Gaffney, Cline & Associates

HYDROCARBON PROSPECTIVE RESOURCE STATEMENT

MARTINEZ DEL TINEO PROSPECT

PUESTO GUARDIAN AREA, ARGENTINA,

AS OF OCTOBER 31, 2011

Prepared for

UTE PUESTO GUARDIAN

January 2012 -

Gaffney, Cline & Associates

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Hydrocarbon Prospective Resource Statement
Martinez del Tineo Prospect
Puesto Guardian Area, Argentina, as of October 31, 2011

Ing. José Endara:

This resource statement has been prepared by Gaffney, Cline & Associates (GCA) at the request of Petrolera San Jose (PSJ), participant in the UTE PUESTO GUARDIAN that operates the Puesto Guardián Area in the Northwest Basin of Argentina.

GCA has conducted an independent audit examination as of October 31, 2011, of the hydrocarbon exploration resources of the mentioned area. On the basis of technical and other information made available to us concerning this property unit, we hereby provide the resource statement given in the table below

Statement of Gross Field (100%) Hydrocarbon Prospective Resource Volumes

Martinez del Tineo Prospect , Puesto Guardián Area, Argentina

as of October 31, 2011

Prospect	Geologic Chance of Success	Fluid	Unrisked Recoverable Volume Estimates		
			Low	Best	High
Martinez del Tineo	26%	Gas (Bcf)	300	570	1,090
		Condensate (Mbbl)	7.600	14,500	27,600

Condensate volumes are reported in thousands of barrels. Natural gas is reported in billions (10^9) of cubic feet (at standard conditions of 14.7 psia and 60 degrees Fahrenheit). Volumes reported above correspond to conventional resources in the Cabure Formation. Annex 3 includes further information on source rocks relevant to Puesto Guardian.

The conventional prospect in the Martinez del Tineo area is within a 3D seismic survey with surrounding 2D lines that connect to other parts of the basin. The 3D seismic survey

acquired in 2006, and the outlining 2D seismic lines were reviewed by GCA on SMT Kingdom software at a workstation in PSJ's office.

The prospect in the Martinez del Tineo area is a gas prospect targeting the Paleozoic sedimentary sequence. The deep gas fields of the Tarija Basin about 110 km north of this prospect are analogous. The Martinez del Tineo prospect is located in the southwestern part of the Lomas de Olmedo Basin.

The structure over Martinez del Tineo is a large anticline trending NE-SW and plunging to the NE. The 3D seismic lines are of good quality and show strong evidence of rollover in a NW-SE direction as observed in dip lines from the Cretaceous through the Paleozoic sections. The deeper Paleozoic section shows a tighter structure with steeper flanks and more curvature at the apex than the younger Cretaceous section. Faults are prevalent in the Cretaceous and Paleozoic on both the crest and flanks of the structure. Attribute extraction was available for review and showed some positive results in the Lecho Formation of Lower Cretaceous age, while work in the Paleozoic section is still under consideration.

Strike lines show a high angle fault cutting across the structure running E-W providing south closure and creating a large uplifted north fault block. Strike lines over the crest of the structure show subtle rollover indicating some closure independent of the fault. The high angle fault shows larger displacement on the NW flank of the structure than the SE flank. Thereby, the closure area of the structure is limited by where the fault displacement decreases on the SE flank to the point of allowing communication between the fault blocks. GCA estimated that to be at the -2500 mss contour on the Top Paleozoic map and used that as the Best Estimate of the area of the prospect. That calculates to 24 km^2 of closure.

The seal of the Martinez del Tineo structure is provided by the Rincon Shale, which is equivalent stratigraphically to the Icla Shale in the Tarija Basin. The Icla Shale is the seal for the hydrocarbons trapped in the Santa Rosa sandstones in the Devonian gas fields of the Tarija Basin. Above the Rincon Shale is the Devonian Unconformity. In some areas of the Lomas de Olmedo Basin the Rincon Shale has been truncated by the Devonian Unconformity, in which case the unconformity itself can act as a seal.

