INDEPENDENT CONFIRMATION OF SIGNIFICANT PROSPECTIVE RESOURCES IN MADAGASCAR

ASX RELEASE

Tellus Resources Ltd is an Australian-based oil, gas and mineral exploration company with licences in Utah, South Australia, Queensland and New South Wales.

Directors:

Robert Kennedy ***(Chairman)***
Carl Dorsch ***(Managing Director)***
Neil Young ***(Non-Executive Director)***

Issued Shares:

172,348,295 ordinary shares

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Tellus Resources Ltd ("TLU" or "the Company") advises that it has received a report from Denver USA based MHA Petroleum Consultants LLC ("MHA") that provides an independent confirmation of significant prospective resources in Block 3114, Madagascar. Note that by definition, prospective resources are risked and recoverable.

The report, titled *Technical Review and Prospective Oil Resources Assessment Block 3114 Madagascar* is attached and available also on the Company's website through the following link: www.tellusresources.com.au

MHA have estimated the risked prospective recoverable resources in a single drill-ready prospect (the Betoiky Prospect) are as follows:

Interest	Low (mmstb)	Best (mmstb)	High (mmstb)
25%	2.6	9.7	27.2
80%	8.4	31.1	86.9
100%	10.5	38.9	108.6

The estimated quantities of petroleum (million standard barrels of oil – mmstb) 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. The basis of risking is discussed in the MHA report.

As advised to the market on 11 June 2014 TLU has entered into a binding Agreement to acquire a 25% interest (with the right to acquire up to an 80% interest) in this block for the issuance of 85M TLU shares, subject to shareholder approval.

Carl Dorsch, the Company's Managing Director, commented on the report as follows:

"MHA's report provides the Company with enormous encouragement that it has acquired a very material prospective resource base in onshore Madagascar. Importantly, these large numbers are for risked recoverable resources – and are only for one drill ready target in what is a very large and prospective block. The Company has already received early stage farm-in interest in this asset from a number of investor and industry sources.

Technical Review & Prospective Oil Resources Assessment Block 3114 Madagascar

Prepared for

TELLUS RESOURCES LTD

July 2014

MHA Petroleum Consultants LLC

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Introduction

Caravel Energy Ltd (CRJ) is selling its 25% interest in PetroMad Mauritius Ltd (PetroMad) to Tellus Resources Ltd (TLU) along with the right to acquire up to an 80% interest in block 3114 on shore Madagascar. Block 3114 is approximately 10,000 km^2 and is formally known as the Bezaha Concession (Figure 1). TLU requested assistance from MHA Petroleum Consultants to provide a technical and prospective resource assessments based on the data provided by CRJ and PetroMad. Data for the assessment was provided by CRJ and PetroMad.

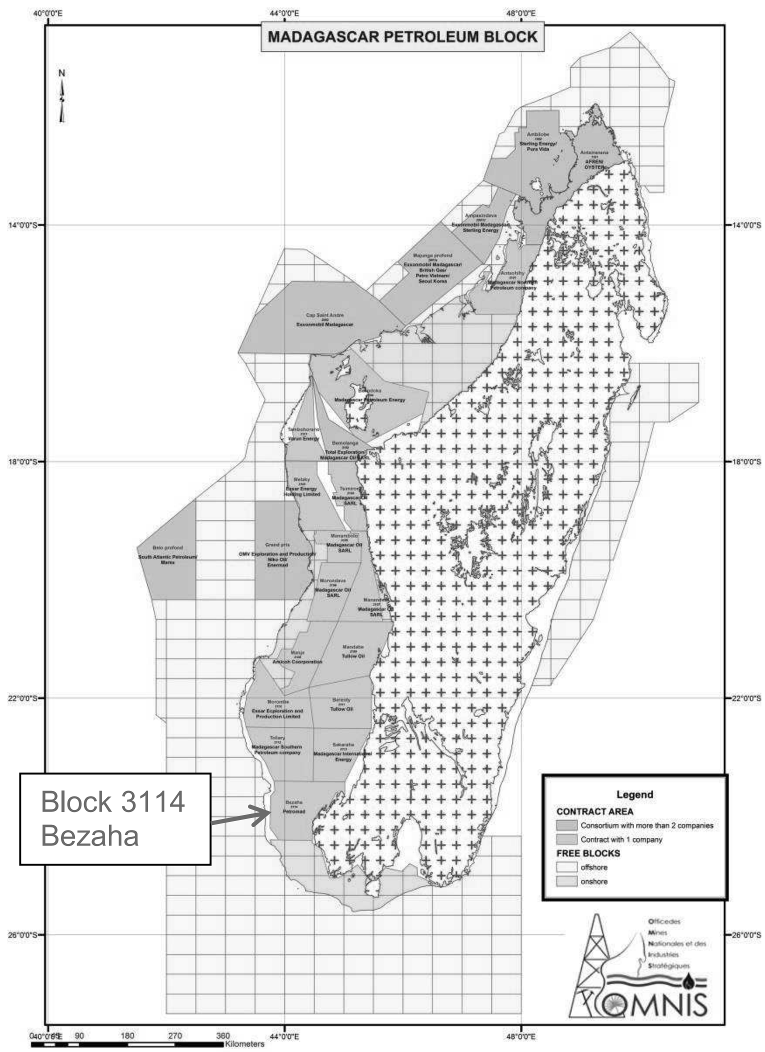

Figure 1 Madagascar petroleum exploration blocks (OMNIS)

MHA has been providing intermittent geologic, geophysical, and engineering support for CRJ on the Madagascar project since 2010. In summary, they have:

- Reviewed all past technical reports provided by CRJ
- Initiated a literature search for geologic publications related to Madagascar geology and its petroleum potential
- Evaluated available well data reports for the three wells drilled in Block 3114
- Reviewed legacy 2D seismic data on the block and evaluated previous seismic interpretations
- Reviewed legacy gravity and magnetics data and evaluated previous interpretations
- Licensed new remote sensing data over the block and initiated a geologic interpretation based on geomorphology, spectral analysis, and published geologic mapping
- Monitored industry activity in the area surrounding Block 3114
- Managed the acquisition and processing of a 2D seismic program in 2013
- Visited the block to evaluate the seismic crew, to scout surface access for drilling and future seismic, and to scout outcrops of objective reservoir rock.
- Interpreted new 2D seismic data and mapped prospective structures
- Initiated preparations for the drilling of an exploratory well

The goal of the MHA effort was to gain a thorough and in-depth understanding of the geology and petroleum potential of the region and, specifically, to develop drillable prospects on Block 3114 for CRJ. Time limitations and budget constraints did not allow MHA to finalize the evaluation to their satisfaction, however significant progress was made which allowed MHA to elevate one exploratory prospect to drillable status and identify additional leads.

