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Independent Reserve and Resource Evaluation Report

2019 Update on the Estimation of the Methane and Helium Reserves of the Tetra4 Virginia Gas Field in the Free State of the Republic of South Africa

Renergen Limited

Prepared for: Mr. Stefano Marani

March 01, 2019

Mr. Stefano Marani
Chief Executive Officer
Renergen Limited
1 Bompas Road
Dunkeld West
Johannesburg, 2196
Republic of South Africa

Re: AN UPDATE ON THE ESTIMATION OF METHANE AND HELIUM RESERVES AND RESOURCES AND ASSOCIATED ECONOMICS OF THE TETRA4 VIRGINIA GAS FIELD IN THE FREE STATE OF THE REPUBLIC OF SOUTH AFRICA

Dear Mr. Marani:

At the request of Renergen Limited (Renergen), MHA Petroleum Consultants (MHA) has conducted an update to its March 2018 independent assessment of the unconventional methane and helium reserves and resources in the Tetra4 Virginia Gas Field, located in the Free State of the Republic of South Africa. This evaluation is primarily an economic update, based on the analysis methodology described herein using technical and economic data supplied by Tetra4, has an effective date of March 1, 2019. Material changes to this report are the inclusion of the HDR-1 well as a Proved Developed Producing well, updated CAPEX and OPEX costs, updated currency exchange rates, and an updated field development plan. Ongoing work by Tetra4 that may have a positive future impact that is discussed within this report includes the evaluation of a shallow conventional “White Sandstone” play, increased evaluation and definition of the helium market, and future potential of the South Africa liquid fuels market.

This evaluation includes estimates of recoverable methane and helium volumes from Proved Developed Non-Producing wells (PDNP’s), Proved Undeveloped locations (PUDs), total proved, probable, and possible reserves. MHA has now added the HDR-1 well as a Proved Developed Producing reserve (PDPs) due to the established history of production and sales of gas to the Megabus fleet. Associated pre-tax net present value of future income for selected discount rates are presented for Reserves volumes. MHA has estimated the volumes of Contingent Resources, those volumes of gases that are discovered but are not yet considered commercially viable for extraction due to one or more contingencies. MHA has also estimated the volumes of Prospective Resources, those volumes of gases that are undiscovered, but the likelihood of their existence can be estimated. Prospective Resources thus carry significant exploration risk. All Prospective Resources volumes presented in this report are un-risked. 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, due to the effects 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 the company or corporation owning working interest in the project.

Resource and 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 aligned with the Australian Stock Exchange (ASX) rules in conjunction with the SPE PRMS guidance and specific additional rules. Our evaluation based upon data supplied by Tetra4, supplemented where necessary by MHA's corporate awareness of current South African industry costs and best practices.

RESERVE AND RESOURCE ESTIMATES

The 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 guidelines (attached). The reserve and resource estimates contained in this report have been prepared as of March 1st, 2019 and are generated from the data supplied to MHA from Tetra4. Sustained commercial sales of methane gas from pilots located on the Tetra4 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 methane and helium reserves and net present values at Tetra4 specified discount rates are summarized in Table 1. For the purposes of clarification the use of the abbreviation 'M' equates to millions throughout this text and the abbreviation of 'm' equates to thousands.

Table 1: Summary of Methane and Helium Net Gas Reserves and Net Present Values at Selected Discount Rates

Virginia Gas Project – Specified Prices and Costs

	PDP	PDNP	PUDs	Total Proved (1P)	Probable	Proved +Probable (2P)	Possible	Proved+ Probable+ Possible (3P)
Methane (BCF)	.89	13.29	26.57	40.76	98.23	138.99	145.18	284.18
Helium (BCF)	.03	0.33	0.65	1.01	2.39	3.41	3.45	6.86
								Net Present Value (MZAR)
Undiscounted	466	6,462	13,440	17,069	50,367	64,477	75,065	135,196
5%	231	3,471	5,820	7,995	20,988	27,754	30,430	56,387
8%	172	2,580	4,049	5,599	14,369	19,059	20,481	38,224
10%	146	2,170	3,303	4,541	11,620	15,375	16,376	30,624
15%	106	1,502	2,175	2,878	7,516	9,788	10,301	19,242
20%	83	1,113	1,562	1,945	5,318	6,758	7,092	13,162
30%	58	695	934	978	3,104	3,699	3,929	7,127

Unrisked net Contingent Resources were calculated from the technically recoverable gas volumes for each type well multiplied by the number of locations in the portion of the Virginia Gas Field classified as Contingent Resources and, in the case of helium, multiplied by a constant helium content of 3%. These gas volumes were combined with the same prices and costs used for estimating Reserves to obtain the net Contingent Resources in Table 2 below.

Table 2: Summary of Net Methane and Helium Contingent Resources
Virginia Gas Field – Specified Prices and Costs

Category Contingent Resources (BCF)	Low Case (C1)	Best Case (C2)	High Case (C3)
Methane	237.3	435.9	648.5
Helium	7.9	14.4	20.9

Unrisked gross Prospective Resources (Table 3) were calculated volumetrically as the technically recoverable gas volumes for each type well multiplied by the number of locations in that portion of the Virginia Gas Field classified as Prospective Resources. No economics were calculated for methane Prospective Resources, and no helium Prospective Resources were estimated as part of this work.

Table 3: Summary of Gross Methane Prospective Resources
Virginia Gas Field

Category Prospective Resources (BCF)	Low Case	Best Case	High Case
Methane	640	1,278	2,069

***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 hydrocarbons."*

STATEMENT OF RISK

The accuracy of resource, reserve, 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 and value assigned to a property, but also may impact the total company reserve and economic status. The resources, reserves 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 MHA's opinion that the estimated resources, reserves, 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, MHA makes no warranties concerning the data and interpretations of such data. In no event shall MHA be liable for any special or consequential damages arising from Renergen's use of MHA's interpretation, reports, or services produced as a result of its work for Renergen. Neither MHA, nor any of our employees have any interest in the subject properties and neither the employment to do this work, nor the compensation, is contingent on our estimates of the resources or economic evaluations for the properties in this report. This report was prepared for the exclusive use of Renergen and will not be released by MHA to any other parties without Renergen'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 our offices.

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

Sincerely,

Jeffrey B. Aldrich

Partner
MHA Petroleum Consultants

John P. Seidle

John P. Seidle

Partner
MHA Petroleum Consultants

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BACKGROUND

Renergen's Tetra4's South Africa Virginia gas project, which is located in the Free State, is approximately 250 km southwest of Johannesburg. The exploration and production rights, which combined are known as the Virginia Gas Project, covers a large area where gas emitting boreholes have been identified from mineral exploration activities. Several of these boreholes are flowing gas at high production rates and have been doing so for decades. Past studies have conducted a work program which involved the cataloging and sampling of the gas emitting boreholes, a soil gas geochemistry survey, and structural mapping. The gas emitting boreholes, or "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 because of what was regarded as dangerously high gas emission rates. Tetra4 now owns 100% working interest in 187,427.2189 hectares (Figure 1) that currently has 18 wells currently producing gas and 28 wells that are known to have produced gas in the past but are now currently capped.

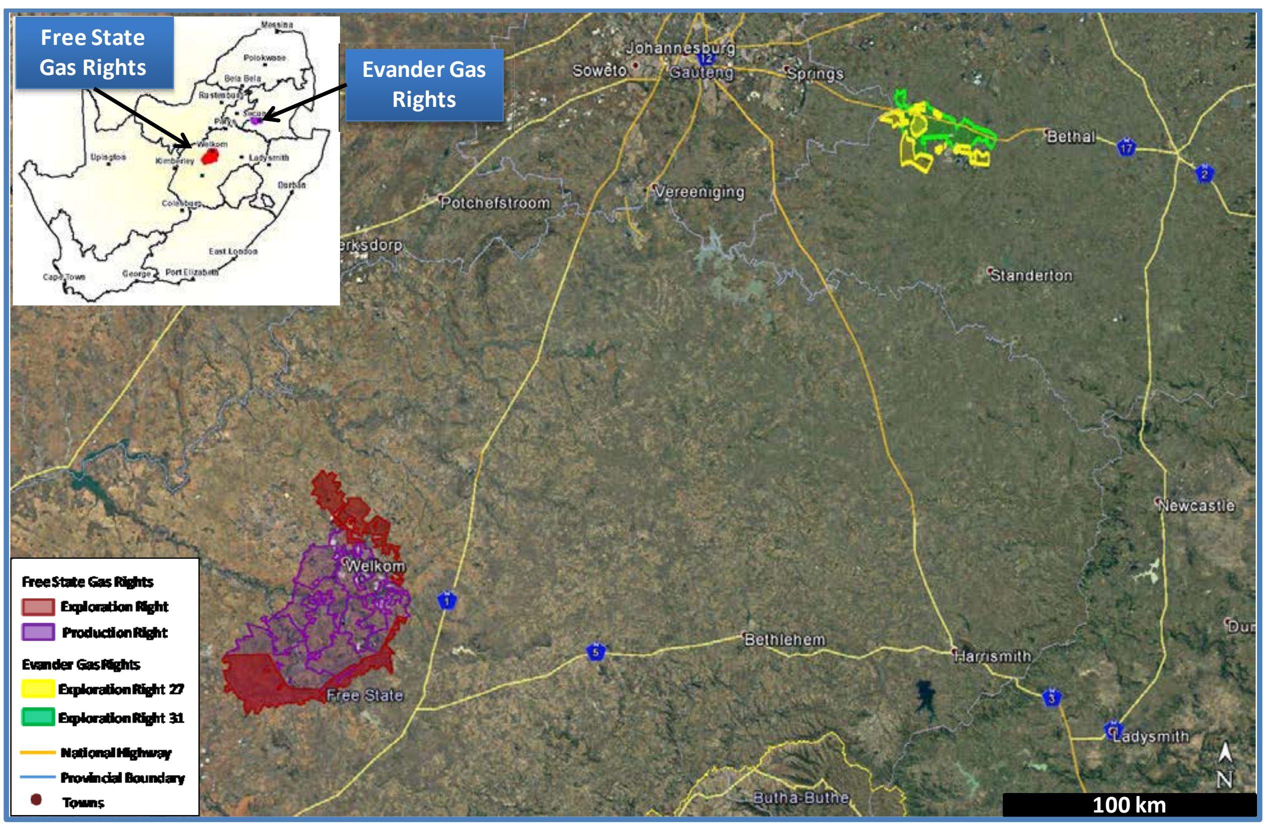


Figure 1: Location Map

The Tetra4 Production License is subject to a 5% state tax plus an overriding royalty (ORRI) on certain concurrent leases that are owned by GFI Mining South Africa (GFIMSA) of Goldfields. The Goldfields ORRI is an additional 1% on top of the state tax on all wells and locations that are located within the Goldfields mining leases. These two reductions in the revenue stream, the state tax, and the GFIMSA ORRI, have been accounted for in the economic analysis.