The target in the Martinez del Tineo prospect is the Cabure Formation, which is equivalent to the Santa Rose in the Tarija Basin. The Santa Rosa sandstones are near shore shallow marine deposits with a high percentage of quartz. These sandstones, of Devonian age, have lost most of their original porosity over time from cementation of adjacent quartz grains. Santa Rosa sandstones matrix porosity is 3 to 4%. The Andean uplift compressed and folded these sandstones into tight anticlines, inducing fractures. The fractures were opened over the apex of the anticlines creating excellent reservoir rocks with an additional 2 or 3% porosity and with high permeability.

The Cabure Formation in the S. Ren.e-1 and Mal.x-1 wells show some sandstones with porosity as high as 10%. The Cabure sandstones will have additional fracture porosity in the Martinez de Tineo structure depending on the curvature of the anticline. However, the wells that penetrated the Cabure Formation are 80km to the south and 60km to the SE of this prospect and the Santa Rosa Formation of the Tarija Basin is 110km to the north. Therefore, GCA used the Santa Rosa (4.5%+2%fractures) as the Low Estimate porosity and used (13%+2.5%fractures) as the High Estimate porosity. The Best Estimate porosity calculates 10% (8%+2%fractures) which is more similar to Cabure well porosity with fractures (10%+2%fractures) than to Santa Rosa, respecting distance from Martinez del Tineo.

The range of expected thicknesses for the hydrocarbon reservoirs at Martinez del Tineo prospect were taken from the Santa Rosa gas-condensate reservoirs found in the Tarija Basin. The gas saturation ranges were also obtained from the Santa Rosa gas condensate reservoirs in the Tarija Basin. GCA used a recovery factor of 75%, which is high for the Santa Rosa, but the water drive is not expected to be as strong at the Martinez del Tineo prospect.

The Devonian gas-condensate reservoirs found in the Huamampampa and Santa Rosa sandstones in the Tarija Basin were sourced from the Los Monos Shale of Upper Devonian age and the Kirusillas Shale from Silurian age. The Los Monos source rock, or an equivalent, is not present in the SW part of Lomas de Olmedo Basin. The only Paleozoic source rock in the Lomas de Olmedo Basin is the Copo Fm (in some areas of the basin it is named Cachipunco). It is equivalent to the Kirusillas Fm in the Tarija Basin and it is known to have Total Organic Carbon (TOC) values around 1%. The Los Monos Shale has TOC values around 1%.

The Source Rock factor has some uncertainty with only one Paleozoic source rock at Martinez del Tineo area compared to the Tarija Basin where there are two. The remaining prospective factor is Timing. In Tarija Basin there is better understanding of Los Monos source rock generation and explusion to ridge structures than for the Kirusillas Fm. At Martinez del Tineo the only Paleozoic source rock is the Copo Fm (Kirusillas equivalent). There is a small concern that Copo expulsion may have been before the building of Martinez del Tineo structure. But knowing that in the Tarija Basin there are shallow Carboniferous age oil fields and deep Devonian gas fields, strongly suggests that in the Lomas de Olmedo Basin the shallow Cretaceous age oil fields will have associated deep Paleozoic gas fields as well.

Detailed information is provided in Annex 1.

Economic Estimate

The operator of the area estimated the economic performance of a notional development project based on the unrisked Best Estimate Prospective Resource volumes. The project consists of drilling 12 wells starting with two in mid 2012, four wells per year in 2013 and 2014 and two wells in 2015 at a cost of US$6.5 million per well. Also production facilities (US$118 million) and export pipeline (US$133 million) were considered.

The production is scheduled to start in August 2012. Gas price was estimated at US$4.00/MMBtu and condensate price at US$65.00/bbl. Royalties due to the provincial state of 10.5% and a tax of 1.8% are deducted from gross income. The operator's cashflow analysis is presented in Annex 2.

It is GCA opinion that the start of production was estimated too early in time. At least one more year is needed from discovery to perform long term tests and to install facilities including the export pipeline. On other hand GCA estimates that the cost of the pipeline is excessive. Probably a better estimation would be half of the quoted value

It should be emphasized that this is an exploratory opportunity, and the associated volumes are classified as Prospective Resources. 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.