Block 3114 provides a very attractive frontier exploration opportunity. The area has been very lightly explored with only 2 wells drilled in the 1950's and one well in the 1970's; neither using good seismic data. There is strong evidence of a viable petroleum system in the area. New 2D seismic data is of good quality and has revealed attractive trapping geometries. Mapping of this limited 2D dataset has revealed one drillable prospect and several leads, suggesting that additional seismic acquisition will continue to reveal drillable prospects. Reasonably good access exists between the prospect site and the active port in the city of Tulear.

Regional Geologic Framework

The onshore portion of the Morondava Basin is a long and narrow depocenter which is located on the west side of Madagascar and results principally the separation of Madagascar from Africa (Figure 2). Both structure and stratigraphy display a clear N-S strike orientation with a general E-W thickening of Mesozoic and Cenozoic sediments from the zero-edge on the east side of the basin.

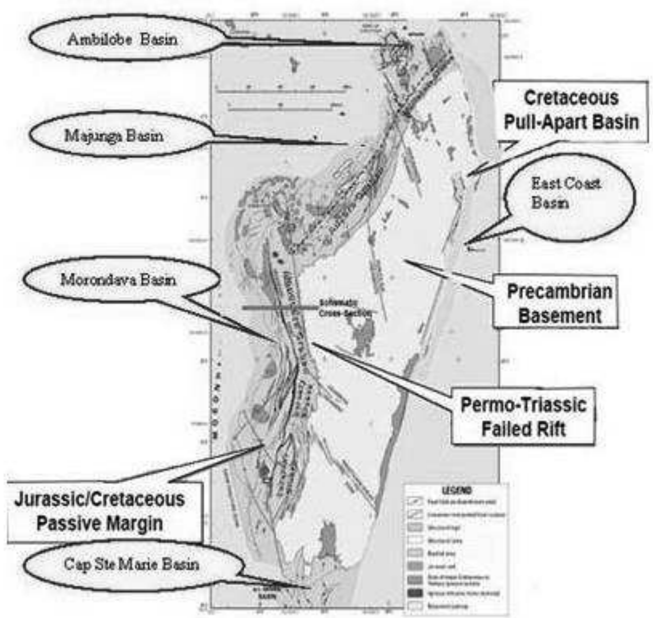

Figure 2 Structural Map of Madagascar (OMNIS)

The characteristics of faulting indicate that the basin history has been dominated by extensional tectonics combined with a wrench component that imparted trans-tensional and perhaps trans-pressional stresses on the rocks. In general, the Permo-Triassic section (which comprises the primary reservoir targets) is heavily faulted while the overlying Jurassic-Cretaceous and younger strata are faulted to a much lesser degree. A generalized stratigraphic column is presented in Figure 3.

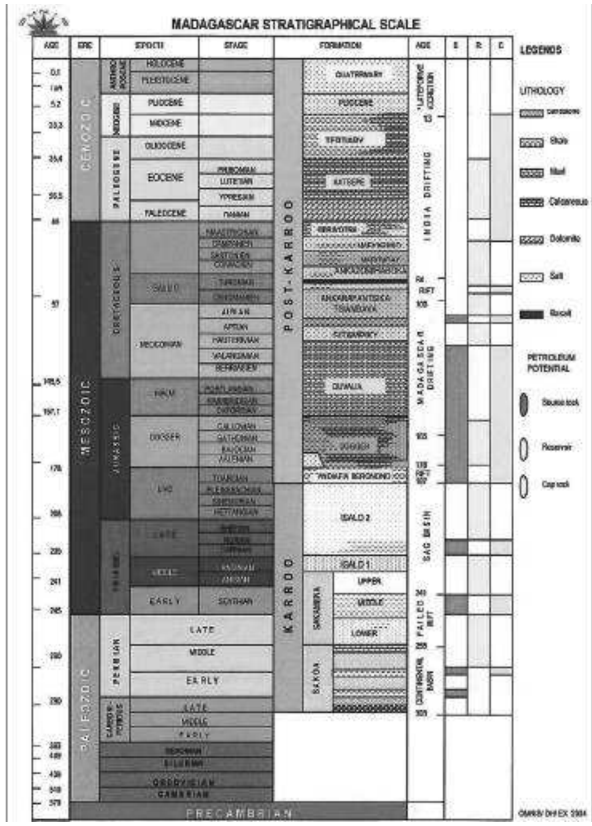

Figure 3 Generalized stratigraphic Column Onshore Madagascar (NSAI, 2010)

The Permo-Triassic section is almost entirely comprised of clastic rocks that were deposited in lacustrine, fluvial, marginal marine, and near-shore marine environments. Younger strata comprise a combination of carbonate and clastic deposition and have been interpreted as originating in shallow marine and marginal marine environments after the rifting from Africa was completed.

Exploration History and Petroleum System

There has yet to be any commercial hydrocarbon production from the Morondava Basin. However, this is attributed more to the nature and history of exploration in Madagascar than to a lack of a viable petroleum system. Only about 65 exploratory wells have been drilled in the entire Morondava. Based on the few wells we have studied closely in Block 3114 as well as some of the available literature, it appears that most of these wells were drilled either without seismic, with very poor quality 2D seismic, or with insufficient seismic to adequately define a trap. In other words, it is highly likely that most of these wells were not drilled on actual structural closures.

