmental and social licenses for the SN-9 project.

Stock Options

The Company's stock option plan provides for the issue of stock options to directors, officers, employees, charities and consultants, who are all considered related parties to the Company. The plan provides that stock options may be granted up to a number equal to 10% of the Company's outstanding 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 at September 30, 2021, a total of 9,915,400 (December 31, 2020 – 7,912,600) 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, 2019	2,876,600	1.33
Options issued	5,456,000	0.79
Options exercised	(330,000)	0.42
Options expired	(90,000)	0.45
Balance, December 31, 2020	7,912,600	1.01
Options issued	2,250,000	0.91
Options exercised	(170,000)	0.33
Options forfeited	(77,200)	7.95
Options amended (old price)	(125,000)	8.00
Options amended (new price)	125,000	0.91
Balance, September 30, 2021	**9,915,400**	**0.85**

In July 2021, the Company granted an aggregate of 2,250,000 stock options under the Company's stock option plan to directors, officers, employees, consultants of the Company and charitable organizations with an exercise price of C$0.91 per stock option, exercisable for a period of 10 years from July 15, 2021, the date of the grant. In addition, the Company also re-priced 125,000 stock options previously granted to charitable organizations to an exercise price of C$0.91. Of the options granted, the Company issued 50,000 stock options to a charitable organization and 100,000 stock options to a consulting firm that have an affiliation with certain directors of the Company.

The following summarizes information about stock options outstanding as at September 30, 2021:

Exercise prices (C$)	Number of options outstanding	Weighted average term to expiry (years)	Number of options exercisable
0.275	1,376,000	8.73	1,376,000
0.45	2,125,000	7.76	2,125,000
0.91	2,375,000	9.58	2,375,000
1.00	3,900,000	9.15	3,900,000
6.10	29,400	4.89	29,400
8.00	110,000	5.86	110,000
	9,915,400	**8.85**	**9,915,400**

Warrants

As at September 30, 2021, a total of 19,962,763 (December 31, 2020 – 21,449,745) 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, 2019	6,291,666	9.40
Warrants issued on convertible debenture conversion	21,666,659	0.15
Warrants issued on private placement, March 2020	2,000,000	0.18
Warrants issued on private placement, May 2020	10,000,000	0.23
Warrants issued on private placement, December 2020	2,036,412	1.50
Warrants exercised	(20,544,992)	0.15
Balance, December 31, 2020	21,449,745	3.03
Warrants issued on private placement, February 2021	4,469,650	1.75
Broker warrants issued on private placement, February 2021	510,600	1.15
Warrants exercised	(6,467,232)	0.20
Balance, September 30, 2021	**19,962,763**	**1.28**

Pursuant to the bought deal and non-brokered private placement of units in February 2021 (see above), the Company issued 8,510,000 units and 429,300 units, respectively, each consisting of one common share and one-half share purchase warrant. Each full warrant can be exercised to purchase one additional common share at a price of C$1.75 until February 10, 2024. In connection with the above, the underwriters received 510,600 non-transferable broker warrants equal to 6.0% of the aggregate number of units sold. Each broker warrant is exercisable into one common share at a price of C$1.15 per share until February 10, 2024.

The following summarizes information about total purchase warrants outstanding as at September 30, 2021:

Exercise prices (C$)	Number of warrants outstanding	Weighted average term to expiry (years)	Number of warrants exercisable
0.18	2,000,000	0.49	2,000,000
0.23	5,321,101	0.66	5,321,101
1.15	510,600	2.36	510,600
1.50	2,036,412	2.25	2,036,412
1.75	4,469,650	2.36	4,469,650
10.50	5,625,000	0.83	5,625,000
	19,962,763	**1.28**	**19,962,763**

Subsequent to September 30, 2021, warrant holders have exercised 2,564,990 warrants resulting in the issuance of 2,564,990 common shares. Based on the exercise price of warrants exercised, approximately C$721,214 in gross proceeds was received by the Company.

As of the date of this MD&A, the Company has 119,880,155 common shares, 9,915,400 stock options, and 25,539,373 warrants.