This audit examination was based on resource estimates and other information provided by PSJ to GCA through November 18, 2011 and included such tests, procedures and

adjustments as were considered necessary. All questions that arose during the course of the audit process were resolved to our satisfaction.

It is GCA's opinion that the estimates of hydrocarbon resource volumes as of October 31, 2011, are, in the aggregate, reasonable and have been prepared in accordance with the Resource definitions approved by the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers in March 2007 (included as Annex 4).

This assessment has been conducted within the context of GCA's understanding of PSJ's petroleum property rights as represented by PSJ's management. GCA is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties or interests.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas reserves or resources prepared by other parties may differ, perhaps materially, from those contained within this report. The accuracy of any Reserve or Resource estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, Reserve and Resource estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

For this assignment, GCA served as independent resource auditors. The firm's officers and employees have no direct or indirect interest holding in PSJ. GCA's remuneration was not in any way contingent on reported resource estimates.

Finally, please note that GCA reserves the right to approve, in advance, the use and context of the use of any results, statements or opinions expressed in this report. Such approval shall include, but not be confined to, statements or references in documents of a public or semi-public nature such as loan agreements, prospectuses, reserve statements, press releases etc. This report has been prepared for PSJ and should not be used for purposes other than those for which it is intended.

Yours sincerely
Gaffney, Cline & Associates

Cesar E. Guzzetti
General Manager – Latin America Southern Cone

Enclosures

ANNEX 1

PROSPECT EVALUATION TABLES

Prospect Evaluation Tables

Prospect	Martinez del Tineo
Basin	Northwest
Country	Argentina
Objective Formation	Cabure
Fluid	Gas
Final Depth (mss)	3,600

Geologic Chance Factors	
Trap & Seal	90%
Reservoir Rock	70%
Source & Migration	60%
Geologic Timing	70%
Chance of Success	**26%**

Accumulation Parameters	Estimates		
	Low	Best	High
Area (Km^2)	18.0	24.0	32.0
Net Thickness (m)	30.0	42.4	60.0
Geometric Factor	0.90	0.90	0.90
Net Rock Vol (MMm^3)	486	916	1,728
Average Porosity	0.065	0.100	0.155
Average Sg	0.60	0.701	0.82
FVF (Bg)	0.0030	0.0030	0.0030
Gas Volume in Place (MMm^3)	11,283	21,507	40,993
Recovery Factor	0.75	0.75	0.75
G O R (m^3/m^3)	7,000	7,000	7,000

Unrisked Gross (100%) Field Recoverable Volumes				
Gas	MMm^3	8,462	16,130	30,745
	Bcf	300	570	1,090
Condensate	Mm^3	1,209	2,304	4,390
	Mbo	7,600	14,500	27,600

ANNEX 2

ECONOMIC EVALUATION

Gaffney, Cline & Associates

Economic Evaluation
Unrisked Best Estimate Case Cashflow
Martinez del Tineo Devonian Prospect

Year	Field Production		Gross Income		
	Gas MMm3	Condensate Mm3	Gas US$M	Condensate US$M	Total US$M
2012	101	13	14,232	5,101	19,332
2013	699	89	98,397	37,449	135,847
2014	1,385	210	195,045	88,231	283,276
2015	1,872	248	263,677	104,320	367,997
2016	1,783	237	251,123	99,793	350,915
2017	1,569	209	220,988	87,818	308,806
2018	1,359	181	191,351	76,093	267,444
2019	1,163	155	163,734	65,133	228,867
2020	988	131	139,174	55,363	194,537
2021	840	112	118,298	47,059	165,357
2022	714	95	100,553	40,000	140,553
2023	609	81	85,825	34,135	119,959
2024	532	71	74,929	29,767	104,696
2025	474	63	66,729	26,495	93,224
2026	426	57	60,056	23,845	83,902
Total	14,516	1,949	2,044,110	820,603	2,864,713