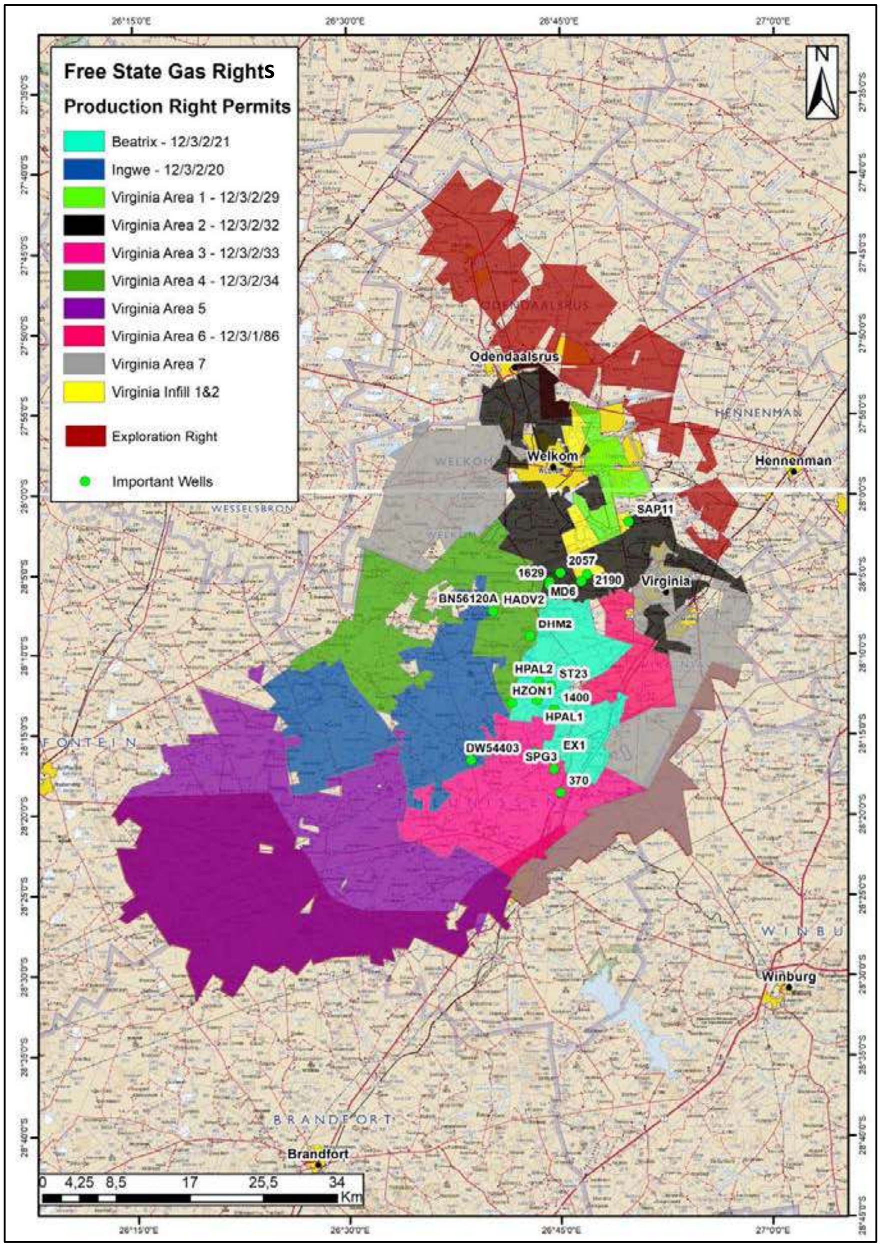


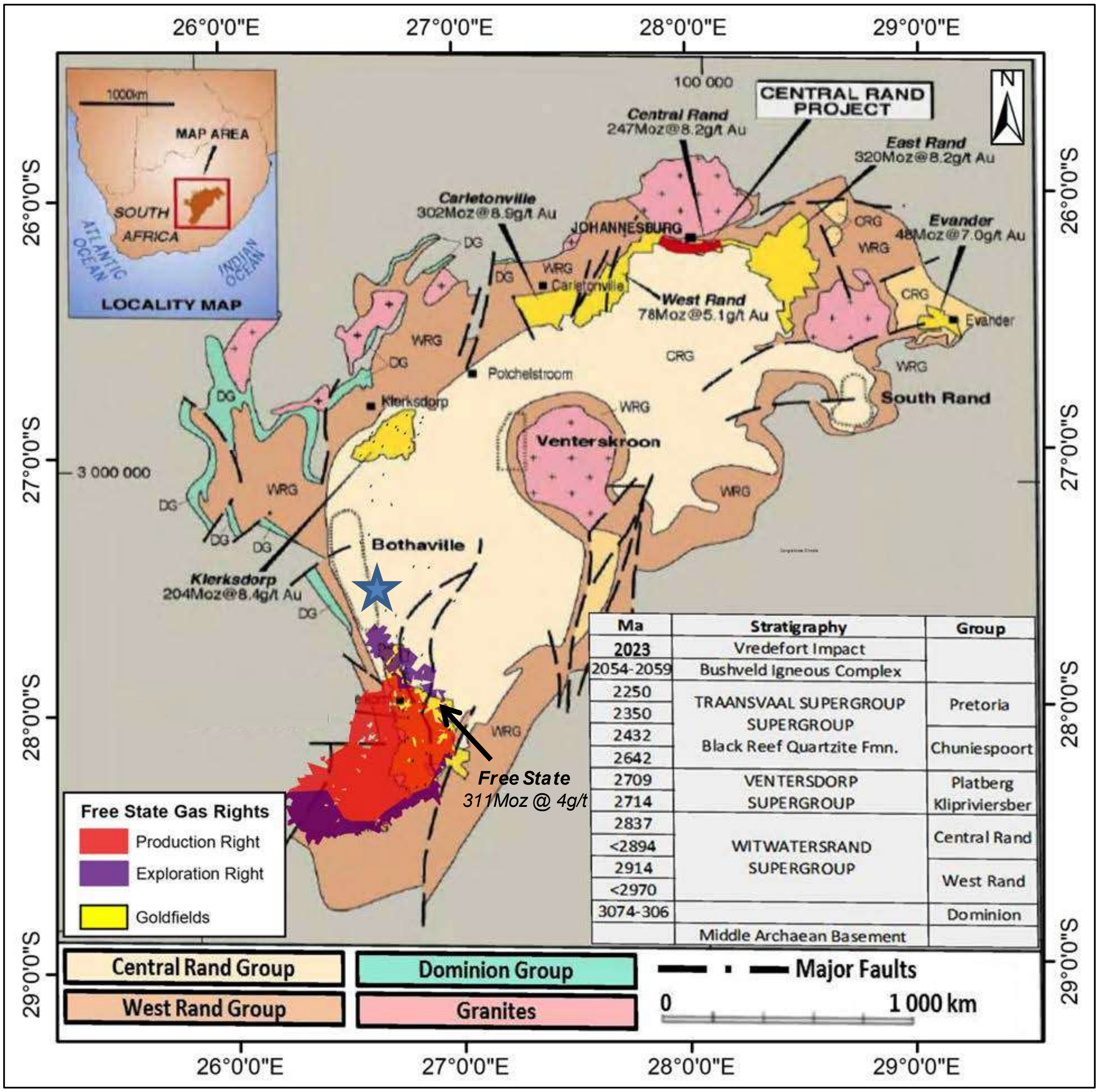
Figure 2: Permit Map

GEOLOGY

REGIONAL GEOLOGY

The Virginia Gas Field Project overlies Witwatersrand Precambrian age Supergroup of meta-sediments that host the Welkom Goldfield. These ‘basement’ lithologies have been tectonically flexed into a large north to south trending anticline that is in turn bisected by a large extensional graben (low area) and many large faults that extend deep into the earth’s crust. Uncomfortably overlying the Witwatersrand Supergroup is the Venterdorp Supergroup of primarily volcanic lithologies. Many of the larger faults do not extend beyond the upper Ventersdorp formations. After another large unconformity lies the Karoo Supergroup, a Permian aged sedimentary section composed of sandstones, coal seams and carbonaceous shales. There is often a basal glacial deposit on top of the unconformity that separates the Karoo from the Ventersdorp known as the Dwyka Tillite.

The primary source of the Methane gas is primarily microbial in origin from deep within the Witwatersrand Supergroup with groundwater circulating through the large faults and coming in contact with bacteria living deep within the crust. Methane isotope studies demonstrate that very little, if any, of the methane can be attributed to the Karoo coal beds or the carbonaceous shales. Thus, the methane is a biogenic and a continuing renewable resource. Being a renewing resource conventional in-place, static, estimates of gas volumes are not applicable and the authors of this study have instead relied on pressure decline analysis. The helium, as with almost all helium around the world, is either mantle-derived, that is from deep within the earth or from decay of radioactive minerals within the crust, and as the helium moves up the large faults mixes with the microbial methane in the deep subsurface. The rate of recharge of the methane, and thus also the helium, gas is not known. There is anecdotal evidence of historic blowers within the Tetra4 license area producing methane gas for over forty years without any discernable pressure drop however there are no quantified studies to date.



Ma	Stratigraphy	Group
2023	Vredefort Impact	
2054-2059	Bushveld Igneous Complex	
2250	TRAANSVAAL SUPERGROUP SUPERGROUP Black Reef Quartzite Fmn.	Pretoria
2350		
2432		Chuniespoort
2642		
2709	VENTERSDORP SUPERGROUP	Platberg
2714		Klipriviersber
2837	WITWATERSRAND SUPERGROUP	Central Rand
<2894		
2914		West Rand
<2970		
3074-306		Dominion
	Middle Archaean Basement	

Figure 3: Regional Geologic Map of the surface geology.

The Virginia Gas Project is annotated in the southwest corner of the map.

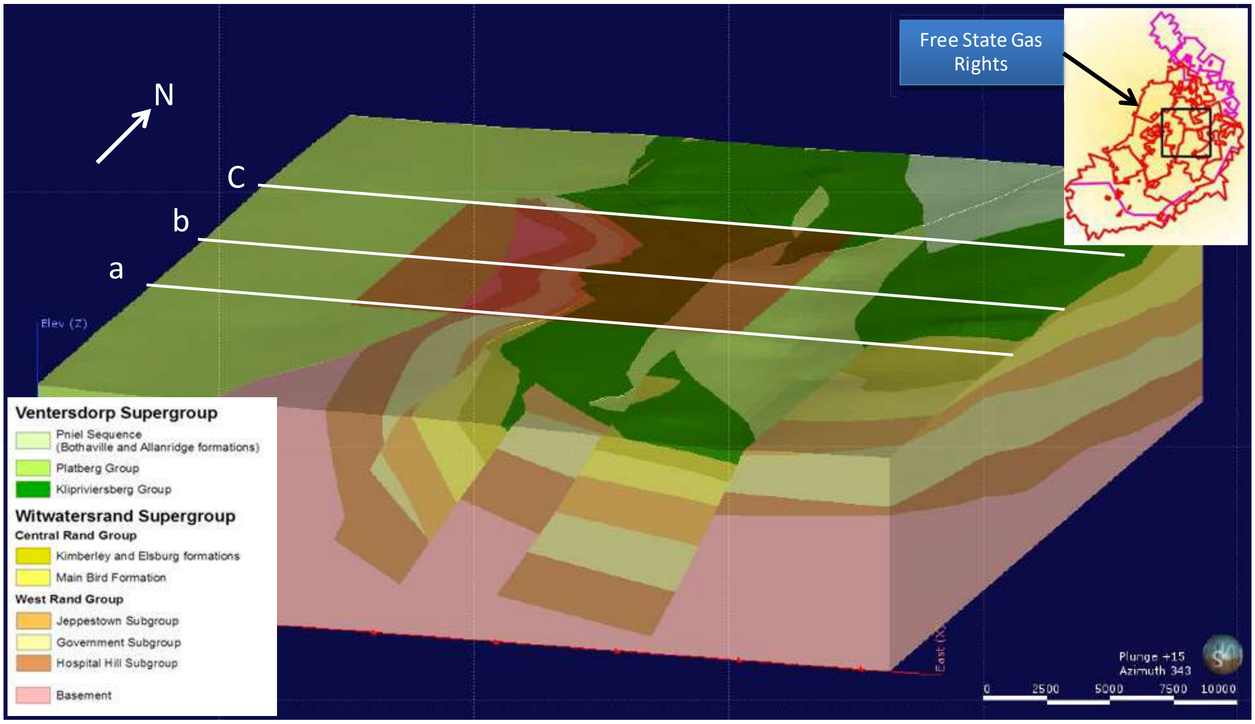


Figure 4: Map of Known Rand Group Faults

The known gas wells are associated with the wells intersecting the faults that penetrate the Witwatersrand Supergroup.

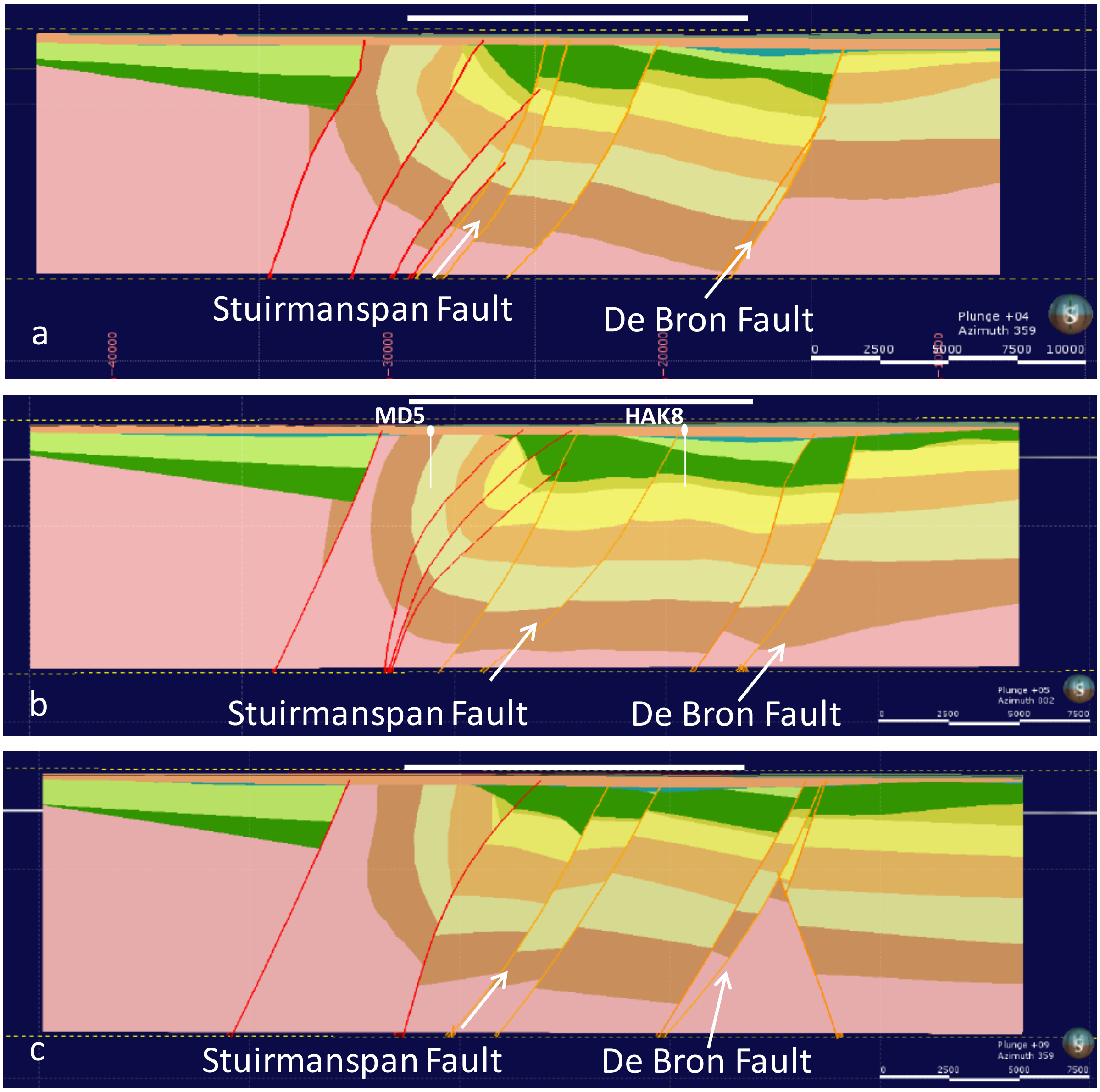


Figure 5: West to East Cross-Section within the area of the Virginia Gas Project

Demonstrating the tilted nature of the rock strata and the penetration of the faults into the Witwatersrand Supergroup.

EXISTING WELLS AND PRODUCTION HISTORY

HISTORIC WELLS

There are nearly two thousand wellbores which have been drilled, either for water, mining assessment, or for disposal, across the Welkom District over the past several decades and many tens of these wells have naturally produced flammable gas and have been called "blowers." Data from the South Africa Council for Geosciences lists at least 136 historic wells within the production area and notes that 68 of them produced gas in the past, 18 are currently producing gas (blowers), 29 have odors, and 28 are dormant.