Importantly, a number of these exploratory wells were indeed technical successes or significant show wells. Notable among these were the discovery of the multi-billion barrel Bemolanga and Tsimiroro fields. These fields are non-commercial because the oil has been significantly biodegraded, due to their proximity to the surface, and so the oil is very low gravity. Extensive investment has been made in these two fields in recent years in an effort to commercialize the fields through steam flooding the reservoirs. So it is possible that these fields may become commercial in the near future. Other notable wells include a 1987 Petro-Canada well and a

1991 Shell well that flow tested high quality oil and gas, but at non-commercial rates primarily due to high transportation costs. The prospective portions of Block 3114 are on strike with the two large oil fields and the two non-commercial discoveries, and Block 3114 efforts are targeting equivalent reservoirs.

In the last several years there have been press-releases by two Chinese companies attesting to discoveries in the two blocks immediately north of Block 3114 (Blocks 3112 and 3113). One release reported test rates up to 400 BOPD of light oil. Although CRJ representatives have visited the well sites and had brief conversations with the operators, no further information has become available on these discoveries.

In 1986 Robertson Research generated a report on the source rock quality and maturity of Permo-Triassic rocks based on a limited number of samples from well cuttings, core, and outcrop. A number of samples yielded good TOC levels and suitable maturity levels for the generation of light oil and gas. Some of the well samples were from wells in the Block 3114 area.

The above information indicates that there is an active and viable petroleum system in the onshore Morondava Basin. The USGS to concluded in a 2012 assessment of the Morondava Basin that there is a mean undiscovered conventional oil resource of 10.75 billion barrels and a mean undiscovered gas resource of 167 trillion cubic feet. The lack of commercial production is attributed to the fact that only a small number of wells have been drilled relative to the size of the basin and many of the wells, particularly the older ones, appeared to have been drilled without sufficient risk reduction (because of reliance on old and low quality seismic, insufficient seismic, or no seismic guidance).

Reservoir and Seal

The primary objective section in Block 3114 is the Permo-Triassic clastic Karoo Sequence (Figure 3). This section of sands and shales varies significantly in thickness due to several unconformities as well as variable accommodation space related to growth faults, but is anticipated to be over 2000m thick in the area of the current Block 3114 leads and prospects.

Stratigraphic correlation is very difficult in Block 3114 due to the fluvial and deltaic origin of most of the strata combined with the paucity of wells and poor quality of the well logs. Additional stratigraphic complexity results from dramatic thickness changes across many of the faults.

Reservoir quality may be an issue with many of the Permo-Triassic sands because of the fairly short transport distance from the igneous and metamorphic sources to the east. This short transport distance suggests that a high feldspar and lithic component may have resulted in a significant percentage of clay in the sandstones. Low permeability is mentioned in some of the well reports. However intervals of high porosity and permeability sandstones are also mentioned in core and cutting evaluations. This good reservoir quality was also supported by the observation of some high quality coarse grained sandstones seen where the objective section outcrops to the east.

Seals in the form of clean shale intervals occur throughout the Permo-Triassic section. Although not always clearly defined on the old logs, thick shales sequences occur in the outcrop belt of the same age rocks up dip and to the east of the prospective area. The thickness of the prospective section combined with the common occurrence of shale sequences creates numerous opportunities for the optimal scenario of reservoir sands to occurring below sealing facies.

Structure and New 2D Seismic Data

Extensional normal faulting appears to be the dominant structural style seen on the higher quality 2D seismic data acquired in 2013 on Block 3114, especially for the Permo-Triassic section. This is also the structural style interpreted from seismic data and reported by past operators on blocks to the north of 3114.

In 2013, 165 km of 2D data was acquired and processed. This 2D seismic data is typically good quality and reveals a higher degree of faulting than previously identified in Block 3114 from the poorer quality legacy seismic data. This new seismic data reveals encouraging prospective fault traps and anticlinal geometries. The fault traps are in the form of rotated fault blocks that potentially set up high-side fault dependent closures, and the anticlines are potential fault independent rollovers. We have been very encourage that with this limited dataset, one area is already sufficiently well-defined to be considered a drillable prospect and a second prospect is only in need of a drill site delineation line. Equally encouraging are the number of leads identified on this new dataset suggesting that structural closures may be fairly common in this part of the block.

In summary the frequency of faults may limit the size of any single accumulation, but the number of favorable trapping geometries observed on this limited dataset suggests that any exploratory drilling success should be highly repeatable.

Betioky Prospect

The Betioky prospect is currently considered the candidate for the initial exploratory well. While we recognize the limitations of 2D data, TLU is fortunate that three of the new 2D lines identify a fairly well defined faulted anticline of attractive size. This structure has been mapped as having up to 12 square km of fault independent closure and up to 53 square km of fault dependent closure. Figure 4 presents the structure and location of the seismic lines for the Betioky Prospect.