Year	Royalties US$M	Gross Inc. Tax US$M	Operating Expenses US$M	Other Expenses US$M	Capital Expediture US$M
2012	2,030	348	7,349	3,015	54,000
2013	14,264	2,445	7,239	5,328	139,500
2014	29,744	5,099	7,362	8,117	83,800
2015	38,640	6,624	7,486	9,909	52,000
2016	36,846	6,316	7,614	9,627	0
2017	32,425	5,558	7,744	8,865	0
2018	28,082	4,814	7,876	8,118	0
2019	24,031	4,120	8,011	7,427	0
2020	20,426	3,502	8,149	6,819	0
2021	17,362	2,976	7,172	6,273	0
2022	14,758	2,530	6,464	5,819	0
2023	12,596	2,159	5,907	5,454	0
2024	10,993	1,885	5,472	5,197	0
2025	9,789	1,678	5,135	5,018	0
2026	8,810	1,510	4,779	4,885	0
Total	300,795	51,565	103,759	99,872	329,300

Year	Net Cashflow US$M	Cumulative Cashflow US$M	8% Disc. Cashflow US$M	10% Disc. Cashflow US$M	12% Disc. Cashflow US$M
2012	-47,410	-47,410	-45,620	-45,203	-44,798
2013	-32,930	-80,339	-29,340	-28,543	-27,782
2014	149,154	68,815	123,049	117,531	112,355
2015	253,338	322,153	193,516	181,479	170,387
2016	290,513	612,665	205,475	189,190	174,455
2017	254,214	866,879	166,483	150,501	136,301
2018	218,554	1,085,433	132,527	117,627	104,626
2019	185,279	1,270,712	104,027	90,653	79,194
2020	155,641	1,426,353	80,914	69,229	59,398
2021	131,573	1,557,926	63,335	53,203	44,833
2022	110,982	1,668,908	49,466	40,797	33,765
2023	93,844	1,762,752	38,729	31,361	25,492
2024	81,149	1,843,901	31,009	24,653	19,682
2025	71,604	1,915,506	25,335	19,776	15,506
2026	63,917	1,979,423	20,940	16,048	12,358
Total	1,979,423		1,159,843	1,028,302	915,771

ANNEX 3

UNCONVENTIONAL GAS RESOURCES

Unconventional Gas Resources

Unconventional shale gas and shale oil resources are being discovered in many basins around the world. Initially, unconventional shale was exploited in North America and then it spread to other continents. Interest in the shale source rocks in South America began in late 2010 in the Neuquén Basin with the Vaca Muerta Shale. Other shale source rocks are being tested in the Neuquén Basin and other basins in Argentina are being considered. As of this writing, interest in the shale source rocks in the Tarija Basin has been discussed as the next unconventional play in Argentina.

The conventional prospect at Martinez del Tineo in the Lomas de Olmedo Basin used analogies from the Tarija Basin. For an unconventional shale resource play at Martinez del Tineo, again, attention can be directed to the Tarija Basin for analogies. But in the Tarija Basin the unconventional plays are still in the minds of geologists but have not been tested with the drill bit and hydraulic fracturing techniques. However, to properly investigate the potential of hydrocarbon discoveries at Martinez del Tineo, unconventional plays should be considered.

The Paleozoic shale source rock at Martinez del Tineo with unconventional potential is the Copo Fm (Chancipunco Fm in some areas) of Silurian age, with a thickness of 550 – 600 m and Total Organic Carbon (TOC) values of 1%. The Copo Fm is equivalent to the Kirusillas Fm in the Tarija Basin. In the Tarija Basin there are two Paleozoic source rocks, the Kirusillas Fm and the Los Monos Fm. In the Martinez del Tineo area the Los Monos was truncated by the Upper Devonian Unconformity which has truncated more of the Devonian section than in the Tarija Basin. The uplifted Paleozoic section at Martinez del Tineo is the highest part of the Paleozoic section in the Puesto Guardian Block. That has placed the Copo Fm at a shallower depth which is more conducive to shale gas development.

The Vaca Muerta Shale in central Argentina may be the closest unconventional shale gas play to compare. However, the Vaca Muerta Fm is Jurassic to Early Cretaceous in age with TOC values 1 to 8%. The Copo Fm is Silurian age with TOC values near 1%. Some better comparisons might be found in North America.