EVALUATED WELLS

Twelve wells were evaluated for the original 2008 Molopo reserves evaluation study (Burning Flame, Burning Cross, Flame 1, ML-1, Retreat, Sand, SP-3, Squatter, DBE-1, Kotze EX-1, ST23, and Tewie). Molopo drilled three additional wells in 2009 (HADV1, HADV2, and HADR1). Tetra4 took over the project and drilled 4 wells in 2016 (MDR1, MDR4, MDR5 and 2057) and in 2017 reworked an older well that had resumed flowing gas (2190).

For the 2019 update MHA has included a new well that Tetra4 drilled in 2018, the T4 WN 01, which was drilled to test a shallow conventional sandstone play, plus 12 historic wells or vents (AD1A, SH3, P7, W1, SP8, TR3, TR4, TR5, TR6, TR7, TR8, and AL4) that were described in the publication of Hugo, P.: "*Helium in the Orange Free State Gold-Field*" (1963) which documented these wells and vents as far back as 1957. Using the published data and on-site verifications, as possible, these wells were added to the Tetra4 database. The importance of this data is twofold, A) the new well opens an additional play for Tetra4 within the lease area and B) the data from the historic wells support both the longevity of the wells and the gas composition; including the high helium concentrations.

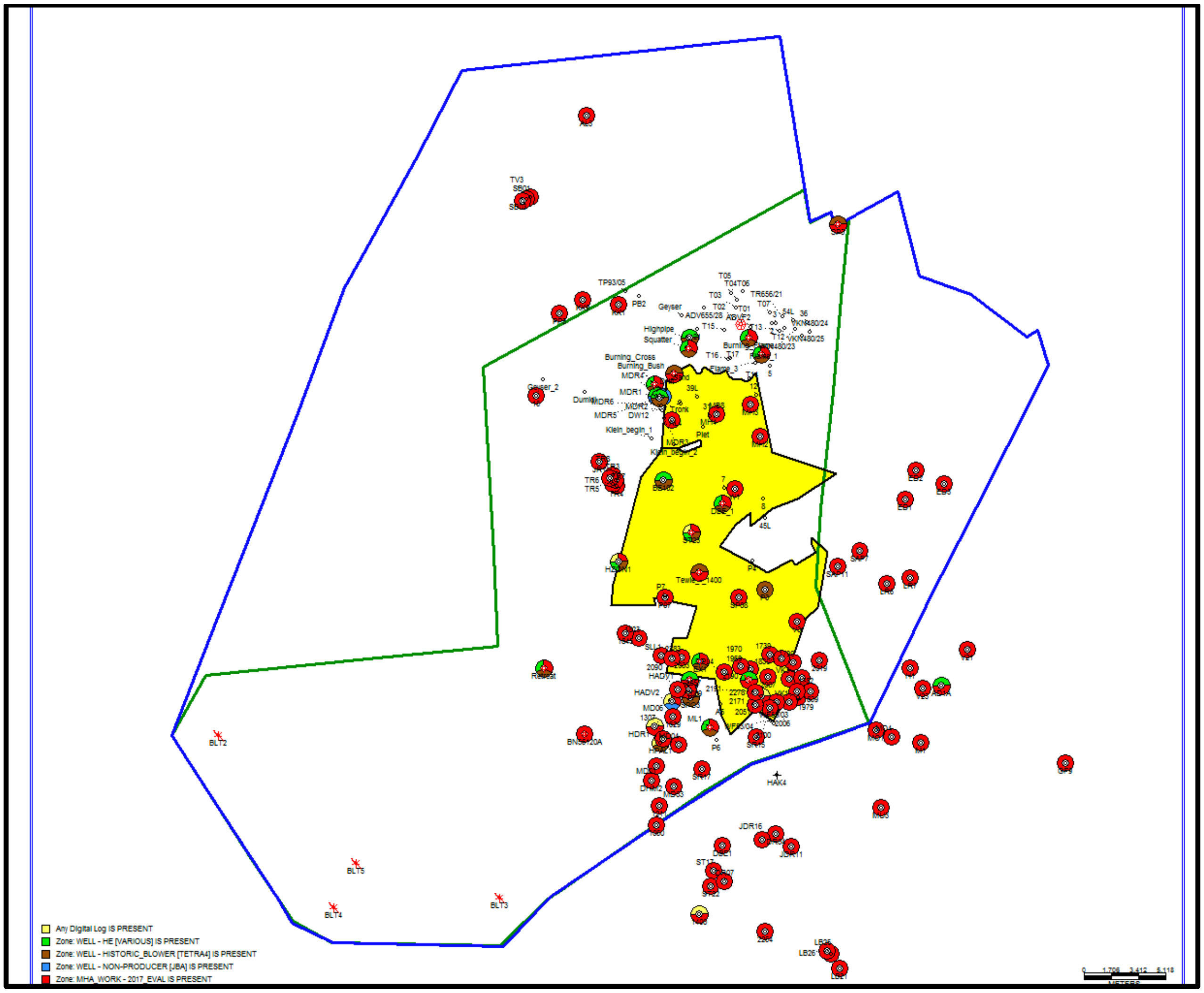


Figure 6: Map of the Tetra4 well Control. Yellow area is Goldfields Mining Area.

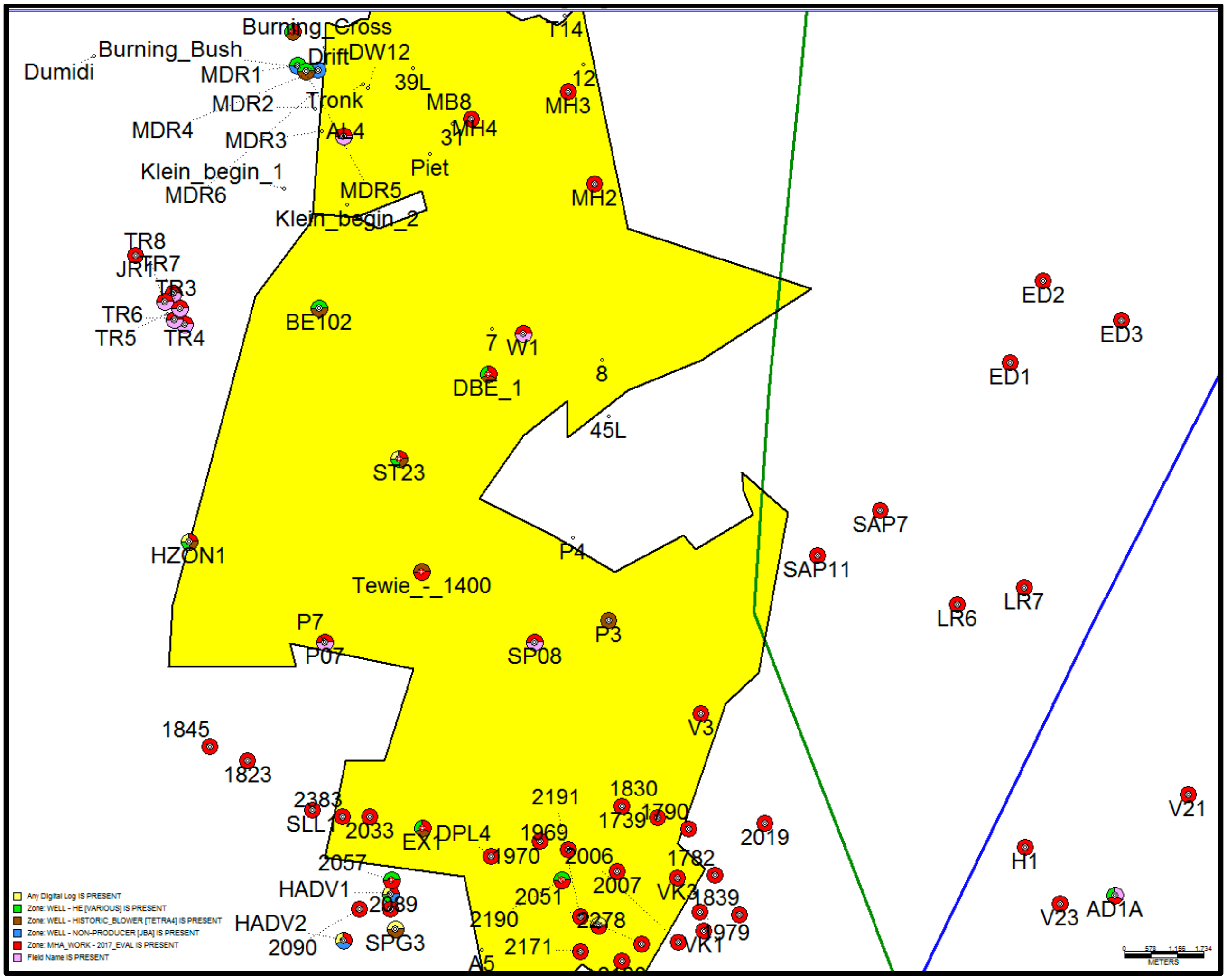


Figure 7: Enlargement of the primary development area

METHODOLOGY

Data Set

Tetra4 delivered to MHA driller's logs, completion reports, LAS files, gas analysis reports, production test data, and license data from the Virginia Gas Fields Project in the Free State in South Africa.

Analysis

MHA 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, Tetra4 development plans and market conditions.

Table 4: List of Existing Blowers (PDNP wells)

Tetra4 Existing Methane Producers		CH4 Producer	He Producer
HDR 1		X	X
BEI 02		X	X
Burning Cross		X	X
EX 1		X	X
Highpipe		X	X
HZON 1		X	X
MDR 5		X	X
ML 1		X	X
Retreat		X	X
ST 23		X	X
SPG 3 \ Lucky		X	X
Squatter		X	X
Tewie-1400		X	X
Burning Flame		X	X
DBE 1		X	X
SP 3		X	X
Flame 1		X	
Sand		X	
BN 56120A		X	X
2190		X	X

VOLUMETRICS

PAST STUDIES

Volumetric Assessments have been conducted by MHA Petroleum Consultants in 2008 and by Venmyn-Deloitte in 2015 and 2016. The 2008 MHA study analyzed 12 existing blowers and concluded that the best well annual decline rates ranged from 3 to 7% with an economic cutoff of 30,000 scf/day. Initial production rates ranged from a low of 150,000 scf/day to a high of 380,000 scf/day with a best case of 260,000 scf/day. The MHA study determined that the Estimated Ultimate Recovery (EUR), on a per well basis of marketable gas, varied from a Low case of 0.9 BCF to a High Case of 2.6 BCF with a Best Case of 1.7 BCF.

The 2016 Venmyn-Deloitte assessment was done after the HADV1, HADV2, HDR1, HPAL1, HZON1, MDR1, MDR4, MDR5, and 2057 wells were drilled. In drilling these 9 wells, there were 7 wells with gas shows and 5 wells that had sustained gas production. The Venmyn-Deloitte report concluded that the annual decline rates averaged from 2 to 6% but did not use an economic cut off to calculate the EURs. They ran their range of Initial Production rates from 140,000 scf/day to 300,000 scf/day and used 150,000 scf/day as the Best Case. The production runs were allowed to run out 49.5 years into the future, which gave a slightly optimistic EUR. The EURs that were presented in the report ranged from a Low case of 0.9 BCF to a High Case of 3.5 BCF.

The 2008 MHA report assigned 54 locations to the P2 (Probable) Reserve Category, an additional 63 locations to the P3 (Possible) Reserve Category, and no locations to the Proved Category. There were 357 locations assigned to the Contingent Resources Category.

The 2016 Venmyn-Deloitte report assigned 52 locations to P1 (Proved), 60 to the P2 (Probable), and 128 locations to P3 (Possible). Thus far, at best 17 wells that have tested gas, and a drilling program that has about a 60% commercial success rate Venmyn-Deloitte assigned 240 well locations to the Reserve Category and with 22% of the locations having a 90% confidence factor of delivering the base case EUR. There were no Contingent Resources assigned.

In 2017 MHA conducted another assessment (below) for IDC reviewing the updated test information and new wells. This report, prepared for an update on the JSE Stock Exchange News Service, draws substantially from the IDC Report, with permission from IDC. It uses the IDC 2017 Reserve and Resource volumetric assessments but generates a different economic analysis based on the complete 1P-2P-3P volumes of gas rather than a limited first phase field development plan that was used for the 2017 IDC report.

2017 Assessment

MHA reviewed the updated test data from the HADV1, HADV2, HDR1, HZON1, MDR1, MDR5, and 2057 wells plus addition flare and test data from selected historic blowers. This data confirmed but did not alter, MHA's original assessment of a range of well performance and lacking sustained, long-term, well production data MHA did not change either the range of expected decline rates nor the range of expected EURs for the wells. MHA expected the current ranges captured the inherent uncertainties and as more data is made available through sustained production the range of uncertainties will be reduced.

The continued drilling and testing, plus the advancement of gas sales agreements and Tetra4's advancement of development and marketing plan allowed MHA, in 2017, to elevate many of the locations into the PROVED category. MHA assigned Proved, Developed, Non-Producing (PDNP) status, on a project basis subject to the submitted Tetra4 development plan and budget, to all wells that have tested significant rates of gas and assigned two offset Proved Undeveloped (PUD) locations to each well, except for well MDR5 which has no offset locations. Thus, MHA assigned 18 PDNP and 34 PUD locations for 52 Proved well locations. In addition, MHA assigned 4 Possible and 4 Probable well locations for seventeen PDNP locations; thus, there were 68 Possible and 68 Probable locations for a total of 188 total Reserve locations. All offset wells were expected to be drilled on a spacing of about 1well\ 0.91 km^2 or 225 acres. It is important to note that wherever MHA has assigned an undrilled location, it is for the purposes of accounting for undrilled reserves and may not be the exact location that Tetra4, for operational or permitting reasons, chooses, to drill. All wells in the program and economics were planned as vertical wells; however Tetra4 had expressed interest and had started planning for slant wells that might intersect more fault and fracture surfaces. As this style of wells had not been executed as of the time of this report MHA did not include them in the economics nor construct a type curve for these wells, however as Tetra4 demonstrates its ability to execute these style of wells and these wells have improved economics it is possible that, with measurable flow data, MHA will be able to forecast increased recoveries per well with slant or horizontal style wells.