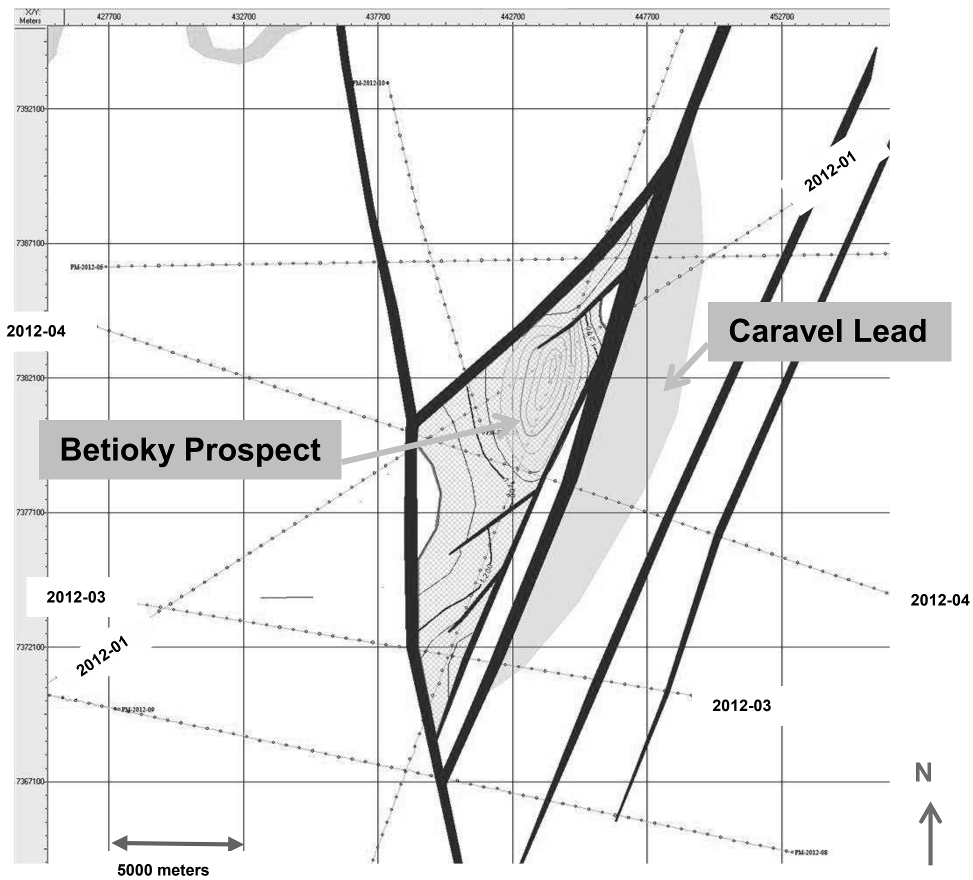

Figure 4 Location of seismic lines over the Betioky Prospect and Caravel lead

Another attractive quality of this prospect is that the culmination of the structure persists with depth in roughly the same geographic location. In other words a single vertical well can test the crest of the anticline for as much as 2000 meters of prospective section. This geometry is very important for this initial exploratory well because we know so little about which portions of the prospective Permo-Triassic section comprise the best reservoir quality and top seal. The very thick interval of prospective rock involved in this anticline provides the very real potential for a significant thickness of stacked pay.

Example seismic lines over the prospect area are presented in Figures 5 and 6.

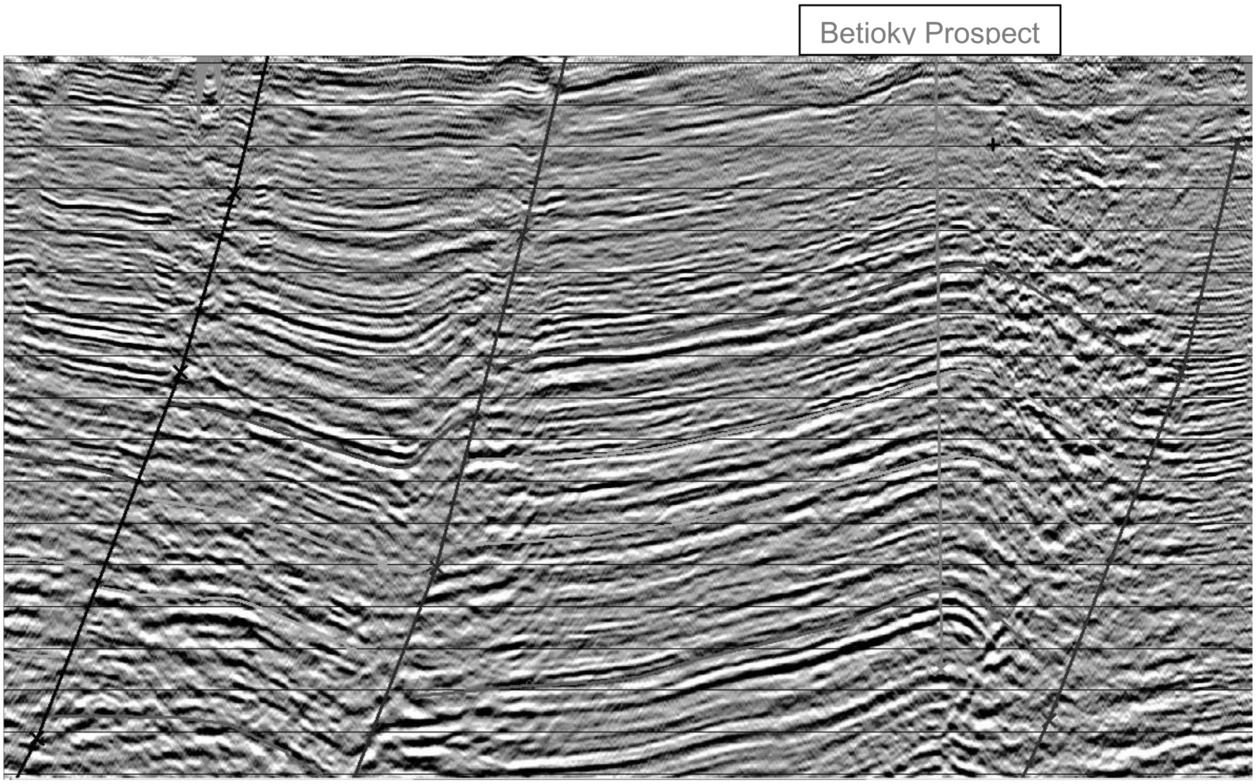

Figure 5 Betioky Prospect on Line 2012-01

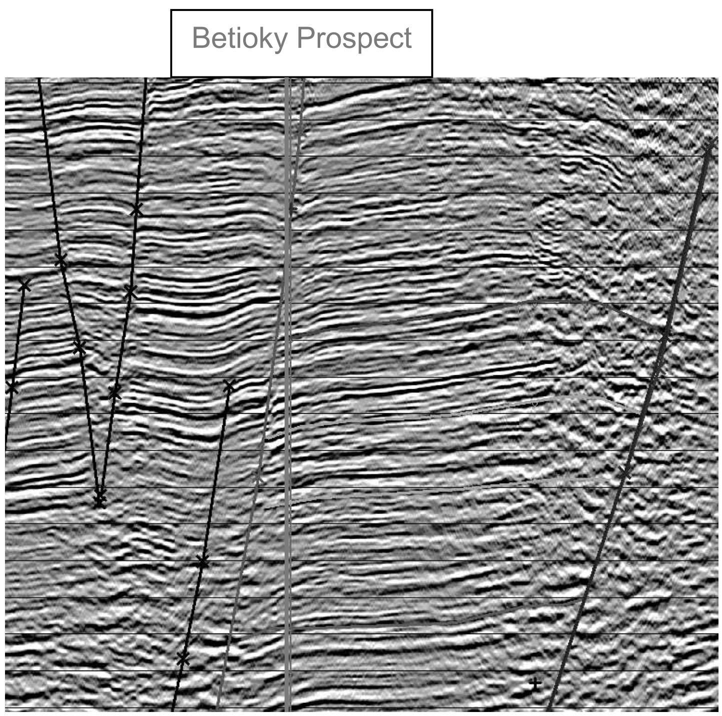

Figure 6 Line 2012-04 with Betioky Prospect

This prospect is located in an area that is relatively easy to access near the large village of Betioky. In a success case, oil could be trucked on an existing road network to the port city of Tulear.