The Utica Shale is a good analogy because it is of Ordovician age with TOC values of 0.5 to 2.5%, two factors similar to the Copo Fm. The Utica Shale lies beneath the Marcellus Shale, and is too deep to develop economically where the Marcellus is active. The Utica Shale is found at shallower depths in eastern Ohio and up into Canada.

Only 16 producing wells have been drilled in the Utica as of September 2011 so there is not much data available. It is drawing attention because it is high in natural gas liquids. The Ohio Department of Natural Resources estimates a recoverable Utica Shale potential between 1.5 and 5.5 billion barrels of oil and between 3.8 and 15.7 trillion cubic feet of natural gas. Chesapeake has reported rates of 3 to 5 MMcfg/d plus 1000 barrels of condensate. The Utica is as thick as 500ft in some areas, but activity is focused in eastern Ohio where it ranges from 100 to 350ft thick. There is still comparatively little known about the Utica Shale.

Two other Shale gas plays in North America that are analogous to the Copo Fm are the Marcellus Shale and the Woodford Shale. Below are some comparative statistics for the Marcellus Shale and Woodford Shale, both of Devonian age.

		TOC	Thickness	IP	EUR/well	Additional Data
Marcellus	1	3-12%	50- 200 ft	5 mmcf/d	NA	40-160ac sp/2,500' lateral
	2	4-6%	50-300 ft	3-8 mmcf/d	NA	
	3	6-12%	50-300 ft	NA	3.5 - 4 bcf	
Woodford	1	1-14	120-220	4.5	NA	640ac sp/2,500-5,000' lateral
	2	4-10+	90-300	2-10	NA	

(1) GCA Shale Gas Workshop Sep 2011
(2) Pioneer Resources
(3) Alberto Messatesta at XVIII Congreso Geológico Argentino - May 2011

Marcellus Shale production has been mostly dry gas wells with little or no condensate reported. Woodford Shale production has quoted condensate rates from 1 to 370 barrels per day.

Notice that both of these source rock shales are much thinner than the Copo Fm. The Copo Fm is about 6 or 7 times thicker than the Marcellus Shale or Woodford Shale. But the Copo Fm has lower TOC values. The Copo Fm shale, with such a large thickness, may be developed with more vertical wells than horizontals.

The area for the shale gas play at Martinez del Tineo will be limited by the depth of the Copo Fm in the north, NW, and east. It will not, however, be limited in the south by the large high angle fault which limits the conventional prospect area at Martinez del Tineo. The shale itself traps the gas and faulting is not needed for trap or seal. As the wells are drilled deeper on the flanks of the structure, the drilling costs will increase to the point that the wells become uneconomic. The map of the Top of the Paleozoic shows a steep NW flank which begins around the -2550 mss contour. The interval from the Top of the Paleozoic through some of the Rincon Shale (depending on the Devonian Unconformity), through the Cabure Fm, and through the Copo Fm is another 1200 to 1400 m. At that depth wells are not likely to be economic for shale gas development in the Copo Fm. Using the Top of Paleozoic map, the area inside the -2500 mss contour and within the exploitation border (south limit) of Martinez del Tineo measures 55 km^2 (21.2 $miles^2$)

GCA considered the low TOC content (1%) and the large thickness (550-600 m) of the Copo Fm as offsetting factors, so the range of IP's and EUR from the above statistics of both the Marcellus and the Woodford may apply. The range of IP's is 3-8 MMcfg/d, and the range of EUR per well is about 3-8 Bcf. Below are the ranges of recoverable gas from 160 acre spacing and 80 acre spacing.

Condensate production varies in Shale gas plays depending on the depth of burial of the source rock. It would be difficult to predict what type of condensate yields to expect from the Copo Fm. Most likely there will be "sweet spots" where the gas yields good condensate rates and other areas of low yields or even dry gas production.