2019 Assessment

MHA has reviewed the updated production from the HDR1 well, limited single test data from other wells that are not currently on production and the data from the 2018 Tetra4 T4 WN 01 well that was drilled to test the shallow "White Sand" play towards the eastern edge of the license. MHA has also reviewed the Tetra4 updated drilling schedule, OPEX and CAPEX costs and sales agreements in order to update the MHA financial model.

The "White Sand" play Is a Permian Karoo age sandstone that was identified in a 44 borehole study by Shango Solutions commissioned by Tetra4 as part of a broader study of the fractured basement play. Gas flows from the Permian sandstone were identified in 3 wells (2057, 2089, and HAK4) and a 3D model of the sandstone was developed. Tetra4 extended that model and drilled the T4 WN 01 well beyond the initial boundaries defined by Shango Solutions and encountered 73 meters of gas bearing Karoo sandstone and siltstone with the well. This well did not test gas at commercial rates however the potential for this play, as a conventional, low pressure, gas resource, to potentially add to the future resource and future reserve base of Tetra4 has been established by four wells penetrating the sandstone over a wide area, each with good gas content. As Tetra4 continues to evaluate this play MHA will use the new data to assess the ability to add new volumes to Tetra4's reserve and resource base.

Additionally, Tetra4 has added data from 2 existing blowers to the database and MHA has reviewed this data and confirmed that both wells, BN 56120A (AKA Dumidi) and 2190 (AKA Big Flame) are Proved Developed Non-Producing (PDNP) wells, and each will have 2 offset, Proved Undeveloped (PUD) locations, 4 Probable, and 4 Possible locations assigned to each well for a total of 22 new reserve well locations. These new reserve locations and volumes are removed from the Contingent Resource volumes of the 2018 Report.

Based on this discussion the Technically Recoverable Methane Volumes associated with the reserve categories are referenced in Table 5. A potential risk is that the rate of recharge of the methane, and thus also the helium, gas is not known. There is anecdotal evidence of historic blowers within the Tetra4 license area producing methane gas for over forty years without any discernable pressure drop however there are no quantified studies to date.

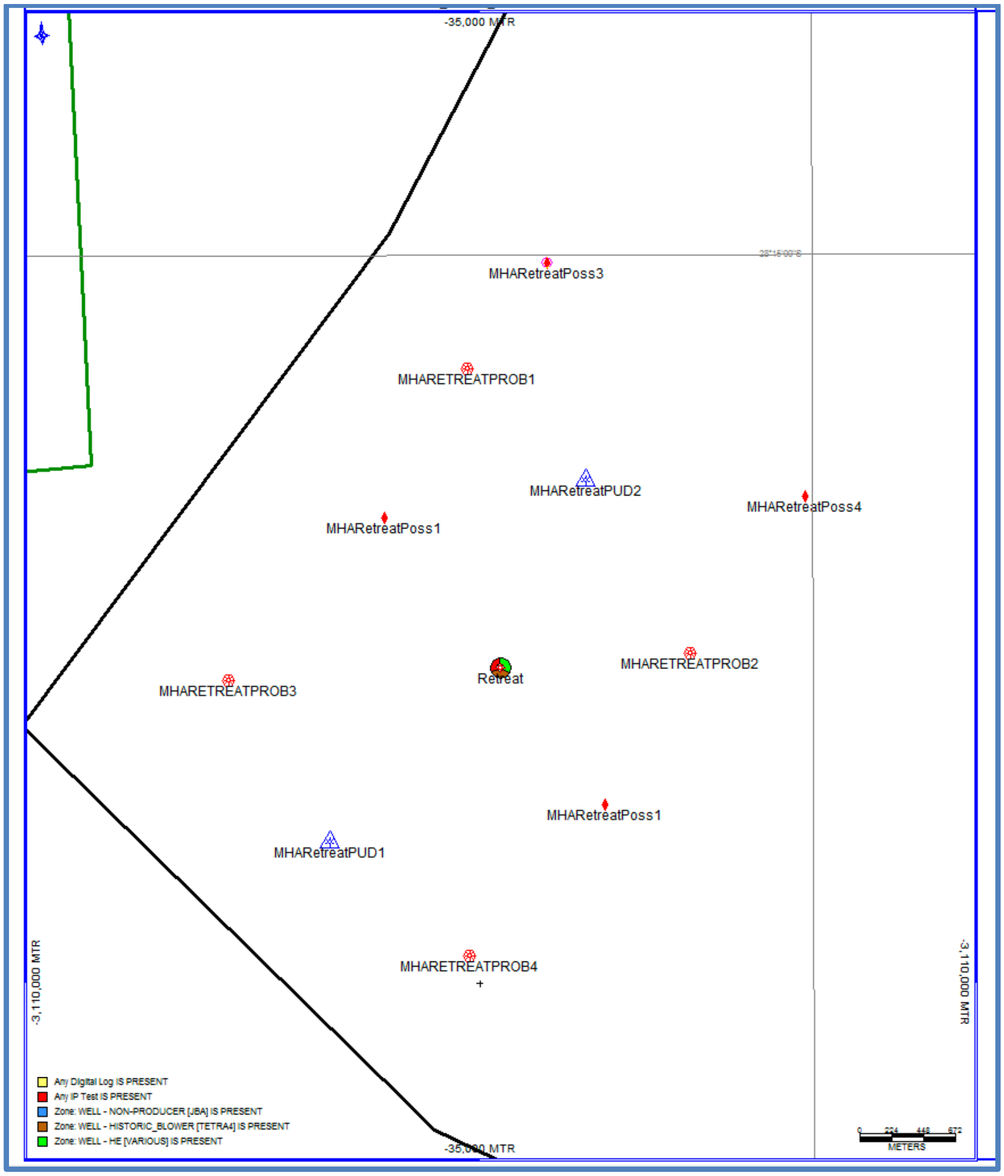


Figure 8: Idealized Spacing of New Field Development Wells

Idealized spacing of an existing Blower (Retreat) and a symmetrical spacing of two PUD wells (blue triangles), four Probable wells (red hexagons), and four Possible wells (small red diamonds).

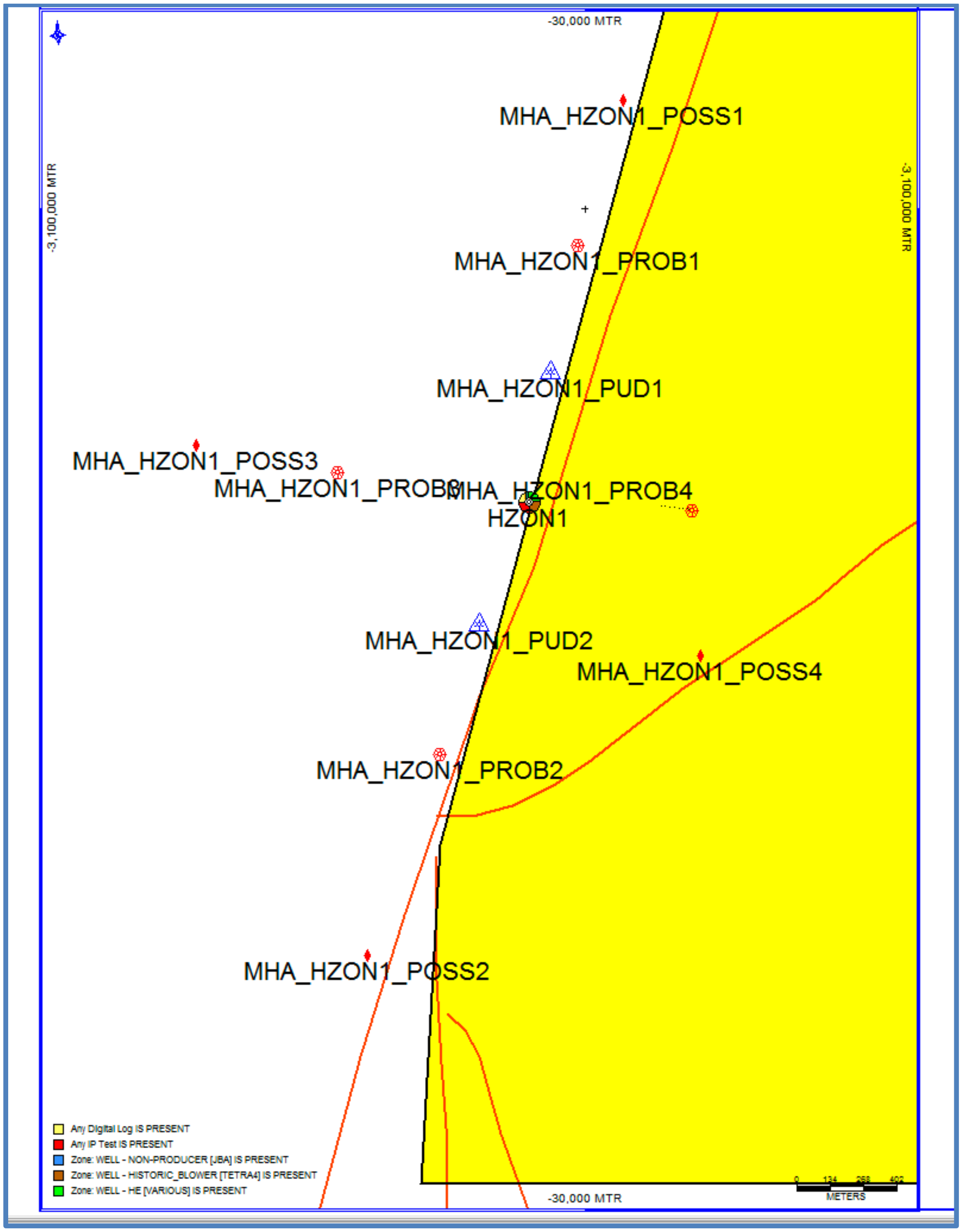


Figure 9: Typical Spacing of Field Development Wells Influenced by Faults

A more typical development scenario where wells are spaced out along known fault and fracture spacing around an existing blower, HZON1 with two PUD wells (blue triangles), four Probable wells (red hexagons), and four Possible wells (small red diamonds).

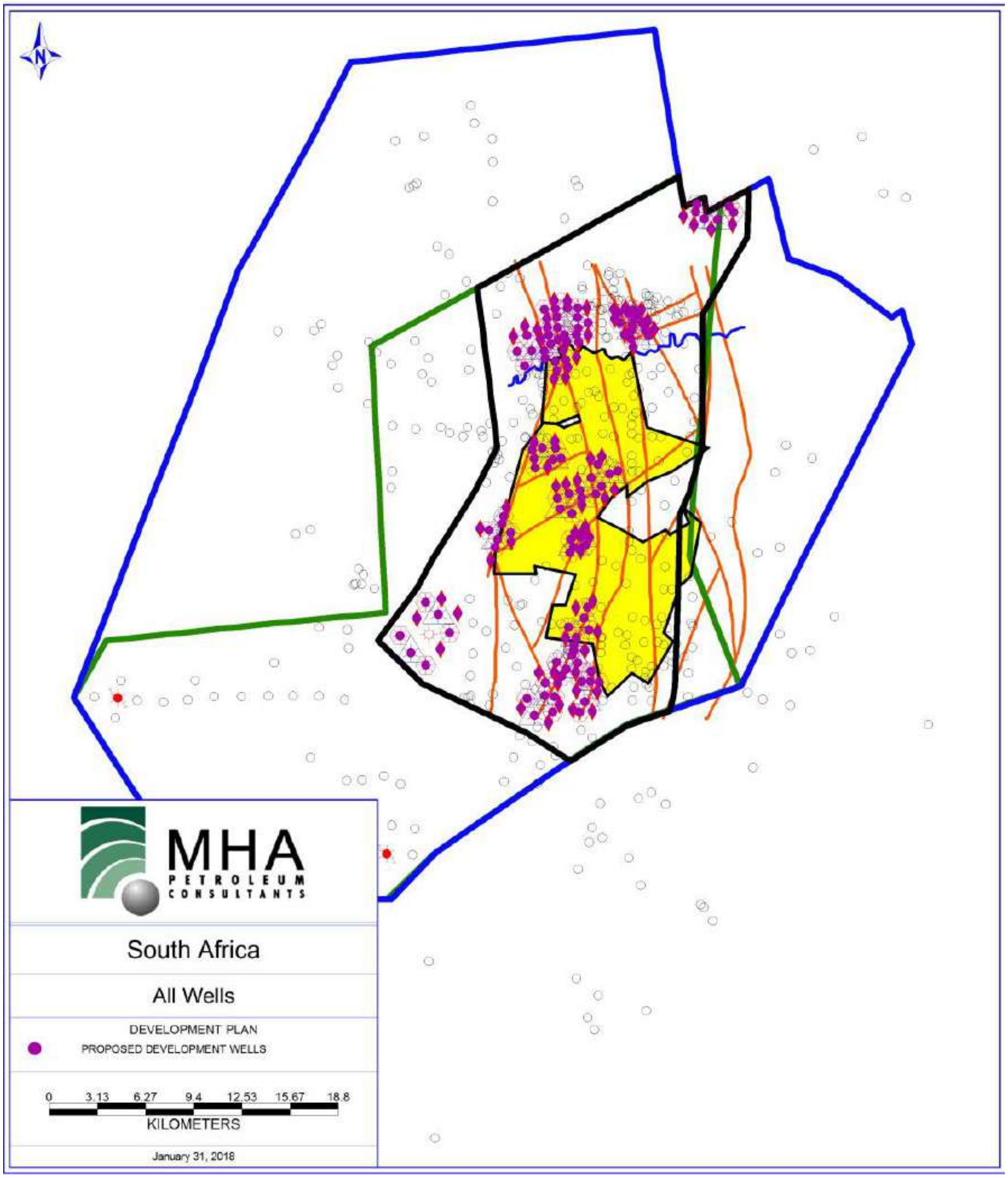


Figure 10: Map Proved, Probable and Possible well locations

Map of the existing wells and the future wells with Proved locations (Blue Triangles with purple centers), Probable locations (Red Hexagons with purple centers) and Possible locations (small Red diamonds with purple centers). In the black outline is the area defined as the "Core Area" for the Contingent Resources. All Prospective Resources are outside of the "Core Area."

