TERM SHEET EXECUTED WITH THE IDC TO DEVELOP SOUTH AFRICA'S LARGEST ONSHORE LNG PROJECT

HIGHLIGHTS

- **Afro Energy (Pty) Ltd ("Afro Energy"), a subsidiary of Kinetiko Energy Limited[1] ("KKO"), has executed a non-binding Term Sheet ("Term Sheet") with the Industrial Development Corporation of South Africa ("IDC") to co-develop a new joint venture ("JV") for the appraisal and production of LNG to deliver 50MW growing to 500MW gas equivalent energy.**
- **The first stage 50MW equivalent project is estimated to cost approximately A$138M[2] comprising A$90M[2] equity and A$48M[2] debt.**
  - **IDC shall equity fund approximately A$52M[2] for 30% JV interest.**
  - **Afro Energy shall equity fund approximately $A38M[2] for 70% JV interest.**
  - **Afro Energy has the right to introduce third party investors to the JV for part or all of its 70% interest and can stage payment.**
- **The second stage intends the parties expand the JV to 500MW LNG gas equivalent, which would be the largest on shore LNG project in South Africa. The IDC intends to fund 30% of the second stage development.**
- **The IDC has been granted the option to participate in the co-development of further 1,000MW LNG gas equivalent projects, totalling 1.5GW.**
- **The Term Sheet underpins the Company's strategic objectives to unlock over 2TCF in gas reserves and become a sustainable cleaner energy solution for the South African economy.**

[1] Kinetiko Energy Limited currently holds 49% economic interest in Afro Energy (Pty) Ltd, being the entity which holds the exploration permits. Kinetiko notes, however, that it has recently obtained the necessary shareholder approvals allowing it to, among other things, acquire a 100% economic interest in Afro Energy, and expects to complete the transaction shortly.
Once the acquisition is complete, Kinetiko will be the sole shareholder of Afro Energy and therefore all the obligations noted for Afro Energy under the Term Sheet will then be assumed 100% by KKO.
[2] The Term Sheet uses South African Rand to set out the respective parties' financial commitments. For the purposes of this announcement all Australian dollar amounts use an exchange rate of Rand/ AUD of 0.0825: 1 as at 20 August 2023 sources from XE.com

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Kinetiko Energy Ltd (ASX: **KKO**) (“**Kinetiko”** or “**the Company”**) is developing an energy transition solution for South Africa focused on commercialising advanced shallow conventional gas and coal bed methane projects, is pleased to provide the following update on its onshore gas exploration and production development activities.

Kinetiko CEO, Nick de Blocq, commented:

> *“This is a step change in the scale of the Company’s development and represents a national project to support South Africa’s transition to cleaner, reliable, affordable energy. I cannot overstate the importance of this massive step we have taken in collaboration with our IDC joint venture partners, as it represents a level of confidence in our project from high layers of Government. The project has been registered under the Strategic Infrastructural Projects management mechanism that operates from the Office of the President. This is expected to expedite all State and Government-related processes in terms of permitting and licensing and minimising of red-tape. We are beyond delighted to be able to say that our journey towards a large-scale project commercialisation and production has now begun.”*

Material Details of the Term Sheet

The Industrial Development Corporation of South Africa (“**IDC**”) and Afro Energy have executed a non-binding Term Sheet to jointly develop the appraisal and production of natural gas (“**NG**”) within Afro Energy’s granted Exploration Rights for commercial liquified-natural gas (“**LNG**”) use, being the equivalent size of 50MW developing to 500MW. The project consists of the following:

a) “**Block 1**” – a 50MW-equivalent LNG size operation for commercial development of on-shore wells within the existing granted Exploration Rights.

b) “**Further Blocks**” - being the commercial development of additional on-shore natural gas wells within the existing granted Exploration Rights, for the balance of gas for 450MW-equivalent LNG size operations, being incorporated via further block SPV’s.

Block 1 costs of upstream and midstream activities for natural gas development are approximately R1.68B (One billion and six hundred and eighty million South African Rand). The Sproule Report (attached in full to this announcement, and also summarised in Company’s ASX announcement dated 21 August 2023) outlines the capital expenditure and operating costs assumptions that provide the

Company with a reasonable basis for the Block 1 project having positive economics The gas is intended be sold to an LNG-offtaker to supply 50MW of equivalent LNG.

While off take agreements are not in place KKO has executed a memorandum of understanding with FFS Refiners (refer Company's ASX announcement dated 2 March 2023) and letter of intent with Gruner Energy (refer Company's announcement 16 February 2023) for the potential off take of LNG. The envisaged capital and funding structure of the Project for Block 1 is as follows:

a) The R1.68B (A$138M) of required funding to be split:
   1. Equity R1.09B (A$90M) (65%); and
   2. Debt R0.59B (A$48M) (35%)

b) The IDC will invest equity totalling R630M for a 30% share of the equity in the Block 1 SPV:
   a. R435M (A$52M) on the effective date of the Shareholders Agreement; and
   b. R195M (A$16M) on successful completion of the bankable feasibility study

c) Afro Energy can invest the remaining R456M (A$38M) for a 70% share of the equity in Block 1 SPV;

d) The IDC to provide debt funding of R210M (A$17M) of the R590M (A$48M) debt funding on successful completion of the bankable feasibility study; and

e) The IDC shall underwrite any equity shortfall on Afro Energy's 70% equity portion for the 50MW-equivalent project. The IDC underwriting shall be limited such that it shall be restricted to no more than 49.99% equity Block 1 SPV.

Afro Energy is not obligated to invest the R456M (A$38M) and has the right to introduce a third party investor for part or all its 70% interest in Block 1 but only with the prior written consent of the IDC which shall not be unreasonably withheld. The Term Sheet does not stipulate a timing obligation on Afro Energy to invest for its 70%. However, given the existing binding joint venture the Company has with the IDC it anticipates that it will need to provide funding contemporaneously with the IDC's investment and the formal terms of such investment will be set out in the formal transaction documentation, including shareholders agreement, to be entered into by the parties shortly and disclosed to the market in accordance with KKO's continuous disclosure obligations under the ASX Listing Rules.

The scope of the bankable feasibility study has not been defined, however the Company anticipates given its existing binding joint venture with the IDC that it will work with the IDC to agree economic parameters for the bankable feasibility study expected to be completed with the conclusion of IDC internal approvals.

The parties estimate that Block 1 for 50 MW equivalent of LNG will be developed over 2-3 years and Further Blocks for 450 MW equivalent of LNG will be developed over 9-10 years.

Block 1 SPV and Further Block SPV's will only deal with the upstream activities. The parties hereby agree to create another SPV ("**SPV2**"), for downstream and midstream activities, where the LNG off-taker/investor will directly invest into, which until then is initially held 70% by IDC and 30% by Afro Energy.

For the Further Blocks the IDC will participate as 30% equity investor for the gas required for the 450MW equivalent in LNG and Afro Energy has the right to introduce a third-party investor for part of its 70% share in SPV 1 and Further Blocks but only with the prior written consent from the IDC, which consent shall not be unreasonably withheld.

Afro Energy shall retain gas resources for IDC participation for the 500 MW-equivalent LNG of 0.7TCF plus an option in favour of IDC for another 1000 MW-equivalent equating to 1.4TCF, totalling 1500 MW-equivalent or 2.1 TCF.

The IDC has been granted a 60-day exclusivity period in which the parties will endeavour to complete the formal legal documentation and obtain necessary internal approvals to give rise to binding obligations. The IDC internal approvals include the execution of finance documents comprising joint venture agreements, shareholder agreements and loan agreements which must be approved by the IDC investment committee and board.

Kinetiko Energy Limited currently holds 49% economic interest in Afro Energy (Pty) Ltd, being the entity which holds the exploration permits. Kinetiko notes, however, that it has recently obtained the necessary shareholder approvals allowing it to, among other things, acquire a 100% economic interest in Afro Energy, and expects to complete the transaction shortly. Once the acquisition is complete, Kinetiko will be the sole shareholder of Afro Energy and therefore all the obligations noted for Afro Energy under the Term Sheet will then be assumed 100% by KKO.

About IDC

The Industrial Development Corporation is a national development finance institution whose primary objectives are to contribute to the generation of balanced, sustainable economic growth in Africa, and to the economic empowerment of the South African population, thereby promoting the economic prosperity of all citizens. The IDC achieves this by promoting entrepreneurship through the building of competitive industries and enterprises based on sound business principles. www.idc.co.za

-ENDS-

This announcement is authorised for release to the market by the Board of Directors of Kinetiko Energy Limited.

For more information visit: www.kinetiko.com.au or contact,

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About Kinetiko Energy and Afro Energy

Kinetiko Energy is an Australian gas explorer focused on advanced shallow conventional gas and coal bed methane (CBM) opportunities in rapidly developing markets in Southern Africa. South Africa has extensive gassy coal basins, widespread energy infrastructure and growing gas demand. The Company has achieved maiden gas reserves and a 6Tcf 2C contingent resources and large potential exploration area, comprising approximately 6,000km2 of granted and applied exploration rights.

The Company's vision is to commercialise an energy transition solution for South Africa.

ASX: KKO | kinetikoenergy.com.au

Independent Reserve Evaluation Report

Estimation of Natural Gas Reserves and Resources with Associated Economics of the Licenses ER 270, 271 & 272 in the Republic of South Africa

As of July 1, 2023

Submitted to: Kinetiko Energy Limited

Think Energy. Discover Value

Sproule

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August 14, 2023

Mr. Nicholas de Blocq
Chief Executive Officer
Kinetiko Energy Limited
4118 4th Floor
Sunclare Centre
Claremont, 7706
Republic of South Africa

Re: Estimation of Natural Gas Reserves and Resources with Associated Economics of the Licenses ER 270, 271 & 272 in the Republic of South Africa (As of July 1, 2023)

Dear Mr. de Blocq:

At the request of Kinetiko Energy Limited ("Kinetiko" or "Company"), Sproule B.V. ("Sproule"), an independent sub-surface consultancy based in Calgary, Canada, has conducted an independent evaluation of the conventional natural gas reserves and resources in South African Licences ER 270, 271 and 272 which, as of the date of the report, are owned 49% by Afro Energy and 51% by Badimo Gas. Kinetiko has signed a restructuring agreement with both parties with the planned intention for a full merger of both Afro Energy and Badimo Gas into Kinetiko within 2023. Thus, for the purposes of this report all of the reserves and resource tables are presented as a 100% working interest at the request of Kinetiko although technically, at the date of the report, they are a partner of Afro Energy; a minority interest holder in all three licenses. Kinetiko, on behalf of the partnership, has applied to the Petroleum Agency of South Africa to advance the licenses from exploration rights to production rights. The Amersfoort Gas Field, on the Exploration Right ER271, is located in the Mpumalanga Province of the Republic of South Africa and Kinetiko operates the license under the name of Afro Energy, a wholly owned subsidiary. This evaluation is both a geologic and an economic evaluation, based on the analysis methodology described herein using technical and economic data supplied by Kinetiko, and has an effective date of July 1, 2023.

This evaluation includes estimates of recoverable gas volumes from Proved Reserves including Proved Developed Non-Producing wells (PDNPs) and Proved Undeveloped locations (PUDs) of a thirty (30) gas well program to support an LNG facility. In addition to the total Proved Reserves, Probable and Possible reserves are also estimated. Associated pre-tax net present value of future income for selected discount rates are presented for Reserves volumes. The estimates of Reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of Reserves and future net revenue for all properties, because of aggregation. Further, estimates of Net Present Value, either discounted or undiscounted, are a calculation of the Reserve value at a given date and are not a representation of the fair market value of a company or corporation owning a working interest in the project. This evaluation is limited to the Amersfoort Gas Field within ER271 and is not nor should not be construed as an evaluation of the entirety of ER271.

The independent Reserve estimates and associated economics contained in this report are prepared in accordance with the Society of Petroleum Engineers (SPE) Petroleum Resources Management (PRMS) guidance and provides a Technical Value, defined as an assessment of a mineral asset's future net economic benefit at the valuation date under a set of assumptions deemed most appropriate by a practitioner excluding any premium or discount to account for market considerations. These estimates are also in accordance with both the Australian Stock Exchange (ASX) rules (specifically Listing Rule 05 for Oil and Gas Companies) and the Johannesburg SAMOG code for oil and gas reporting in conjunction with the SPE PRMS guidance and specific additional rules. Sproule's evaluation is based upon data supplied by Kinetiko and the monetary estimates used for the economic evaluation, supplemented where necessary by Sproule's corporate awareness of current South African industry costs and best practices. A site visit was not required to prepare this report as one of the principals, namely Mr. Aldrich, is very familiar with Mpumalanga Province and drilling core holes in the Amersfoort Gas Field.

Reserve and Resource Estimates

The independent reserve and resource estimates presented in this report have been prepared for publication in both South Africa under the SAMOG regulatory guides and Australia using an evaluation approach for unconventional resources consistent with Society of Petroleum Engineers Petroleum Resources Management System (SPE PRMS) 2018 and the SPE 2011 PRMS Application Guidelines. The Reserve estimates contained in this report have been prepared as of July 1, 2023 and are independently generated from the data supplied to Sproule from Kinetiko. Sustained commercial sales of natural gas from pilots located on the Kinetiko licenses and periodic measurements of the free flow gas volumes from multiple blowers, some producing for decades, allow estimation of the gas production decline rate and thus ultimate recoverable volumes of gas.

Estimated net natural gas reserves and the associated net present values at discount rates specified by Kinetiko are summarized in Table 1. For the purposes of clarification, the use of the abbreviation 'MM' equates to millions of the specified currency, or volumes, and the abbreviation 'M' equates to thousands of the specified currency, or volumes throughout this text. Sproule has calculated the economics according to the assumptions detailed in the following report and are presented in Table 1 as both Undiscounted (NPV=0%), and at the specified discount factors. Sproule makes no recommendation as to which discount factor should be used.

The net reserves and net present values presented in Table 1 are for a 30-well development program in which 5 previously drilled DST wells (which will be converted to PDP wells) are categorized as PDNP reserves. The PUD reserves consist of 25 new wells which will be drilled as part of the development program. Since the economics were run on a total 30-well project basis (not individual well basis), the PDNP reserves and values were determined by multiplying the Total 1P values by 16.7% (or 5/30 th's). The PUD reserves and values were determined by multiplying the Total 1P values by 83.3% (or 25/30 th's).

Table 1: Summary of Net Gas Reserves and Net Present Values at Selected Discount Rates for ER 271 Gas Field Development Project

	PDP	PDNP	PUD	Total Proved (1P)	Proved + Probable (2P)	Proved+ Probable+ Possible (3P)
Gas (MMCF)	0.0	655.3	3,276.5	3,931.8	6,427.5	10,047.4
Net Present Value (M$US)						
0%	0.0	241.9	1,209.7	1,451.6	11,879.5	27,961.1
5%	0.0	102.0	509.8	611.8	6,159.7	11,888.3
8%	0.0	31.0	155.1	186.1	4,146.1	7,617.4
10%	0.0	-10.0	-49.9	-59.9	3,157.0	5,753.0
15%	0.0	-92.3	-461.6	-553.9	1,468.5	2,890.7

Due to rounding certain totals may not be consistent from one presentation to the next.

Reserves are defined by the PRMS Guidelines as follows; Proved Reserves (1P) are defined as meaning 90% or greater confidence that the volumes will be produced, Proved Plus Probable Reserves (2P) means there is a 50% or greater confidence of the volumes being produced and the Proved Plus Probable Plus Possible (3P) are Reserves that have a 10% or greater confidence of being produced. Proved, Probable, and Possible Reserves have been assigned to all wells. The following abbreviations are used throughout the report: Proved Developed Producing (PDP) for a well that is currently producing hydrocarbons for commercial production, Proved Developed Non-Producing (PDNP) for a well that has been drilled and completed in a producing reservoir but is not currently, for whatever reason, on production, Proved Undeveloped (PUD) for a well location that is within the area that is defined as having Proved Reserves however the well is as of the date of the report undrilled. Proved, Probable and Possible Reserves were defined according to different type curves, as defined in the report below, and were assigned to each well or future location.

Contingent Resources are those volumes that have been discovered but either are not yet defined sufficiently to be classified as reserves or are not currently planned for development. Contingent Resources were stochastically calculated from the volumetric calculation of the original gas in place (OGIP) times a recovery factor for the sandstone and the CBM plays classified as Contingent Resources. No economics were calculated for the methane. Similar to the reserve categories the C1 category has a 90% confidence the calculated volumes being technically capable of being produced, without economic consideration, the C2 category has a 50% or greater confidence level and the C3 has a 10% or greater confidence level. Estimated net methane Contingent Resources are summarized in Table 2, 3 and 4.

Table 2: Contingent Conventional Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1C	2C	3C
ER 271	1044	1741	2697
ER 270	851	1439	2232
ER 272	823	1093	1423
Total	**2718**	**4273**	**6352**

Table 3: Contingent CBM Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1C	2C	3C
ER-270			
Sorbed CR	78.6	1,028.1	5,896.5
Free CR	-	42.9	1,071.0
Total CR	**78.6**	**1,071.0**	**6,967.5**
ER-271			
Sorbed CR	39.4	515.3	2955.5
Free CR	0	21.5	255.2
Total CR	**39.4**	**536.8**	**3,210.7**
ER-272			
Sorbed CR	11	144.3	827.5
Free CR	0	6	71.5
Total CR	**11.0**	**150.3**	**899.0**
Total CBM CR	**129.0**	**1,758.1**	**11,077.2**

Table 4: Total Contingent Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1C	2C	3C
Total CBM and SST CR	**2,846.0**	**6,031.4**	**17,429.1**

Prospective Resources are, by definition, undiscovered resources. In the Afro Energy License there are areas that have not been adequately explored by well control to state that there are continuous gas columns and continuity of the gas reservoir. There is every reason to anticipate that future drilling will expand the field into these areas and these areas are defined as the Prospective Area. These form drillable targets for gas prospects. Net Prospective Resources were stochastically calculated from the volumetric calculation of the original gas in place (OGIP) times a recovery factor for the sandstone and the CBM plays were classified as Prospective Resources. No economics were calculated for Prospective Resources. Estimated net methane Prospective Resources are summarized in Table 5.

Table 5: Prospective Conventional Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1U	2U	3U
ER 271	0	0	0
ER 270	3201	5413	8396
ER 272	303	406	529
Total	**3504**	**5819**	**8925**

***PROSPECTIVE RESOURCES**: "The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable commercial gases."*

STATEMENT OF RISK

The accuracy of reserves, resources, and economic evaluations is always subject to uncertainty. The magnitude of this uncertainty is generally proportional to the quantity and quality of data available for analysis. As a prospect, project, or well matures and new information becomes available revisions may be required which may either increase or decrease the previous estimates. Sometimes these revisions may result not only in a significant change to the reserves, resources and value assigned to a property, but also may impact the total company reserves, resources and economic status. The independent reserves, resources and economic forecasts contained in this report were based upon a technical analysis of the available data using accepted geoscience and engineering principles. However, they must be accepted with the understanding that further information and future reservoir performance subsequent to the date of the estimate may justify their revision. It is Sproule's opinion that the independent estimated reserves, resources, economics, and other information as specified in this report are reasonable and have been prepared in accordance with generally accepted geoscience and petroleum engineering and evaluation principles. Notwithstanding the aforementioned opinion, Sproule makes no warranties concerning the data and interpretations of such data. Neither Sproule, nor any of its employees have any interest in the subject properties and neither the employment to do this work, nor the compensation, is contingent on Sproule's estimates of the resources or economic evaluations for the properties in this report. This report was prepared for the exclusive use of Kinetiko and can only be relied upon by Kinetiko. Other parties that view the report can do so for informational purposes only unless written consent is provided by Sproule. The report will not be released by Sproule to any other parties without Kinetiko's written permission (other than the stated purpose set out above). The data and work papers used in this preparation of this report are available for examination by authorized parties in Sproule's offices.

Thank you for this opportunity to be of service to Kinetiko. If you have any questions or wish to discuss any aspect of the report further, please feel free to contact either of us.

Sincerely,

Sproule B.V.

Responsible Member Validation

The following Responsible Member of Sproule B.V. certify that our internal quality control process has been completed in accordance with our Professional Practice Management Plan.

Doug Ashton, P.Eng.
Vice President, Reservoir Services

QUALIFICATIONS

Jeffrey B. Aldrich is a Senior Geoscientist in Sproule and is a Certified Petroleum Geologist, #6254, by the American Association of Petroleum Geologists (AAPG) and a Licensed Professional Geoscientist, #394; He is an active member of the AAPG and the Society of Petroleum Engineers (SPE). He has over thirty years as a practicing petroleum geologist/geophysicist and over twenty years of experience in oil and gas reserve evaluations. He holds a Bachelor of Science degree in Geology from Vanderbilt University and a Master's of Science degree in Geology from Texas A&M University. He is an instructor in the PetroSkills Alliance and is the Course Director for "Prospect and Play Analysis", "Evaluating and Developing Shale Reservoirs", "Unconventional Resource and Reserve Estimation", and "Coalbed Methane Reservoirs".

Mark Stouffer is a Senior Petroleum Engineer with over 30 years of experience in reservoir and evaluation engineering in the US and internationally. He is a qualified reserves evaluator, as defined in SEC and SPE-PRMS. Mark has managed and participated in several complex reservoir projects in the U.S. Gulf of Mexico, Permian Basin, Green River Basin, DJ Basin, and internationally in Thailand and Hungary.

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BACKGROUND

Kinetiko's South Africa Amersfoort gas project, which is in the Mpumalanga Province, is approximately 200 km southeast of Johannesburg (Figure 1).

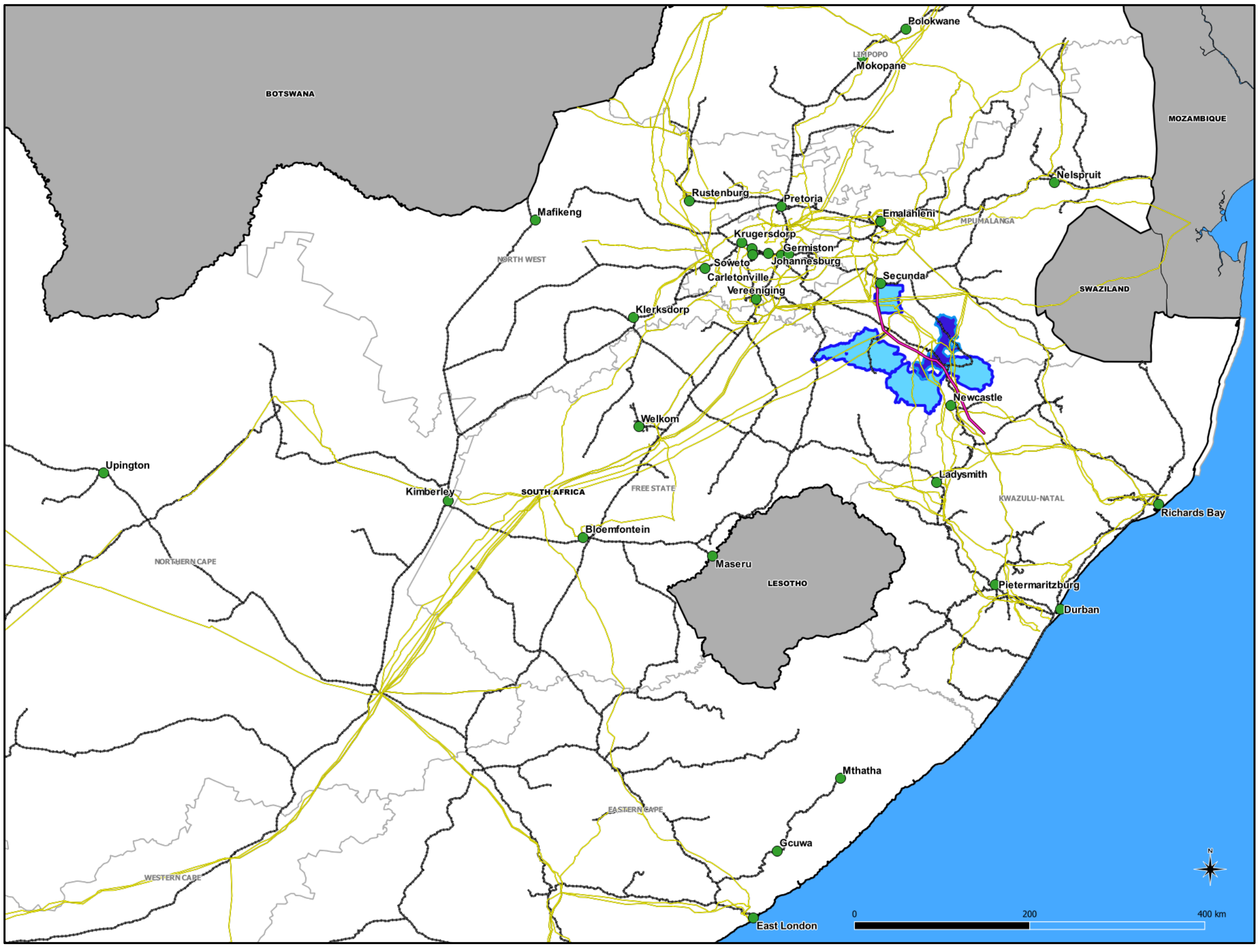

Figure 1: Location Map (Supplied by Kinetiko)