Caravel Lead

The Caravel lead is a high-side fault trap in the block immediately east of the Betioky Prospect. Several seismic lines identify east dip away from a large down-to-the-west trapping normal fault (Figure 7). Because the reflection character in this block is not sufficiently distinct, an additional strike line is proposed for this lead. This strike line will be located to identify the culmination of the closure and the optimal location for the drill-site.

As with the Betioky Prospect, it appears that a vertical well will be able to test a very thick section of prospective section in a crestal or near crestal position. As currently mapped, the lead area is about 40 square km, although once the proposed delineation line is acquired, the new data and new mapping will require a revision in that areal size.

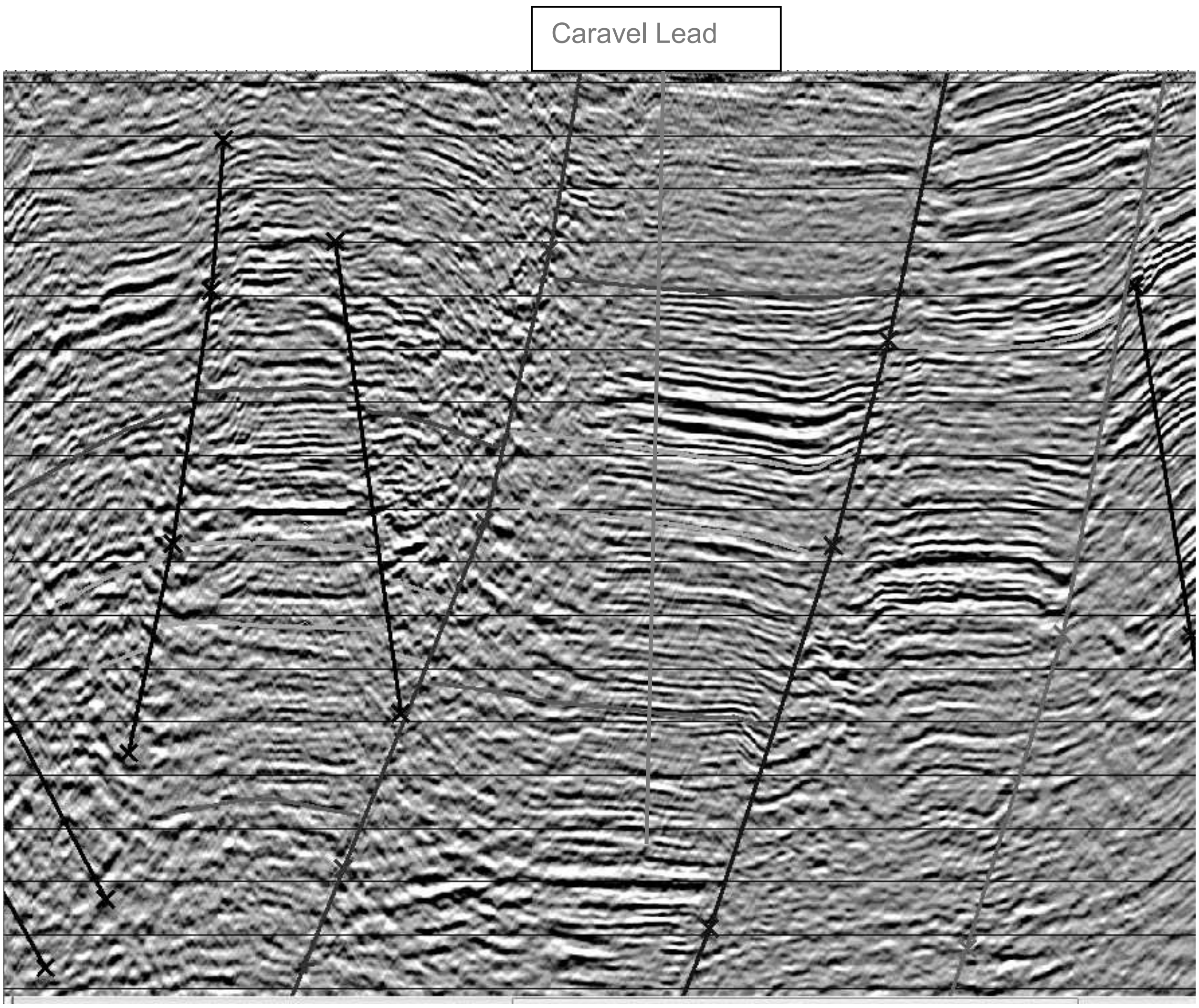

Figure 7 Caravel Lead on seismic line 2012-03

As with the Betioky Prospect, this lead is located in an area that is relatively easy to access near the large village of Betioky. In a success case, oil could be trucked on an existing road network to the port city of Tulear.

Engineering

Prospective resources in the Betioky prospect were estimated from a series of Monte Carlo realizations using the Crystal Ball software package driven by input distributions developed from data supplied by CRJ, TLU and PetroMad augmented by public domain information as necessary. Original oil in place was calculated volumetrically as the product of area, net thickness, porosity, water saturation, geometric factor, and hydrocarbon risk factor divided by oil formation volume factor.

The area distribution, supplied by geophysical and geologic analysis, was triangular with minimum, most likely, and maximum values of 12 km2 (3,000 acres), 24 km2 6,000 acres), and 53 km2 (13,000 acres), respectively.

The net thickness distribution, also triangular, had minimum, most likely, and maximum values of 0.3 m (1 ft), 62.5 m (205 ft), and 121 m (397 ft), respectively. This distribution was obtained from geophysical and geologic analysis based on news releases by Chinese firms actively drilling north of this area.