Table 5: Technically Recoverable Methane Volume Estimates-Virginia Gas Field

Category	Recoverable Volumes (Bcf)		Totals (Bcf)
	Developed	Undeveloped	
Proven (1P)	15.7	29.5	45.3
Probable (P2)		109.2	109.2
Possible (P3)		161.3	161.3
Total (P+P+P)	**15.7**	**297.0**	**315.8**

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves

MHA has defined a core area that has been delineated by drilling and testing within the production license of 505.12 Km2. Within that area are 19 development locations of 11 wells each (209 well locations) and a reserve development area of approximately 190 Km2 or 0.91km2/well. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. Removing the 190 Km2 that have been assigned to the Reserve area from the total 505.12 Km2 in the core production area leaves 315.12 Km2 of area in the Contingent Resource Category. With a well spacing of 0.91 Km2/well that equates to 346 contingent wells. MHA assigned volumes to these wells probabilistically using a range of EURs, with the C1 category of 0.9 BCF/well, C2 category 1.7 BCF/well and C3 category 2.6 BCF/well. **Contingent Resources are considered discovered; however, there is no certainty that it will be commercially viable to produce any portion of the resources**.

Table 6: Technically Recoverable Contingent Methane Volume Estimates of the Virginia Gas Field

Category	EUR/Well	Total BCF
Contingent (C1)	0.9	294.8
Contingent (C2)	1.7	529.7
Contingent (C3)	2.6	952.0

MHA has assigned all of the production area outside of the defined core area as Prospective Resource area. This area has historic gas blowers on the license, there are existing deep gold and other metal mines and there are, in the South African Geologic Survey and literature, mapped faults that extend deep into the sub-surface. There is reasonable expectation that there will be the same type of gas occurrences within the rest of the production area however neither the historic operators nor the current operators of the license have delineated the resource to an extent that it can be considered a Contingent Resource. MHA has taken the same range of EURs/well as in the Contingent Resource area but has, until there is sufficient information to warrant updating the evaluation, doubled the distance between the wells from the well spacing used in the Contingent Resource evaluation area to 1.82 Km2/well. **There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.**

The entire production license is 1,874.2 Km2 and once the 505.12 Km2 core production area is removed their remains 1,369.08 Km2 of Prospective Resource area. Using a 1.82 Km2/well density that will equate to an unrisked, a potential 752 wells. MHA has run a probabilistic distribution of recoverable volumes using the range of EURs calculated for the recoverable methane in the development area. No helium is assessed as there is insufficient information at this time.

Table 7: Technically Recoverable Prospective Methane Volume Estimates of the Virginia Gas Field

Category	EUR/Well	Total BCF
Prospective Resource Low Estimate	0.9	640.6
Prospective Resource Best Estimate	1.7	1,278.4
Prospective Resource High Estimate	2.6	2,068.9

***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 hydrocarbons."*

TECHNICALLY RECOVERABLE HELIUM RESERVES

MHA has used the He concentration data supplied by Tetra4 to map the spatial distribution of He enrichment in the produced gases. Seven of the tested wells tested Helium (He) concentrations at least 2% by volume or greater, and some of wells tested over 10%; including the 2057 well. The 2016 Venmyn-Deloitte report made the assumption that all wells would produce an average of 2% He and all wells would be scrubbed for He and the He sold. MHA has used the data available and mapped out the He concentrations by well and found that there appears to be a significant enrichment trend on the west side of the De Bron fault with all wells to the east of the fault showing no testable He concentrations, at least until you cross the Virginia fault and move further east. Only the AD1 well, outside of the production license and well to the east of the Virginia fault, shows enrichment of He gas on the eastern side of the production area. It is very important to note that there is A) a sparsity of well sampling over the structural high, B) most of the wells that did have gas compositional sampling did not sample for helium, and C) there is anecdotal evidence that even those wells that attempted to sample for helium used improper methodologies. It is, therefore, a distinct possibility that there is sufficient helium concentration over the entire lease for gathering and commercial sales and once sufficient data is gathered the maps are subject to revision.

This area of low to zero concentrations coincides with a structural high of the Base of the Karoo. All other known readings of He gas east of the De Bron fault until the Virginia fault is crossed, appear, at this time until more data is available, to have low to zero enrichment of He. Thus, MHA has assigned He reserves only to a mapped area in the center of the production license but has increased the average He concentration in those wells to 3-4%. Gas percentages of up to 4% are found in this zone and an average He concentration of 3.05% over 202.4 Km2 has been mapped. Within the mapped He concentration area MHA has 7 known blowers or wells that all have tested greater than 2% He concentrations. Within the concentration area, MHA has mapped an additional 14 Proved well locations, 26 Probable well locations, and 27 Possible well locations. The estimated volumes of technically recoverable helium are shown in Tables 8 and 9.

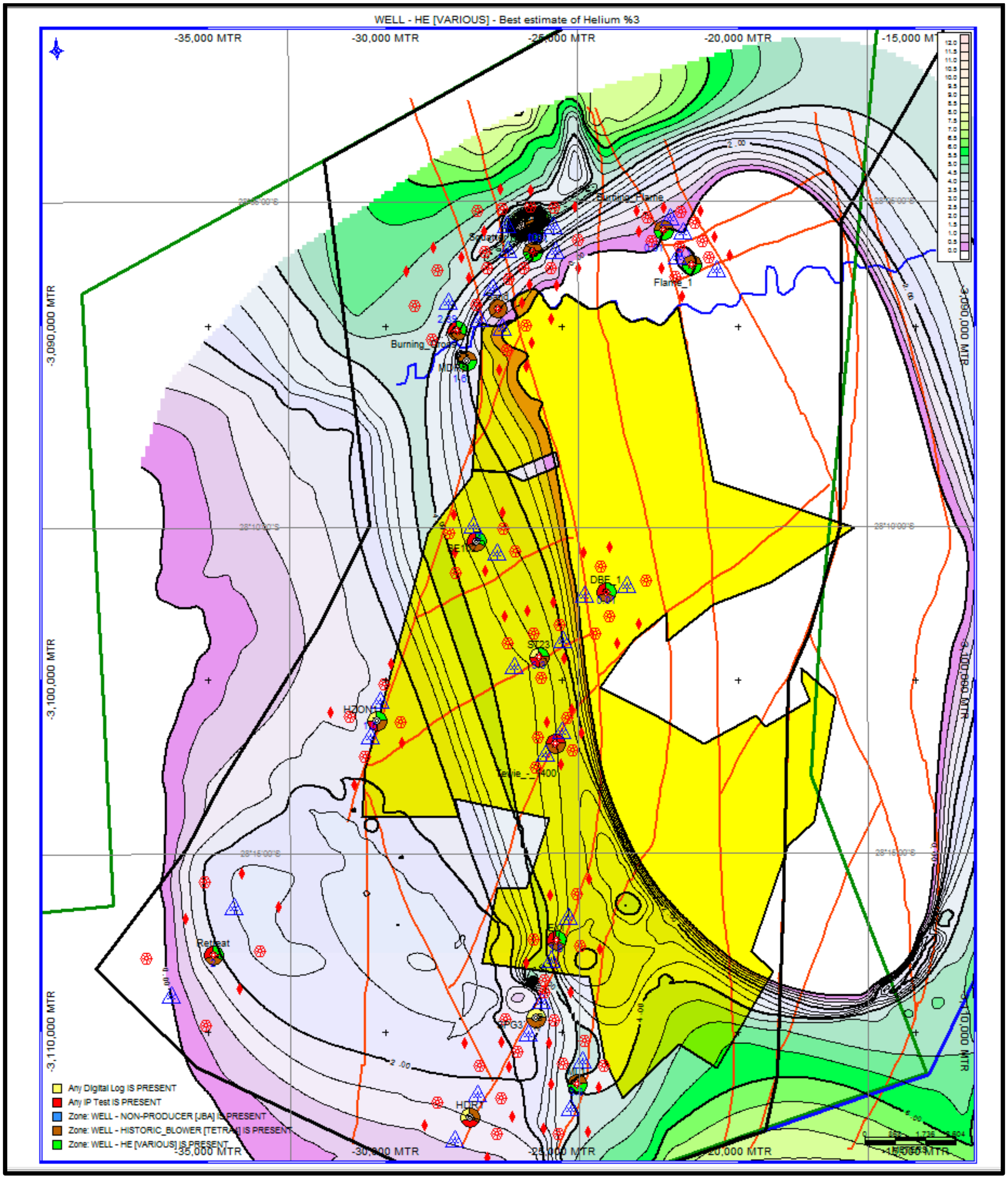


Figure 11: Map of Helium Concentration in %

Wells with measured helium concentrations have green annotations. The Yellow polygon is the area of the Goldfields Mining Lease.

Table 8: Technically Recoverable Helium Estimates of the Virginia Gas Project

	# of Wells	EUR (BCF)	He%	He/Well (BCF)	Reserves
PDP	1	1.2	0.0305	0.0366	0.0366
Proved Dev NP	14	0.9	0.0305	0.02745	0.3843
PUD	28	0.9	0.0305	0.02745	0.7686
Prob	56	1.7	0.0305	0.05185	2.9036
Poss	56	2.6	0.0305	0.0793	4.4408
Total (P+P+P)	**155**				**8.5339**

Table 9: Technically Recoverable Helium Volume Estimates by Contingent Resource Category - Virginia Gas Field

Number of Wells	Low Case (C1) (Bcf)	Best Case (C2) (Bcf)	High Case (C3) (Bcf)
346	10.1	19.1	29.2

ECONOMICS

TETRA4 OPERATING CONDITIONS AND SALES AGREEMENTS

Tetra4 operates under a Production License from the Petroleum Authority of South Africa and must pay a 5% royalty based on wellhead price to the South African Revenue Service. An additional royalty of one percent of wellhead price is owed to the GFI Mining South Africa (GFIMSA) or Goldfields on all new wells located on their existing licenses.

Tetra4 plans to sell 30% of its LNG production into the local wholesale LNG market and 70% into the local transport market.

Tetra4 has provided to MHA a signed Gas Sales Agreement (GSA) with Unitrans Passenger Limited (Megabus) for the purchase of natural gas. The gas will be sold in liquefied state by the liter, and the purchase price is indexed to a local pricing point for 0.005% sulphur diesel at the Megabus purchase price minus a 30% discount.

Renergen has disclosed to its shareholders and MHA that several original engine manufacturers (OEMs) have agreed to begin manufacturing LNG capable heavy trucks for the South African market, although these agreements are not with Renergen nor Tetra4 directly. This has the potential to accelerate the market for liquid fuel gas in South Africa that Tetra4 wishes to supply as Tetra4 has been supplying to Megabus. It is anticipated that as these agreements are completed Tetra4 can potentially move forward its field development plan, although MHA has not factored these potential contracts into the economic analysis for reserve estimation.

Tetra4 has also provided MHA a signed Gas Sales Agreement with Linde Global Helium (Linde) for the purchase of Helium gas at the price point of approximately $200/mcf escalating according to US CPI index.

Renergen has entered into a commitment letter with OPIC, the United States' government development finance institution, for OPIC to provide capital assistance for the development of the helium resource, indicating the United States' government's level of interest in the Virginia Gas Project as part of the global helium supply system.

The Tetra4 field development plans call for the construction of a gas gathering system, setting compression, the installation of the above-mentioned gas processing facilities and as production increases, an expansion of the entire system. MHA has reviewed Tetra4's detailed plans for abandonment and rehabilitation of the wells and all infrastructures that have been submitted to, and accepted by, the Petroleum Authority of South Africa (PASA). These plans meet, and in places exceed, governmental regulations for abandonment, rehabilitation, and monitoring.

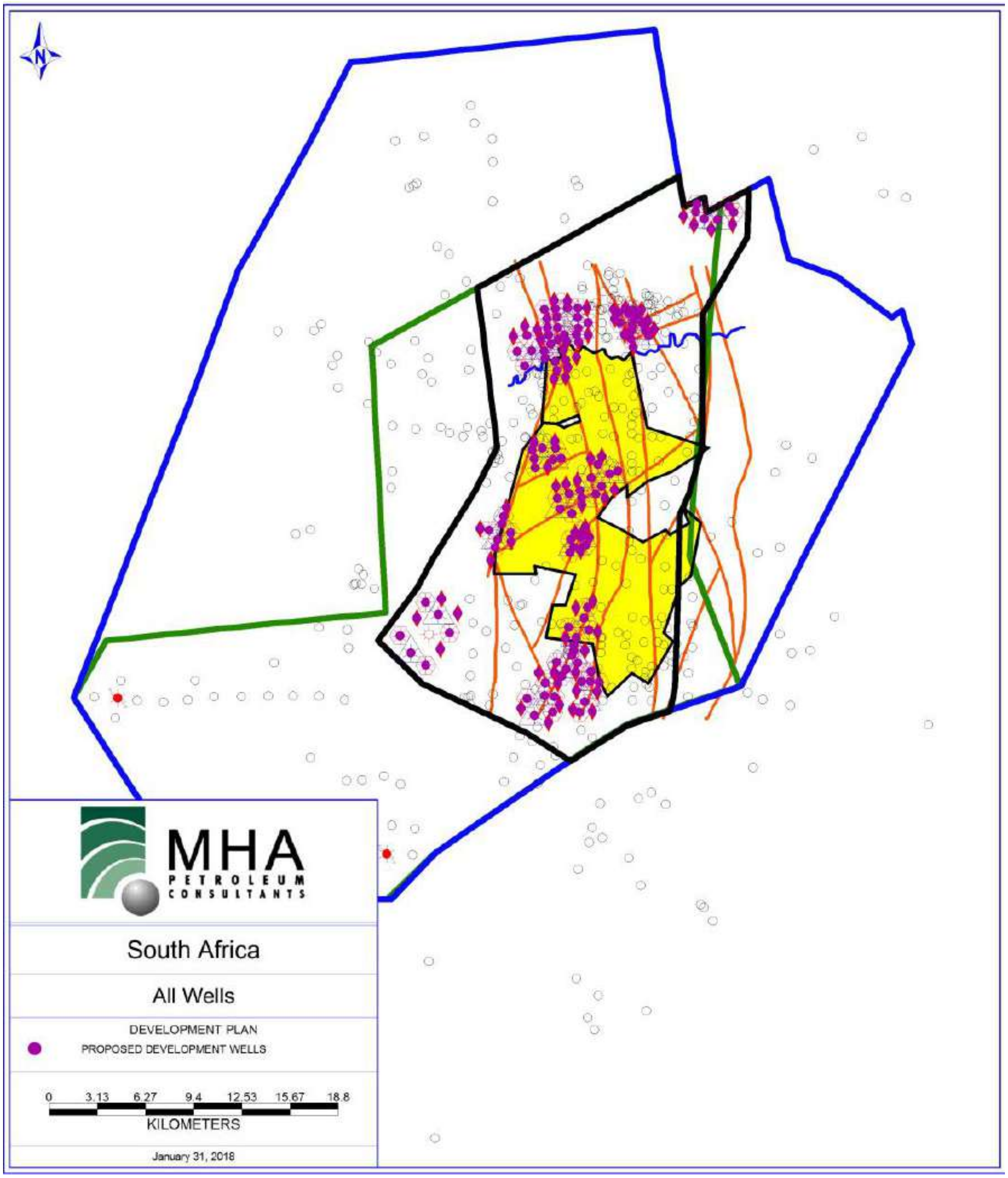


Figure 12: Map Tetra4 Virginia Gas License and Current Plus Planned Wells

ECONOMIC PARAMETERS

Proved Developed Producing Well

Sufficient production data are now available to classify the HDR-1 well as Proved Developed Producing (PDP) reserves. Decline curve analysis of this well (Figure 12) yields a shallow annual decline of 4.73%/yr.