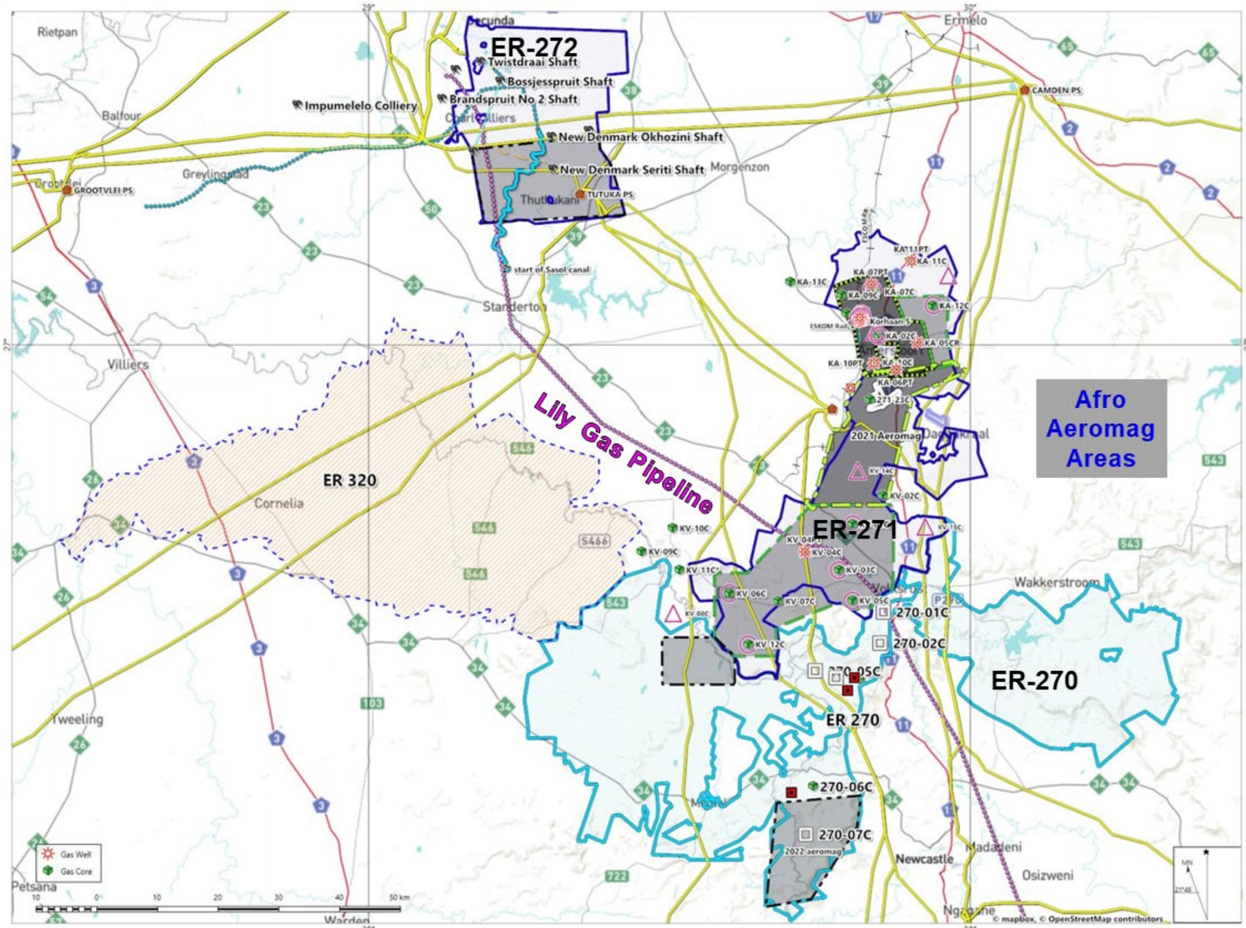

Figure 2: Permit Map ER270, ER271 and ER-272 is the Combined License (Supplied by Kinetiko)

The exploration and production rights, which combined are known as the Amersfoort Gas Project (Figure 2), covers a large area where gas emitting boreholes have been identified from mineral exploration activities. Several of these boreholes are flowing gas at relatively high production rates and have been doing so for decades. Past work programs involved the cataloging and sampling of the gas emitting boreholes, a soil gas geochemistry survey, and structural mapping. The gas emitting boreholes ("blowers") were drilled by mining companies to explore for gold in Witwatersrand formations which underlie the coal-bearing Karoo and Ventersdorp lavas. Some flowing wells were capped due to dangerously high gas emission rates. Kinetiko, through Afro Energy, now owns 100 percent working interest in ER271, ER-270 and ER-272, which, after the relinquishments in the first renewal period, will be 367,866 hectares (909016.68 acres or 3678.66 Km^2). ER271 currently has five wells capable of producing gas to an LNG plant and several other existing permitted locations adjacent to the existing wells.

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The Kinetiko Production License is subject to a 5% government tax as described in the Mineral and Petroleum Resource Development Act of 2002.

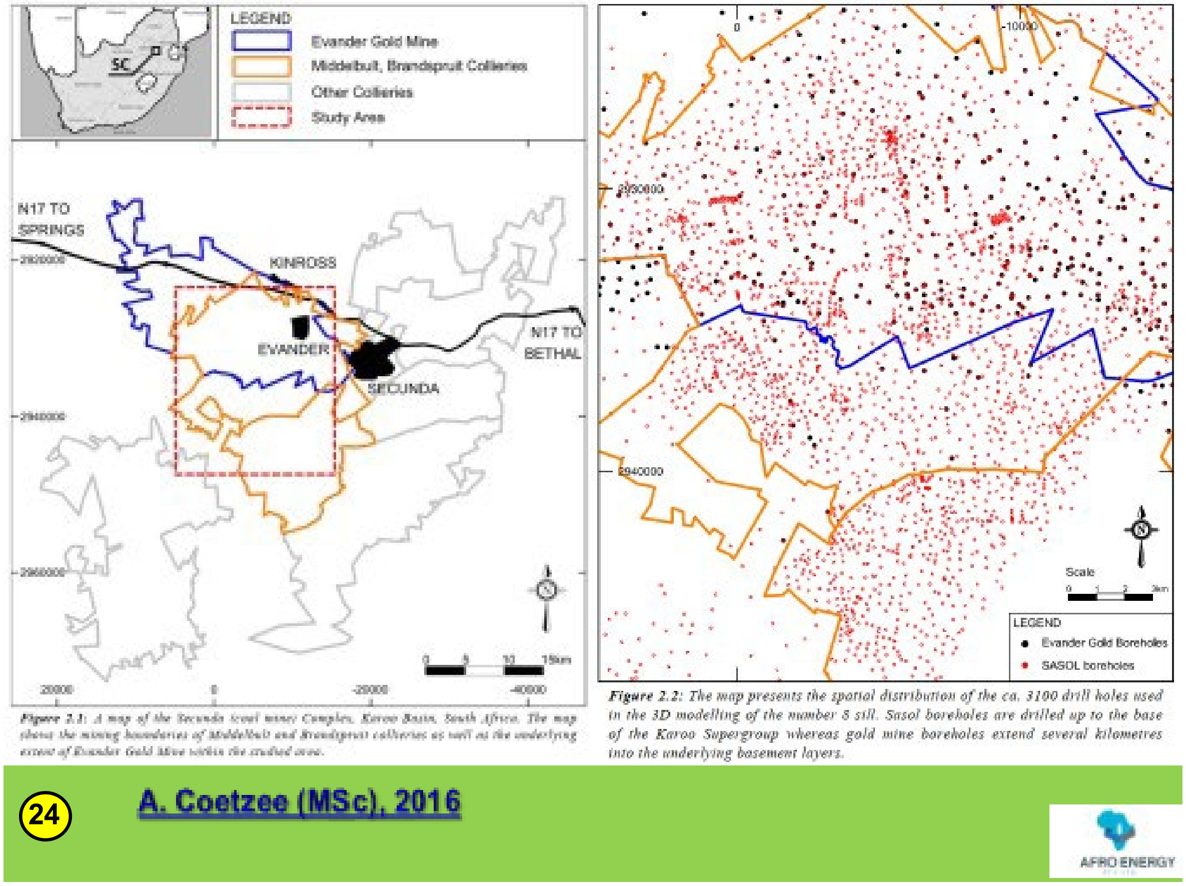


Figure 3: Map of the Regional Well Control (Supplied by Kinetiko)

Sproule has also evaluated gas volumes in the other Kinetiko exploration rights. The Reserve section of this report only refers to the Exploration Right ER271 that has been granted in the center of the Amersfoort Gas Field. The remaining oil and gas resources are categorized as contingent or prospective resources and discussed in the relevant section of this report.

GEOLOGY

REGIONAL GEOLOGY

The Amersfoort Project is located on the northeastern extent of the Karoo Supergroup. The Karoo Supergroup, Figure 4, ranges from Late Carboniferous to Late Jurassic and attains a maximum thickness of approximately 12km in the southeastern portion of the Main Karoo Basin.

Main Karoo Basin, which covers an area of approximately 700,000km^2. Other smaller basins comprising of significant Karoo strata include the Springbok Flats, Ellisras, Tshipise and Tuli Basins to the north of the main basin (Johnson et al., 2006). The Main Karoo Basin constitutes a retro-arc foreland basin wedging north over the Kaapvaal Craton. This basin was produced as deltaic and marginal marine sediments filled the basin during a period of basin formation adjacent to a magmatic arc and fold-thrust belt. Deposition into the Main Karoo Basin commenced with the Dwyka Group, followed by the Ecca, and Beaufort Groups, the Molteno, the Elliot and the Clarens Formations and the igneous Drakensburg Group. The Cape Fold Belt formed while sedimentation of the Karoo strata was still in progress, resulting in intense deformation of the basement, lower Karoo and the Cape Supergroup to the south-western part of the basin (Johnson et al., 2006).

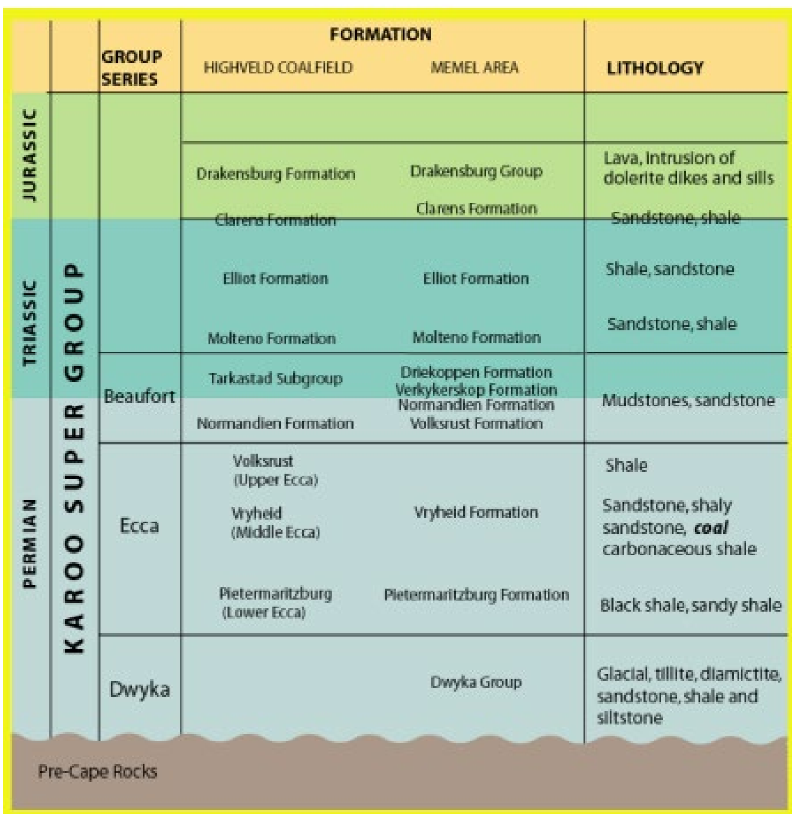


Figure 4: General Stratigraphy of the Karoo Super Group (Supplied by Kinetiko)

Volcanic activity increased during the Jurassic Period which resulted in ash and lava flows interbedded with the sandstones and shales. The Main Karoo Basin, Figure 5, was then filled by basaltic lavas of the Drakensberg Group up to 1,400m thick. Volcanic activity further increased, reflecting the mid-Jurassic break up of African Gondwana and the formation of rifted continental margin basins and rifted continental basins within the continent. General stratigraphy of the Karoo Suppergroup is shown in Figure 4. The extent of the Main Karoo and other Karoo basins is illustrated in Figure 5. The Karoo Supergroup is primarily underlain by Archaean Gneisses with localized Ventersdorp or Witwatersrand Supergroups occurring within the project area. Dykes of the Precambrian Olifants River Dyke Swarm transect the basement geology in the Amersfoort Project area. Karoo age sediments also occur in South America, India, Australia and Antarctica since these five continents were together as the super continent of Gondwana during deposition (Scheffler, 2004). Coals in the Permian age portion of the Karoo Supergroup are geographically widespread and are related to two different depositional settings, the marine foreland basin in Southern Africa and half-graben continental rift basins throughout other areas of Africa.

The Amersfoort Project typically consists of outcrop of Ecca Group sandstone and shales of the Vryheid and Volksrust Formations, which are heavily intruded by Jurassic Period dolerite sills and dykes. In the northeastern portion of the Karoo Basin, the Ecca Group contains coal formations where vegetation grew in large, swampy deltas along the Karoo Basin shores. Coal in the Amersfoort Project area is primarily high volatile bituminous rank and occurs in the Vryheid Formation. The Amersfoort Project occurs over the Ermelo, Highveld, Utrecht and Klip River Coalfields (Venmyn Deloitte, 2016).

Wells evaluated for the reserve evaluation are KA-11PT, KA-07PT, KA-03PT, KA03PT2, KA04PT, KA-05PT, KA-06PT, and KA-10PT. Kinetiko supplied drilling locations for all wells permitted for 2022 and 2023.

The evaluation is based on Kinetiko's development plan of a small-scale gas-to-power project in the area of interest. The area of interest lies to the north and west of the town of Amersfoort, 200 km east southeast of Johannesburg

The target formation for gas production is the Vryheid Formation of the Ecca Group of the Karoo Super Group, as shown in Figure 6. The interval consists of sandstones, siltstones, carbonaceous mudstones, and coals deposited in shore and deltaic settings during Permian time. Dolerite dikes and sills were later injected into this sequence of rocks and provided the heat necessary to convert the organic matter in the sediments to gas. The Project is targeting conventional accumulations of natural gas in sandstone reservoirs that are derived from Coal Bed Methane (CBM) occurring within these Karoo coal seams. Extensive dolerite dykes and sills act as traps for the gas but also compartmentalize the reservoir, both vertically and horizontally. Gas can be extracted from the coal and sandstone without fracking

The main trapping mechanism for the gas is provided by the thick dolerite top sill that is ubiquitously present in the areas. Other dolerite dikes and sills, and clastic facies changes may provide for further lateral and vertical barriers or baffles.

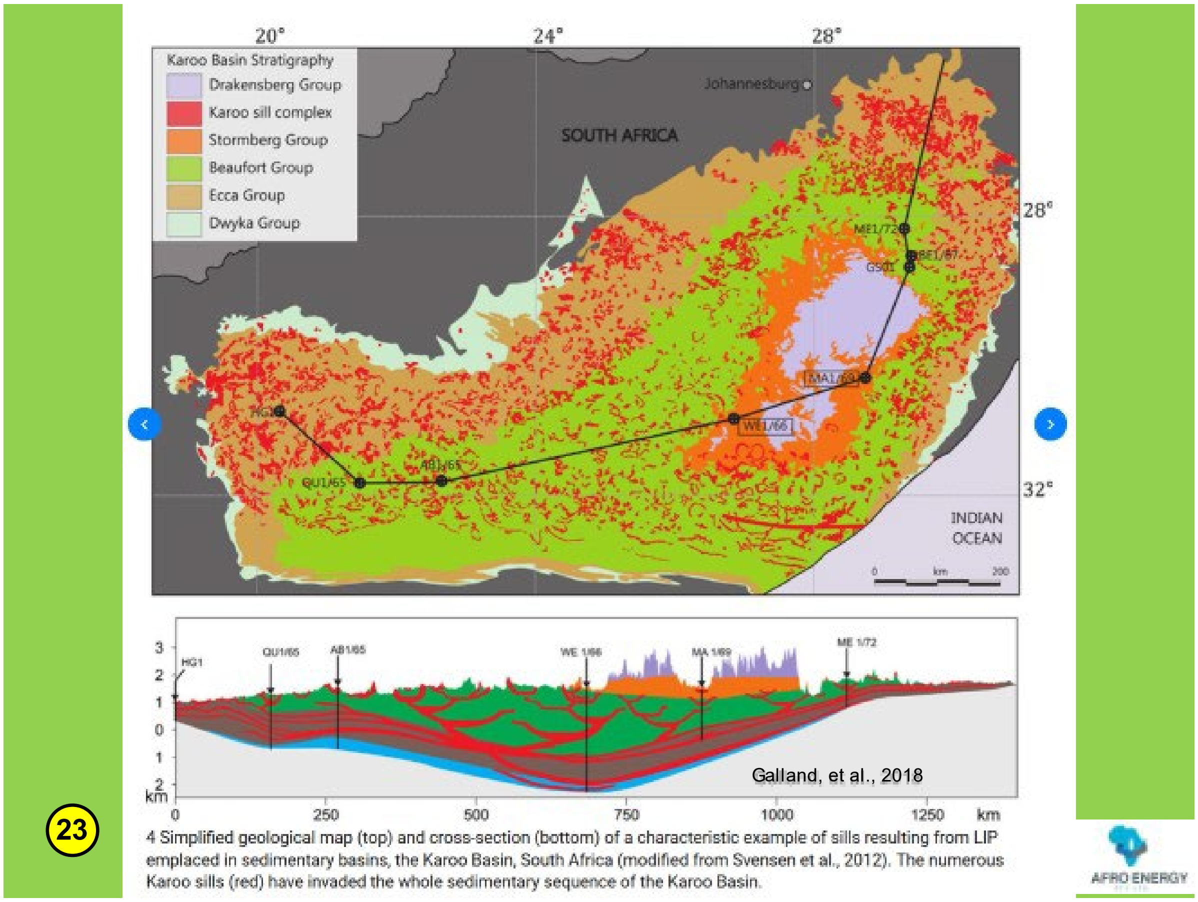


Figure 5: Regional Geologic Map of the Surface Geology (Supplied by Kinetiko)

Gas has been noted flowing out of many of the historic boreholes which have been drilled either to supply water for farmland, or as mineral exploration boreholes. Thus, the natural gas, which is typed to be thermogenic in origin and from the interbedded coal seams, is regional in nature and the larger area is a resource play. This report evaluates the gas production from a limited number of boreholes that were drilled and tested specifically to provide gas to an LNG facility. The trapping mechanism for the gas has been surmised to be the dolerite sills, vertically, and dolerite dikes and clastic facies changes, laterally.

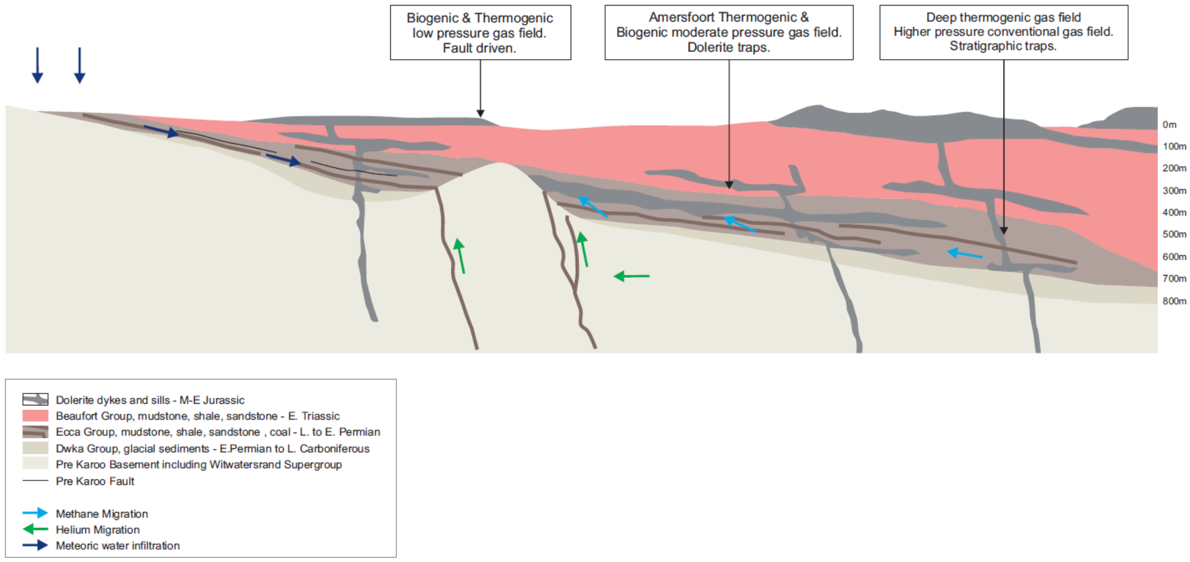


Figure 6: NW to SE Cross-Section Across the Amersfoort Gas Field (Supplied by Kinetiko)

METHODOLOGY

DATA AND ANALYSIS

Kinetiko provided Sproule with driller's logs, completion reports, LAS files, gas analysis reports, production test data, and license data from the Amersfoort Gas Fields Project in the Mpumalanga province in South Africa. In addition, the Company provided Sproule with shape files of its geologic interpretation of fractures, sills and dykes within the license. Further the Company provided Sproule with its current capital spending plan (CAPEX), operational expenditures (OPEX), gas to power sales agreements for an LNG plant.

Sproule reviewed the well data, LAS files, gas analysis reports, production test data, and historical geological data to ascertain the source of the gas, reservoir conditions, reservoir extents, Kinetiko development plans and market conditions. Sproule conducted its own petrophysical review and evaluation of the core and wireline log data. Geospatial information and well data were loaded into the SLB Petrel workstation software for 3D geomodelling evaluation and use of the SLB GE0-X package for stochastic volumetric calculations of original gas in place and technically recoverable volumes.

The production and pressure data from the aforementioned wells was analyzed and a best-case type curve was calculated. This type curve was used as the basis for the economic analysis which used ARIES version 5000.2.3 software by Halliburton.

DATA SET

The data provided by Kinetiko consists of:

- Wells, coring sites, exploration license, magnetic survey boundary, road and railway point and line data in google earth format
- Well location and summary description data in Microsoft Excel tabular format
- Wireline log data for 32 wells
- A series of reports, including aeromagnetic survey interpretation reports, core description reports, petrographic, mineralogical and conventional core analysis reports

Sproule has used Schlumberger's Petrel™ software to set up a project for analytical and interpretation purposes. The model has been set up in WGS1984-UTM35S coordinate reference system, the units used are metric.

37 well locations have been loaded into the project and are shown in Table 6.

Table 6: Well Locations

Name	Type	Surface X m	Surface Y m	Latitude deg	Longitude deg	Datum	Datum m	MD m	Logs
KA-03CR	Gas	779881	7014644	-26.96	29.82	GL	1665	413	Yes
KA-03PTR BEAST	Gas	779820	7014688	-26.96	29.82	GL	1669	402	No
KA-03PT2 SOB	Gas	779629	7014942	-26.96	29.82	GL	1684	459	No
K3	Gas	780074	7014559	-26.96	29.82	GL	1665	449	Yes
K4	Gas	779498	7014570	-26.96	29.82	GL	1689	443	Yes
K5	Gas	779677	7014369	-26.96	29.82	GL	1672	432	Yes
KA-11PT	Gas	788390	7024022	-26.88	29.90	GL	1638	371	No
KA-07PT	Gas	781636	7020406	-26.91	29.84	GL	1628	273	Yes
KA-10PT	Gas	781744	7007384	-27.03	29.84	GL	1701	425	No
KA-06PT	Gas	785373	7006212	-27.04	29.88	GL	1643	300	No
270-03C	Gas	778275	6955223	-27.50	29.82	GL	1653	605	Yes
270-05C	Gas	770929	6956932	-27.48	29.74	GL	1667	597	Yes
270-06C	Gas	770204	6938006	-27.66	29.74	GL	1553	545	Yes
KA-04C	Gas	777477	7015686	-26.95	29.79	GL	1689	425	Yes
KA-05C	Gas	789027	7010567	-27.00	29.91	GL	1666	203	Yes
KA-06C	Gas	785454	7006317	-27.04	29.88	GL	1643	366	Yes
KA-07C	Gas	782670	7019159	-26.92	29.85	GL	1625	438	Yes
KA-09C	Gas	776655	7018733	-26.93	29.79	GL	1657	376	Yes
KA-10C	Gas	782063	7007529	-27.03	29.84	GL	1691	463	Yes
KA-11CR	Gas	788097	7024122	-26.87	29.90	GL	1653	417	Yes
KA-12C	Gas	791667	7016687	-26.94	29.94	GL	1682	334	Yes
KA-13C	Gas	768231	7021145	-26.91	29.70	GL	1647	232	Yes
KV-01C	Gas	777644	6980936	-27.27	29.80	GL	1682	542	Yes
KV-02C	Gas	782773	6985511	-27.22	29.86	GL	1789	623	Yes
KV-03C	Gas	775277	6973494	-27.33	29.78	GL	1694	571	Yes
KV-04C	Gas	769742	6976514	-27.31	29.73	GL	1734	620	Yes
KV-05C	Gas	777331	6968396	-27.38	29.80	GL	1690	588	Yes
KV-06C	Gas	757166	6970001	-27.37	29.60	GL	1743	662	Yes
KV-07C	Gas	765158	6968545	-27.38	29.68	GL	1772	673	Yes
KV-09C	Gas	742846	6977190	-27.31	29.45	GL	1617	514	Yes
KV-10C	Gas	748056	6980902	-27.27	29.51	GL	1668	559	Yes
KV-11	Gas	748965	6974028	-27.33	29.52	GL	1724	632	Yes
KV-12CR	Gas	760106	6961570	-27.44	29.63	GL	1717	654	Yes
272-01C	Gas	719380	7037601	-26.77	29.21	GL	1595	300	Yes
272-02C	Gas	719035	7039546	-26.75	29.20	GL	1607	280	Yes
272-06C	Gas	725374	7047656	-26.67	29.26	GL	1632	100	No
272-08C	Gas	728170	7049287	-26.66	29.29	GL	1629	100	No

The logged wells have been examined in a correlation panel for geological correlation purposes. In the Korhaan area, the wells show remarkable lateral correlatability, which is in line with both known sedimentary deposition environment and the short inter-well distance.