COMMITMENT SUMMARY UPDATE

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

Block	2022	2023	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 process and interpret 204.4 km of 2D seismic and drill one exploration well (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. On account of the ongoing COVID-19 outbreak during which non-essential oil & gas operations were suspended by the Government of Colombia for several months, program extensions are being provided by the ANH. The Company expects that the extension request to the ANH for an additional 6 months on the current deadline of December 2021 will be granted.
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 2022.

The expenditures provided in the above table only represent the Company's estimated cost to satisfy contract requirements. Actual expenditures to satisfy these commitments, initiate production or create 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.

In December 2020, the Company entered into a memorandum of understanding (the "MOU") with GTX International Corp. ("GTX") pursuant to which GTX is to build and 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 field in Colombia to existing national infrastructure. The MOU outlines that the Company and GTX will enter into a take-or-pay agreement (the “ToP Agreement”) pursuant to which NG will agree 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 per thousand cubic feet (“mcf”) of gas. The ToP Agreement will have a term of 18 years and the Company’s Guaranteed Commitment will convert after six years into payment for only the capacity that is used. Under the terms of the MOU, the execution of the ToP Agreement is conditional upon 1) the successful acquisition by GTX of $10 million in financing, and 2) the construction of the Pipeline Facilities and the satisfactory results of operational trials of the infrastructure by GTX. In February 2021, GTX completed a $10 million brokered offering of senior-secured debentures that bear interest at a rate of 15% per annum, payable monthly, which mature six years from the issuance date. Of the $10 million raised, $2.6 million of the debenture offering was subscribed for by directors or affiliates of directors of NGE. As of the date hereof, construction of the Pipeline Facilities by GTX is still in progress.

RELATED PARTIES

During the period ended September 30, 2021 and 2020, there were separate related party transactions as follows:

I. The Company paid a monthly advisory fee to a firm affiliated with a director of NG. As per the consulting agreement with this firm, NG pays a monthly fee of C$10,000 (September 30, 2020 – C$10,000) plus reimbursable expenses. Furthermore, additional fees are to be paid pursuant to the closing of successful financing arrangements, divestitures, or acquisitions for which the firm provides advisory services. During the period ended September 30, 2021, administrative success fees were paid upon closing of the private placement through units which resulted in the Company paying C$102,802 to the firm. During the period ended September 30, 2020, administrative success fees were paid upon closing of the private placement through units which resulted in the Company paying C$21,000 to the firm. Also during the period ended September 30, 2020, in conjunction with the completion of the Maria Conchita and SN-9 loan, the firm was paid $28,500 as an administrative success fee for their advisory services. As at September 30, 2021, there were no outstanding payables owed to the firm.

II. For periods ended September 30, 2021, and 2020, the Company incurred expenditures of $31,728 and $42,309 respectively, in office rental costs in Colombia. The related office space was rented from an entity affiliated with a certain director of the Company.

III. For the periods ended September 30, 2021 and 2020, the Company incurred expenditures of $269,103 and $247,668 respectively, in professional fees for general corporate services as well as technical services related to exploration activities in Colombia. Such services were provided by a contracted service provider affiliated with a certain director of the Company. For the year ended December 31, 2020, the Company issued 320,000 stock option to members of the service provider. The Black-Scholes fair value recognized in the form of the expense associated with the vesting of these options was $104,835. As at September 30, 2021, there were no outstanding payables owed to the firm.

IV. In July 2021, the Company issued 50,000 and 100,000 stock options to a charitable organization and a consulting firm that have affiliations with certain directors of the Company. The Black-Scholes fair value recognized in the form of expenses associated with the vesting of these options was $35,440 and $70,879 respectively.

V. In February 2021, the Company completed the non-brokered private placement offering 429,300, on the same terms as those issued pursuant to the bought deal financing, for a deemed value of $388,452 (C$493,695). The issuance of the non-brokered private placement through units was completed as repayment for the outstanding balance of the Maria Conchita loan of $350,000 plus accrued interest. Of the units issued, 253,000 units were issued to Company directors.