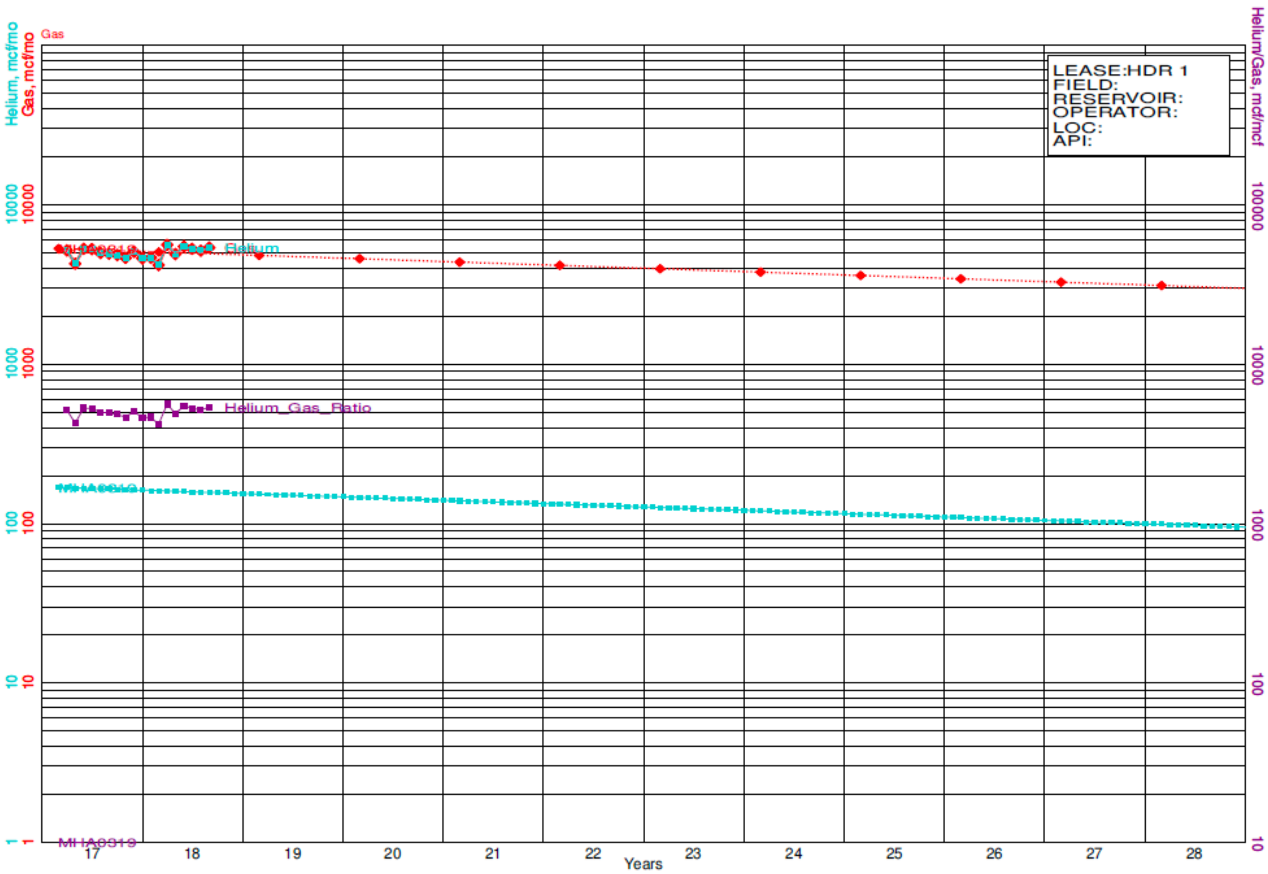


Figure 13: HDR-1 decline curve

Type well rates and recovery are on a gross gas volume. Produced gas volumes were multiplied by 0.9 to account for 10% impurities in the produced gas stream and were subject to a 5% shrink. Helium production was forecasted from methane production volumes and the assumed 3% helium in the wellhead gas stream. 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, due to the effects of aggregation.

Capital Costs

Well drilling and completion CAPEX was 1.5 mZAR per well. The recent drilling campaign of 9 wells resulted in 5 producers and 4 dry holes. This dry hole risk of roughly 40% was addressed by decreasing the type well gas production rate by a factor of 0.6. Connection CAPEX was 1.0 mZAR per well. Pipeline capital of 170 mZAR was allocated into two payments of 68 mZAR (scheduled for May 19 and Dec 19) and one payment of 34 mZAR (scheduled for May 20). Capital for the initial methane and helium liquefaction plants was 121.48 mZAR and 52.48 mZAR, respectively. Development of the Virginia Field will require additional liquefaction plants for each 6 mmcfd increment in gross gas production. CAPEX for these additional methane and helium liquefaction plants was 180.0 mZAR and 100.0 mZAR, respectively. Based on the three type wells discussed above, new plants will be required for every 40 1P wells drilled (6 mmcfd/150 mcfd per well), every 24 2P wells, and every 16 3P wells. All capital costs were escalated at 2 %/yr.

Operating expenses

Fixed lease operating expenses (LOE's), assigned at the plant level rather than individual wells, were 1,500 mZAR per month. The variable OPEX was 13.9 ZAR/mcf, reflecting truck transport of the methane and helium. All operating expenses were escalated at 2%yr until the price doubled then the LOE was held constant for the life of the project.

Prices

The methane price was a blended price reflecting the 30%/70% split between the wholesale and transport sectors discussed above. The wholesale LNG price of 217 ZAR/mcf was escalated at the South African CPI of 6%/year and the transport diesel equivalent LNG price of 245 ZAR/mcf was escalated based on historical diesel prices, 10%/yr. The resulting blended price was 236 ZAR/mcf and escalated at 9%/yr. The blended price was held constant once the initial price had doubled.

The initial helium price of 2863 ZAR/mcf (200 USD/mcf) was held constant for the first two months then was escalated at the average US CPI of 2.4%/yr. forecast. Monthly methane and helium prices are plotted in Figure 14 and listed in Appendix 1.

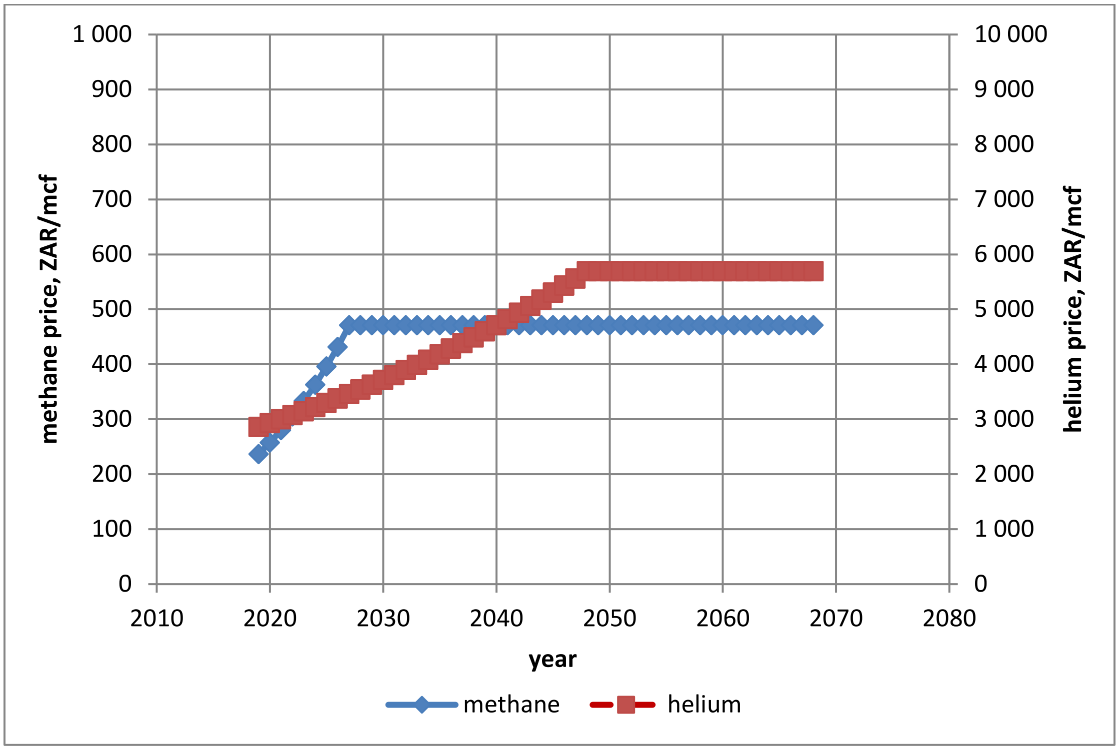


Figure 14: Methane and Helium Monthly Prices

MHA assumed a methane BTU factor of 1.01 Gj/mcf (0.960 mmbtu/mcf). Shrink, which accounts for gas used by the plant, measurement imbalances, and surface losses, as well as helium extraction, was assumed to be a constant 5 % throughout the life of the field. All wells are burdened with a 5% overriding royalty interest (ORRI) on the wellhead gas price plus those wells in the Goldfields area are subject to an additional 1% ORRI. The well counts associated with field development of Reserves and Contingent Resources are given in Table 10 below.

Table 10: Wellcount by Reserve and Contingent Resource Category

Reserves	PDNP	Total Proved (1P)	Probable	Proved + Probable (2P)	Possible	Proved + Probable + Possible (3P)
Number of wells	19	58	76	134	76	210
Contingent Resources		**Low Case**		**Best Case**		**High Case**
Number of Methane wells		346		346		346
Number of He wells		346		346		346

RESERVE ECONOMICS

Based on the economic parameters discussed above, reserves and economics were calculated for the Virginia Gas Field. Gross and net methane and helium reserves based on a 10% discount rate are collected in Table 11.

Table 11: Gross and Net Methane and Helium Reserves

1P Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
TOTAL PDNP	14,765.3	346.0	13,288.8	327.7
TOTAL PUD	29,526.1	691.9	26,573.5	655.3
TOTAL 1P PRV	45,285.1	1,069.5	40,759.0	1,013.1
2P Reserve Cat	**Gross CH4 (MMCF)**	**Gross Helium (MMCF)**	**Net CH4 (MMCF)**	**Net Helium (MMCF)**
TOTAL PDNP	14,765.3	346.0	13,288.8	327.7
TOTAL PUD	29,526.1	691.9	26,573.5	655.3
TOTAL PROVED	45,285.1	1,069.5	40,759.0	1,013.1
TOTAL PROBABLE	109,146.6	2,528.4	98,231.8	2,394.7
TOTAL 2P PRV+PRB	154,431.7	3,597.9	138,990.9	3,407.8
3P Reserve Cat	**Gross CH4 (MMCF)**	**Gross Helium (MMCF)**	**Net CH4 (MMCF)**	**Net Helium (MMCF)**
TOTAL PDNP	14,765.3	346.0	13,288.8	327.7
TOTAL PUD	29,526.1	691.9	26,573.5	655.3
TOTAL PROVED	45,285.1	1,069.5	40,759.0	1,013.1
TOTAL PROBABLE	109,146.6	2,528.4	98,231.8	2,394.7
TOTAL POSSIBLE	161,318.0	3,640.7	145,186.0	3,448.2
TOTAL 3P PRV+PRB+POS	315,749.7	7,238.6	284,176.8	6,856.1

At the request of Tetra4, net present values associated with the reserves volumes were calculated for various discount rates. The results are shown in Table 12.