Porosity was described with a normal distribution having a mean of 13.3% and a standard deviation of 5.9%. This distribution was generated using Crystal Ball to fit porosities measured on sidewall cores taken from the Isalo and Sakamena zones in the BW-1 and SW-1 wells.

The triangular water saturation took the minimum, most likely, and maximum values of 30%, 40%, and 50%, respectively, from a review of the East Bezaha Block (RPS, 2010).

The oil formation volume factor was based upon depth, which was described as a uniform distribution ranging from 1200 m to 3500 m. Assuming a normally pressured formation (0.433 psi/ft) and using the average geothermal gradient of 2.75°C/100 m taken from the BW-1 and SW-1 well logs, reservoir pressure and temperature were calculated as functions of depth. The subject lead is suspected to host a light oil, analogous to the 41˚ API oil found in the Manandaza-1 well (RPS Energy, 2010). No gas-oil ratio's (GOR's) have been reported for oil in this area, consequently, this study assumed a GOR of 1,000 scf/stb, typical for a 41 ˚ API black oil. Industry standard correlations were used to estimate oil formation volume factors as a function of depth. A depth randomly generated by Crystal Ball was then used to compute the corresponding oil formation volume factor.

Reservoirs have pinchouts, sub seismic faults, and sealing joints which preclude exploitation of the entire volume defined by seismic interpretation. The geometric factor is the ratio of exploitable reservoir volume to seismic volume. This study assumed a triangular geometric factor distribution with minimum, most likely, and maximum values of 0.60, 0.80, and 0.95, respectively.

The hydrocarbon risk factor captures the risk that the reservoir volume estimated above will be charged with hydrocarbons. A triangular distribution was assumed here. Geophysical and geologic analysis led to assigning minimum, most likely, and maximum hydrocarbon risk values of 0.68, 0.90, and 1.0, respectively.

Estimated ultimate recovery was calculated as the product of original oil in place and a recovery factor. The recovery factor was triangular with minimum, most likely, and maximum values of 4%, 13%, and 40%, reflecting our current understanding that the dominant drives for reservoirs in this lead could be undersaturated oil expansion, solution gas drive, and/or a strong water drive.

The risk of discovery captures the chance that an exploration well will encounter hydrocarbons. The risk of discovery for the Betioky prospect is thought to be fairly high as the subject prospect is on strike with, and has characteristics similar to, several recent discoveries and a significant effort using modern technologies is being expended to identify likely hydrocarbon targets in the prospect. Consequently, this study assumed a chance of discovery of 80%.

The risk of development reflects the uncertainty that any discovery in the subject prospect will be commercial. Oilfield infrastructure is being built to support exploitation of fields to the north of the subject lead. As noted above, Betioky is near a town of the same name and oil can be trucked to the port city of Tulear. Lastly, the government of Madagascar actively supports oil and gas exploitation and no regulatory delays are anticipated in commercializing any find on this prospect. Thus, this study assumed a chance of development of 90%.

Monte Carlo Realizations

Using the input distributions described above, a series of 10,000 Crystal Ball realizations was done to develop the gross prospective resources distribution shown in Figure 8.

	value		distribution parameters				ref/comments
area, ac =	6,000		3,000	6,000	13,000	triangle-min/mode/max	D. Brewster per Deb G email 18 July 2014
net thickness, ft =	205		1	205	397	triangle-min/mode/max	RPS, Sep 2010, p. 6, Update on Prog release 29 Aug 11, Madagascar
porosity, % =	13.3	Boi,	13.3	5.9		normal-mean/std dev	Madagascar_Log_Data_Porosity and Perm summary_jps.xlsx
Sw, % =	40	rb/stb	30	40	50	triangle-min/mode/max	RPS, Sep 2010, p. 11
depth, m =	1,822	1.55	1,200	3,500		uniform-endpoints	depth=1200 m to 3500 m, Deb G. email 7 July 14
geometry factor =	0.80		0.60	0.80	0.95	triangle-min/mode/max	assumption - reservoir vol not = seismic vol
hc risk factor =	0.90		0.60	1.00		uniform-endpoints	assumption - chance that hc's are present
ooip, million stb =	354.4						
recovery, % =	13		4	13	40	triangle-min/mode/max	reo - sec 4 - und sat/soln gas/wtr drive
eur, mmstb =	46.07						
risk of discovery, % =		80%					assumption - chance that hc's will be found
risk of development, % =		90%					assumption - chance that hc's will be developed
prospective resource, million stb =		33.17	Note these are gross prospective resources and must be multiplied by client's interest to obtain net prospective resources				

CB fit to prosp res distribution = Lognormal Location=-5.06,Mean=52.71,Std. Dev.=51.76

	Percentile	million stb
	100%	0.1
low estimate	90%	10.5
	80%	17.1
	70%	23.6
	60%	30.5
best estimate	50%	38.9
	40%	48.6
	30%	61.3
	20%	80.0
high estimate	10%	108.6
	0%	580.4
	p10/p90 =	10.3

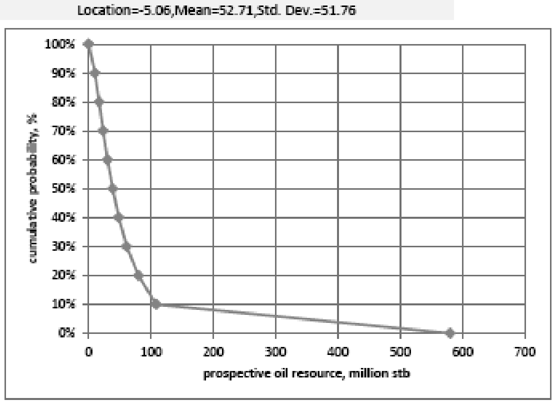

Figure 8 Betioky prospect prospective oil resource distribution

The P90 value (that is, 90% of all realizations had prospective resources equal to or greater than this value) of 10.5 mmstb was taken as the low estimate. The P50 value (half of the realizations were greater, half were smaller) of 38.9 mmstb was used for the best estimate. The P10 value (10% of all realizations were equal to or greater than this value) of 108.6 mmstb provided the high estimate of gross prospective resources for the Betioky prospect. 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. The effective date of these prospective resources is 14 July 2014.