VI. For the year ended December 31, 2020, the Company issued 205,000 stock options to charitable organizations that have affiliations with certain directors of the Company. The Black-Scholes fair value recognized in the form of the expense associated with the vesting of these options was $32,385.

VII. For the year ended December 31, 2020, the Company recognized expenditures on exploration activities of $1,099,592 for technical services provided from certain service providers affiliated with certain directors of the Company. Furthermore, or the year ended December 31, 2020, the Company issued 230,000 stock options, to members of the service providers. As at September 30, 2021, there were no outstanding payables owed to the service providers.

VIII. In August 2020, the Company completed the debt financing arrangement of the SN-9 loan for committed proceeds of $2,500,000 before transaction costs. Of the total loan proceeds including the drawdown facility, approximately $1,512,500 were provided by directors of the Company.

IX. In July 2020, the Company completed the debt financing arrangement of the Maria Conchita loan for proceeds of $350,000 before transaction costs. Of the total loan proceeds, approximately $206,250 were provided by directors of the Company. The full balance of the loan and interest were repaid to the lenders in February 2021 through the issuance of units of the Company (see above).

X. In May 2020, the Company completed the non-brokered private placement through units for proceeds of C$1,800,000 before issue costs. Of the total proceeds, approximately C$339,480 were from subscriptions by directors or by investors related to directors of the Company.

XI. In May 2020, the Company completed the debt financing arrangement of a bridge loan for proceeds of $100,000. Total loan proceeds were provided by a director of the Company. The full balance of the loan and $3,000 in interest were repaid to the lender in August 2020.

XII. In March 2020, the Company completed the non-brokered private placement through units for proceeds of C$300,000 before issue costs. Of the total proceeds, approximately C$265,000 were from subscriptions by directors or by investors related to directors of the Company.

SELECTED QUARTERLY INFORMATION

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

	Q3 2021	Q2 2021	Q1 2021	Q4 2020
Net loss	(2,350,803)	(936,492)	(1,298,672)	(19,153,079)
Comprehensive loss	(2,231,135)	(897,121)	(1,282,873)	(19,683,899)
Net loss per share (basic & diluted):	(0.02)	(0.01)	(0.01)	(0.23)

	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Net income (loss) from continuing operations	(15,210,453)	(2,449,415)	160,170	2,062,356
Loss from discontinued operations	(1,232,194)	(106,130)	(353,039)	(4,996,076)
Net loss	(16,442,647)	(2,555,545)	(192,869)	(2,933,720)
Comprehensive income (loss)	(17,047,824)	(2,735,973)	312,545	(3,002,598)
Net income (loss) per share (basic & diluted):				
Continuing operations	(0.32)	(0.07)	0.01	0.07
Discontinued operations	(0.03)	-	(0.01)	(0.17)
Net loss	(0.35)	(0.07)	0.00	(0.10)

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 these consolidated financial statements:

i) *Identification of cash-generating units*
The Company's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

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 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*
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 VAT on purchases is recoverable from the Colombian government. Management evaluates the timing and likelihood of future sales to determine if the VAT paid on purchases can be applied to VAT collected on sales, thereby utilizing the VAT paid by the Company to reduce any future VAT remittance obligations.

Key sources of estimation uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period, that 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 and probable reserves and prospective resource estimates include estimates regarding production profile, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves and prospective resources may change from period to period. Changes in reported reserves and prospective resources can impact the carrying values of the Company's petroleum and 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 petroleum and natural gas reserves represent the estimated quantities of petroleum, 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 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 petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if the ability to produce is supported by either actual production or conclusive formation tests. Prospective resource 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 petroleum and gas reserves and prospective resources are determined pursuant to National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities.

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 have to 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 profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse.

vi) Derivative liabilities
Derivative liabilities are initially recognized at fair value on the date entered and are subsequently remeasured to their fair value at the end of each reporting period. Changes in the fair value of any derivative instrument are recognized immediately as a component of net finance expense (income) in the consolidated statement of loss and consolidated loss. The fair value of the derivative liabilities is subject to measurement uncertainty due to the assumptions made for the inputs in the Black-Scholes option valuation. In assessing the fair value of derivative liabilities,

estimates have been to be made regarding the expected volatility in share price and risk-free rate at each reporting period end date.