A ubiquitous dolerite sill is found at the top of each well, while a minor dolerite sill about 15 m thick is interpreted to be present in K3 and K5 wells. Sand is present at the equivalent level in K4. Apart from this difference, the wells show several sequences that laterally correlate, mostly coarsening up depositional cycles that are consistent with the fluviatile nature of these deposits as described on published literature (Figure 7).

KA-03CR well is the only well of this group that has been cored. The core has been described (paper copy available), and petrographic analyses as well as conventional core analyses have been performed on core sample plugs.

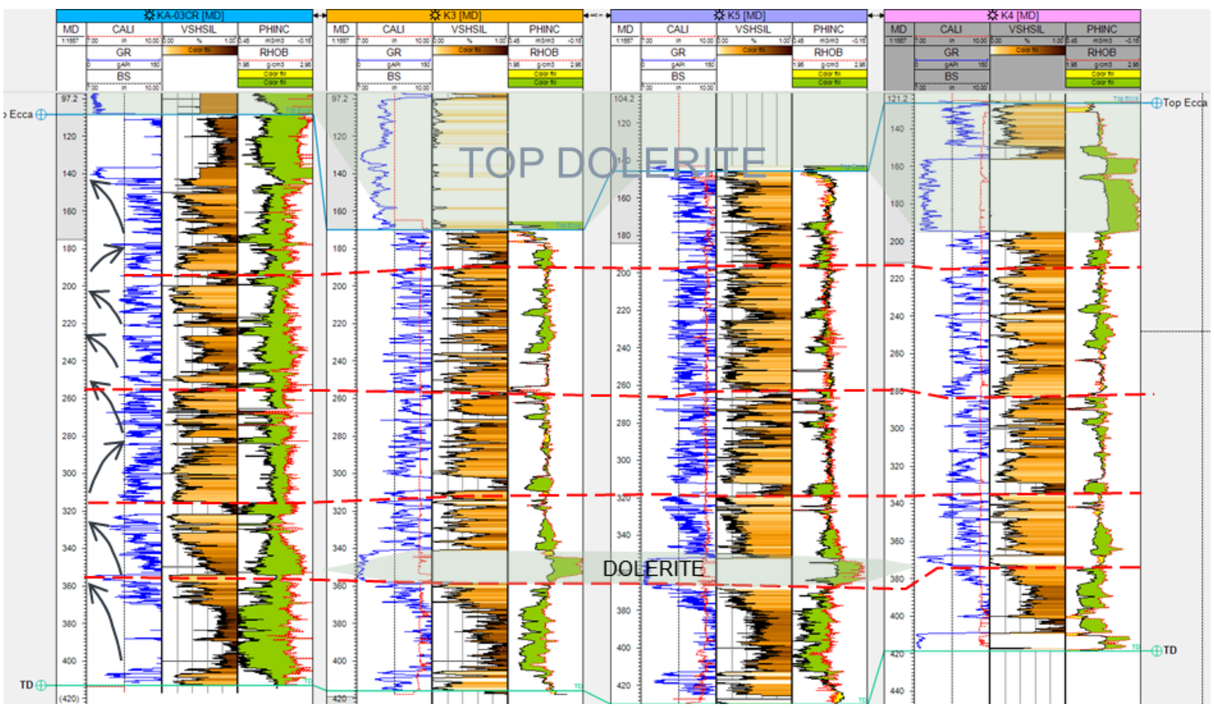


Figure 7: Well Correlation Panel of the Korhaan Wells. Note the Considerable Lateral Correlatability of the Cycles and the Thick Uniform, Dolerite Sill at the Top of Each Well (Well Data Supplied by Kinetiko. Analysis and Correlations by Sproule)

The core description that was made available in hard copy (pdf) format has also been transferred (digitized) into the Petrel project. The core description compares well with the interpretation that can be inferred from the analysis of the wireline logs; coarsening up cycles are characterized by gradual changes from mudstone or siltstone at the base to mostly fine-grained sandstones at the top of the cycles. Coarse-grained sandstones are present, but rare. This is in line with the general geological settings of the area, the Permian river system was draining an area characterized by glacial deposits, the predominantly flat glacial topography and the abundance of fine material due to glaciogenic processes is well recorded in the Korhaan wells.

Main mineralogical components are quartz (31-81.5%), alkali feldspars (6.4-27.5%), clays (including mica, 5.5-29.5%), up to 10% plagioclase, and lesser (<1%) quantities of titanium oxides, iron oxides, calcite and zircon. Mineralogy has been determined through XRD, SEM and EDS analyses. Van der Westhuizen, W., & de Bruiyn, H. (2006)

WELL DATA

Test Data

Kinetiko Energy Ltd., and its partners, have production tested eleven (11) wells (KA-03PT2, KA-03PTR, KA-05PT, KA-06PT, KA-07PT, KA-10PT/KA-10PTR, KA-11PT, Korhaan 3, Korhaan 4, Korhaan 5 and KV-04PT) mostly offsetting the cored wells. Figure 8 shows the location of the tested wells. The green circles highlight the wells tested positively for the gas production, while gas production was only in trace amounts in the 4 well highlighted with red circles. Most of the tests were conducted between 2012-13 except for 3 Korhaan wells tested in 2022. The only well tested in the Southern area of ER-271 (KV-04T) failed to produce any free gas during the well test. Although several wells produced gas, only one of the analyzed wells had sufficient production results, i.e. stabilized gas production rates followed by a prolonged shut-in with an accompanying pressure buildup, that had the ability of be analyzed using pressure transient analysis techniques. This well is the KA-03PTR. The inability to achieve stabilized gas production in the other wells was mostly due to the inability to lift sufficient water to keep the well de-watered. The production test wells' openhole completions did not allow for selectively completing the gas bearing zones and avoiding excessive water entry into the wellbore.

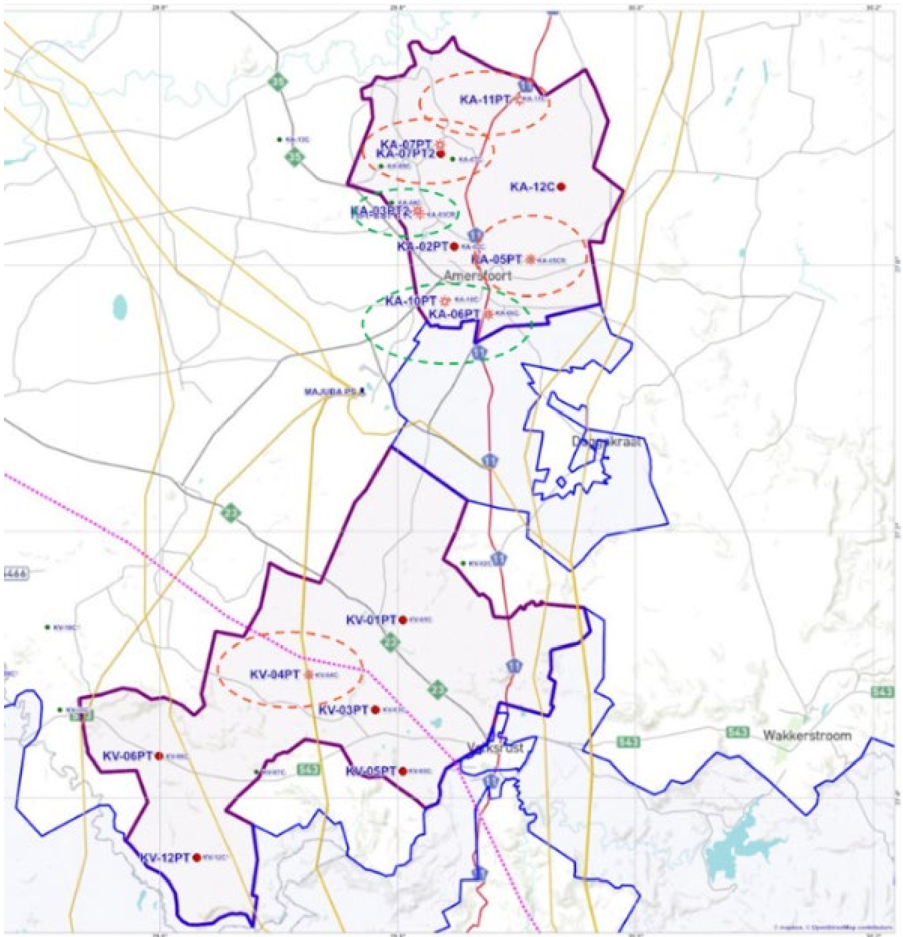


Figure 8: Location of Wells in Er-271 Area with Green Circles Highlighting the Wells Tested Positively for the Gas Production, While Red Circles Indicate Wells Producing Only Trace Amounts of Gas (Supplied by Kinetiko)

Routine Core Analysis

Kinetiko and its partners have cored 30 wells with four of the cored wells, KA-03CR and KA-05C, 271-23C and 270-06C have had plugs analyzed for porosity, permeability and rock matrix density. Klinkenberg corrected air permeabilities ranged from a high of 378.01 md to a low of 0.001 md. A power law relationship between porosity and permeability has been established from the core data and is used to estimate average absolute permeability from openhole log calculated porosities.

Sproule

Gas Analysis

Gas samples were reported from the Venmyn Deloitte 2016 Report.

A number of samples were taken for both gas and water qualities. Samples were taken from the permeability test well sites, except for one sample from cored well KA-06C. Water test work was completed by Aquatico Laboratories (Pty) Ltd, an ISO/IEC 17025:2005 accredited laboratory based in Centurion. Water was analyzed for pH, total dissolved solids, total alkalinity and various elements. Gas composition analysis was completed by Australian Laboratory Services (Pty) Ltd (ALS), based in Witbank. Gas composition was measured by ALS using gas chromatography for C1 to C12 hydrocarbons, oxygen, nitrogen, and other components. The gross and net calorific values of the samples were also calculated. One sample as sent to the American Mobile Research Inc. lab in Wyoming for extended fractional gas analysis. Methane content is consistently greater than 93% in all samples, with the majority of the remaining content made up of nitrogen. No helium has been detected in the samples. The test results are provided in Table 7.

Table 7: Gas Analyses Results

SAMPLE No.	WELL No.	O_2	N_2	H_2	CH_4	CO	C_2H_6	CO_2	He	H_2S	C_3H_8	TOTAL	GROSS CV (MJ/cuM @STP)	NET CV (MJ/cuM @STP)
3D	KA-03PTR	<0.1%	3.80%	<0.1%	95.40%	<0.1%	0.30%	<0.1%	N.D.	N.D.	N.D.	**96%**	37.83	34.19
30	KA-03PTR	<0.1%	2.70%	<0.1%	95.50%	<0.1%	1.60%	<0.1%	N.D.	N.D.	N.D.	**97%**	38.88	35.15
KA 10 PT - 11/01/2013	KA 10 PT- 11	<0.1%	4.80%	<0.1%	94.80%	<0.1%	<0.1%	<0.1%	N.D.	N.D.	N.D.	**95%**	37.42	33.82
KA-03PT 2	KA-03PT2	<0.1%	3.30%	<0.1%	96.00%	<0.1%	0.30%	<0.1%	N.D.	N.D.	N.D.	**96%**	38.23	34.55
KA-07PT 14-04-13	KA-07PT	0.10%	2.20%	<0.1%	96.30%	<0.1%	0.10%	<0.1%	N.D.	N.D.	N.D.	**96%**	37.82	34.18
KA-06FT	KA-06PT	< 0.1%	0.50%	<0.1%	98.80%	<0.1%	0.40%	0.10%	N.D.	N.D.	N.D.	**99%**	39.35	35.57
KA-06C-A GAS	KA-06C	N/A	5%	N/A	93.56%	0.14%	0.80%	N/A	N.D.	N.D.	0.07%	**94%**	N/A	N/A
	AVERAGE	**0.10%**	**3.15%**	**0.00%**	**95.77%**	**0.00%**	**0.58%**	**0.10%**	**N.D.**	**N.D.**	**0.07%**	**96%**	**38.26**	**34.58**

PETROPHYSICS

Sproule conducted petrophysical analysis for all 32 wells using PRIZM module in Geographix software. The objective of the analysis was to estimate the effective porosity, water saturation and net reservoir and pay thicknesses for the Lower Karoo Sandstone Formation to assist in determining the reservoir parameter ranges to be used in the probabilistic volumetric estimation.

In the analysis, the volume of shale (Vsh) was computed from Gamma Ray. The apparent porosity was calculated using the average of the Neutron and Density porosity values when both the logs are available. The effective porosity (PHIE) was calculated by correcting the apparent porosity for the estimated volume of shale within the formation. The formation water resistivity (Rw) was estimated from the total dissolved solids (TDS) for the water samples available in the data package obtained from the Company. A value of 0.6 ohm-meters was used as formation water resistivity for all the wells except K4 well where the Rw is estimated to be 1.5 ohm-meters. The water saturation (Sw) was calculated using the Modified Simandoux equation with values of a, m and n set to 1, 2, and 2, respectively. Net pay was determined using effective porosity cutoff of 5%, volume of shale cutoff of 60% and water saturation cutoff of 65%. The reservoir has an average net-to-gross of 44% with an effective porosity of 10% and an average water saturation of 50%. A comparison of log derived porosity against core porosity shows excellent match (Figure 9).The results of the petrophysical analysis are shown in the cross-section (Figure 10, Figure 11) and Table 8 below. The well logs also match the observed production performance of the wells in a qualitative way. The wells associated with good gas production during well tests (Figure 10) show better reservoir character and higher gas saturation in comparison to the wells associated with no or trace gas production (Figure 11). After the petrophysical analysis was completed and the results were compared against the well tests it was determined that the resistivity logs, which are a major component of the net pay calculations, are not currently normalized across the area of interest and have over an order of magnitude of range of values. There is also no observed gas\water contact within the area of interest. Thus, for the Contingent and Prospective Resource evaluations the Net Reservoir calculations for each well were used rather than the Net Pay.

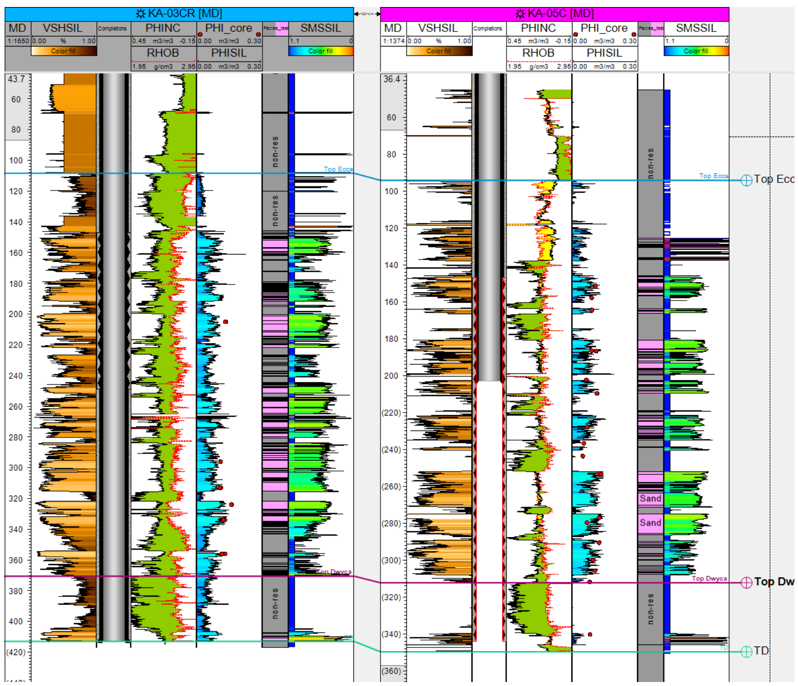


Figure 9: Comparison of Log Derived Porosity Against Core Porosity (Red Dots) Measured in Ka-03cr And Ka-05c Wells (Data Supplied by Kinetiko. Correlations and Analysis by Sproule)

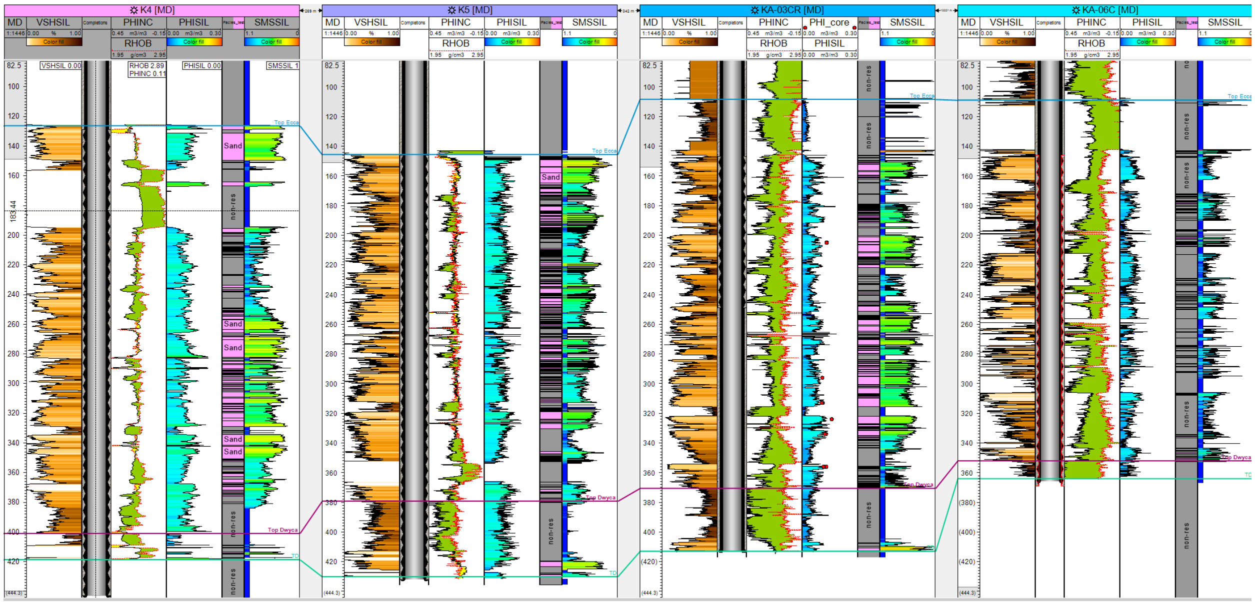


Figure 10: Petrophysical Analysis of the Four Wells With Reasonable Gas Production During Well Tests in the Amersfoort Gas Field (Data supplied by Kinetiko. Correlations and analysis by Sproule)

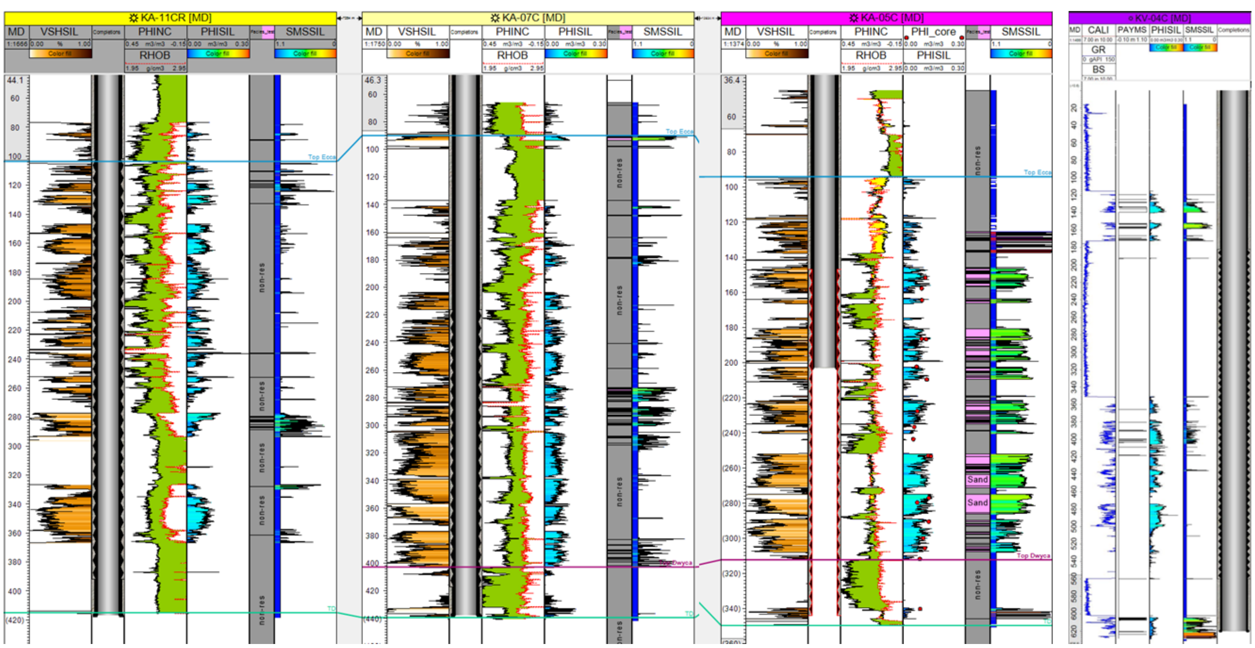


Figure 11: Petrophysical Analysis of the Four Wells with No / Trace Gas Production During Well Tests in the Amersfoort Gas Field (Data Supplied by Kinetiko. Correlations and Analysis by Sproule)

Sproule

Table 8: Petrophysical Analysis Results. Net Res Have Been Used for the Contingent and Prospective Resources

Well	Top	Base	Gross	Net Res	Pay	PHIE	Sw	Vsh	N/G Res	N/G Pay
272-01C	73.00	298.00	225.00	125.50	109.40	0.13	0.38	0.23	0.56	0.49
272-02C	79.00	280.00	201.00	127.90	122.15	0.13	0.29	0.28	0.64	0.61
270-03C	288.00	574.00	286.00	137.75	113.45	0.10	0.42	0.29	0.48	0.40
270-05C	121.00	595.00	474.00	172.75	149.55	0.12	0.37	0.29	0.36	0.32
270-06C	240.00	521.00	281.00	131.00	95.30	0.09	0.47	0.31	0.47	0.34
271-23C	225.00	482.00	256.63	83.99	0.07	0.15	0.59	0.35	0.33	0.00
272-06C	76.00	345.00	269.00	208.60	195.40	0.14	0.31	0.21	0.78	0.73
272-08C	72.00	279.00	207.00	153.80	140.85	0.12	0.35	0.29	0.74	0.68
K3	189.69	340.06	150.37	102.90	60.50	0.09	0.53	0.37	0.68	0.40
K4	195.21	408.84	213.63	178.09	101.20	0.11	0.47	0.31	0.83	0.47
K5	152.50	351.83	199.33	162.92	97.02	0.11	0.52	0.32	0.82	0.49
KA-03C-R	150.50	357.90	253.09	139.10	102.40	0.09	0.49	0.28	0.55	0.40
KA-03PT2										
KA-04C	147.00	324.00	177.00	103.75	78.45	0.12	0.41	0.26	0.59	0.44
KA-05C	145.00	308.00	163.00	88.20	71.00	0.09	0.50	0.31	0.54	0.44
KA-06C	147.00	353.00	206.00	85.40	38.60	0.07	0.53	0.37	0.41	0.19
KA-07C	166.00	403.00	237.00	90.30	25.20	0.06	0.46	0.34	0.38	0.11
KA-07PT	149.26	378.00	228.74	139.10	21.20	0.09	0.52	0.36	0.61	0.09
KA-09C	115.00	357.00	242.00	80.40	45.70	0.08	0.42	0.29	0.33	0.19
KA-10C	140.50	461.00	320.50	55.55	32.15	0.07	0.46	0.38	0.17	0.10
KA-11CR	77.00	366.00	289.00	93.90	28.00	0.08	0.49	0.41	0.32	0.10

Table 8: Petrophysical Analysis Results. Net Res have been used for the Contingent and Prospective Resources (Cont'd)

Well	Top	Base	Gross	Net Res	Pay	PHIE	Sw	Vsh	N/G Res	N/G Pay
KA-12C	107.00	254.00	147.00	83.50	62.40	0.11	0.51	0.24	0.57	0.42
KA-13C	105.00	250.00	145.00	75.50	40.80	0.10	0.54	0.24	0.52	0.28
KV-01C	166.00	544.00	378.00	129.60	23.50	0.07	0.48	0.42	0.34	0.06
KV-02C	307.00	620.00	313.00	106.75	24.00	0.08	0.54	0.40	0.34	0.08
KV-03C	82.00	568.00	486.00	108.30	19.95	0.09	0.48	0.34	0.22	0.04
KV-04C	115.50	628.00	512.50	97.30	14.90	0.09	0.47	0.31	0.19	0.03
KV-05C	112.00	338.00	226.00	68.10	12.20	0.08	0.55	0.43	0.30	0.05
KV-06C	160.00	650.00	490.00	117.30	40.80	0.08	0.41	0.41	0.24	0.08
KV-07C	88.00	659.00	571.00	49.60	22.80	0.07	0.40	0.37	0.09	0.04
KV-09C	50.00	510.00	460.00	122.25	42.50	0.07	0.47	0.23	0.27	0.09
KV-10C	345.00	555.00	489.37	57.10	25.90	0.07	0.43	0.33	0.12	0.05
KV-11	99.00	536.00	436.25	267.90	72.60	0.08	0.43	0.29	0.61	0.17
KV-12CR	284.00	574.00	290.00	54.55	0.60	0.24	0.47	0.30	0.19	0.00

MAPPING

Apart from sparse well data, the only other subsurface data available in the area are aeromagnetic surveys. Magnetic surveys are of good quality and can be used to interpret major tectonic and sedimentary features, but they are not suitable to image detailed or small scale features as metre scale dikes for instance.