	Area + wells per (sq mi)	Number of Wells	Rec/Well (Bcf)	Range (Bcf)
Low Estimate	16sqmi 4/sqmi	64	3 to 8	192 - 512
	16sqmi 8/sqmi	128	3 to 8	384 - 1,024
Best Estimate	20sqmi 4/sqmi	80	3 to 8	240 - 640
	20sqmi 8/sqmi	160	3 to 8	480 - 1,280
High Estimate	24sqmi 4/sqmi	96	3 to 8	288 - 768
	24sqmi 8/sqmi	192	3 to 8	570 - 1,536

The range of expected recoverable gas volumes is understandably large because there are too many factors to consider. The above estimates are very general, but the notable fact is that shale gas potential exists in the Martinez del Tineo area.

There also exists the shale oil potential in the shallow Yacoraite Fm of Cretaceous age. The Yacoraite Fm produced in the Martinez del Tineo oil field and the shales of the Olmedo Fm above the Yacoraite and the Las Avispas shales within the Yacoraite are source rocks. Although these are thin shales they are at shallow depth with oil potential.

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ANNEX 4

Petroleum Resources Management System

Definitions and Guidelines

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System
Definitions and Guidelines ([1])

March 2007

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 definition 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.

The SPE PRMS 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.,

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 SPE PRMS 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.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

RESERVES

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: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided 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 development and production status. 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.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

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. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

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. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate 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), 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 may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain**.** Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within

the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

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

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

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

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,
(2) wells which were shut-in for market conditions or pipeline connections, or
(3) wells not capable of production for mechanical reasons

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,
(2) from deepening existing wells to a different (but known) reservoir,
(3) from infill wells that will increase recovery, or
(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
(a) recomplete an existing well or
(b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable 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.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

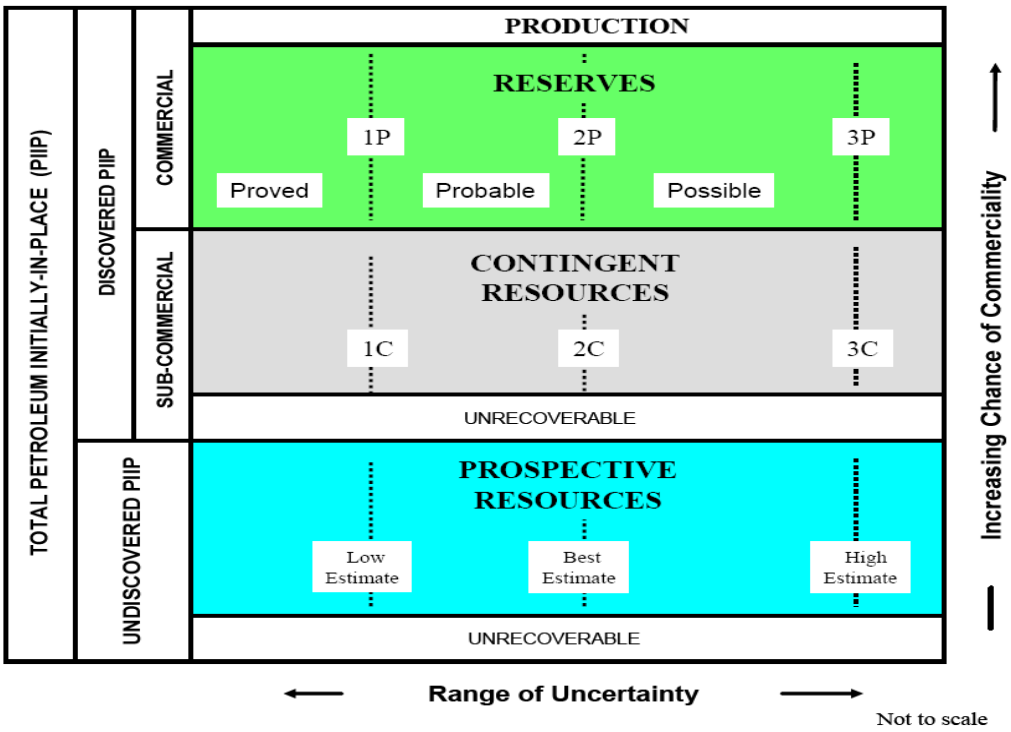
Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Gaffney, Cline & Associates

RESOURCES CLASSIFICATION



PROJECT MATURITY