PRINCIPAL BUSINESS RISKS

The Company's business and results of operations are subject to a number of risks and uncertainties including, but not limited to the following:

Crude Oil and Natural Gas Development

Exploration, development, production of oil and natural gas involves a wide variety of risks which include but are not limited to the uncertainty of finding oil and gas in commercial quantities, securing markets, commodity price fluctuations, exchange and interest rate exposure and changes to government regulations, including regulations relating to prices, taxes, royalties and environmental protection. The oil and gas industry is intensely competitive and the Company competes with a large number of companies with greater resources.

The Company's ability to obtain reserves in the future will depend not only on its ability to develop its current properties but also on its ability to acquire new prospects and producing properties. The acquisition, exploration and development of new properties also require that sufficient capital from outside sources will be available to the Company in a timely manner. The availability of equity or debt financing is affected by many factors many of which are beyond the control of the Company.

Foreign Operations

There are a number of risks associated with conducting foreign operations over which the Company has no control, including political instability, potential and actual civil disturbances, ability to repatriate funds, changes in laws affecting foreign ownership and existing contracts, environmental regulations, oil and gas prices, production regulations, royalty rates, income tax law changes, potential expropriation of property without fair compensation and restriction on exports.

Addition of Reserves and Resources

The Company's future crude oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Company successfully discovering and developing or acquiring new reserves and resources. The addition of new reserves and resources will depend not only on the Company's ability to explore and develop properties but also, in the case of reserves, on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that the Company's exploration, development or acquisition efforts will result in the discovery and development of commercial accumulations of oil and natural gas.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the control of the Company. Estimates of reserves depend in large part upon the reliability of available geological and engineering data and require certain assumptions to be made in order to assign reserve volumes. Geological and engineering data is used to determine the probability that a reservoir of oil and/or natural gas exists at a particular location, and whether, and to what extent, such hydrocarbons are recoverable from the reservoir. Accordingly, the ultimate reserves discovered by the Company may be significantly less than the total estimates.

Exploration Risks

The exploration of the Company's properties may from time to time involve a high degree of risk that no production will be obtained or that the production obtained will be insufficient to recover drilling and completion costs. The costs of seismic operations and drilling, completing and operating wells are uncertain to a degree. Cost overruns can adversely affect the economics of the Company's exploration programs and projects. In addition, the Company's seismic operations and drilling plans may be curtailed, delayed or cancelled as a result of numerous factors, including, among others, equipment failures, weather or adverse climate conditions, shortages or delays in obtaining qualified personnel, shortages or delays in the delivery of or access to equipment, community issues and social unrest, necessary governmental, regulatory, or other third party approvals and compliance with regulatory requirements.

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, accounts receivable and restricted cash represent the maximum credit exposure. As at September 30, 2021, the Company had $2,426,520 (December 31, 2020 - $2,706,991) in restricted cash towards development activity and joint operations in Colombia.

As at September 30, 2021, the Company had $1,000,541 (December 31, 2020 - $491,454) in accounts receivable and prepaids. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company does not consider any of its receivables past due.

The Company maintained a VAT receivable balance of $2,162,656 as of September 30, 2021 (December 31, 2020 - $1,651,981), 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.

The Company held cash and cash equivalents of $1,690,663 (December 31, 2020 - $1,208,765) as at September 30, 2021. The Company manages the credit exposure related to cash and cash equivalents and short-term investments by selecting counter parties (i.e., Banks) based on 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 at September 30, 2021:

	Less than 1 year	1-2 years	Thereafter	Total
Trade accounts payable	2,076,467	-	-	2,076,467
Capital payables	962,319			962,319
Aruchara loan - principal	1,600,000	-	-	1,600,000
SN-9 loan - principal	2,500,000	-	-	2,500,000
Aruchara loan - finance costs	436,666	-	-	436,666
SN-9 loan - finance costs	420,458	-	-	420,458
	7,995,910	**-**	**-**	**7,995,910**

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 at September 30, 2021 nor were there any in the previous year ended December 31, 2020.