However, an interpreted version of the 2014 aeromagnetic survey has been used to delineate the maximum polygon that can be interpreted as a possible compartment for the Korhaan wells above. The map has been geo-referenced and imported in Petrel. The major lineaments have been adjoined to form a closed polygon that in this evaluation has been used as closed segment, or compartment, around the Korhaan wells (Figure 12).

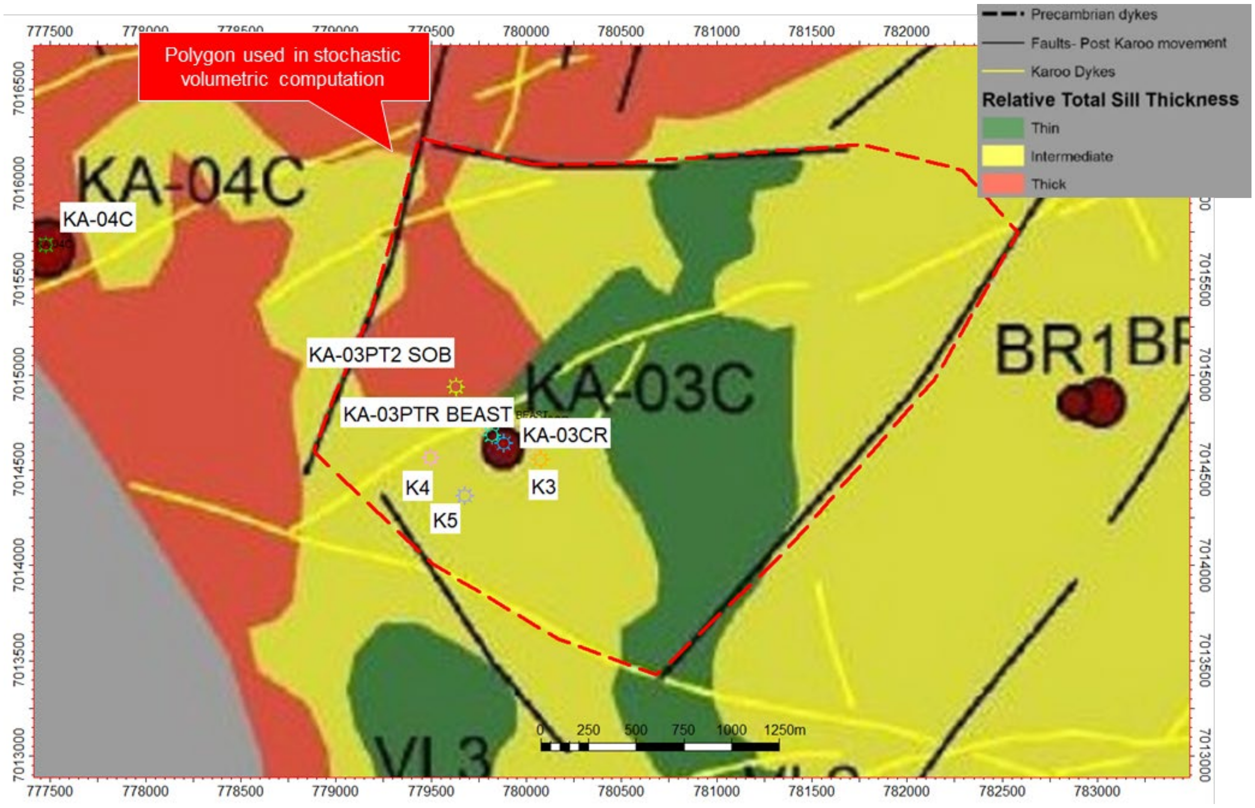


Figure 12: Interpreted Map Based on Aeromagnetic Survey Showing Tectonic and Intrusion Lineaments, and Interpreted Sill Thickness. Drilled and Cored Wells are plotted. Hatched Polygon is the Polygon Corresponds to the Development Area, used in the Stochastic Volumetric Computation (Data Supplied by Kinetiko. Correlations and Analysis by Sproule)

STOCHASTIC VOLUMETRICS

Volumetrics have been calculated in GeoX, a separate Schlumberger software suitable to compute stochastic volumetrics.

The inputs are from various sources, these are summarized in Table 9.

Structure closure considers that a conventional structural closure is not present. However, the presence of gas in the area is proven in that each well drilled in the area contains gas. The trap considered in this study is one of a tabular, slanted monocline sealed at the top by the ubiquitous thick dolerite sill. The lateral closure is interpreted to be provided by vertical dikes and/ or faults, as shown in Figure 12. The polygon that has been used as the areal input in the stochastic computation corresponds to the 30 wells planned development in the Korhaan area at 400 m spacing. A +/- 20% has been considered in the stochastic model to account for the area uncertainty. The reservoir parameters are all from the petrophysical evaluation of the well logs. Their values and distributions are also summarized in Table 10.

The formation volume factor has been calculated using an average reservoir pressure of 335 psi and a composition as per provided gas analyses. The calculated value of 23 scf/rcf has been used as an average value. A range of ±10% has been used to assign a uniform distribution in the stochastic volumetrics.

Table 9: Parameters Used for Stochastic Volumetrics

	SOURCE of DATA			STOCHASTIC INPUTS		
				Distribution type	input	value
Area *[km2]*	Considers drainage radius of 200m per well	Area	6.8	LogNorm 2LoHi	P90	5.9
					P10	8.3
Reservoir thickness *[m]*	from petrophysical interpretation	Min		Normal LoHi	P90	140
		Avg	216			
		Max			P10	290
NTG *fr*	from petrophysical interpretation	Min		Normal LoHi	P90	0.24
		Avg	0.29			
		Max			P10	0.34
Poro *fr*	from petrophysical interpretation	Min	0.09	Normal LoHi	P90	0.09
		Avg	0.10			
		Max	0.11		P10	0.11
Sg *fr*	from petrophysical interpretation	Min	0.53	Normal LoHi	Min	0.45
		Avg	0.49			
		Max	0.47		P10	0.55
Bg *scf/rcf*	Calculated for 335 psi avg res-pressure		23	Uniform	Min	21
					Max	25

The results of the volumetric computation are shown in Table 10 and Figure 13 below. The gas in place in the development area ranges between 10.2 bcf (P90) and 26.9 bcf (P10) with P50 estimate at around 17.3 bcf.

Table 10: Inputs and Results of The Stochastic Volumetric Estimates for Korhaan Development Area In Amersfoort Gas Field

Parameter [Units]	Dist. type	Mean	Std. dev.	P99	P90	P50	P10	P1
Area of closure [km2]	Ln3HLM	7.06	0.921	5.19	5.9	7.01	8.3	9.36
Reservoir Thickness [m]	NrmLoHi	215	57.3	85.6	140	215	290.1	344.5
Geometric factor [decimal]	Const	1	0	1	1	1	1	1
Net/gross ratio [decimal]	NrmLoHi	0.29	0.0382	0.204	0.24	0.29	0.34	0.376
Porosity [decimal]	NrmLoHi	0.1	0.00764	0.0827	0.09	0.1	0.11	0.117
Trap fill [decimal]	Const	1	0	1	1	1	1	1
Gas saturation [decimal]	NormMS	0.5	0.0373	0.416	0.451	0.5	0.549	0.584
Gas expansion factor (1/Bg) [scf	Unif	23	1.15	21	21.4	23	24.6	25
KORHAAN-2023 [Karoo_Kinetico.Ecca Fm Permian.K3-4-5]								

Resource Type [Units]	Dist. type	Mean	Std. dev.	P99	P90	P50	P10	P1
Non Assoc. Gas [1e9 scf]								
Accumulation size	MC(10000)	18.1	6.68	6.06	10.2	17.3	26.9	37.5
KORHAAN-2023 [Karoo_Kinetico.Ecca Fm Permian.K3-4-5]								

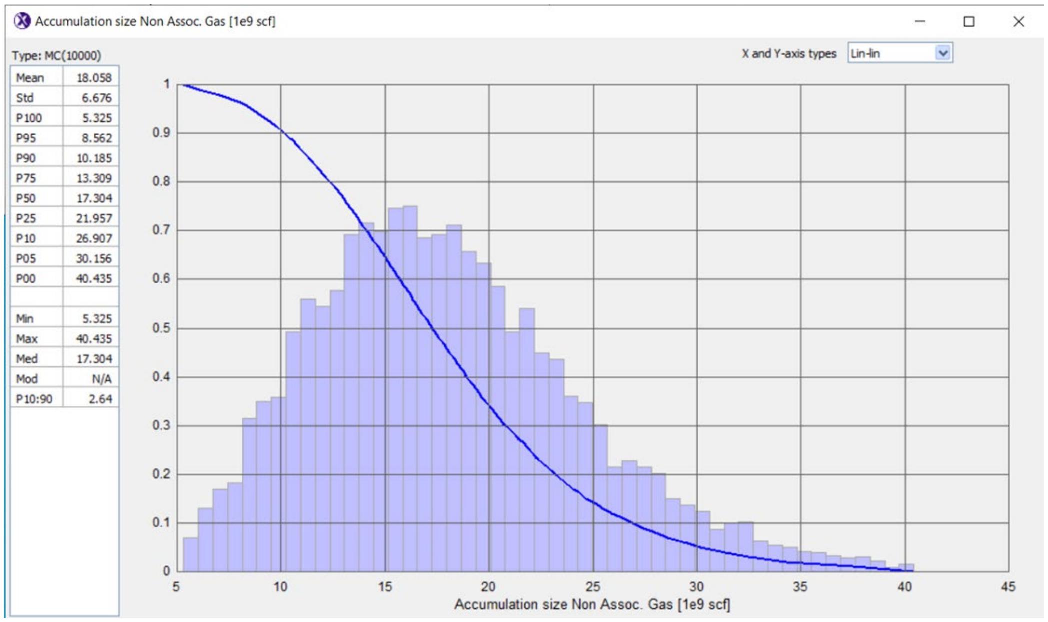


Figure 13: Stochastic Volumetric Results Corresponding to Korhaan Development Area in Amersfoort Gas Field

VOLUMETRICS

PAST STUDIES

Past studies of the Amersfoort Gas Field by independent 3rd Party assessments include the 2016 Contingent Resource Report by Venmyn Deloitte which assessed the Coalbed Methane (CBM) resources and the 2019 Contingent Resources Report by Michael Ratway which evaluated the Vryheid Sandstone resources. Additionally, Renergen Ltd has published production profiles from shallow gas wells in its Virginia Gas Field located in the Free State of South Africa. The reservoirs are not an analog for the Amersfoort Gas Field, however, the wells are approximately at the same depth, are at approximately the same reservoir pressure and the limited well data indicates that the initial well flow rates are similar. Therefore, it is valuable to consider the data from the Virginia Gas Field until such time as there is sufficient production data from Amersfoort to reduce the uncertainties on the ultimate recoveries of the wells.

ECONOMICS

KINETIKO OPERATING CONDITIONS AND SALES AGREEMENTS

Kinetiko will operate under a Production License, under the name of Afro Energy, from the Petroleum Agency of South Africa which is subject to a 5% royalty based on wellhead price to the South African Revenue Service. They are in the process of converting the Exploration Right to a Production Right which is expected to be finalized by mid-2024. Current discussions with JV partners will allow the Company to sell the gas to drive two 5 ktpa LNG plants.

For the purposes of this evaluation, the economic modeling uses the initial gas price of 9.5 $/MMbtu based on the MOU agreement. The minimum and maximum gas rate required for the LNG plant operation ranges between 600 to 700 Mcf/d.

ENGINEERING

TYPE WELLS

Gas production profiles for this evaluation were generated with three type wells. These type wells were constructed from Kinetiko production data and Original Gas in Place (OGIP) volumetrics combined with public domain analog type wells. Daily gas and water production volumes, fluid levels, and wellhead pressures were available for the Korhaan 3, Korhaan 4, Korhaan 5, KA-03PTR (The Beast), KA-03PT2 (Son of the Beast), KA-06PT and KA-10PTR wells. As seen in Figure 12, the first four wells form a rectangle roughly 300 m on a side (giving a 22 acre well spacing) and the fifth well, KA-03PT2, is located approximately 300 m to the northwest. Production tests for these five wells and two others are summarized in Table 11.

Table 11: Production Test Data from the Tested Wells

Well	test dates start	test dates end	test duration, days	peak gas rate, mcfd	stablized water rate, bpd	estimated reservoir pressure, psia
KA-03PTR	10-Dec-12	8-Dec-13	363	230	32	355
KA-03PT2	28-Oct-13	29-Dec-13	18	300	0	310
K4	7-Jun-21	24-Jun-21	17	35	80	-
K5	26-Apr-22	2-May-22	6	14	40	236
K3	20-May-22	3-Jun-22	14	80	50	223
KA-06PT	3-Oct-13	16-Oct-13	14	10	52	425
KA-10PTR	17-Jun-13	9-Aug-13	53	50	125	443
KA-10PT	12-Dec-12	27-Jan-13	46	20	45	354
KA-05PT	21-Apr-13	16-May-13	25	0	60	-
KA-07PT (Shallow)	19-Mar-13	25-Mar-13	6	0	-	-
KA-07PT (Full)	6-Apr-13	25-May-13	49	3	150	-
KA-11PT	4-Mar-13	24-Mar-13	20	0	137	-
KV-04PT	15-Nov-13	7-Dec-13	22	0	47	-

Production tests lasted about two weeks with the exception of KA-03PTR which produced gas and water for almost a full year in 2013. Well tests from KA-03 PTR, KA-03 PT2, KA-06PT and KA-10PT were able to produce gas at reasonable rates while the well tests from KA-11PT, KA-07PT, KA-5PT, KV-04PT produced gas only in trace amounts. The relatively low gas rate and high water rate seen in the low rate wells is suspected to be the result of the inability to seal off the water bearing zones and dewatering issues during operation although it could be a manifestation of the short test periods and the stand-alone nature of the well tests.

Average stabilized gas production rate for the seven wells producing gas was 40 to 50 Mcf/d, while average peak gas rate from all the wells including those with zero gas production was also around 57 Mcf/d. Diagnostic plots of gas production from KA-03PTR indicate this well achieved boundary dominated flow only in the last month of the year-long test with a stabilized gas rate of 50 Mcf/d. Average reservoir pressure, calculated from shut-in casing pressures and fluid levels over pump was 335 psia based on the successful well tests. For comparison, simulated gas production by Ratway (2019) reached a plateau of about 27 Mcf/d and reported reservoir pressures ranged from 230 to 250 psia. The higher reservoir pressure compared to the Ratway report is linked to down-hole pressure (“DHP”) estimated based on wellhead pressure (“WHP”) and liquid level measurements while the pressure reported in Ratway’s report are pressure measured at the casing and considered to be representative of the downhole pressure.

Three type wells were constructed for this report. The 1P type well described gas production expected to be equal to or exceeded by 90% of all wells, the 2P type curve is the median type well, and the 3P type well gas rate represents the top 10% of all wells. Analogous to public domain type wells for the Virginia Gas Field, all three type wells have exponential declines with an initial rate of 50 Mcf/d and decline rates adjusted to capture uncertainty in gas recovery. As discussed above, volumetric OGIP based on well tests from KA-03PTR, Korhaan 3, 4, and 5 wells is calculated to be 600 MMcf/well. Recovery factors for the type wells (40% for the 1P well, 60% for the 2P well, and 80% for the 3P well) are considered appropriate due to expected high water production during operation which would limit the maximum gas recoveries. Resulting technically recoverable gas resources (gas TRR's) are 240, 360, and 480 MMcf for the 1P, 2P, and 3P type wells, respectively. Decline rates were calculated by assuming the TRR gas volume was recovered over a 50 year lifetime. The resulting type well coefficients, listed in Table 12, were used to generate the type well gas profiles plotted in Figure 14 and cumulative gas recoveries in Figure 15.

Table 12: Kinetiko 1P, 2P, and 3P Gas Type Well Coefficients

	all wells
Initial Rate, Mcf/d =	50
OGIP, MMcf =	600
TRR lifetime, yr =	50

	1P	2P	3P
Recovery Factor	0.40	0.60	0.80
D, yr-1 =	0.0742	0.0455	0.0292
De, %/yr =	7.15%	4.45%	2.88%
50 yr cum, MMcf =	240	360	480

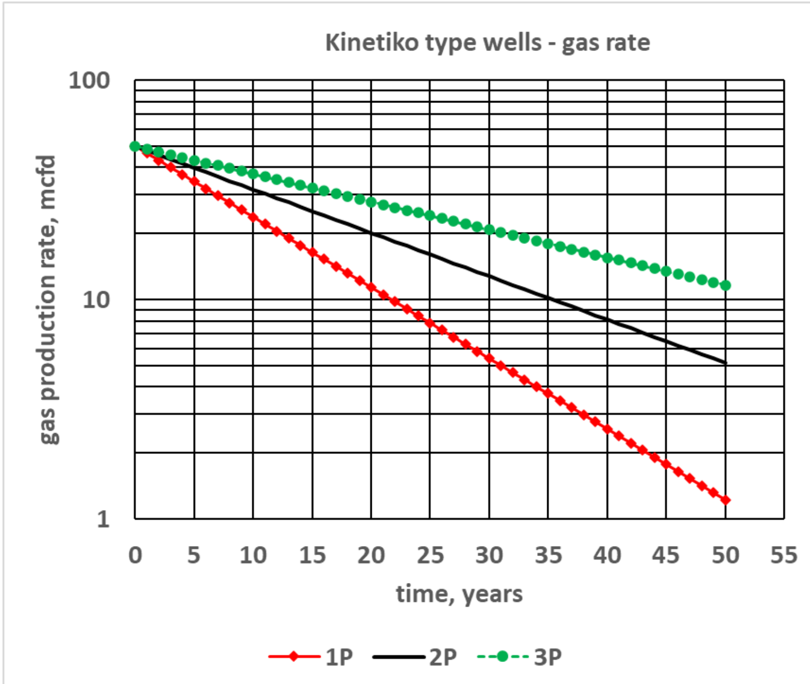


Figure 14: Kinetiko 1P, 2P, and 3P Gas Type Wells

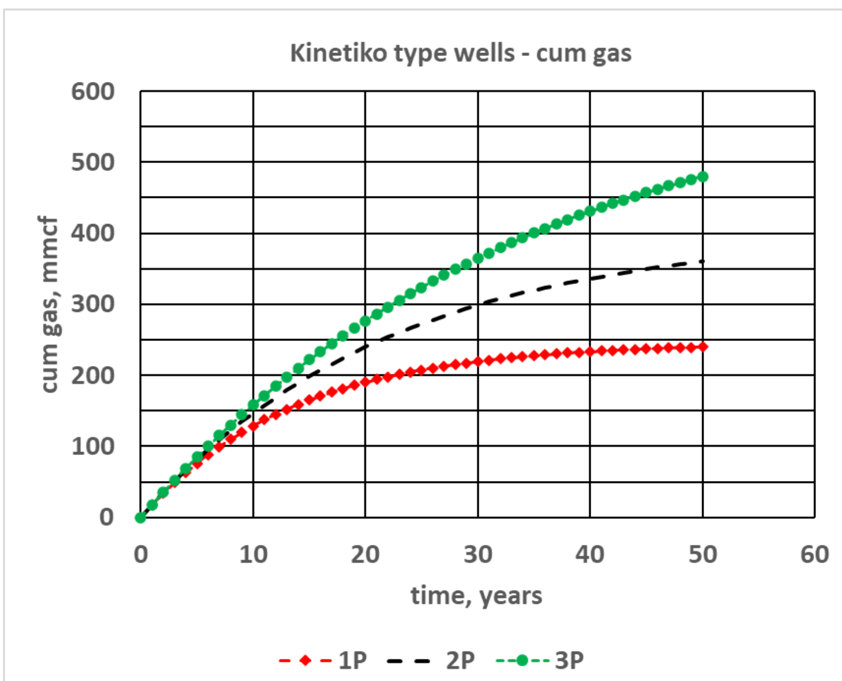


Figure 15: Kinetiko 1P, 2P, and 3P Type Wells Cumulative Gas Production

KINETIKO FIELD DEVELOPMENT PROGRAM

Reserves were estimated for a 30 well development (including 5 existing gas production wells and 25 new drills) developed to provide natural gas to a 5 ktpa LNG plants. All the existing and planned wells are in Korhaan area, in the close vicinity of the wells tested positively during the well tests. Kinetiko plans to drill and complete 25 gas production wells between Jan - July 2024 along with 3 water monitoring wells. The 5 existing wells (KA-03PTR, KA-03PT2, Korhaan 3, Korhaan 4 and Korhaan 5) will be rehabilitated as part of the initial operations to bring on the LNG plant. The first phase of development will be finished in June 2024, following which the gas supply to the planned LNG plant will commence in July 2026. A map of well locations is shown below in Figure 16. The five existing wells (KA-03PTR, KA-03PT2, K3, K4, K5) will be used for production following rehabilitation and hence categorized as Proved Developed Non-Producing wells (PDNP – waiting on pipeline). The white locations are planned well locations, categorized as Proved Un-Developed (PUD).

All the production wells will be equipped with progressive cavity pumps (PCP) to dewater the wells based on the water level measurement to ensure smooth gas production. The production performance of the field will be strongly dependent on the efficiency of dewatering system as well as the ability of the operator to identify and seal off the potential water bearing zones (dolerites/ sand interval) for minimizing the water influx into the wellbore.

In view of high water rates, compression could be beneficial to maintain production at lower reservoir pressure, however it is not currently part of the development plan.

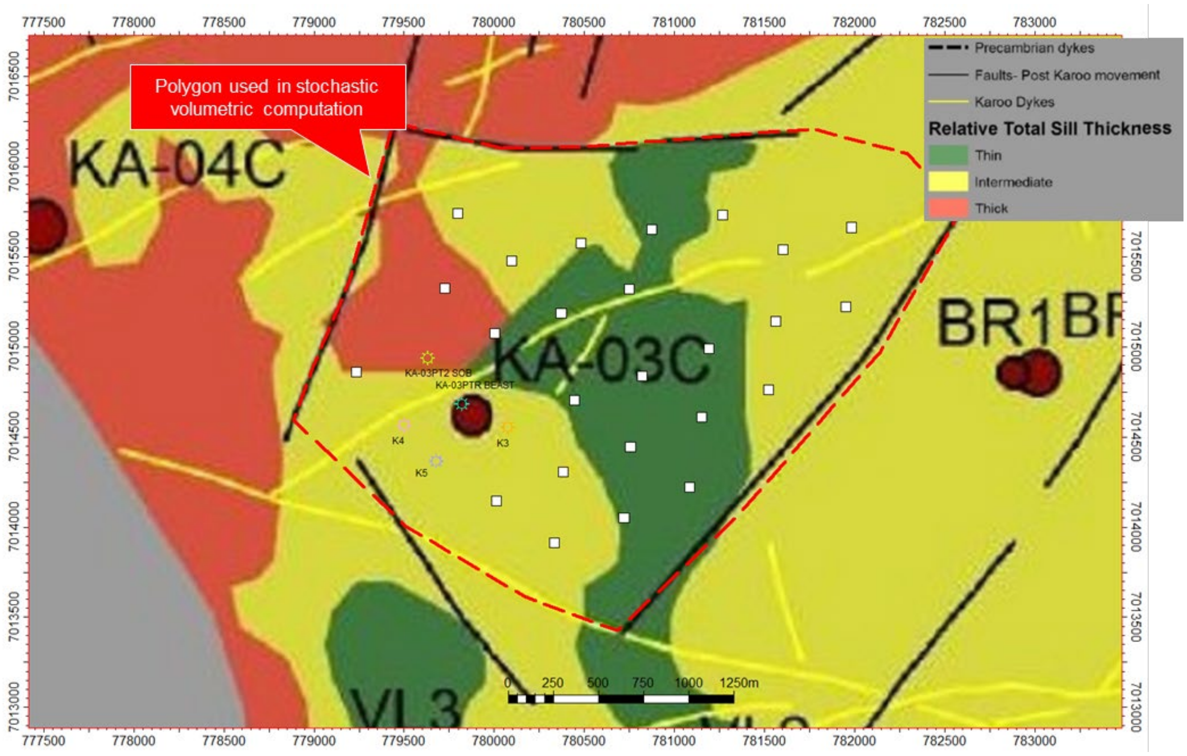


Figure 16: Kinetiko Development Reserve Area Encompassed by Red Polygon With Priority Drilling Plan Indicated by White Squares (Data Supplied by Kinetiko. Correlations and Analysis by Sproule)

ECONOMIC PARAMETERS

PRMS compliant reserves were estimated utilizing the three type wells developed above and the economic assumptions discussed below.

CAPITAL COSTS

Average capital costs per producing well were $274,521, as supplied by the Company. This average includes the costs to drill and complete new wells, well rehabilitation costs for the DST wells, drill the required water monitoring wells, and miscellaneous pump, testing, and contingency costs.

OPERATING EXPENSES

All operating expenses, gas prices and other assumptions were supplied by the Company. The opex is divided into variable well level opex and fixed field level opex. The variable well level opex is based on pump operating costs, pump changeover costs, water treatment costs as well as landowner leases and estimated at 4,071 $/month per well. The fixed field costs are estimated as 20,243 $/month.

The initial gas price was 9.50 $/MMbtu.

All prices and costs are escalated at 6.5 %/yr, the current South African CPI, until doubling. Costs and prices are then held constant for the life of the field.