Tellus Resources currently has a 25% working interest in Betioky, consequently, low, best, and high estimates of net prospective resources (Table 1) are 2.6 mmstb, 9.7 mmstb, and 27.2 mmstb, respectively.

gross prospective resources

low	best	high
10.5	38.9	108.6

current WI = 25%

current net prospective resources

low	best	high
2.6	9.7	27.2

future WI = 80%

future net prospective resources

low	best	high
8.4	31.1	86.9

Table 1 Betioky prospect prospective resource estimate summary (mmstb)

In the future, Tellus Resources' working interest could rise as high as 80%, thus low, best, and high estimates of future net prospective resources are 8.4 mmstb, 31.1 mmstb, and 86.9 mmstb, respectively. These estimates of prospective petroleum resources must be read in conjunction with the cautionary statement on page 12 that 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. The effective date of these prospective resources is 14 July 2014.

http://www.omnis.mg/en/hydrocarbon/hydrocarbon-potential

NSAI, June 30, 2010, Assessment of Contingent and Prospective Oil Resources to the Madagascar Oil Limited Interest in the Tsimiroro PSC 3104 and Assessment of the Petroleum Play Concepts located in Manambolo PSC 3107 Onshore Madagascar, 234 p.

RPS, September 2010, Independent Review of the Lac Bezaha Block, Morondova Basin, Onshore Madagascar, 12 p.

Yangchang Petroleum International Limited, December 31, 2012, Status of Oilfield Block 3113, Madagascar

– 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 resource or reserve assignments. Sometimes these revisions may result not only in a significant change to the resources, reserves, and value assigned to a property, but also may impact the total company resources and reserves and economic status. The resources contained in this report were based upon a technical analysis of the available data using accepted 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 and other information as specified in this report are reasonable, and have been prepared in accordance with generally accepted 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 Tellus Resources' use of MHA's interpretation, reports, or services produced as a result of its work for Tellus Resources Ltd Company.

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– 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 resources or reserves for the properties in this report.

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– This report was prepared for the exclusive use of Tellus Resources Ltd and will not be released by MHA to any other parties without Tellus Resources' written permission. The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices.

–

Debra K. Gomez, M. Sc., P. G.

I, Debra K. Gomez, Vice President of MHA Petroleum Consultants LLC, 730 17th Street, Suite 410, Denver, Colorado 80202, declare the following:

1. I hold the following degrees:
   a. B. Sc., Geology, 1976, University of Southern California
   b. M. Sc., Geology, 1979, Northern Arizona University

2. I am a registered professional geologist:
   a. Licensed Professional Geologist, Wyoming PG-448
   b. Certified Professional Geologist, AIPG8135
   c. Certified Petroleum Geologist, AAPG 6156

3. I am a member of the following professional organization:
   a. American Association of Professional Geologists

4. My contribution to the technical specialist's report pertaining to the Madagascar-based petroleum exploration assets of Tellus Resources Ltd is based on my geologic knowledge and the data provided to me by Tellus Resources Ltd, Caravel Energy Ltd, PetroMad Mauritius Ltd, from public sources, and from the non-confidential files of MHA Petroleum Consultants LLC. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Tellus Resources Ltd.

Debra K. Gomez

Debra K. Gomez, M Sc., P. G.
Vice President

Certificate

John P. Seidle, Ph. D., P. E.

I, John P. Seidle, Vice President of MHA Petroleum Consultants LLC, 730 17th Street, Suite 410, Denver, Colorado 80202, declare the following:

1. I hold the following degrees:
   a. B. S., Aeronautical Engineering, 1972, University of Colorado
   b. M. S., Aeronautical Engineering, 1973, Stanford University
   c. Ph. D., Mechanical Engineering, 1981, University of Colorado

2. I am a registered professional engineer:
   a. Licensed Professional Engineer, Colorado PE 35603
   b. Licensed Professional Engineer, Wyoming PE 9506
   c. Licensed Professional Engineer, Oklahoma PE 16656

3. I am a member of the following professional organization:
   a. Society of Petroleum Engineers (SPE)
   b. Society of Petroleum Evaluation Engineers (SPEE)
   c. American Association of Petroleum Geologists (AAPG)

4. I am a qualified oil and gas reserves evaluator and auditor

5. My contribution to the technical specialist's report pertaining to the Madagascar-based petroleum exploration assets of Tellus Resources Ltd is based on my engineering knowledge and the data provided to me by Tellus Resources Ltd, Caravel Energy Ltd, PetroMad Mauritius Ltd, from public sources, and from the non-confidential files of MHA Petroleum Consultants LLC. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Tellus Resources Ltd.

John P. Seidle

John P. Seidle, Ph. D., P. E.
Vice President

Appendix A

PRMS Definitions

Petroleum Resources Management System

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total 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 development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), 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), working 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 additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

This document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein. Appendix A is a consolidated glossary of terms used in resources evaluations and replaces those published in 2005.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

This SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, including its Appendix, may be 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.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

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

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

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

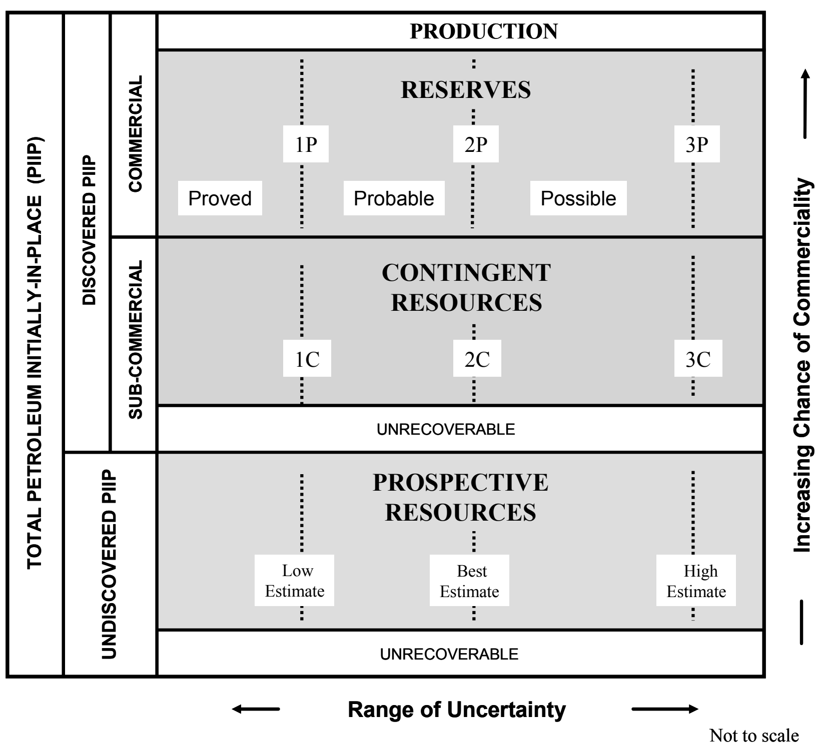

Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has 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 Production Measurement, section 3.2).