Commodity price risk

Commodity price risk is the risk that the fair value of the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and 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 oil revenue was previously derived from oil production on the SRDE Asset in Argentina. With the disposal of Argentina operations in October 2020 (see above), the Company currently has no production revenue.

Foreign currency risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result 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$), respectively. In addition, the majority of the Company's financing and a portion of the administrative costs will be based and paid in Canadian dollars and COP$. Therefore, the Company is exposed to the risk of fluctuations in foreign exchange rates between US dollars, COP$ and Canadian dollars. As at September 30, 2021, the Company had not entered into 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, 2020.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in prevailing market interest rates. Fluctuations of interest rates for the period ended September 30, 2021 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, labour 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 from time to time in the reports and filings made by the Company with securities regulatory authorities.

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 properties and estimated capital commitments and probability of success,
- crude oil production and recovery estimates and targets,
- the existence and size of the oil reserves and resources,
- 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 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 in light of 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 a number of 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 favourable relations with Latin American governmental agencies,
- continuing strong demand for 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 oil successfully to customers,
- the Company's future production levels and oil prices,
- the applicability of technologies for recovery and production of the Company's oil reserves,
- the existence and recoverability of any oil 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 following risks and uncertainties:

- global financial conditions,
- general economic, market and business conditions,
- volatility in market prices for oil and natural gas, the stock market, foreign exchange and interest rates,
- risks inherent in oil and gas operations, exploration, development and production,
- risks inherent in the Company's international operations, including security, political, sovereignty and legal risks in Colombia,
- the failure by counterparties to make payments or perform their operational or other obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties,
- risks related to the timing of completion of the Company's projects and plans,
- uncertainties associated with estimating oil and natural gas reserves and resources,
- competition for, among other things, capital, acquisitions of resources, undeveloped lands and skilled personnel,
- the Company's ability to hold existing leases through drilling or lease extensions or otherwise,
- incorrect assessments of the value of acquisitions or title to properties,
- the failure of the Company or the holder of certain licenses or leases to meet specific requirements of such licenses or leases,
- claims made in respect of the Company's properties or assets,
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties,
- environmental risks and hazards,
- failure to estimate accurately abandonment and reclamation costs,
- the inaccuracy of third parties' reviews, reports and projections,
- rising costs of labour and equipment,
- the failure to engage or retain key personnel,
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry, and
- the other factors discussed under "Principal Business Risks" in this MD&A.

Readers are cautioned that the foregoing lists of assumptions, risks and uncertainties are not exhaustive. 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 except as required by applicable securities laws.

Analogous Information

Certain information in this MD&A may constitute "analogous information" as defined in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("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. In particular, 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 as a result 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 believes the information may be relevant to help define the reservoir characteristics within lands on which NG holds an interest and such information has been presented to help demonstrate the basis for NG's business plans and strategies. However, management cannot confirm whether such analogous information has been prepared in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook and NG is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. NG 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 and such information should not be construed as an estimate of future production levels or the actual characteristics and quality NG's assets. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by NG 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 may be in error and/or may not be analogous to such lands to be held by NG.

Barrels of Oil Equivalent

Where amounts are expressed in a barrel of oil equivalent (“boe”), or barrel of oil equivalent per day (“boe/d”), natural gas volumes have been converted to barrels of oil equivalent on the basis that 6 thousand cubic feet (“mcf”) is equal to one barrel of oil. Use of the term boe may be misleading, particularly if used in isolation. This boe conversion ratio is based on an energy equivalence methodology and does not represent a value equivalency. Indeed, the energy and value relationships may differ widely with market conditions. The conversion does conform to the Canadian Securities Regulators’ National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities.

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*
mmbbl	*million barrels*
mmboe	*million barrels of oil equivalent*
mmcf/d	*million cubic feet per day*
NGLs	*natural gas liquids*
API	*American Petroleum Industry gravity*
m^3	*meters cubed*
ppm	*parts per million*
psig	*pounds per square in gauge*