Table 12: Virginia Gas Field – Methane and Helium Reserves
Net Present Values for Selected Discount Factors, mZAR

Discount Factor	PDNP	Total Proved (1P)	Probable	Proved + Probable (2P)	Possible	Proved + Probable + Possible (3P)
Undiscounted	6,462	17,069	50,367	64,477	75,065	135,196
5%	3,471	7,995	20,988	27,754	30,430	56,387
8%	2,580	5,599	14,369	19,059	20,481	38,224
10%	2,172	4,541	11,620	15,375	16,376	30,624
15%	1,502	2,878	7,516	9,788	10,301	19,242
20%	1,113	1,194	5,318	6,758	7,092	13,162
30%	695	978	3,104	3,699	3,929	7,127

CONTINGENT RESOURCE ECONOMICS

According to the PRMS guidance economics are not required, nor normally run, on Contingent Resources as by definition contingent resources have not met the threshold of "commerciality" due to one or more contingencies. Per Renergen's request, MHA has run Contingent Resource economics for the Virginia Gas Project utilizing costs and prices discussed above. The resulting gas volumes and associated un-risked net present values are in Table 13 below. Contingencies to be resolved include quantification of in-place methane volumes and recharge rates of this biogenic gas play and confidence that the proposed development program will not deplete the contingent resource gas volumes.

Table 13: Net Methane and Helium Contingent Resources and Net Present Values Virginia Gas Field – Specified Prices and Costs

	Low (C1)	Best (C2)	High (C3)
Methane (BCF)	237	435	648
Helium	7.9	14.4	20.8
Net Present Value (MZAR)			
Undiscounted	126,597	234,899	349,070
5%	48,886	89,010	131,607
8%	31,470	56,968	84,118
10%	24,344	43,970	64,899
15%	14,014	25,269	37,300
20%	8,802	15,897	23,489
30%	4,059	7,392	10,958

CONCLUSIONS

Based on analysis of technical and economic data provided by Tetra4, MHA has estimated methane and helium Reserves and Resources for the Virginia Gas Field according to SPE PRMS guidance and SAMOG code. Estimated Reserves and Contingent Resource gross and net methane and helium volumes are presented in Table 14. Net present values of the Reserves at requested discount rates are given in Table 12 above.

Table 14: Virginia Gas Field - Gross and Net Methane and Helium Reserves and Contingent Resources

Reserve Cat	Gross CH4 (MMCF)	Gross Helium (MMCF)	Net CH4 (MMCF)	Net Helium (MMCF)
RESERVES				
TOTAL 1P	45,285.0	1069.5	40759.0	1013.0
TOTAL 2P	154,431.7	3597.9	138,990.8	3407.8
TOTAL 3P	315749.7	7238.6	284,176.8	6856.0
CONTINGENT RESOURCES				
TOTAL C1	262,978.3	8362.7	237,337.9	7944.5
TOTAL C2	483,058.3	15168.0	435,960.1	14409.6
TOTAL C3	718,612.4	21989.5	648,547.7	20890.0

QUALIFICATIONS

Jeffrey B. Aldrich is a Partner in MHA Petroleum Consultants, Inc. (MHA) 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's 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".

John Seidle is a Partner and Senior Reservoir Engineer with MHA Petroleum Consultants LLC in Denver, Colorado. He has more than thirty-five years of experience in unconventional gas and oil reservoir engineering in domestic and international plays. His current duties include unconventional reservoir engineering, reserve studies and economic evaluations, unconventional well performance analysis, and serving as an expert witness for litigation and regulatory hearings. Dr. Seidle is an instructor for industry classes, primarily unconventional reservoirs. Privileged to work with others on over 29 technical papers, he is the author of "Fundamentals of Coalbed Methane Reservoir Engineering". John is editor and chapter author of SPEE Monograph 4, "Estimating Ultimate Recovery of Developed Wells in Low-Permeability Reservoirs". He received a PhD in Mechanical Engineering from the University of Colorado, is a member of SPE, AAPG, and SPEE, and is a Registered Professional Engineer in Colorado, Oklahoma, and Wyoming. Unconventional reservoir experience includes USA, Canada, Australia, China, India, South Africa, New Zealand, Colombia, Mexico, France, UK, Turkey, Poland, Mongolia, Ukraine.

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APPENDIX 1: METHANE AND HELIUM PRICES

As discussed above, the methane price was a blended price reflecting the 30%/70% split between the wholesale and transport sectors discussed above. The wholesale LNG price of 217 ZAR/mcf was escalated at the South African CPI of 6%/year, and the transport LNG price of 171 ZAR/mcf was escalated based on historical diesel prices, 10%/yr. The resulting blended price was 236 ZAR/mcf and escalated at 9%/yr. The blended price was held constant once the initial price had doubled.

The initial helium price of 2863 ZAR/mcf (200 USD/mcf) was held constant for the first two months then was escalated at the average US CPI of 2.4%/yr. forecast.

Annual methane and helium prices are listed in Table A.1 below.

year	methane, ZAR/mcf	helium ZAR/mcf	year	methane, ZAR/mcf	helium ZAR/mcf
2019	236	2,863	2044	471	5,180
2020	257	2,932	2045	471	5,304
2021	280	3,002	2046	471	5,432
2022	306	3,074	2047	471	5,562
2023	333	3,148	2048	471	5,695
2024	363	3,224	2049	471	5,695
2025	396	3,301	2050	471	5,695
2026	432	3,380	2051	471	5,695
2027	471	3,461	2052	471	5,695
2028	471	3,544	2053	471	5,695
2029	471	3,629	2054	471	5,695
2030	471	3,716	2055	471	5,695
2031	471	3,806	2056	471	5,695
2032	471	3,897	2057	471	5,695
2033	471	3,991	2058	471	5,695
2034	471	4,086	2059	471	5,695
2035	471	4,184	2060	471	5,695
2036	471	4,285	2061	471	5,695
2037	471	4,388	2062	471	5,695
2038	471	4,493	2063	471	5,695
2039	471	4,601	2064	471	5,695
2040	471	4,711	2065	471	5,695
2041	471	4,824	2066	471	5,695
2042	471	4,940	2067	471	5,695
2043	471	5,059	2068	471	5,695

APPENDIX 2: 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.

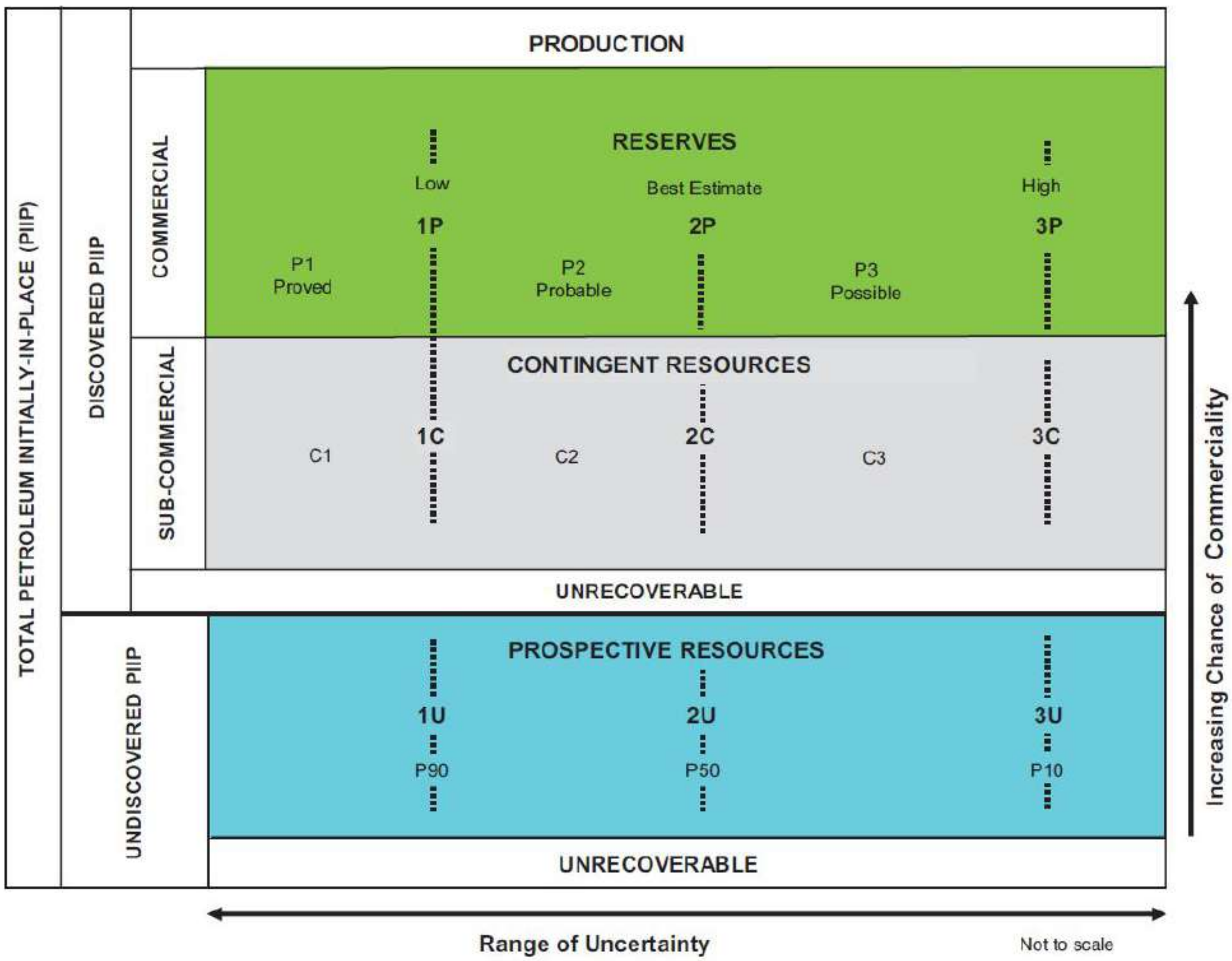


Figure 1.1—Resources classification framework

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).

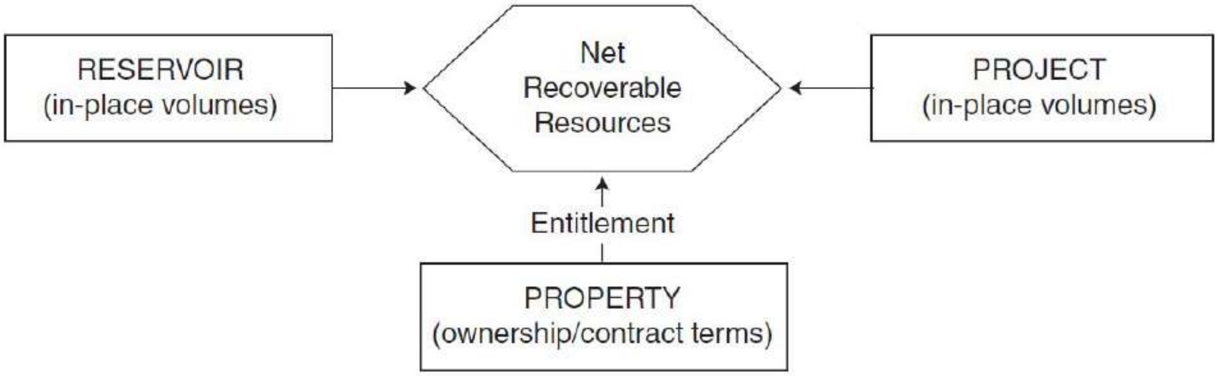


Figure 1.2—Resources evaluation

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.

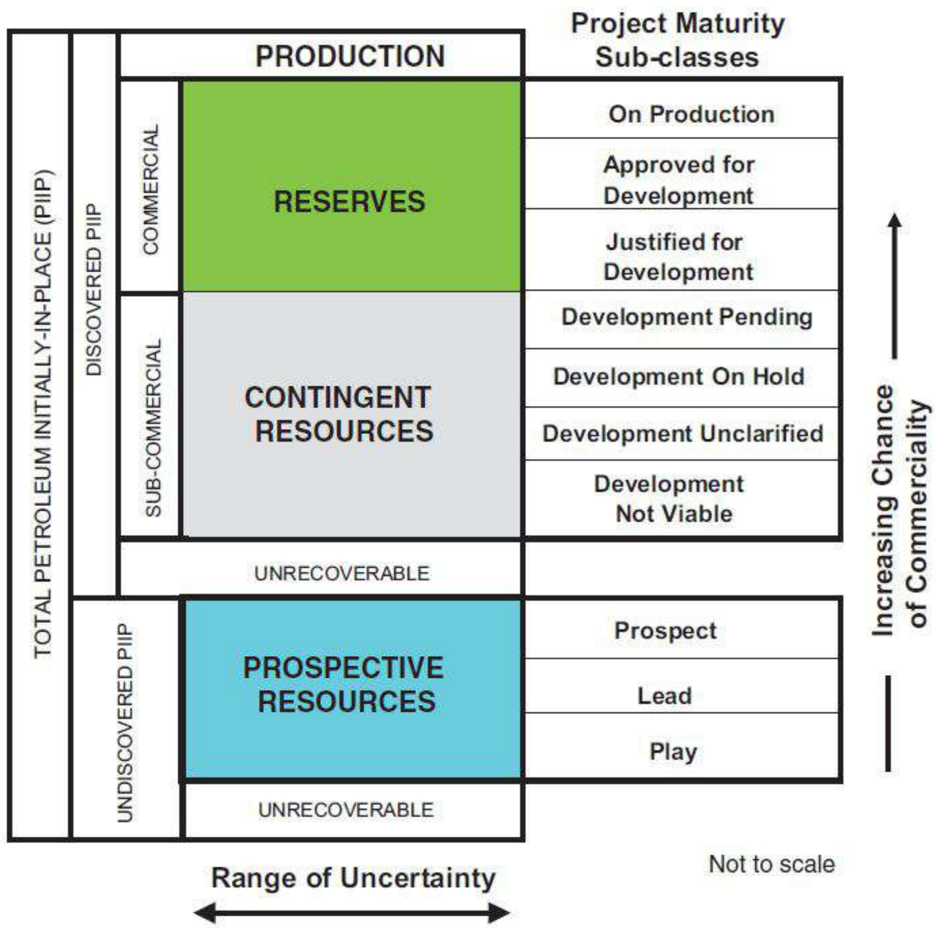


Figure 2.1—Sub-classes based on project maturity

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.