Other assumptions included a shrinkage of 5%, a Btu factor of 0.884, and a 5% royalty. Both Working Interest and NRI are 100%. Plugging and abandonment costs are $5,000 per well.

RESERVE ECONOMICS

Based on the economic parameters discussed above, reserves and economics were calculated for the thirty (30) well development program for the Amersfoort Gas Field in order to support a 5 ktpa LNG plant. Gross and net gas reserves are shown in Table 1.

At the request of Kinetiko, net present values associated with the reserves volumes were calculated for various discount rates. Sproule has calculated the economics according to the assumptions detailed above and has presented the economics as both Undiscounted (NPV=0%), and at various discount factors at the request of Kinetiko. Sproule makes no recommendation as to preference of which discount factor to use. The results are shown in Table 1.

CONTINGENT AND PROSPECTIVE RESOURCES

As mentioned earlier, the gas resources besides the Korhaan development area in Amersfoort gas field have been evaluated and categorized into Contingent and Prospective resources. The areas associated with the contingent resources have demonstrated gas presence based on data obtained from the exploration wells drilled by the Kinetiko. However, these areas need to be further matured, both technically and commercially, in order to be categorized as reserves. The remaining license block areas are considered part of the prospective resources, where further exploration efforts are required to categorize them as contingent resources.

Contingent and Prospective resources in all three license blocks have been calculated using a similar methodology as utilized for the Gas in place estimation in Korhaan development area. The areal estimation is based on the data provided by the Kinetiko, taking into consideration the relinquished areas. Figure 17 and Figure 18 show the boundaries of the polygons used for the estimation of contingent and prospective resources in ER-271 and ER-272 license blocks. The petrophysical logs selected for the volumetric input are based on wells located in the license block or in the close vicinity of the block, in case of scarcity of the data. Table 8 shows a list of wells used for the volumetric evaluation input in the three license blocks. Finally, recovery factors ranging between 40 to 80% were used for the calculation of Contingent and Prospective resources.

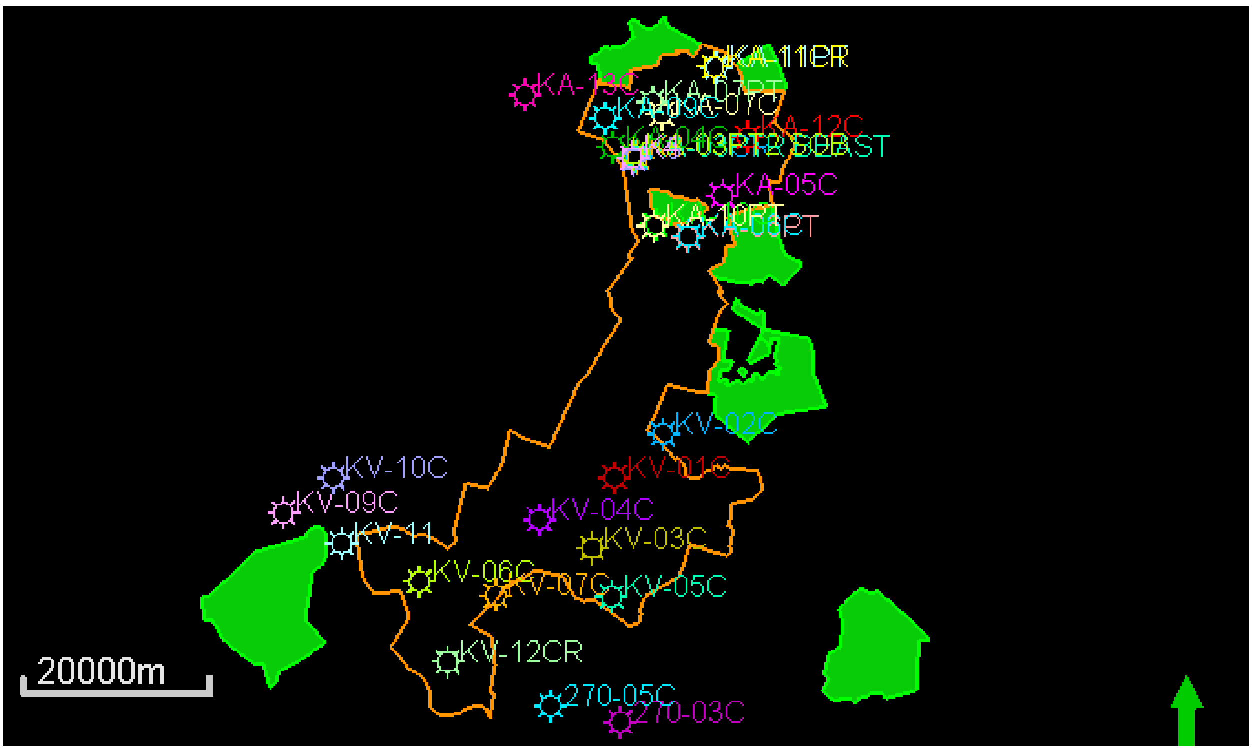
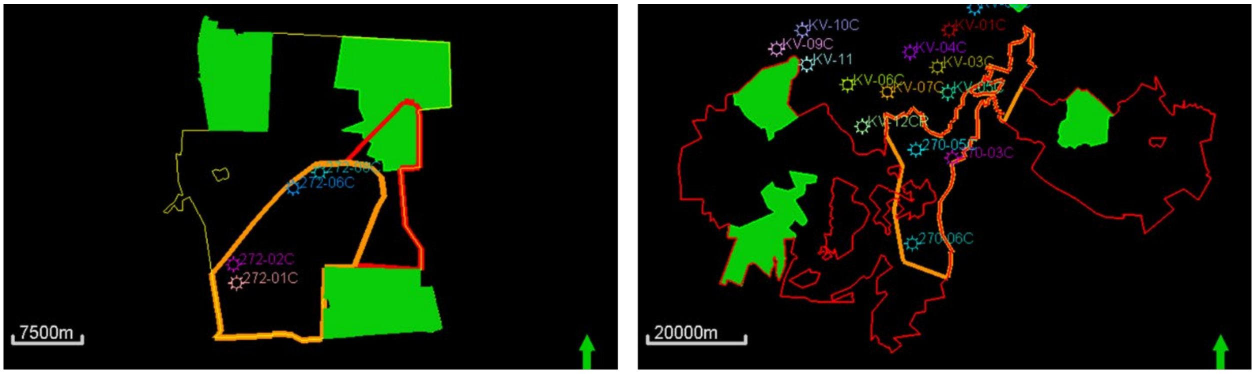


Figure 17: Boundary Polygon in Orange Marks the Area Associated with the Contingent Resources in ER-271 License Block. The Green Polygons Indicate the Relinquished Areas



ER-272 ER-270

Figure 18: Boundary Polygons in Orange Mark The Area Associated With the Contingent Resources, While Red Polygons Mark The Boundary Of Prospective Resource in ER-270 and ER-272 License Blocks. The Green Polygons Indicate the Relinquished Areas. (Data Supplied by Kinetiko. Correlations and Analysis by Sproule)

The results are shown in Table 13. Considering the relatively limited number of wells drilled across the areas, and the large acreage in question, the estimates of contingent and prospective resources have high level of uncertainty.

ESTIMATION OF CBM CONTINGENT RESOURCES

Low, most likely, and high values of Contingent Resources were estimated volumetrically for the 270ER, 271ER, and 272ER acreage blocks. Both sorbed and free gas components were considered. Sorbed gas per unit of gross reservoir volume was the product of density and desorbed gas content. A desorption sample data set supplied by the client was narrowed to 129 samples with a density range from 1.3 gm/cm3 to 1.8 gm/cm3. Low, most likely, and high values of density utilized for volumetrics were 1.32, 1.57, and 1.80 gm/cm3, respectively. Desorbed gas contents for samples in this density range varied widely and showed little correlation with density, primarily due to variations in sample depth and proximity to igneous dykes and sills. Low, most likely, and high sorbed gas contents were 3.0, 4.5, and 9.0 m3/t, respectively.

Free gas per unit of gross reservoir volume was the product of absolute porosity and gas saturation divided by the gas formation volume factor. Porosities and water saturations were determined by Sproule petrophysical analyses. Low, most likely, and high porosities were 1%, 2%, and 4%, respectively, while low, most likely, and high gas saturations (defined as 1 – water saturation) were 0%, 40%, and 95%, respectively. The gas formation volume factor of 0.02716 reservoir volume/standard volume was calculated with industry standard correlations, a reservoir pressure of 512 psia and a reservoir temperature of 66 deg F. Reservoir conditions were calculated using an average midpay depth of 1,148 feet and standard pressure and temperature gradients. On a unit gross reservoir volume basis, the sorbed gas component was typically 12 to 24 times larger than the free gas component.

Typical of unconventional reservoirs, the productive horizons here are reasonably certain to be extensive across the entire Kinetiko leasehold. Productive areas of the three blocks were net areas after any relinquishments and no low, most likely, or high values were utilized to capture additional areal uncertainty. Productive areas for the 270ER, 271ER, and 272ER were 2,045, 1,025, and 287 km2, respectively, for a total of 3,357 km2.

Total net coal thickness in 29 wells was determined by Sproule from petrophysical analysis. Low, most likely, and high net coal thicknesses in this data set were 1.1, 3.1, and 6.3 m, respectively.

CBM Contingent Resources were estimated as the product of productive area, total net coal thickness, and the sum of the sorbed and free gas components. The resulting volumes are summarized in Table 14 below on a total basis. Note that “m m3/km2” denotes millions of standard cubic meters of gas per km2. The most likely total Contingent Resource volume is 49,783 million m3 (1,758 bcf) with 61% held in block 270ER, 31% in block 271ER, and 8% in block 272ER.

Full calculations for each area are collected and summarized in Appendix A.

Table 13: Contingent Conventional Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1C	2C	3C
ER 271	1044	1741	2697
ER 270	851	1439	2232
ER 272	823	1093	1423
Total	2718	4273	6352

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Table 14: Contingent CBM Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1C	2C	3C
ER-270			
Sorbed CR	78.6	1,028.1	5,896.5
Free CR	-	42.9	1,071.0
Total CR	**78.6**	**1,071.0**	**6,967.5**
ER-271			
Sorbed CR	39.4	515.3	2955.5
Free CR	0	21.5	255.2
Total CR	**39.4**	**536.8**	**3,210.7**
ER-272			
Sorbed CR	11	144.3	827.5
Free CR	0	6	71.5
Total CR	**11.0**	**150.3**	**899.0**
Total CBM CR	**129.0**	**1,758.1**	**11,077.2**

Table 15: Total Contingent Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1C	2C	3C
Total CBM and SST CR	2,846.0	6,031.4	17,429.1

CONTINGENCIES

In order for the evaluated contingent resources to eventually become reserves there are several contingencies that must be resolved.

The Regional Sandstone Play:

- Flow assurance and reservoir performance must be obtained through long term testing and\or production in order to ascertain, in areas away from initial five well test program, what the proper drainage and water production will be.
- Understanding of reservoir pressures as a function of reservoir depth and if there is segmentation by volcanic intrusions that will act as production barriers.

The CBM Play

- The technical ability to isolate the relatively thin coals from the sandstones in order to produce them as a separate, isolated formation and dewater them in order to produce the CBM gas.
- The completion technology to bring pressure at the coal seam well bore face down to the critical desorption pressure and not interfere with the sandstone reservoir or bring interference from the sandstones into the softer coalseams.
- Additional Langmuir adsorption isotherm analysis across the play to understand the gas saturation variations with depth and spatially.

PROSPECTIVE RESOURCES

Table 16: Prospective Conventional Resources Calculated for the Three Kinetiko Licenses (in Bcf)

License	1U	2U	3U
ER 271	0	0	0
ER 270	3201	5413	8396
ER 272	303	406	529
Total	3504	5819	8925

CONCLUSIONS

Based on analysis of technical and economic data provided by Kinetiko, Sproule has independently estimated gas Reserves for the Amersfoort Gas Field according to SPE PRMS guidance and ASX Listing Rules. Estimated Reserves and net gas volumes are presented in Table 1. Although the Amersfoort Gas Project is at an early stage of development with a gas to LNG development program, this relatively small project is commercially viable, and the data gathered will help inform much larger gas development projects.

There is a much larger base of contingent resources, in both the sandstone and the coalbed methane plays, that is available to be advanced to reserves with additional testing and\or technology applied. In addition, there are other areas, away from existing well control that are assessed as prospective resources that have an equal chance to be advanced through the stages of contingent resources and reserves through a program of drilling and testing.

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APPENDIX A: PETROLEUM RESOURCES MANAGEMENT SYSTEM

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how resources volumes are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), the Society of Petroleum Engineers (SPE) published definitions for all reserves categories in 1987. In the same year, the World Petroleum Council (WPC), then known as the World Petroleum Congress, independently published reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by supplemental application evaluation guidelines (2001), standards for estimating and auditing reserves information (2001, revised 2007), and a glossary of terms used in resources definitions (2005). In 2007, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) was issued and subsequently supported by the Society of Exploration Geophysicists (SEG). The document is referred to by the abbreviated term SPE-PRMS, with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated. In 2011, the SPE/WPC/AAPG/SPEE/SEG published Guidelines for the Application of the PRMS (referred to as Application Guidelines).

The PRMS definitions and the related classification system are now in common use internationally to support petroleum project and portfolio management requirements. PRMS is referenced for national reporting and regulatory disclosures in many jurisdictions and provides the commodity-specific specifications for petroleum under the United Nations Framework Classification for Resources (UNFC) to support petroleum project and portfolio management requirements. The definitions provide a measure of comparability, reduce the subjective nature of resources estimation, and are intended to improve clarity in global communications regarding petroleum resources.

Technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with related organizations to maintain the definitions and guidelines to keep current with evolving technology and industry requirements.

This document consolidates, builds on, and replaces prior guidance. Appendix A is a glossary of terms used in the PRMS and replaces those published in 2007. It is expected that this document will be supplemented with industry education programs, best practice reporting standards, and future updates to the 2011 Application Guidelines.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language far communicating bath the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

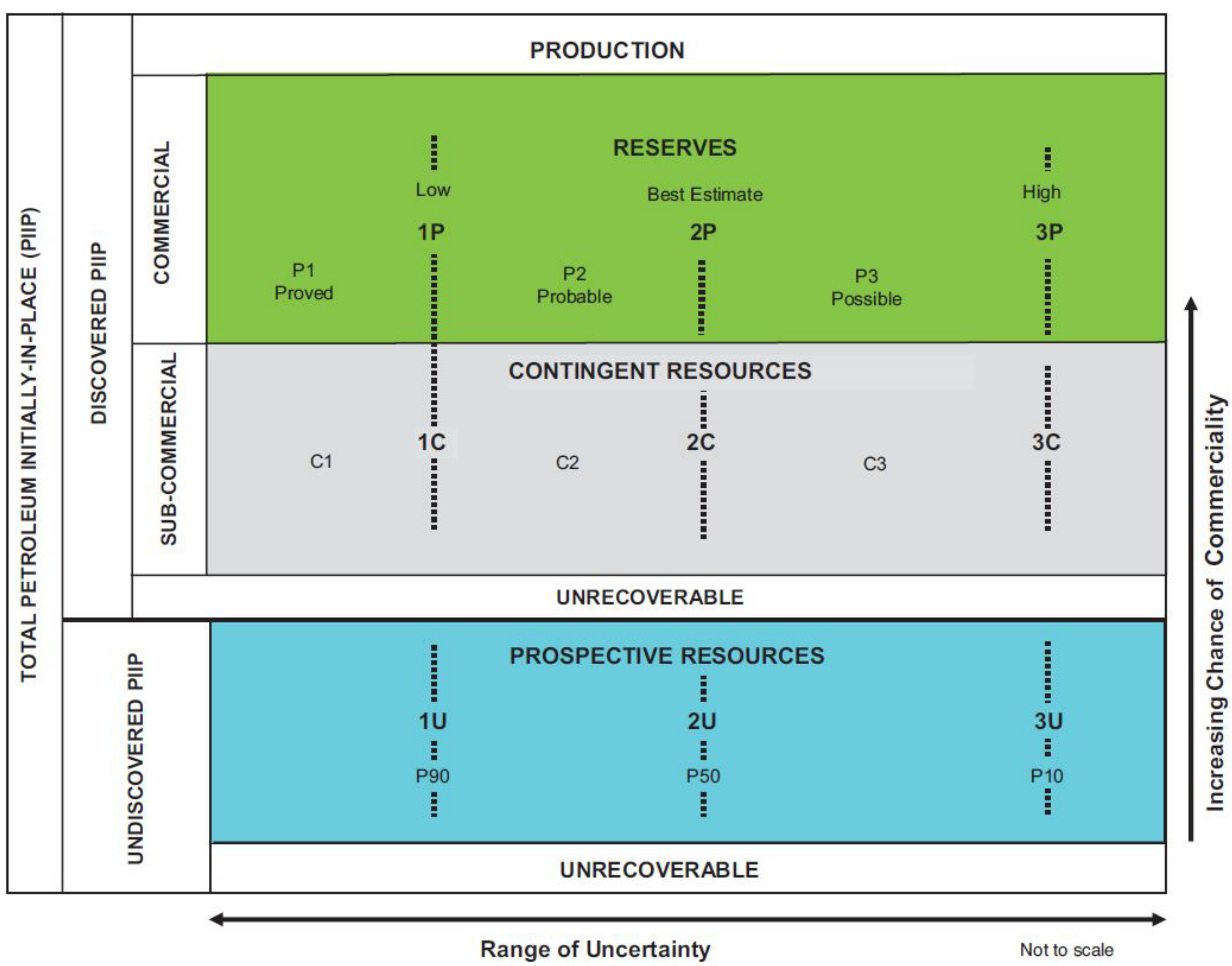

Figure 1.1—Resources classification framework

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, Pc, which is the chance that a project will be committed for development and reach commercial producing status.

1.1.1.5 The following definitions apply to the major subdivisions within the resources classification:

A. Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. Discovered PIIP is the quantity of petroleum that is estimated. as of a given date, to be contained in known accumulations before production.

C. Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. **1**. Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be subclassified based on project maturity and/or characterized by development and production status.

B. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be subclassified based on project maturity and/or economic status.

C. Undiscovered PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. Unrecoverable Resources are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. Estimated Ultimate Recovery (EUR) is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. Technically Recoverable Resources (TRR) are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

1.1.0.9 Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

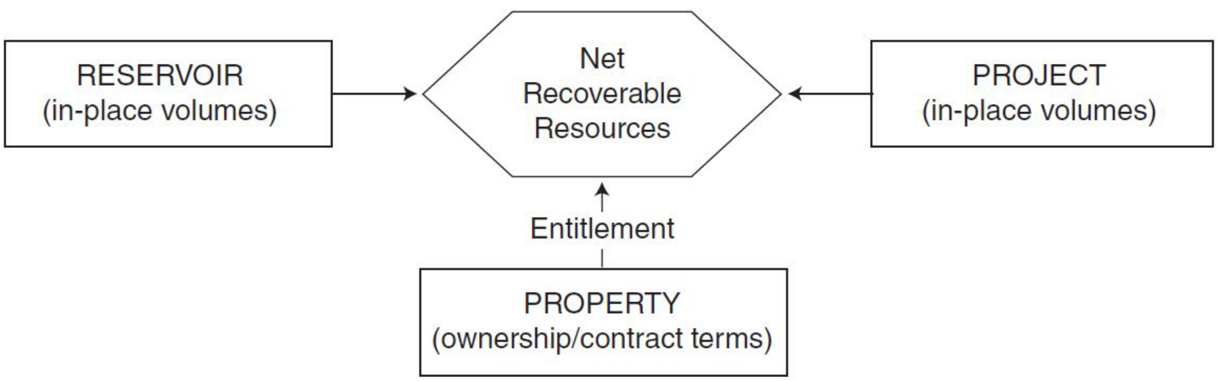

Figure 1.2—Resources evaluation

1.2.0.3 The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of Investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

1.2.0.9 The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.0.0.1 To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure 1.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, Pc (the vertical axis labeled Chance of Commerciality) and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.

B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.

C. Evidence to support a reasonable time-frame for development.

D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).

E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, C02) can be sold, stored, re-injected, or otherwise appropriately disposed.

F. Evidence that the necessary production and transportation facilities are available or can be made available.

G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.1.3 Project Status and Chance of Commerciality

2.1.3.1 Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

2.1.3.2 As a project moves to a higher level of commercial maturity in the classification (see Figure 1.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, Pc, which incorporates the following underlying chance component(s):

A. The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the “chance of geologic discovery," *Pg*.

B. Once discovered, the chance that the known accumulation will be commercially developed is called the “chance of development," *Pd*.

2.1.3.3 There must be a high degree of certainty in the chance of commerciality, *Pc*, for Reserves to be assigned; for Contingent Resources, *Pc*= *Pd*; and for Prospective Resources, *Pc* is the product of *Pg* and *Pd*.

2.1.3.4 Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

2.1.3.5 Project Maturity Sub-Classes

2.1.3.5.1 As Figure 2.1 illustrates, development projects and associated recoverable quantities may be subclassified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

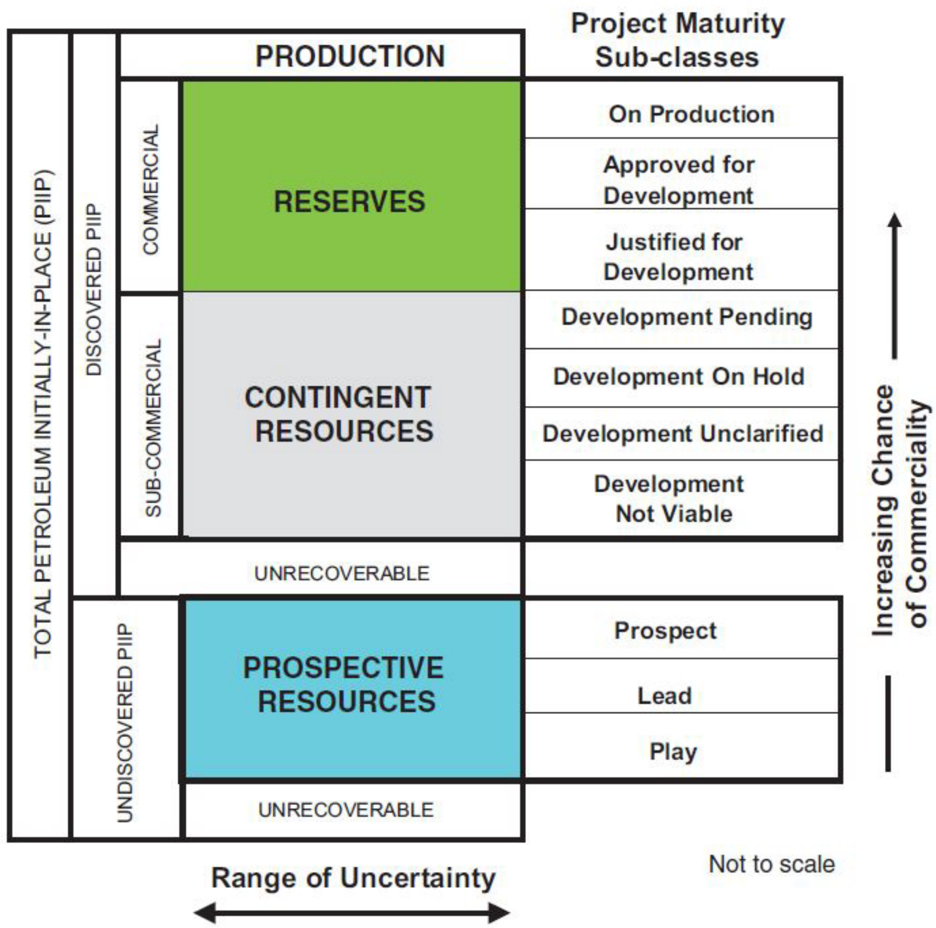

Figure 2.1—Sub-classes based on project maturity

2.1.3.5.2 Maturity terminology and definitions for each project maturity class and sub-class are provided in Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

2.1.3.5.3 Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

2.1.3.5.4 Projects that are classified as Reserves must meet the criteria as listed in Section 2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

2.1.3.5.5 Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

2.1.3.5.6 Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

2.1.3.5.7 Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

2.1.3.5.8 For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure 2.1 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

2.1.3.5.9 For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, *Pg*, and chance of development, *Pd*, which together determine the chance of commerciality, *Pc*. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources subclass.

2.1.3.6 Reserves Status

2.1.3.6.1 Once projects satisfy commercial maturity (criteria given in Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (Table 2 provides detailed definitions and guidelines):

A. Developed Reserves are quantities expected to be recovered from existing wells and facilities.

1. Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

2. Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

B. Undeveloped Reserves are quantities expected to be recovered through future significant investments.

2.1.3.6.2 The distinction between the "minor costs to access" Developed Non-Producing Reserves and the "significant investment" needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

2.1.3.6.3 Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see Section 3.1, Assessment of Commerciality).

2.1.3.6.4 Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section 2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

2.1.3.6.5 Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1 P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

2.1.3.7 Economic Status

2.1.3.7.1 Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

A. Economically Viable Contingent Resources are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section 2.1.2.

B. Economically Not Viable Contingent Resources are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

2.1.3.7.2 The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

2.1.3.7.3 For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

2.1.3.7.4 The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section 2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best-estimate case.

2.1.3.7.5 The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

2.1.3.7.6 Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is “undetermined."

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).

B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1 , C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.0.3 There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

2.2.0.4 Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as “split classification."

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g. ., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.1.6 While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

2.2.2.8 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

> **A**. Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
>
> **B**. Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
>
> **C**. Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (JP) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been

met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

2.2.2.9 One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

2.2.2.10 A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

2.2.2.11 It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see Section 4.2, Resources Assessment Methods). If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

2.3 Incremental Projects

2.3.0.1 The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure 1.1). with preference for applying project maturity sub-classes (Figure 2.1). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section 2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

2.3.0.2 An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

2.3.0.3 Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see Section 2.1 .2, Determination of Commerciality).