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

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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. 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 level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

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 discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

1.2 Project-Based Resources Evaluations

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

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

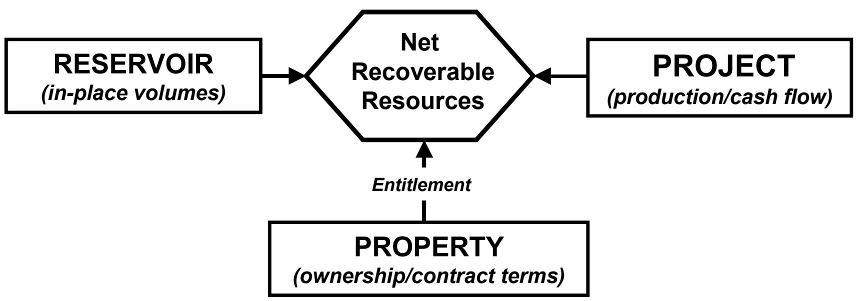

Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant'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.

In context of this data relationship, “project” is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level 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 that project.

An accumulation or potential accumulation of petroleum may be 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 resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. 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 largely based 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.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see Commercial Evaluations, section 3.1). “Conditions” include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system as 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 (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are “categorized” to reflect uncertainty (the horizontal axis). The actual workflow of classification vs. categorization varies with individual projects and is often an iterative analysis process leading to a final report. “Report,” as used herein, refers to the presentation of evaluation results within the business entity conducting the assessment and should not be construed as replacing guidelines for public disclosures under guidelines established by regulatory and/or other government agencies.

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is 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 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.1.3 Project Status and Commercial Risk

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 by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

2.1.3.1 <u>Project Maturity Sub-Classes</u>

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

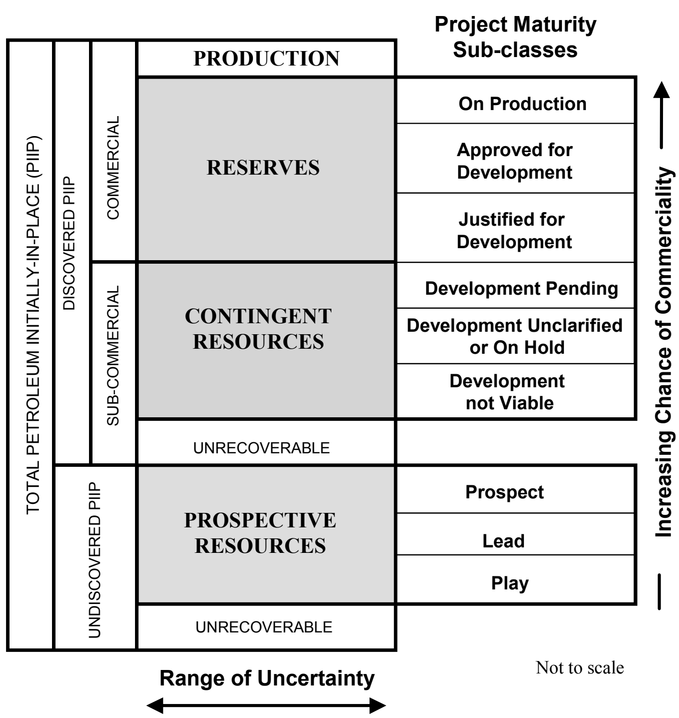

Figure 2-1: Sub-classes based on Project Maturity.

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project Maturity sub-class are provided in Table I. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as "decision gates."

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

2.1.3.2 Reserves Status

Once projects satisfy commercial risk criteria, 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 (detailed definitions and guidelines are provided in Table 2):

- Developed Reserves are expected quantities to be recovered from existing wells and facilities.
    - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
    - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.
- Undeveloped Reserves are quantities expected to be recovered through future investments.

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

2.1.3.3 <u>Economic Status</u>

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions (see Commercial Evaluations, section 3.1). Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates (see also Reference Point, section 3.2.1). Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

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

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

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 (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. 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 Commercial Evaluations, section 3.1).

Table III presents category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. 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.

- 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.

- Possible Reserves are those additional reserves which 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 (3P) Reserves, which is equivalent to the high estimate scenario. In this context, 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.

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

2.3 Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe.

Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources (see Determination of Commerciality, section 2.1.2).

2.3.1 Workovers, Treatments, and Changes of Equipment

Incremental recovery associated with future workover, treatment (including hydraulic fracturing), re-treatment, changes of equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed or Undeveloped Reserves depending on the magnitude of associated costs required (see Reserves Status, section 2.1.3.2).

2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in Reserves estimates. If the eventual installation of compression was planned and approved as part of the original development plan, incremental recovery is included in Undeveloped Reserves. However, if the cost to implement compression is not significant (relative to the cost of a new well), 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

Technical and commercial analyses may support drilling additional producing wells to reduce the spacing beyond that utilized within the initial development plan, subject to government regulations (if such approvals are required). Infill drilling may have the combined effect of increasing recovery efficiency and accelerating production. Only the incremental recovery can be considered as additional Reserves; this additional recovery may need to be reallocated to individual wells with different interest ownerships.

2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir performance. It includes waterflooding, secondary or tertiary recovery processes, and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified).

The judgment on commerciality is based on pilot testing 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.

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 program, where the response provides support for the analysis on which the project is based.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

2.4 Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.