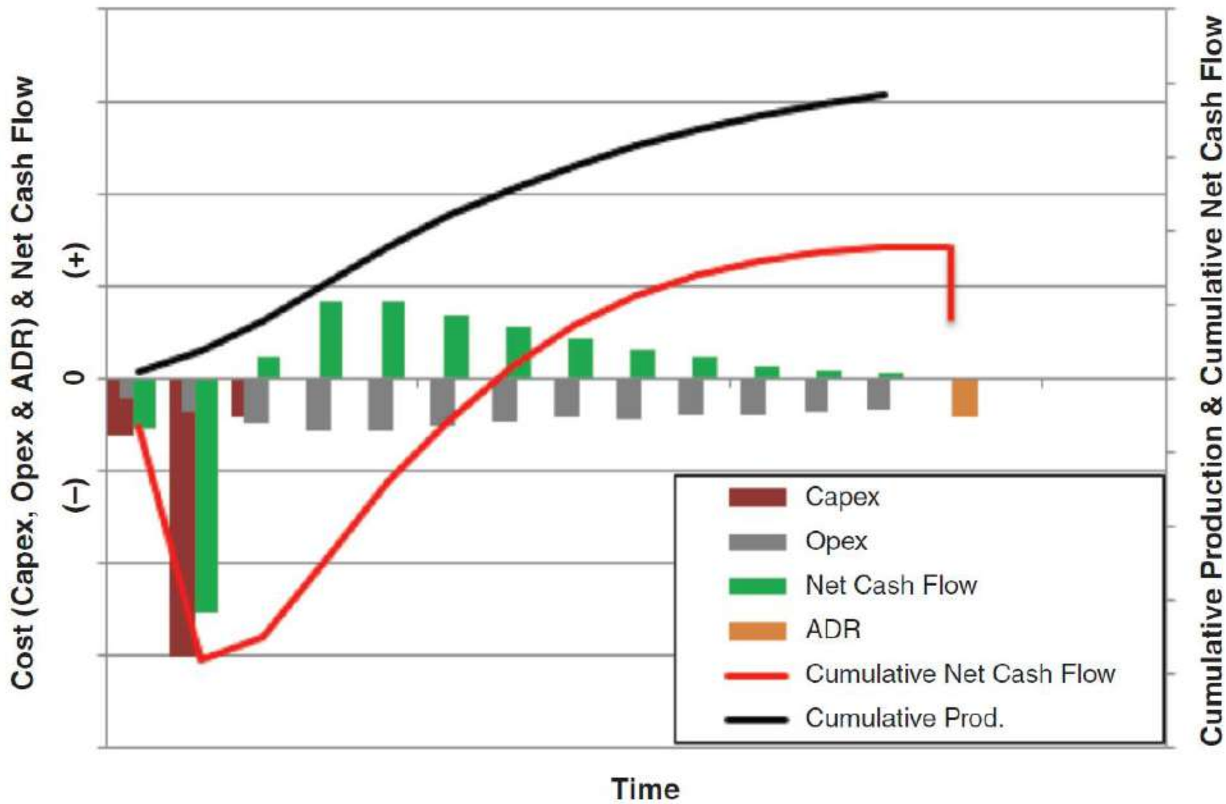


Figure 3.1—Undeveloped project economic forecast

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.

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 3: WELL DATABASE

Well Name	UWI	Label	Easting	Northing	RL	Hole Angle	Total Depth
HDR 1	VR1239	HDR01	27610.29	3112421.65	1294.00	90.00	484.00
Burning Cross	VR1187	1307	27976.6	3111368.3	1287.60	90.00	1092.33
EX 1	VR0512	EX01				90.00	
Highpipe	VR0846	2057	25854.4	3108505.8	1323.17	90.00	1627.00
HZON 1	VR2352	HZON01				90.00	
MDR 5			27251	3111658.5	1219.52	90.00	350.00
ML 1	VR1126	1370	24573	3132720.1	1410.95	90.00	1237.75
Retreat	VR0091	DW54403	34874.4	3129059.8	1372.37	90.00	513.70
ST 23	VR0588	ST23	25671.9	3120629.3	1340.77	90.00	1866.95
SPG 3 \ Lucky	VR1162	SPG03	25320.9	3130173.8		90.00	
Squatter	VR0848	2089	25852.4	3109095.8	1317.36	90.00	1750.60
Tewie-1400	VR0453	1400	25187.6	3123069.8	1357.15	90.00	1459.55
Burning Flame	VR0854	2190	22134.5	3108509.2	1344.08	90.00	1411.40
DBE 1	VR0489	DBE1	23747.2	3118794.8	1344.99	90.00	1090.00
SP 3	VR1026	SAP11	16593.4	3101476.4	1362.54	90.00	
Flame 1	VR0858	2278	21345.5	3109501.8	1335.32	90.00	1287.50
Sand	VR1191	1629	26806.6	3110762.9	1296.20	90.00	2163.24
BN 56120A	VR0037	Dumidi	32288.3	3111882.8	1300.10	90.00	356.00

For additional information an expanded electronic version is available.

APPENDIX 4: TETRA4 PRICING FORECAST MARCH 2019

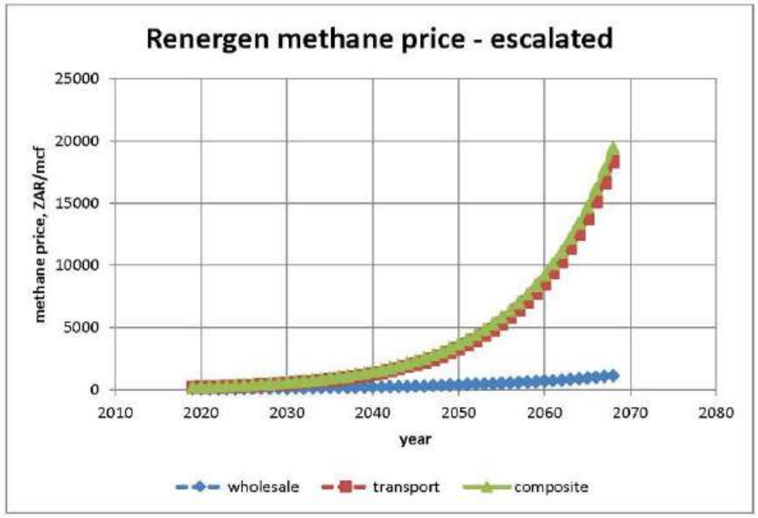
Methane Price Calculation

		ref/comment/tab in ss
wholesale LNG fraction =	30%	Inputs
transport fraction =	70%	Inputs
scf/GJ =	1016	Inputs
wholesale LNG price, ZAR/GJ =	220	Inputs
wholesale LNG price, ZAR/mcf =	217	
wholesale LNG price fraction, ZAR/mcf =	65	
diesel price, ZAR/l =	14.20	Inputs
diesel enery content, MJ/kg =	48	Google
diesel density, kg/l =	0.832	Google
discount to diesel =	0.7	Inputs
diesel equiv LNG price, ZAR/mcf =	245	
diesel equiv LNG price fraction, ZAR/mcf =	171	
composite gas price, ZAR/mcf =	236	

Methane Escalated Price Calculation

escalation, %/yr = | 6% | 10%

count	year	wholesale	transport	composite	esc, %/yr
		methane price, ZAR/mcf			
1	2019	65	171	236	1.000
2	2020	69	189	257	1.089
3	2021	73	207	280	1.089
4	2022	77	228	306	1.090
5	2023	82	251	333	1.090
6	2024	87	276	363	1.090
7	2025	92	304	396	1.090
8	2026	98	334	432	1.091
9	2027	104	368	471	1.091
10	2028	110	404	514	1.091
11	2029	116	445	561	1.091
12	2030	123	489	613	1.092
13	2031	131	538	669	1.092
14	2032	139	592	731	1.092
15	2033	147	651	798	1.092
16	2034	156	716	872	1.093
17	2035	165	788	953	1.093
18	2036	175	867	1042	1.093
19	2037	185	953	1139	1.093
20	2038	197	1049	1245	1.093
21	2039	208	1154	1362	1.094



Helium Escalated Price Calculation

escalation, %/yr = 2.4%

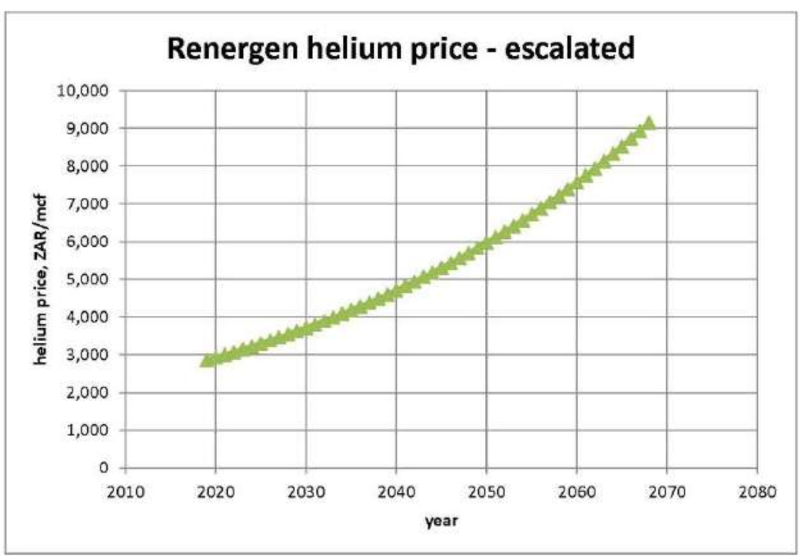
kg He/mcf He = 4.69

ZAR/USD 14.33

Ref: helium_kg_mcf_conversion.xls

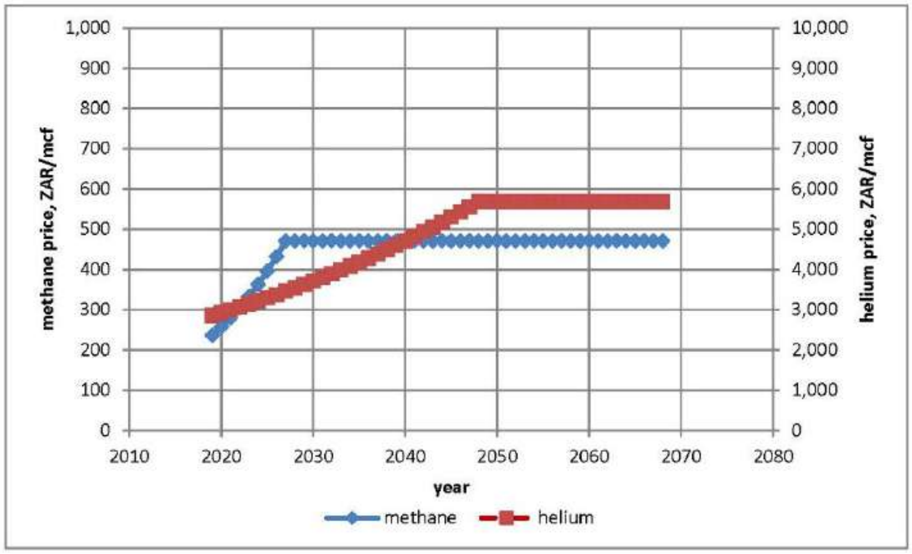
Ref: Renergen_LHGP Phase II Debt Model v0.6MHA_jps.xls

count	year	USD/kg	USD/mcf	ZAR/mcf
		helium price		
1	2019	42.60	199.79	2,863
2	2020	43.62	204.59	2,932
3	2021	44.67	209.50	3,002
4	2022	45.74	214.53	3,074
5	2023	46.84	219.68	3,148
6	2024	47.96	224.95	3,224
7	2025	49.11	230.35	3,301
8	2026	50.29	235.88	3,380
9	2027	51.50	241.54	3,461
10	2028	52.74	247.33	3,544
11	2029	54.00	253.27	3,629
12	2030	55.30	259.35	3,716
13	2031	56.63	265.57	3,806
14	2032	57.98	271.95	3,897
15	2033	59.38	278.47	3,991
16	2034	60.80	285.16	4,086
17	2035	62.26	292.00	4,184
18	2036	63.75	299.01	4,285
19	2037	65.28	306.18	4,388
20	2038	66.85	313.53	4,493
21	2039	68.46	321.06	4,601



Methane and Helium Prices

count	year	methane, ZAR/mcf	helium ZAR/mcf
1	2019	236	2,863
2	2020	257	2,932
3	2021	280	3,002
4	2022	306	3,074
5	2023	333	3,148
6	2024	363	3,224
7	2025	396	3,301
8	2026	432	3,380
9	2027	471	3,461
10	2028	471	3,544
11	2029	471	3,629
12	2030	471	3,716
13	2031	471	3,806
14	2032	471	3,897
15	2033	471	3,991
16	2034	471	4,086
17	2035	471	4,184
18	2036	471	4,285
19	2037	471	4,388
20	2038	471	4,493
21	2039	471	4,601



year	methane, ZAR/mcf	helium ZAR/mcf
2019	236	2,863
2020	257	2,932
2021	280	3,002
2022	306	3,074
2023	333	3,148
2024	363	3,224
2025	396	3,301
2026	432	3,380
2027	471	3,461
2028	471	3,544
2029	471	3,629
2030	471	3,716
2031	471	3,806
2032	471	3,897
2033	471	3,991
2034	471	4,086
2035	471	4,184
2036	471	4,285
2037	471	4,388
2038	471	4,493
2039	471	4,601
2040	471	4,711
2041	471	4,824
2042	471	4,940
2043	471	5,059
2044	471	5,180
2045	471	5,304
2046	471	5,432
2047	471	5,562
2048	471	5,695
2049	471	5,695
2050	471	5,695
2051	471	5,695
2052	471	5,695
2053	471	5,695
2054	471	5,695
2055	471	5,695
2056	471	5,695
2057	471	5,695
2058	471	5,695
2059	471	5,695
2060	471	5,695
2061	471	5,695
2062	471	5,695
2063	471	5,695
2064	471	5,695
2065	471	5,695
2066	471	5,695
2067	471	5,695
2068	471	5,695

APPENDIX 5: ABBREVIATIONS

This appendix contains a list of abbreviations found in MHA Petroleum Consultants, Inc. 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
M	Millions
m	thousands
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
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

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

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)