2.3.1 Workovers, Treatments, and Changes of Equipment

2.3.1.1 Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section 2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

2.3.1.2 Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

2.3.2 Compression

2.3.2.1 Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

2.3.3.1 Technical and commercial analyses may support drilling additional producing wells to reduce the well spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and accelerating production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

2.3.4 Improved Recovery

2.3.4.1 Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

2.3.4.2 Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

2.3.4.3 The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

2.3.4.4 Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

2.4 Unconventional Resources

2.4.0.1 The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in-place characteristics, extraction method applied, or degree of processing required.

A. Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

B. Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

2.4.0.2 For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

2.4.0.3 Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

2.4.0.4 The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

2.4.0.5 A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the “learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also Section 3.1.2 Economic Criteria).

3.0 Evaluation and Reporting Guidelines

3.0.0.1 The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" in this document refers to the presentation of evaluation results within the entity conducting the evaluation and should not be construed as replacing requirements for public disclosures established by regulatory and/or other government agencies or any current or future associated accounting standards.

3.0.0.2 Reserves and resources evaluations are based on a set of defined conditions that are used to classify and categorize a project's expected recoverable quantities. The defined conditions include the factors that impact commerciality, such as decision hurdle rates; commodity prices; operating and capital costs; technical subsurface parameters; marketing, sales route(s); environmental, governmental, legal, and social factors; and timing issues. These factors are forecast for the project over time, and evaluators must clearly identify and document the assumptions used in the evaluation because these assumptions can directly impact the project quantities eligible for classification as Reserves or Resources. A project with Contingent Resources may not yet have all defined conditions addressed, and reasonable assumptions should be made and documented.

3.0.0.3 Hydrocarbon evaluations recognize production and transportation practices that involve methods of extraction other than through the flow of fluids from wells to surface facilities, such as surface mining of bitumen or in-situ conversion processes.

3.1 Assessment of Commerciality

3.1.0.1 Commercial assessments are conducted on a project basis and are based on the entity's view of future conditions. The forecast commercial conditions, technical feasibility, and the entity's decision to commit to the project are several of the key elements that underpin the project's resources classification. Commercial conditions include, but are not limited to, assumptions of an entity's investment hurdle criteria; financial conditions (e.g., costs, prices, fiscal terms, taxes); partners' investment decision(s); organization capabilities; and marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., cash flow analysis, historical costs, comparative market values, key economic parameters) (see Section 2.1.2, Determination of Commerciality). The guidelines herein apply only to assessments based on cash-flow analysis. Moreover, modifying factors that may additionally influence investment decisions, such as contractual or political risks, should be recognized so the entity may address these factors if they are not included in the project analysis.

3.1.1 Net Cash-Flow Evaluation

3.1.1.1 Project-based resource economic evaluations are based on estimates of future production and the associated net cash-flow schedules for each project as of an effective date. These net cash flows should be discounted using a defined discount rate, and the sum of the future discounted cash flows is termed the net present value (NPV) of the project. The calculation shall be based upon an appropriately defined reference point (see Section 3.2.1, Reference Point) and should reflect the following:

A. The forecast production quantities over identified time periods.

B. The estimated costs and schedule associated with the project to develop, recover, and produce the quantities to the reference point, including abandonment, decommissioning, and restoration (ADR) costs, based on the entity's view of the expected future costs.

C. The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods, taking into account any sales contracts or price hedges specific to a property, including that portion of the costs and revenues accruing to the entity.

D. Future projected production- and revenue-related taxes and royalties expected to be paid by the entity.

E. A project life that is limited to the period of economic interest or a reasonably certain estimate of the life expectancy of the project, which is typically truncated by the earliest occurrence of either technical, license, or economic limit.

F. The application of an appropriate discount applicable to the entity at the time of the evaluation.

3.1.2 Economic Criteria

3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic. Production from the project is economic when the revenue attributable to the entity interest from production exceeds the cost of operation. A project's production is economically producible when the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity's interest. The ADR costs are excluded from the economically producibility determination. A project is commercial when it is economic and it meets the criteria discussed in Section 2.1.2.

3.1.2.2 Economic viability is tested by applying a forecast case that evaluates cash-flow estimates based on an entity's forecasted economic scenario conditions (including costs and product price schedules, inflation indexes, and market factors). The forecast made by the evaluator should reflect and document assumptions the entity assesses as reasonable to exist throughout the life of the project. Inflation, deflation, or market adjustments may be made to forecast costs and revenues.

3.1.2.3 Forecasts based solely on current economic conditions are estimated using an average of those conditions (including historical prices and costs) during a specified period. The default period for averaging prices and costs is one year. However, if a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified. In developments with high well counts and a continuous program of activity, the use of a learning curve within a resources evaluation may be justified to predict improvements in either time taken to carry out the activity, the cost to do so, or both, if confirmed by operational evidence and documented by the evaluator. The confidence in the ability to deliver such savings must be considered in developing the range of uncertainty in production and NPV estimates.

3.1.2.4 All costs, including future ADR liabilities, are included in the project economic analysis unless specifically excluded by contractual terms. ADR is not included in determining the economic producibility or for determining the point the project reaches the economic limit (see Section 3.1.3, Economic Limit). ADR costs are included for project economics but are not included in judging economic producibility or determining the economic limit (see Section 3.1.3, Economic Limit). ADR costs may also be reported for other purposes, such as for a property sale/acquisition evaluation, future field planning, accounting report of future obligations, or as appropriate to the circumstances for which the resource evaluation is conducted. The entity is responsible for providing the evaluator with documentation to ensure that funds are available to cover forecast costs and ADR liabilities in line with the contractual obligations.

3.1.2.5 Figure 3.1 illustrates a net cash-flow profile for a simple project. The project's cumulative net cash flow exceeds the ADR liability, thereby satisfying the economic viability required to consider a project's quantities as Reserves. The project's economic production (i.e., economic producibility) is truncated at the economic limit when the maximum cumulative net cash flow is achieved, before consideration of ADR.

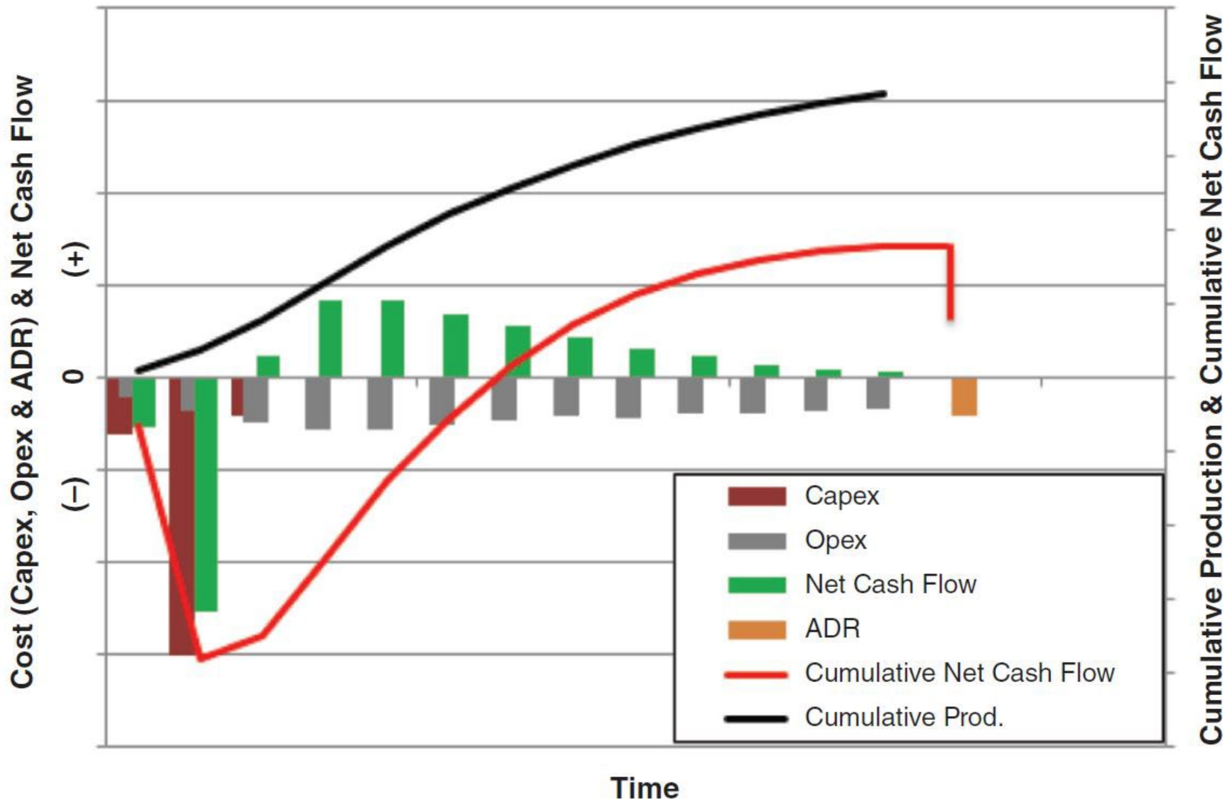

Figure 3.1—Undeveloped project economic forecast

3.1.2.6 Alternative economic scenarios may also be considered in the decision process and, in some cases, may supplement reporting requirements. Evaluators may examine a constant case in which current economic conditions are held constant without inflation or deflation throughout the project life.

3.1.2.7 Evaluations may also be modified to accommodate criteria regarding external disclosures imposed by regulatory agencies. For example, these criteria may include a specific requirement that, if the recovery were confined to the Proved Reserves estimate, the constant case should still generate a positive cash flow. External reporting requirements may also specify alternative guidance on the definition of current conditions or defined criteria with which to evaluate Reserves.

3.1.2.8 There may be circumstances in which the project meets criteria to be classified as Reserves using the best estimate (2P) forecast but the low case is not economic and fails to qualify for Proved Reserves. In this circumstance, the entity may record 2P and 3P estimates and no Proved Reserves. As costs are incurred in future years (i.e. become sunk costs) and development proceeds, the low estimate may eventually become economic and be reported as Proved Reserves. Some entities, according to internal policy or to satisfy regulatory reporting requirements, will defer reclassifying projects from Contingent Resources to Reserves until the low estimate case is economic.

3.1.3 Economic Limit

3.1.3.1 The economic limit is defined as the production rate at the time when the maximum cumulative net cash flow occurs for a project. The entity's entitlement production share, and thus net entitlement resources, includes those produced quantities up to the earliest truncation occurrence of either technical, license, or economic limit.

3.1.3.2 In this evaluation, operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes, but for purposes of calculating the economic limit, should exclude depreciation, ADR costs, and income tax as well as any overhead that is not required to operate the subject property. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated nonhydrocarbons (see Section 3.2.4, Associated Non-Hydrocarbon Components).

3.1.3.3 For a given project, no future development costs can exist beyond the economic limit date. ADR costs are not included in the economic limit calculations, even though they may be reported for other purposes.

3.1.3.4 Interim negative project net cash flows may be accommodated in periods of development capital spending, low product prices, or major operational problems provided that the longer-term cumulative net-cash-flow forecast determined from the effective date becomes positive. These periods of negative cash flow will qualify as Reserves if the following positive periods more than offset the negative.

3.1.3.5 In some situations, entities may choose to initiate production below or continue production past the economic limit. Production must be economic to be considered as Reserves, and the intent to or act of producing sub-economic resources does not confer Reserves status to those quantities. In these instances, the production represents a movement from Contingent Resources to Production. However, once produced such quantities can be shown in the reconciliation process for production and revenue accounting as a positive technical revision to Reserves. No future sub-economic production can be Reserves.

3.2 Production Measurement

3.2.0.1 In general, all petroleum production from the well or mine is measured to allow for the evaluation of the extracted quantities' recovery efficiency in relation to the PIIP. The marketable product, as measured according to delivery specifications at a defined reference point, provides the basis for sales production quantities. Other quantities that are not sales may not be as rigorously measured at the reference point(s) but are as important to take into account.

3.2.0.2 The operational issues in this section should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development.

3.2.1 Reference Point

3.2.1.1 Reference point is a defined location within a petroleum extraction and processing operation where the produced quantities are measured or assessed. A reference point is typically the point of sale to third parties or where custody is transferred to the entity's midstream or downstream operations. Sales production and estimated Reserves are normally measured and reported in terms of quantities crossing this point over the period of interest.

3.2.1.2 The reference point may be defined by relevant accounting regulations to ensure that the reference point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to the delivery specifications at a defined price. In integrated projects, the appropriate price at the reference point may need to be determined using a netback calculation.

3.2.1.3 Sales quantities are equal to raw production less non-sales quantities (those quantities produced at the wellhead but not available for sales at the reference point). Non-sales quantities include petroleum consumed as lease fuel, flared, or lost in processing, plus non-hydrocarbons that must be removed before sale (including water). Each of these may be allocated using separate reference points but, when combined with sales, should sum to raw production. Sales quantities may need to be adjusted to exclude components added in processing but not derived from raw production. Raw production measurements are necessary and form the basis of many engineering calculations (e.g., material balance and production performance analysis) based on total reservoir voidage. Substances added to the production stream for various reasons, such as diluents added to enhance flow properties, are not to be counted as Production, sales quantities, Reserves, or Resources.

3.2.2 Consumed In Operations (CIO)

3.2.2.1 CiO (also termed lease fuel) is that portion of produced petroleum consumed as fuel in production or plant operations before the reference point.

3.2.2.2 Although Reserves are recommended to be sales quantities (see Section 1.1), the CiO quantities may be included as Reserves or Resources; when included these quantities must be stated and recorded separately from the sales portion. Entitlement rights for the fuel usage must be in place to recognize CiO as Reserves. Flared gas and oil and other petroleum losses must not be included in either product sales or Reserves but once produced are included in produced quantities to account for total reservoir voidage.

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3.2.2.3 The CiO quantities must not be included in the project economics because there is neither a cost incurred for purchase nor a revenue stream to recognize a sales quantity. The CiO fuel replaces the requirement to purchase fuel from external parties and results in lower operating costs. All actual costs for facilities-related equipment, the costs of the operations , and any purchased fuel must be included as an operating expense in the project economics.

3.2.3 Wet or Dry Natural Gas

3.2.3.1 The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed reference point. Thus, for gas that is sold as wet gas, the quantity of the wet gas would be reported, and there would be no reporting of any associated hydrocarbon liquids extracted downstream of the reference point. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

3.2.3.2 When liquids are extracted from the gas before sale and the gas is sold in dry condition, then the dry gas quantity and the extracted liquid quantities, whether condensate and/or natural gas liquids (NGLs), must be accounted for separately in resources assessments at the agreed reference point(s).

3.2.4 Associated Non-Hydrocarbon Components

3.2.4.1 In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the reference point. Correspondingly, the accounts will reflect the value of the petroleum product at the reference point. If it is required to remove all or a portion of non-hydrocarbons before delivery, the Reserves and Production should reflect only the marketable product recognized at the reference point.

3.2.4.2 Even if an associated non-hydrocarbon component, such as helium or sulfur, removed before the reference point is subsequently separately marketed, these quantities are included in the voidage extraction quantities (e.g., raw production) from the reservoir but are not included in Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the project's economic evaluation.

3.2.5 Natural Gas Re-Injection

3.2.5.1 Natural gas production can be re-injected into a reservoir for a number of reasons and under a variety of conditions. Gas can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In cases where the gas has no transfer of ownership and with a development plan that is technically and commercially mature, the gas quantity estimated to be eventually recoverable can be included as Reserves.

3.2.5.2 If injected gas quantities are included as Reserves, these quantities must meet the criteria in the definitions, including the existence of a viable development, transportation, and sales marketing plan. Gas quantities should be reduced for losses associated with the re-injection and subsequent recovery process. Gas quantities injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Gas quantities purchased for injection and later recovered are not classified as Reserves.

3.2.6 Underground Natural Gas Storage

3.2.6.1 Natural gas injected into a gas storage reservoir, which will be recovered later (e.g., to meet peak market demand periods) should not be included as Reserves.

3.2.6.2 The gas placed in the storage reservoir may be purchased or may originate from prior native production. It is important to distinguish injected gas from any remaining native recoverable quantities in the reservoir. On commencing gas production, allocation between native gas and injected gas may be subject to local regulatory and accounting rulings. Native gas production would be drawn against the original field Reserves. The uncertainty with respect to original field quantities remains with the native reservoir gas and not the injected gas.

3.2.6.3 There may be occasions in which gas is transferred from one lease or field to another without a sale or custody transfer occurring. In such cases, the re-injected gas could be included with the native reservoir gas as Reserves.

3.2.6.4 The same principles regarding separation of native resources from injected quantities would apply to underground liquid storage.

3.2.7 Mineable Oil Sand

3.2.7.1 Mineable oil sands that meet the criteria listed in Section 2.1.2 can be considered as a potentially economic material and therefore Reserves. Mining operations may result in mined materials being stockpiled rather than processed. Stockpiled mined oil sands should be included in Reserves only when the project to recover and blend the stockpile has achieved technical and commercial maturity. The project's quantities are not included in Production until measured at the reference point.

3.2.8 Production Balancing

3.2.8.1 Reserves estimates must be adjusted for production withdrawals. This may be a complex accounting process when the allocation of Production among project participants is not aligned with their entitlement to Reserves. Production overlift or underlift can occur in oil production records because participants may need to lift their production in parcel sizes or cargo quantities to suit available shipping schedules agreed upon by the parties. Similarly, an imbalance in gas deliveries can result from the participants having different operating or marketing arrangements that prevent gas quantities sold from being equal to the entitlement share within a given time period.

3.2.8.2 Based on production matching the internal accounts, annual production should generally be equal to the liftings actually made by the entity and not on the production entitlement for the year. However, actual production and entitlements must be reconciled in Reserves assessments. Resulting imbalances must be monitored over time and eventually resolved before project abandonment.

3.2.9 Equivalent Hydrocarbon Conversion

3.2.9.1 The industry sometimes simplifies communication of Reserves, Resources, and Production quantities with the term "barrel of oil equivalent" (BOE). The term allows for consolidation of multiple product types into a single equivalent product. In instances where natural gas is the predominate product, liquids may be converted to gas equivalence (i.e. one thousand cubic feet (MCF) volume= 1 McfGE (MCF gas equivalent)).

3.2.9.2 Oil, condensate, bitumen and synthetic crude oil can be summed together without conversion (i.e., 1 bbl volume = 1 BOE). NGLs may need to be converted, depending on the actual composition. Natural gas must be converted to report on a BOE basis.

3.2.9.3 The presentation of Reserve or Resources quantities should be made in the appropriate units for each individual product type reported (e.g. barrels, cubic meters, metric tonnes, joules, etc.). If BOE's or McfGE's are presented, they must be provided as supplementary information to the actual liquid or gas quantities with the conversion factor(s) clearly stated.

3.3 Resources Entitlement and Recognition

3.3.0.1 While assessments are conducted to establish estimates of the total PIIP and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral lease owners (lessors) and contractors (lessees) and is generally referred to as entitlement.

3.3.0.2 Evaluators must ensure that, to their knowledge, the recoverable resource entitlements from all participating entities sum to the total recoverable resources.

3.3.0.3 The ability for an entity to recognize Reserves and Resources is subject to satisfying certain key elements. These include (a) having an economic interest through the mineral lease or concession agreement (i.e., right to proceeds from sales); (b) exposure to market and technical risk; and (c) the opportunity for reward through participation in exploration, appraisal, and development activities. Given the complexities of some agreements, there may be additional elements that must be considered in determining entitlement and the recognition of Reserves and Resources.

3.3.0.4 For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be ·recognized" in external disclosures. For national interests, the reporting of 100% quantities without concession agreement constraints is typically specified.

3.3.1 Royalty

3.3.1.1 Royalty refers to a type of entitlement interest in a resources project that is free and clear of the costs and expenses of development and production to the royalty interest owner as opposed to a working interest where an entity has cost exposure. A royalty is commonly retained by a resources owner (lessor/ host) when granting rights to a producer (lessee/contractor) to develop and produce the resources. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production in-cash or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at the discretion of the royalty owner. In either case, royalty quantities must be deducted from the lessee's entitlement to resources so that only net revenue interest quantities are recognized.

3.3.1.2 In some agreements, production taxes imposed by the host government may be referred to as royalties. These payment obligations are expressed in monetary terms and are typically linked to production rates, quantities produced, cost recovery, the value of production (price sensitive), or the profits derived from it. These payments are not associated with an interest retained by the lessor/host. Thus, such payment obligations are effectively a production tax instead of a royalty. In such cases, the production and underlying resources are controlled by the lessee/contractor who may (subject to contractual terms and/or regulatory guidance) elect to report these obligations as a tax without a corresponding reduction in lessor/ contractor's entitlement.

3.3.1.3 Conversely, if an entity owns a royalty or equivalent interest of any type in a project, the related quantities can be included in resources entitlements and should not be included in entitlements of others.

3.3.2 Production-Sharing Contract Reserves

3.3.2.1 Production-sharing contracts (PSCs) of various types are used in many countries instead of conventional tax-royalty systems. Under the PSC terms, producers have an entitlement to a portion of the production. This net entitlement. often referred to as entitlement, occurs when a net economic interest is held by an entity and is estimated using a formula based on the contract terms incorporating costs and profits. The terms of the PSC provide the remuneration to the host government/lessor that would be accomplished by the royalty in other agreements.

3.3.2.2 Ownership of the production is retained by the host government; however, the contractor may receive title to the prescribed share of the quantities when produced or at point of sale and may claim that share as their Reserves.

3.3.2.3 Risk service contracts (RSCs) are similar to PSCs, but the producers may be paid in cash rather than in production. As with PSCs, the Reserves claimed are based on the entity's economic interest as risk is borne by the contractor. Care needs to be taken to distinguish between an RSC and a pure service contract. Reserves can be claimed in an RSC, whereas no Reserves can be claimed for pure service contracts because there is insufficient exposure to petroleum exploration, development, and market risks and the producers act as contractors.

3.3.2.4 Unlike conventional tax-royalty agreements, the cost recovery system in production-sharing, risk-service, and other related contracts typically reduce the production share and hence Reserves entitlement to a contractor in periods of high price and increase quantities in periods of low price. While this ensures cost recovery, it also introduces significant price-related volatility in annual Reserves estimates under cases using a constant case. The terms governing cost recovery in a particular PSC may require special treatment of items such as taxes, overhead, and ADR to determine entitlement.

3.3.2.5 The treatment of taxes and the accounting procedures used can also have a significant impact on the Reserves recognized and production reported from these contracts.

3.3.3 Contract Extensions or Renewals

3.3.3.1 As production-sharing or other types of agreements approach the specified end date, extensions may be obtained through contract negotiation, by the exercise of options to extend, or by other means.

3.3.3.2 Reserves cannot be claimed for those quantities that will be produced beyond the expiration date of the current agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. Such reasonable expectation may be based on the status of renewal negotiations and historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term must be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

3.3.3.3 Similar logic should be applied where gas sales agreements are required to ensure adequate markets. Reserves should not be claimed for quantities that will be produced beyond those specified in the current agreement or that do not have a reasonable expectation to be included in either contract renewals or future agreements.

APPENDIX B: ONE LINE SUMMARIES

KINETIKO ENERGY LIMITED
TOTAL 1P
ONELINE SUMMARY
EFFECTIVE JULY 1, 2023

Well	RES CAT	WI	NRI	Life (Years)	Start	Gross Oil (Mbbl)	Gross Gas (MMCF)	Net Oil (Mbbl)	Net Gas (MMCF)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	P&A Costs (M$)	Investment (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
FIELD COSTS																				
FACILITIES CAPEX		0.000	0.000	19.33	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.9	-140.9	-128.1	0.0	0.0	0.0	0.0
WELL CAPEX		0.000	0.000	19.33	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,675.5	-11,675.5	-6,643.8	0.0	0.0	0.0	0.0
FIELD OPEX		0.000	0.000	19.33	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	7,539.5	0.0	0.0	-7,539.5	-2,927.0	0.0	0.0	0.0	0.0
VARIABLE WELL OPEX		0.000	0.000	19.33	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	34,613.8	0.0	0.0	-34,613.8	-12,108.7	0.0	0.0	0.0	0.0
SUBTOTAL FIELD COSTS						**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**42,153.2**	**0.0**	**11,816.5**	**-53,969.7**	**-21,807.6**	**0.0**	**0.0**	**0.0**	**0.0**
WELLS																				
DST CONVERSION 01	2PDNP	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
DST CONVERSION 02	2PDNP	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
DST CONVERSION 03	2PDNP	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
DST CONVERSION 04	2PDNP	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
DST CONVERSION 05	2PDNP	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 01	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 02	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 03	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 04	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 05	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 06	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 07	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 08	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 09	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 10	3PUD	1.000	0.950	19.33	07/2024	0.0	183.3	0.0	165.4	2,175.2	0.0	0.0	10.0	0.0	2,165.2	1,005.4	0.0	183.3	0.0	0.0
NEW WELL 11	3PUD	1.000	0.950	19.33	07/2027	0.0	167.5	0.0	151.1	2,188.9	0.0	0.0	10.0	0.0	2,178.9	838.8	0.0	167.5	0.0	0.0
NEW WELL 12	3PUD	1.000	0.950	19.33	07/2027	0.0	167.5	0.0	151.1	2,188.9	0.0	0.0	10.0	0.0	2,178.9	838.8	0.0	167.5	0.0	0.0
NEW WELL 13	3PUD	1.000	0.950	19.33	09/2029	0.0	153.7	0.0	138.7	2,134.5	0.0	0.0	10.0	0.0	2,124.5	716.5	0.0	153.7	0.0	0.0
NEW WELL 14	3PUD	1.000	0.950	19.33	09/2029	0.0	153.7	0.0	138.7	2,134.5	0.0	0.0	10.0	0.0	2,124.5	716.5	0.0	153.7	0.0	0.0
NEW WELL 15	3PUD	1.000	0.950	19.33	10/2031	0.0	138.1	0.0	124.6	2,014.3	0.0	0.0	10.0	0.0	2,004.3	596.4	0.0	138.1	0.0	0.0
NEW WELL 16	3PUD	1.000	0.950	19.33	10/2031	0.0	138.1	0.0	124.6	2,014.3	0.0	0.0	10.0	0.0	2,004.3	596.4	0.0	138.1	0.0	0.0
NEW WELL 17	3PUD	1.000	0.950	19.33	11/2033	0.0	120.0	0.0	108.3	1,807.6	0.0	0.0	10.0	0.0	1,797.6	472.0	0.0	120.0	0.0	0.0
NEW WELL 18	3PUD	1.000	0.950	19.33	11/2033	0.0	120.0	0.0	108.3	1,807.6	0.0	0.0	10.0	0.0	1,797.6	472.0	0.0	120.0	0.0	0.0
NEW WELL 19	3PUD	1.000	0.950	19.33	12/2035	0.0	98.8	0.0	89.2	1,498.3	0.0	0.0	10.0	0.0	1,488.3	343.8	0.0	98.8	0.0	0.0
NEW WELL 20	3PUD	1.000	0.950	19.33	12/2035	0.0	98.8	0.0	89.2	1,498.3	0.0	0.0	10.0	0.0	1,488.3	343.8	0.0	98.8	0.0	0.0
NEW WELL 21	3PUD	1.000	0.950	19.33	01/2038	0.0	74.2	0.0	66.9	1,124.5	0.0	0.0	10.0	0.0	1,114.5	227.8	0.0	74.2	0.0	0.0
NEW WELL 22	3PUD	1.000	0.950	19.33	01/2038	0.0	74.2	0.0	66.9	1,124.5	0.0	0.0	10.0	0.0	1,114.5	227.8	0.0	74.2	0.0	0.0
NEW WELL 23	3PUD	1.000	0.950	19.33	02/2040	0.0	45.4	0.0	41.0	688.5	0.0	0.0	10.0	0.0	678.5	123.7	0.0	45.4	0.0	0.0
NEW WELL 24	3PUD	1.000	0.950	19.33	02/2040	0.0	45.4	0.0	41.0	688.5	0.0	0.0	10.0	0.0	678.5	123.7	0.0	45.4	0.0	0.0
NEW WELL 25	3PUD	1.000	0.950	19.33	03/2042	0.0	11.9	0.0	10.7	180.0	0.0	0.0	10.0	0.0	170.0	27.9	0.0	11.9	0.0	0.0
SUBTOTAL WELLS						**0.0**	**4,356.6**	**0.0**	**3,931.8**	**55,721.3**	**0.0**	**0.0**	**300.0**	**0.0**	**55,421.3**	**21,747.7**	**0.0**	**4,356.6**	**0.0**	**0.0**
GRAND TOTAL 1P						**0.0**	**4,356.6**	**0.0**	**3,931.8**	**55,721.3**	**0.0**	**42,153.2**	**300.0**	**11,816.5**	**1,451.6**	**-59.9**	**0.0**	**4,356.6**	**0.0**	**0.0**

Scenario: SPR0723_1P30W
Input Settings: SET0723

KINETIKO ENERGY LIMITED
TOTAL 2P
ONELINE SUMMARY
EFFECTIVE JULY 1, 2023

Well	RES CAT	WI	NRI	Life (Years)	Start	Gross Oil (Mbbl)	Gross Gas (MMCF)	Net Oil (Mbbl)	Net Gas (MMCF)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	P&A Costs (M$)	Investment (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
FIELD COSTS																				
FACILITIES CAPEX		0.000	0.000	30.92	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.9	-140.9	-128.1	0.0	0.0	0.0	0.0
WELL CAPEX		0.000	0.000	30.92	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12,193.8	-12,193.8	-5,811.5	0.0	0.0	0.0	0.0
FIELD OPEX		0.000	0.000	30.92	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	13,167.0	0.0	0.0	-13,167.0	-3,466.7	0.0	0.0	0.0	0.0
VARIABLE WELL OPEX		0.000	0.000	30.92	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	59,816.5	0.0	0.0	-59,816.5	-13,380.8	0.0	0.0	0.0	0.0
SUBTOTAL FIELD COSTS						**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**72,983.6**	**0.0**	**12,334.7**	**-85,318.3**	**-22,787.1**	**0.0**	**0.0**	**0.0**	**0.0**
WELLS																				
DST CONVERSION 01	2PDNP	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
DST CONVERSION 02	2PDNP	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
DST CONVERSION 03	2PDNP	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
DST CONVERSION 04	2PDNP	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
DST CONVERSION 05	2PDNP	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 01	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 02	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 03	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 04	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 05	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 06	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 07	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 08	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 09	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 10	3PUD	1.000	0.950	30.92	07/2024	0.0	299.3	0.0	270.1	3,873.5	0.0	0.0	10.0	0.0	3,863.5	1,315.2	0.0	299.3	0.0	0.0
NEW WELL 11	3PUD	1.000	0.950	30.92	07/2029	0.0	272.8	0.0	246.2	3,920.1	0.0	0.0	10.0	0.0	3,910.1	974.2	0.0	272.8	0.0	0.0
NEW WELL 12	3PUD	1.000	0.950	30.92	07/2029	0.0	272.8	0.0	246.2	3,920.1	0.0	0.0	10.0	0.0	3,910.1	974.2	0.0	272.8	0.0	0.0
NEW WELL 13	3PUD	1.000	0.950	30.92	11/2032	0.0	251.5	0.0	227.0	3,775.1	0.0	0.0	10.0	0.0	3,765.1	754.8	0.0	251.5	0.0	0.0
NEW WELL 14	3PUD	1.000	0.950	30.92	11/2032	0.0	251.5	0.0	227.0	3,775.1	0.0	0.0	10.0	0.0	3,765.1	754.8	0.0	251.5	0.0	0.0
NEW WELL 15	3PUD	1.000	0.950	30.92	04/2036	0.0	226.1	0.0	204.1	3,427.6	0.0	0.0	10.0	0.0	3,417.6	538.0	0.0	226.1	0.0	0.0
NEW WELL 16	3PUD	1.000	0.950	30.92	04/2036	0.0	226.1	0.0	204.1	3,427.6	0.0	0.0	10.0	0.0	3,417.6	538.0	0.0	226.1	0.0	0.0
NEW WELL 17	3PUD	1.000	0.950	30.92	09/2039	0.0	196.5	0.0	177.3	2,978.0	0.0	0.0	10.0	0.0	2,968.0	368.1	0.0	196.5	0.0	0.0
NEW WELL 18	3PUD	1.000	0.950	30.92	09/2039	0.0	196.5	0.0	177.3	2,978.0	0.0	0.0	10.0	0.0	2,968.0	368.1	0.0	196.5	0.0	0.0
NEW WELL 19	3PUD	1.000	0.950	30.92	02/2043	0.0	161.8	0.0	146.1	2,453.4	0.0	0.0	10.0	0.0	2,443.4	242.1	0.0	161.8	0.0	0.0
NEW WELL 20	3PUD	1.000	0.950	30.92	02/2043	0.0	161.8	0.0	146.1	2,453.4	0.0	0.0	10.0	0.0	2,443.4	242.1	0.0	161.8	0.0	0.0
NEW WELL 21	3PUD	1.000	0.950	30.92	07/2046	0.0	121.5	0.0	109.6	1,841.0	0.0	0.0	10.0	0.0	1,831.0	147.1	0.0	121.5	0.0	0.0
NEW WELL 22	3PUD	1.000	0.950	30.92	07/2046	0.0	121.5	0.0	109.6	1,841.0	0.0	0.0	10.0	0.0	1,831.0	147.1	0.0	121.5	0.0	0.0
NEW WELL 23	3PUD	1.000	0.950	30.92	11/2049	0.0	75.5	0.0	68.2	1,145.2	0.0	0.0	10.0	0.0	1,135.2	75.5	0.0	75.5	0.0	0.0
NEW WELL 24	3PUD	1.000	0.950	30.92	11/2049	0.0	75.5	0.0	68.2	1,145.2	0.0	0.0	10.0	0.0	1,135.2	75.5	0.0	75.5	0.0	0.0
NEW WELL 25	3PUD	1.000	0.950	30.92	04/2053	0.0	20.7	0.0	18.7	314.4	0.0	0.0	10.0	0.0	304.4	17.0	0.0	20.7	0.0	0.0
SUBTOTAL WELLS						**0.0**	**7,121.8**	**0.0**	**6,427.5**	**97,497.8**	**0.0**	**0.0**	**300.0**	**0.0**	**97,197.8**	**25,944.1**	**0.0**	**7,121.8**	**0.0**	**0.0**
GRAND TOTAL 2P						**0.0**	**7,121.8**	**0.0**	**6,427.5**	**97,497.8**	**0.0**	**72,983.6**	**300.0**	**12,334.7**	**11,879.5**	**3,157.0**	**0.0**	**7,121.8**	**0.0**	**0.0**

Scenario: SPR0723_2P30W
Input Settings: SET0723

KINETIKO ENERGY LIMITED
TOTAL 3P
ONELINE SUMMARY
EFFECTIVE JULY 1, 2023

Well	RES CAT	WI	NRI	Life (Years)	Start	Gross Oil (Mbbl)	Gross Gas (MMCF)	Net Oil (Mbbl)	Net Gas (MMCF)	Net Revenue (M$)	Taxes (M$)	Operating Expense (M$)	P&A Costs (M$)	Investment (M$)	Undisc. NCF (M$)	Discounted NCF @ 10% (M$)	Ultimate Oil (Mbbl)	Ultimate Gas (MMCF)	Cum Oil (Mbbl)	Cum Gas (MMCF)
FIELD COSTS																				
FACILITIES CAPEX		0.000	0.000	47.67	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.9	-140.9	-128.1	0.0	0.0	0.0	0.0
WELL CAPEX		0.000	0.000	47.67	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12,431.7	-12,431.7	-5,082.2	0.0	0.0	0.0	0.0
FIELD OPEX		0.000	0.000	47.67	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	21,304.7	0.0	0.0	-21,304.7	-3,680.1	0.0	0.0	0.0	0.0
VARIABLE WELL OPEX		0.000	0.000	47.67	07/2024	0.0	0.0	0.0	0.0	0.0	0.0	95,969.7	0.0	0.0	-95,969.7	-13,119.3	0.0	0.0	0.0	0.0
SUBTOTAL FIELD COSTS						**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**117,274.4**	**0.0**	**12,572.6**	**-129,847.1**	**-22,009.8**	**0.0**	**0.0**	**0.0**	**0.0**
WELLS																				
DST CONVERSION 01	2PDNP	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
DST CONVERSION 02	2PDNP	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
DST CONVERSION 03	2PDNP	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
DST CONVERSION 04	2PDNP	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
DST CONVERSION 05	2PDNP	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 01	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 02	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 03	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 04	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 05	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 06	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 07	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 08	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 09	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 10	3PUD	1.000	0.950	47.67	07/2024	0.0	467.4	0.0	421.9	6,383.9	0.0	0.0	10.0	0.0	6,373.9	1,549.1	0.0	467.4	0.0	0.0
NEW WELL 11	3PUD	1.000	0.950	47.67	04/2032	0.0	426.3	0.0	384.7	6,402.0	0.0	0.0	10.0	0.0	6,392.0	935.3	0.0	426.3	0.0	0.0
NEW WELL 12	3PUD	1.000	0.950	47.67	04/2032	0.0	426.3	0.0	384.7	6,402.0	0.0	0.0	10.0	0.0	6,392.0	935.3	0.0	426.3	0.0	0.0
NEW WELL 13	3PUD	1.000	0.950	47.67	07/2037	0.0	392.7	0.0	354.4	5,953.2	0.0	0.0	10.0	0.0	5,943.2	577.4	0.0	392.7	0.0	0.0
NEW WELL 14	3PUD	1.000	0.950	47.67	07/2037	0.0	392.7	0.0	354.4	5,953.2	0.0	0.0	10.0	0.0	5,943.2	577.4	0.0	392.7	0.0	0.0
NEW WELL 15	3PUD	1.000	0.950	47.67	11/2042	0.0	353.0	0.0	318.6	5,350.5	0.0	0.0	10.0	0.0	5,340.5	342.2	0.0	353.0	0.0	0.0
NEW WELL 16	3PUD	1.000	0.950	47.67	11/2042	0.0	353.0	0.0	318.6	5,350.5	0.0	0.0	10.0	0.0	5,340.5	342.2	0.0	353.0	0.0	0.0
NEW WELL 17	3PUD	1.000	0.950	47.67	02/2048	0.0	307.4	0.0	277.4	4,659.2	0.0	0.0	10.0	0.0	4,649.2	201.6	0.0	307.4	0.0	0.0
NEW WELL 18	3PUD	1.000	0.950	47.67	02/2048	0.0	307.4	0.0	277.4	4,659.2	0.0	0.0	10.0	0.0	4,649.2	201.6	0.0	307.4	0.0	0.0
NEW WELL 19	3PUD	1.000	0.950	47.67	06/2053	0.0	253.4	0.0	228.7	3,840.8	0.0	0.0	10.0	0.0	3,830.8	114.4	0.0	253.4	0.0	0.0
NEW WELL 20	3PUD	1.000	0.950	47.67	06/2053	0.0	253.4	0.0	228.7	3,840.8	0.0	0.0	10.0	0.0	3,830.8	114.4	0.0	253.4	0.0	0.0
NEW WELL 21	3PUD	1.000	0.950	47.67	09/2058	0.0	191.4	0.0	172.8	2,902.0	0.0	0.0	10.0	0.0	2,892.0	61.4	0.0	191.4	0.0	0.0
NEW WELL 22	3PUD	1.000	0.950	47.67	09/2058	0.0	191.4	0.0	172.8	2,902.0	0.0	0.0	10.0	0.0	2,892.0	61.4	0.0	191.4	0.0	0.0
NEW WELL 23	3PUD	1.000	0.950	47.67	12/2063	0.0	119.4	0.0	107.7	1,809.4	0.0	0.0	10.0	0.0	1,799.4	28.0	0.0	119.4	0.0	0.0
NEW WELL 24	3PUD	1.000	0.950	47.67	12/2063	0.0	119.4	0.0	107.7	1,809.4	0.0	0.0	10.0	0.0	1,799.4	28.0	0.0	119.4	0.0	0.0
NEW WELL 25	3PUD	1.000	0.950	47.67	04/2069	0.0	34.0	0.0	30.7	515.8	0.0	0.0	10.0	0.0	505.8	5.9	0.0	34.0	0.0	0.0
SUBTOTAL WELLS						**0.0**	**11,132.8**	**0.0**	**10,047.4**	**158,108.1**	**0.0**	**0.0**	**300.0**	**0.0**	**157,808.1**	**27,762.8**	**0.0**	**11,132.8**	**0.0**	**0.0**
GRAND TOTAL 3P						**0.0**	**11,132.8**	**0.0**	**10,047.4**	**158,108.1**	**0.0**	**117,274.4**	**300.0**	**12,572.6**	**27,961.1**	**5,753.0**	**0.0**	**11,132.8**	**0.0**	**0.0**

Scenario: SPR0723_3P30W
Input Settings: SET0723

APPENDIX C: RESERVE CASHFLOW SUMMARIES

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
TOTAL FIELD CAPEX & OPEX
TOTAL 1P

DATE : 08/02/2023
TIME : 08:23:42
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_1P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	519.558	0.000	0.000	4526.422	-5045.980	-5045.980	-4576.175
12-2025	0.000	0.000	1072.888	0.000	0.000	0.000	-1072.888	-6118.868	-5462.527
12-2026	0.000	0.000	1142.625	0.000	0.000	0.000	-1142.625	-7261.493	-6320.677
12-2027	0.000	0.000	1279.742	0.000	0.000	706.324	-1986.066	-9247.560	-7675.869
12-2028	0.000	0.000	1425.772	0.000	0.000	0.000	-1425.772	-10673.332	-8560.830
12-2029	0.000	0.000	1565.969	0.000	0.000	801.130	-2367.099	-13040.431	-9888.710
12-2030	0.000	0.000	1764.344	0.000	0.000	0.000	-1764.344	-14804.774	-10793.758
12-2031	0.000	0.000	1919.451	0.000	0.000	908.662	-2828.113	-17632.888	-12102.122
12-2032	0.000	0.000	2168.118	0.000	0.000	0.000	-2168.118	-19801.006	-13021.271
12-2033	0.000	0.000	2339.612	0.000	0.000	1030.627	-3370.240	-23171.246	-14307.427
12-2034	0.000	0.000	2648.498	0.000	0.000	0.000	-2648.498	-25819.744	-15235.362
12-2035	0.000	0.000	2748.728	0.000	0.000	1098.084	-3846.812	-29666.556	-16447.553
12-2036	0.000	0.000	2928.432	0.000	0.000	0.000	-2928.432	-32594.988	-17296.134
12-2037	0.000	0.000	2928.432	0.000	0.000	0.000	-2928.432	-35523.420	-18067.572
S TOT	0.000	0.000	26452.168	0.000	0.000	9071.249	-35523.420	-35523.420	-18067.572
AFTER	0.000	0.000	15701.068	0.000	0.000	2745.210	-18446.278	-53969.696	-21807.638
TOTAL	0.000	0.000	42153.236	0.000	0.000	11816.459	-53969.696	-53969.696	-21807.638

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	0.0	LIFE, YRS.	19.33	5.00	-32724.894
GROSS ULT., MB & MMF	0.000	0.000	DISCOUNT %	10.00	8.00	-25382.400
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	19.33	10.00	-21807.638
GROSS RES., MB & MMF	0.000	0.000	DISCOUNTED PAYOUT, YRS.	19.33	15.00	-15760.768
NET RES., MB & MMF	0.000	0.000	UNDISCOUNTED NET/INVEST.	-3.57	18.00	-13400.613
NET REVENUE, M$	0.000	0.000	DISCOUNTED NET/INVEST.	-2.22	20.00	-12166.945
INITIAL PRICE, $	0.000	0.000	RATE-OF-RETURN, PCT.	0.00	30.00	-8355.698
INITIAL N.I., PCT.	0.000	95.000	INITIAL W.I., PCT.	0.000	60.00	-4635.574
					80.00	-3714.776
					100.00	-3140.298

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
ALL WELLS TOTAL 1P

DATE : 08/02/2023
TIME : 08:23:47
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_1P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	134.378	0.000	121.276	0.000	8.944	0.000	1084.681	1084.681
12-2025	0.000	254.317	0.000	229.521	0.000	9.229	0.000	2118.290	2118.290
12-2026	0.000	236.209	0.000	213.179	0.000	9.829	0.000	2095.353	2095.353
12-2027	0.000	237.309	0.000	214.171	0.000	10.493	0.000	2247.363	2247.363
12-2028	0.000	237.680	0.000	214.506	0.000	11.148	0.000	2391.394	2391.394
12-2029	0.000	232.775	0.000	210.079	0.000	11.893	0.000	2498.410	2498.410
12-2030	0.000	239.368	0.000	216.029	0.000	12.645	0.000	2731.644	2731.644
12-2031	0.000	231.366	0.000	208.808	0.000	13.484	0.000	2815.475	2815.475
12-2032	0.000	241.036	0.000	217.535	0.000	14.342	0.000	3119.894	3119.894
12-2033	0.000	229.920	0.000	207.503	0.000	15.287	0.000	3172.130	3172.130
12-2034	0.000	242.689	0.000	219.027	0.000	16.267	0.000	3562.922	3562.922
12-2035	0.000	228.442	0.000	206.169	0.000	16.792	0.000	3462.068	3462.068
12-2036	0.000	244.329	0.000	220.507	0.000	16.796	0.000	3703.632	3703.632
12-2037	0.000	226.933	0.000	204.807	0.000	16.796	0.000	3439.934	3439.934
S TOT	0.000	3216.750	0.000	2903.117	0.000	13.242	0.000	38443.192	38443.192
AFTER	0.000	1139.840	0.000	1028.705	0.000	16.796	0.000	17278.134	17278.134
TOTAL	0.000	4356.590	0.000	3931.822	0.000	14.172	0.000	55721.328	55721.328

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	1084.681	1084.681	963.082
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	2118.290	3202.972	2714.099
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	2095.353	5298.325	4288.696
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	2247.363	7545.688	5821.188
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	2391.394	9937.082	7306.364
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	2498.410	12435.492	8714.590
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	2731.644	15167.136	10116.647
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	2815.475	17982.612	11428.494
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	3119.894	21102.506	12751.909
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	3172.130	24274.636	13973.859
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	3562.922	27837.558	15222.901
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	3462.068	31299.626	16326.434
12-2036	0.000	0.000	0.000	0.000	0.000	0.000	3703.632	35003.260	17400.272
12-2037	0.000	0.000	0.000	0.000	0.000	0.000	3439.934	38443.192	18306.982
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	38443.192	38443.192	18306.982
AFTER	0.000	0.000	0.000	0.000	300.000	0.000	16978.134	55421.328	21747.728
TOTAL	0.000	0.000	0.000	0.000	300.000	0.000	55421.328	55421.328	21747.728

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	4356.590
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	4356.590
NET RES., MB & MMF	0.000	3931.822
NET REVENUE, M$	0.000	55721.328
INITIAL PRICE, $	0.000	11.906
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	19.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	33336.726
8.00	25568.462
10.00	21747.730
15.00	15206.819
18.00	12620.564
20.00	11260.128
30.00	7024.524
60.00	2972.848
80.00	2073.866
100.00	1567.458

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
GRAND TOTAL 1P

DATE : 08/02/2023
TIME : 08:23:48
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_1P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	134.378	0.000	121.276	0.000	8.944	0.000	1084.681	1084.681
12-2025	0.000	254.317	0.000	229.521	0.000	9.229	0.000	2118.290	2118.290
12-2026	0.000	236.209	0.000	213.179	0.000	9.829	0.000	2095.353	2095.353
12-2027	0.000	237.309	0.000	214.171	0.000	10.493	0.000	2247.363	2247.363
12-2028	0.000	237.680	0.000	214.506	0.000	11.148	0.000	2391.394	2391.394
12-2029	0.000	232.775	0.000	210.079	0.000	11.893	0.000	2498.410	2498.410
12-2030	0.000	239.368	0.000	216.029	0.000	12.645	0.000	2731.644	2731.644
12-2031	0.000	231.366	0.000	208.808	0.000	13.484	0.000	2815.475	2815.475
12-2032	0.000	241.036	0.000	217.535	0.000	14.342	0.000	3119.894	3119.894
12-2033	0.000	229.920	0.000	207.503	0.000	15.287	0.000	3172.130	3172.130
12-2034	0.000	242.689	0.000	219.027	0.000	16.267	0.000	3562.922	3562.922
12-2035	0.000	228.442	0.000	206.169	0.000	16.792	0.000	3462.068	3462.068
12-2036	0.000	244.329	0.000	220.507	0.000	16.796	0.000	3703.632	3703.632
12-2037	0.000	226.933	0.000	204.807	0.000	16.796	0.000	3439.934	3439.934
S TOT	0.000	3216.750	0.000	2903.117	0.000	13.242	0.000	38443.192	38443.192
AFTER	0.000	1139.840	0.000	1028.705	0.000	16.796	0.000	17278.134	17278.134
TOTAL	0.000	4356.590	0.000	3931.822	0.000	14.172	0.000	55721.328	55721.328

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	519.558	0.000	0.000	4526.422	-3961.299	-3961.299	-3613.094
12-2025	0.000	0.000	1072.888	0.000	0.000	0.000	1045.403	-2915.896	-2748.428
12-2026	0.000	0.000	1142.625	0.000	0.000	0.000	952.728	-1963.168	-2031.981
12-2027	0.000	0.000	1279.742	0.000	0.000	706.324	261.296	-1701.872	-1854.681
12-2028	0.000	0.000	1425.772	0.000	0.000	0.000	965.622	-736.250	-1254.466
12-2029	0.000	0.000	1565.969	0.000	0.000	801.130	131.311	-604.939	-1174.121
12-2030	0.000	0.000	1764.344	0.000	0.000	0.000	967.301	362.362	-677.112
12-2031	0.000	0.000	1919.451	0.000	0.000	908.662	-12.638	349.724	-673.629
12-2032	0.000	0.000	2168.118	0.000	0.000	0.000	951.777	1301.501	-269.363
12-2033	0.000	0.000	2339.612	0.000	0.000	1030.627	-198.110	1103.391	-333.568
12-2034	0.000	0.000	2648.498	0.000	0.000	0.000	914.425	2017.816	-12.461
12-2035	0.000	0.000	2748.728	0.000	0.000	1098.084	-384.744	1633.072	-121.119
12-2036	0.000	0.000	2928.432	0.000	0.000	0.000	775.200	2408.272	104.139
12-2037	0.000	0.000	2928.432	0.000	0.000	0.000	511.502	2919.774	239.411
S TOT	0.000	0.000	26452.168	0.000	0.000	9071.249	2919.774	2919.774	239.411
AFTER	0.000	0.000	15701.068	0.000	300.000	2745.210	-1468.144	1451.630	-59.909
TOTAL	0.000	0.000	42153.236	0.000	300.000	11816.459	1451.630	1451.630	-59.909

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	4356.590
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	4356.590
NET RES., MB & MMF	0.000	3931.822
NET REVENUE, M$	0.000	55721.328
INITIAL PRICE, $	0.000	11.906
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	19.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	7.13
DISCOUNTED PAYOUT, YRS.	13.04
UNDISCOUNTED NET/INVEST.	1.12
DISCOUNTED NET/INVEST.	0.99
RATE-OF-RETURN, PCT.	9.51
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	611.832
8.00	186.062
10.00	-59.908
15.00	-553.949
18.00	-780.049
20.00	-906.817
30.00	-1331.173
60.00	-1662.726
80.00	-1640.910
100.00	-1572.840

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
TOTAL FIELD CAPEX & OPEX
TOTAL 2P

DATE : 08/02/2023
TIME : 08:26:12
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_2P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	519.558	0.000	0.000	4526.422	-5045.980	-5045.980	-4576.175
12-2025	0.000	0.000	1072.888	0.000	0.000	0.000	-1072.888	-6118.868	-5462.527
12-2026	0.000	0.000	1142.625	0.000	0.000	0.000	-1142.625	-7261.493	-6320.677
12-2027	0.000	0.000	1216.896	0.000	0.000	0.000	-1216.896	-8478.389	-7151.522
12-2028	0.000	0.000	1295.994	0.000	0.000	0.000	-1295.994	-9774.383	-7955.931
12-2029	0.000	0.000	1451.516	0.000	0.000	801.130	-2252.646	-12027.029	-9226.256
12-2030	0.000	0.000	1617.146	0.000	0.000	0.000	-1617.146	-13644.175	-10055.797
12-2031	0.000	0.000	1722.261	0.000	0.000	0.000	-1722.261	-15366.436	-10858.944
12-2032	0.000	0.000	1862.910	0.000	0.000	967.725	-2830.635	-18197.070	-12045.810
12-2033	0.000	0.000	2131.238	0.000	0.000	0.000	-2131.238	-20328.308	-12867.187
12-2034	0.000	0.000	2269.768	0.000	0.000	0.000	-2269.768	-22598.076	-13662.429
12-2035	0.000	0.000	2341.711	0.000	0.000	0.000	-2341.711	-24939.788	-14408.847
12-2036	0.000	0.000	2488.764	0.000	0.000	1098.084	-3586.848	-28526.636	-15455.260
12-2037	0.000	0.000	2537.616	0.000	0.000	0.000	-2537.616	-31064.252	-16123.745
S TOT	0.000	0.000	23670.892	0.000	0.000	7393.361	-31064.252	-31064.252	-16123.745
AFTER	0.000	0.000	49312.672	0.000	0.000	4941.378	-54254.056	-85318.304	-22787.106
TOTAL	0.000	0.000	72983.568	0.000	0.000	12334.739	-85318.304	-85318.304	-22787.106

	OIL	GAS
GROSS WELLS	0.0	0.0
GROSS ULT., MB & MMF	0.000	0.000
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	0.000
NET RES., MB & MMF	0.000	0.000
NET REVENUE, M$	0.000	0.000
INITIAL PRICE, $	0.000	0.000
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	30.92
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	30.92
DISCOUNTED PAYOUT, YRS.	30.92
UNDISCOUNTED NET/INVEST.	-5.92
DISCOUNTED NET/INVEST.	-2.84
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	0.000

P.W. %	P.W., M$
5.00	-39806.448
8.00	-27867.912
10.00	-22787.104
15.00	-15282.562
18.00	-12713.531
20.00	-11445.580
30.00	-7805.663
60.00	-4465.154
80.00	-3620.607
100.00	-3082.752

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
ALL WELLS TOTAL 2P

DATE : 08/02/2023
TIME : 08:26:16
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_2P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	135.340	0.000	122.144	0.000	8.944	0.000	1092.441	1092.441
12-2025	0.000	261.673	0.000	236.160	0.000	9.231	0.000	2180.050	2180.050
12-2026	0.000	250.107	0.000	225.721	0.000	9.831	0.000	2219.132	2219.132
12-2027	0.000	239.052	0.000	215.744	0.000	10.470	0.000	2258.914	2258.914
12-2028	0.000	228.486	0.000	206.208	0.000	11.151	0.000	2299.410	2299.410
12-2029	0.000	236.432	0.000	213.380	0.000	11.905	0.000	2540.196	2540.196
12-2030	0.000	243.624	0.000	219.870	0.000	12.648	0.000	2780.840	2780.840
12-2031	0.000	232.856	0.000	210.152	0.000	13.470	0.000	2830.692	2830.692
12-2032	0.000	228.624	0.000	206.333	0.000	14.357	0.000	2962.398	2962.398
12-2033	0.000	248.145	0.000	223.951	0.000	15.278	0.000	3421.460	3421.460
12-2034	0.000	237.177	0.000	214.053	0.000	16.271	0.000	3482.797	3482.797
12-2035	0.000	226.694	0.000	204.591	0.000	16.792	0.000	3435.582	3435.582
12-2036	0.000	243.590	0.000	219.840	0.000	16.796	0.000	3692.439	3692.439
12-2037	0.000	241.595	0.000	218.039	0.000	16.796	0.000	3662.189	3662.189
S TOT	0.000	3253.395	0.000	2936.189	0.000	13.234	0.000	38858.536	38858.536
AFTER	0.000	3868.436	0.000	3491.263	0.000	16.796	0.000	58639.248	58639.248
TOTAL	0.000	7121.831	0.000	6427.452	0.000	15.169	0.000	97497.784	97497.784

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	1092.441	1092.441	969.918
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	2180.050	3272.490	2771.580
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	2219.132	5491.622	4438.816
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	2258.914	7750.536	5981.657
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	2299.410	10049.946	7409.384
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	2540.196	12590.142	8840.602
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	2780.840	15370.982	10267.587
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	2830.692	18201.674	11588.102
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	2962.398	21164.072	12843.090
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	3421.460	24585.532	14162.187
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	3482.797	28068.328	15382.864
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	3435.582	31503.910	16478.342
12-2036	0.000	0.000	0.000	0.000	0.000	0.000	3692.439	35196.348	17547.254
12-2037	0.000	0.000	0.000	0.000	0.000	0.000	3662.189	38858.536	18512.330
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	38858.536	38858.536	18512.330
AFTER	0.000	0.000	0.000	0.000	300.000	0.000	58339.248	97197.776	25944.092
TOTAL	0.000	0.000	0.000	0.000	300.000	0.000	97197.784	97197.776	25944.092

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	7121.830
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	7121.830
NET RES., MB & MMF	0.000	6427.452
NET REVENUE, M$	0.000	97497.776
INITIAL PRICE, $	0.000	12.434
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	30.92
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	45966.152
8.00	32013.966
10.00	25944.094
15.00	16751.036
18.00	13518.067
20.00	11902.787
30.00	7205.067
60.00	3030.495
80.00	2116.767
100.00	1600.915

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
GRAND TOTAL 2P

DATE : 08/02/2023
TIME : 08:26:16
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_2P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	135.340	0.000	122.144	0.000	8.944	0.000	1092.441	1092.441
12-2025	0.000	261.673	0.000	236.160	0.000	9.231	0.000	2180.050	2180.050
12-2026	0.000	250.107	0.000	225.721	0.000	9.831	0.000	2219.132	2219.132
12-2027	0.000	239.052	0.000	215.744	0.000	10.470	0.000	2258.914	2258.914
12-2028	0.000	228.486	0.000	206.208	0.000	11.151	0.000	2299.410	2299.410
12-2029	0.000	236.432	0.000	213.380	0.000	11.905	0.000	2540.196	2540.196
12-2030	0.000	243.624	0.000	219.870	0.000	12.648	0.000	2780.840	2780.840
12-2031	0.000	232.856	0.000	210.152	0.000	13.470	0.000	2830.692	2830.692
12-2032	0.000	228.624	0.000	206.333	0.000	14.357	0.000	2962.398	2962.398
12-2033	0.000	248.145	0.000	223.951	0.000	15.278	0.000	3421.460	3421.460
12-2034	0.000	237.177	0.000	214.053	0.000	16.271	0.000	3482.797	3482.797
12-2035	0.000	226.694	0.000	204.591	0.000	16.792	0.000	3435.582	3435.582
12-2036	0.000	243.590	0.000	219.840	0.000	16.796	0.000	3692.439	3692.439
12-2037	0.000	241.595	0.000	218.039	0.000	16.796	0.000	3662.189	3662.189
S TOT	0.000	3253.395	0.000	2936.189	0.000	13.234	0.000	38858.536	38858.536
AFTER	0.000	3868.436	0.000	3491.263	0.000	16.796	0.000	58639.248	58639.248
TOTAL	0.000	7121.831	0.000	6427.452	0.000	15.169	0.000	97497.784	97497.784

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	519.558	0.000	0.000	4526.422	-3953.540	-3953.540	-3606.257
12-2025	0.000	0.000	1072.888	0.000	0.000	0.000	1107.162	-2846.378	-2690.948
12-2026	0.000	0.000	1142.625	0.000	0.000	0.000	1076.506	-1769.871	-1881.861
12-2027	0.000	0.000	1216.896	0.000	0.000	0.000	1042.018	-727.853	-1169.865
12-2028	0.000	0.000	1295.994	0.000	0.000	0.000	1003.416	275.563	-546.547
12-2029	0.000	0.000	1451.516	0.000	0.000	801.130	287.550	563.113	-385.653
12-2030	0.000	0.000	1617.146	0.000	0.000	0.000	1163.693	1726.806	211.790
12-2031	0.000	0.000	1722.261	0.000	0.000	0.000	1108.431	2835.237	729.159
12-2032	0.000	0.000	1862.910	0.000	0.000	967.725	131.764	2967.001	797.280
12-2033	0.000	0.000	2131.238	0.000	0.000	0.000	1290.221	4257.222	1295.000
12-2034	0.000	0.000	2269.768	0.000	0.000	0.000	1213.028	5470.250	1720.434
12-2035	0.000	0.000	2341.711	0.000	0.000	0.000	1093.871	6564.121	2069.495
12-2036	0.000	0.000	2488.764	0.000	0.000	1098.084	105.591	6669.712	2091.995
12-2037	0.000	0.000	2537.616	0.000	0.000	0.000	1124.573	7794.285	2388.586
S TOT	0.000	0.000	23670.892	0.000	0.000	7393.361	7794.285	7794.285	2388.586
AFTER	0.000	0.000	49312.672	0.000	300.000	4941.378	4085.197	11879.481	3156.992
TOTAL	0.000	0.000	72983.568	0.000	300.000	12334.739	11879.482	11879.481	3156.992

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	7121.830
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	7121.830
NET RES., MB & MMF	0.000	6427.452
NET REVENUE, M$	0.000	97497.776
INITIAL PRICE, $	0.000	12.434
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	30.92
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	5.23
DISCOUNTED PAYOUT, YRS.	7.15
UNDISCOUNTED NET/INVEST.	1.96
DISCOUNTED NET/INVEST.	1.53
RATE-OF-RETURN, PCT.	23.58
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	6159.704
8.00	4146.054
10.00	3156.990
15.00	1468.474
18.00	804.536
20.00	457.207
30.00	-600.596
60.00	-1434.659
80.00	-1503.840
100.00	-1481.837

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
TOTAL FIELD CAPEX & OPEX
TOTAL 3P

DATE : 08/02/2023
TIME : 08:28:37
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_3P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2036	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2037	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AFTER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	519.558	0.000	0.000	4526.422	-5045.980	-5045.980	-4576.175
12-2025	0.000	0.000	1072.888	0.000	0.000	0.000	-1072.888	-6118.868	-5462.527
12-2026	0.000	0.000	1142.625	0.000	0.000	0.000	-1142.625	-7261.493	-6320.677
12-2027	0.000	0.000	1216.896	0.000	0.000	0.000	-1216.896	-8478.389	-7151.522
12-2028	0.000	0.000	1295.994	0.000	0.000	0.000	-1295.994	-9774.383	-7955.931
12-2029	0.000	0.000	1380.234	0.000	0.000	0.000	-1380.234	-11154.616	-8734.745
12-2030	0.000	0.000	1469.949	0.000	0.000	0.000	-1469.949	-12624.565	-9488.779
12-2031	0.000	0.000	1565.496	0.000	0.000	0.000	-1565.496	-14190.060	-10218.821
12-2032	0.000	0.000	1793.783	0.000	0.000	908.662	-2702.445	-16892.504	-11373.298
12-2033	0.000	0.000	1953.431	0.000	0.000	0.000	-1953.431	-18845.936	-12126.148
12-2034	0.000	0.000	2080.404	0.000	0.000	0.000	-2080.404	-20926.340	-12855.044
12-2035	0.000	0.000	2146.344	0.000	0.000	0.000	-2146.344	-23072.684	-13539.189
12-2036	0.000	0.000	2146.800	0.000	0.000	0.000	-2146.800	-25219.484	-14161.274
12-2037	0.000	0.000	2244.504	0.000	0.000	1098.084	-3342.588	-28562.072	-15041.091
S TOT	0.000	0.000	22028.906	0.000	0.000	6533.168	-28562.072	-28562.072	-15041.091
AFTER	0.000	0.000	95245.536	0.000	0.000	6039.462	-101284.992	-129847.072	-22009.820
TOTAL	0.000	0.000	117274.440	0.000	0.000	12572.630	-129847.064	-129847.072	-22009.820

	OIL	GAS
GROSS WELLS	0.0	0.0
GROSS ULT., MB & MMF	0.000	0.000
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	0.000
NET RES., MB & MMF	0.000	0.000
NET REVENUE, M$	0.000	0.000
INITIAL PRICE, $	0.000	0.000
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	47.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	47.67
DISCOUNTED PAYOUT, YRS.	47.67
UNDISCOUNTED NET/INVEST.	-9.33
DISCOUNTED NET/INVEST.	-3.22
RATE-OF-RETURN, PCT.	0.00
INITIAL W.I., PCT.	0.000

P.W. %	P.W., M$
5.00	-43523.996
8.00	-27803.214
10.00	-22009.828
15.00	-14356.481
18.00	-11942.669
20.00	-10778.366
30.00	-7481.609
60.00	-4399.205
80.00	-3590.595
100.00	-3067.469

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
ALL WELLS TOTAL 3P

DATE : 08/02/2023
TIME : 08:28:42
DBS : SPROULE
SETTINGS : SET0723
SCENARIO : SPR0723_3P30W

R E S E R V E S A N D E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	135.890	0.000	122.641	0.000	8.944	0.000	1096.886	1096.886
12-2025	0.000	265.957	0.000	240.027	0.000	9.232	0.000	2216.032	2216.032
12-2026	0.000	258.378	0.000	233.186	0.000	9.833	0.000	2292.812	2292.812
12-2027	0.000	251.014	0.000	226.540	0.000	10.472	0.000	2372.252	2372.252
12-2028	0.000	243.860	0.000	220.084	0.000	11.152	0.000	2454.445	2454.445
12-2029	0.000	236.910	0.000	213.811	0.000	11.877	0.000	2539.485	2539.485
12-2030	0.000	230.158	0.000	207.718	0.000	12.649	0.000	2627.472	2627.472
12-2031	0.000	223.598	0.000	201.798	0.000	13.471	0.000	2718.507	2718.507
12-2032	0.000	244.306	0.000	220.486	0.000	14.364	0.000	3167.046	3167.046
12-2033	0.000	246.241	0.000	222.232	0.000	15.280	0.000	3395.630	3395.630
12-2034	0.000	239.223	0.000	215.899	0.000	16.273	0.000	3513.281	3513.281
12-2035	0.000	232.405	0.000	209.745	0.000	16.792	0.000	3522.130	3522.130
12-2036	0.000	225.781	0.000	203.768	0.000	16.796	0.000	3422.481	3422.481
12-2037	0.000	237.465	0.000	214.312	0.000	16.796	0.000	3599.591	3599.591
S TOT	0.000	3271.187	0.000	2952.246	0.000	13.189	0.000	38938.052	38938.052
AFTER	0.000	7861.660	0.000	7095.147	0.000	16.796	0.000	119170.104	119170.104
TOTAL	0.000	11132.847	0.000	10047.393	0.000	15.736	0.000	158108.160	158108.160

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	0.000	0.000	0.000	0.000	1096.886	1096.886	973.834
12-2025	0.000	0.000	0.000	0.000	0.000	0.000	2216.032	3312.918	2804.996
12-2026	0.000	0.000	0.000	0.000	0.000	0.000	2292.812	5605.730	4527.368
12-2027	0.000	0.000	0.000	0.000	0.000	0.000	2372.252	7977.983	6147.411
12-2028	0.000	0.000	0.000	0.000	0.000	0.000	2454.445	10432.428	7671.205
12-2029	0.000	0.000	0.000	0.000	0.000	0.000	2539.485	12971.913	9104.468
12-2030	0.000	0.000	0.000	0.000	0.000	0.000	2627.472	15599.385	10452.579
12-2031	0.000	0.000	0.000	0.000	0.000	0.000	2718.507	18317.892	11720.597
12-2032	0.000	0.000	0.000	0.000	0.000	0.000	3167.046	21484.938	13061.755
12-2033	0.000	0.000	0.000	0.000	0.000	0.000	3395.630	24880.568	14370.726
12-2034	0.000	0.000	0.000	0.000	0.000	0.000	3513.281	28393.848	15601.929
12-2035	0.000	0.000	0.000	0.000	0.000	0.000	3522.130	31915.978	16724.860
12-2036	0.000	0.000	0.000	0.000	0.000	0.000	3422.481	35338.460	17716.830
12-2037	0.000	0.000	0.000	0.000	0.000	0.000	3599.591	38938.052	18663.550
S TOT	0.000	0.000	0.000	0.000	0.000	0.000	38938.052	38938.052	18663.550
AFTER	0.000	0.000	0.000	0.000	300.000	0.000	118870.104	157808.160	27762.798
TOTAL	0.000	0.000	0.000	0.000	300.000	0.000	157808.160	157808.160	27762.798

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	11132.846
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	11132.846
NET RES., MB & MMF	0.000	10047.393
NET REVENUE, M$	0.000	158108.160
INITIAL PRICE, $	0.000	12.677
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	47.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	0.00
DISCOUNTED NET/INVEST.	0.00
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	55412.332
8.00	35420.640
10.00	27762.798
15.00	17247.194
18.00	13807.782
20.00	12126.858
30.00	7328.192
60.00	3091.569
80.00	2158.984
100.00	1631.482

KINETIKO ENERGY LIMITED
30 WELL DEVELOPMENT PROGRAM
GRAND TOTAL 3P

DATE : 08/02/2023
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SCENARIO : SPR0723_3P30W

R E S E R V E S   A N D   E C O N O M I C S

AS OF DATE: 07/2023

--END-- MO-YEAR	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----	TOTAL NET SALES -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	135.890	0.000	122.641	0.000	8.944	0.000	1096.886	1096.886
12-2025	0.000	265.957	0.000	240.027	0.000	9.232	0.000	2216.032	2216.032
12-2026	0.000	258.378	0.000	233.186	0.000	9.833	0.000	2292.812	2292.812
12-2027	0.000	251.014	0.000	226.540	0.000	10.472	0.000	2372.252	2372.252
12-2028	0.000	243.860	0.000	220.084	0.000	11.152	0.000	2454.445	2454.445
12-2029	0.000	236.910	0.000	213.811	0.000	11.877	0.000	2539.485	2539.485
12-2030	0.000	230.158	0.000	207.718	0.000	12.649	0.000	2627.472	2627.472
12-2031	0.000	223.598	0.000	201.798	0.000	13.471	0.000	2718.507	2718.507
12-2032	0.000	244.306	0.000	220.486	0.000	14.364	0.000	3167.046	3167.046
12-2033	0.000	246.241	0.000	222.232	0.000	15.280	0.000	3395.630	3395.630
12-2034	0.000	239.223	0.000	215.899	0.000	16.273	0.000	3513.281	3513.281
12-2035	0.000	232.405	0.000	209.745	0.000	16.792	0.000	3522.130	3522.130
12-2036	0.000	225.781	0.000	203.768	0.000	16.796	0.000	3422.481	3422.481
12-2037	0.000	237.465	0.000	214.312	0.000	16.796	0.000	3599.591	3599.591
S TOT	0.000	3271.187	0.000	2952.246	0.000	13.189	0.000	38938.052	38938.052
AFTER	0.000	7861.660	0.000	7095.147	0.000	16.796	0.000	119170.104	119170.104
TOTAL	0.000	11132.847	0.000	10047.393	0.000	15.736	0.000	158108.160	158108.160

--END-- MO-YEAR	AD VALOREM TAX -----M$----	PRODUCTION TAX -----M$----	DIRECT OPER EXPENSE -----M$----	INTEREST PAID -----M$----	ABANDONMENT COST -----M$----	EQUITY INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMULATIVE CASHFLOW -----M$----	CUM. DISC. CASHFLOW -----M$----
12-2023	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2024	0.000	0.000	519.558	0.000	0.000	4526.422	-3949.094	-3949.094	-3602.342
12-2025	0.000	0.000	1072.888	0.000	0.000	0.000	1143.145	-2805.949	-2657.530
12-2026	0.000	0.000	1142.625	0.000	0.000	0.000	1150.187	-1655.762	-1793.309
12-2027	0.000	0.000	1216.896	0.000	0.000	0.000	1155.356	-500.406	-1004.111
12-2028	0.000	0.000	1295.994	0.000	0.000	0.000	1158.450	658.045	-284.726
12-2029	0.000	0.000	1380.234	0.000	0.000	0.000	1159.252	1817.296	369.723
12-2030	0.000	0.000	1469.949	0.000	0.000	0.000	1157.523	2974.819	963.800
12-2031	0.000	0.000	1565.496	0.000	0.000	0.000	1153.011	4127.830	1501.776
12-2032	0.000	0.000	1793.783	0.000	0.000	908.662	464.600	4592.431	1688.457
12-2033	0.000	0.000	1953.431	0.000	0.000	0.000	1442.200	6034.630	2244.577
12-2034	0.000	0.000	2080.404	0.000	0.000	0.000	1432.877	7467.507	2746.884
12-2035	0.000	0.000	2146.344	0.000	0.000	0.000	1375.786	8843.293	3185.670
12-2036	0.000	0.000	2146.800	0.000	0.000	0.000	1275.681	10118.974	3555.555
12-2037	0.000	0.000	2244.504	0.000	0.000	1098.084	257.003	10375.977	3622.460
S TOT	0.000	0.000	22028.906	0.000	0.000	6533.168	10375.977	10375.977	3622.460
AFTER	0.000	0.000	95245.536	0.000	300.000	6039.462	17585.104	27961.088	5752.975
TOTAL	0.000	0.000	117274.440	0.000	300.000	12572.630	27961.080	27961.088	5752.975

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	11132.846
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	11132.846
NET RES., MB & MMF	0.000	10047.393
NET REVENUE, M$	0.000	158108.160
INITIAL PRICE, $	0.000	12.677
INITIAL N.I., PCT.	0.000	95.000

LIFE, YRS.	47.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	4.93
DISCOUNTED PAYOUT, YRS.	5.94
UNDISCOUNTED NET/INVEST.	3.22
DISCOUNTED NET/INVEST.	2.10
RATE-OF-RETURN, PCT.	28.69
INITIAL W.I., PCT.	100.000

P.W. %	P.W., M$
5.00	11888.336
8.00	7617.426
10.00	5752.970
15.00	2890.713
18.00	1865.113
20.00	1348.492
30.00	-153.418
60.00	-1307.636
80.00	-1431.612
100.00	-1435.987

APPENDIX D: ABBREVIATIONS

This appendix contains a list of abbreviations found in Sproule reports, as well as a table comparing Imperial and Metric units. Two conversion tables, used to prepare this report, are also provided.

AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
BOE	barrels of oil equivalent
bopd	barrels of oil per day
bwpd	barrels of water per day
Cr	Crown
DCQ	daily contract quantity
DSU	drilling spacing unit
FH	Freehold
GCA	gas cost allowance
GOR	gas-oil ratio
GORR	gross overriding royalty
LPG	liquid petroleum gas
MMZAR	Millions of South African ZAR's
M	thousands
mcfd	thousands of cubic feet per day
Mcfpd	thousands of cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
NC	'new' Crown
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
OC	'old' Crown
ORRI	overriding royalty interest
PDP	Proved Developed Producing
PDNP	Proved Developed Non-Producing
PUD	Proved Undeveloped
P&NG	petroleum and natural gas
PSU	production spacing unit
PVT	pressure-volume-temperature
TCGSL	TransCanada Gas Services Limited
UOCR	Unit Operating Cost Rates for operating gas cost allowance
WI	working interest

Imperial Units			Metric Units	
M (10^3)	one thousand	**Prefixes**	k (10^3)	one thousand
MM (10^6)	million		M (10^6)	million
B (10^9)	one billion		T (10^{12})	one billion E
T (10^{12})	one trillion		(10^{18})	one trillion G
			(10^9)	one milliard
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	mile		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
Mcfpd	thousand cubic feet per day			
MMcf	million cubic feet			
MMcfpd	million cubic feet per day			
Bcf	billion cubic feet (10^9)			
bbl	barrels		m^3	cubic metre
Mbbl	thousand barrels			
stb	stock tank barrel		stm^3	stock tank cubic metres
bbl/d	barrels per day		m^3/d	cubic metre per day
Btu	British thermal units	**Energy**	J	joules
			MJ/m^3	megajoules per cubic metre (10^6)
			TJ/d	terajoule per day (10^{12})
oz	ounce	**Mass**	g	gram
lb	pounds		kg	kilograms
ton	ton		t	tonne
lt	long tons			
Mlt	thousand long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	Kelvin
M$	thousand dollars	**Dollars**	k$	thousand dollars

Sproule

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
day	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Sproule

Conversion Factors — Metric to Imperial

cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise

Conversion Factors — Imperial to Metric

barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf) (@ 14.65 psia, 60°F)	x 0.03743222	= megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
$/bbl	x 6.29287	= $/$m^3$ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t) pounds
(lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)