Fw: Excelaron CUP appeal hearing
John McKenzie to: Annette Ramirez 05/10/2012 08:09 AM

Hi Annette,

Please post with the other Excelaron Hearing (5/15) correspondence. Thanks!

John McKenzie
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----- Forwarded by John McKenzie/Planning/COSLO on 05/10/2012 08:08 AM -----

From:	Ron Skinner <RON@HUASNAVALLEYFARM.COM>
To:	John Nall <jnall@co.slo.ca.us>
Cc:	John McKenzie <jdmckenzie@co.slo.ca.us>, Ellen Carroll <elcarroll@co.slo.ca.us>, wmcdonald@co.slo.ca.us
Date:	05/10/2012 08:05 AM
Subject:	Excelaron CUP appeal hearing

John,
Attached is a letter submitted on behalf of the Huasna Foundation with 2 attachments. An earlier draft of this letter was submitted to the Board of Supervisors spearately:

Cover letter to county.pdf

Huasna Foundation Analysis.pdf GCA Report 10-27-10.pdf

Ron Skinner
ron@huasnavalleyfarm.com
(805) 473-3827

To: Mr. John Nall, SLO County Planning Department (by email and hand-delivered)
May 10, 2012

I submit this letter on behalf of the Huasna Foundation as evidence in the record for the Board of Supervisors hearing regarding the appeal of the Excelaron (Mankins) CUP. I have submitted an earlier draft of this letter to each supervisor individually.

I own and operate a farm in the Huasna Valley, own mineral rights in the designated Huasna Oilfield, and am President of the Huasna Foundation, a non-profit organized on behalf of residents in the Huasna Area. I hold a Bachelor's degree in Engineering Physics from Cornell University and a Master's degree in Physics from UC Irvine. I have worked at Sandia National Laboratory and have published several peer-reviewed scientific publications. For the past 15 years I have farmed and raised a family in the Huasna Valley. During the last 5 of those years I have thoroughly investigated the prospects for oil development in the Huasna Area and have concluded that the adverse impacts from such oil development far outweigh the very minimal potential benefits.

At the March 8, 2012 Planning Commission hearing, Commissioner Jim Irving asked the question, "is there economically recoverable oil in Huasna?" In response, Art Halleran, of Excelaron, cited a study by a Texas-based engineering firm, Gaffney, Cline, and Associates (GCA). Attached to this letter, is my analysis of the GCA report and Mr. Halleran's claims. This analysis relies on simple geometric arguments using the numbers presented in the GCA report and Excelaron EIR. The important conclusions of this analysis are as follows:

1. **Oil production estimates and benefits of Excelaron's 12-well project have been overstated by Excelaron by at least a factor of ten.**
2. **Excelaron's 12-well project represents only one phase in Excelaron's undisclosed strategy to develop a much larger field with far greater adverse environmental impacts.**
3. **Excelaron's two-phase field development scheme prevents the true environmental impacts from being identified and evaluated.**

On March 8, 2012, the San Luis Obispo County Planning Commission properly concluded that Excelaron's 12-well project is not compatible with the SLO County General Plan and not in keeping with the rural character of the Huasna Valley. If the Board of Supervisors takes action to reverse the Planning Commission's decision, it will establish an entitlement for oil processing and transportation volumes that contemplate, and would accommodate, future project expansion not considered by the EIR. In addition, impacts from the 12 well, first-phase project will alter the baseline for environmental analysis of future expansion. This expansion, as envisioned by Excelaron and delineated in the GCA report, is a field encompassing 600+ acres, with the facilities, extraction methods and wells necessary to produce 1,000 barrels of oil per day. Such expansion would have substantially greater impacts than Excelaron's currently proposed 12-well project.

Sincerely,
Ron Skinner, President
Huasna Foundation

cc. John McKenzie, Ellen Carrol, Whitney McDonald

EXCELARON CONDITIONAL USE PERMIT (DRC2009-00002)

Huasna Foundation Analysis of Gaffney, Cline and Associates Report

DISCUSSION

United Hunter & Oil Gas Corporation owns a 65% interest in Excelaron. Arthur Halleran is CEO of United Hunter and represents Excelaron. As CEO of United Hunter, Mr. Halleran solicited Gaffney, Cline & Associates (GCA) to evaluate United Hunter's resources in the Huasna field. What follows is a discussion of field reserves as identified in the GCA report as it relates to Excelaron's proposed project. For ease of discussion, "Excelaron" will frequently be used in place of United Hunter since Mr. Halleran represents Excelaron in obtaining its Conditional Use Permit.

A review of the GCA report identifies critical facts and information that are fundamental to understanding the true scope and impacts of the project. Specifically:

1. Oil production estimates and benefits of Excelaron's 160 acre, 12-well project have been overstated by Excelaron by at least a factor of ten.
2. Excelaron's 12-well project represents only one phase in Excelaron's undisclosed strategy to develop a much larger field with far greater adverse environmental impacts.
3. Excelaron's two-phase field development scheme prevents the true environmental impacts from being identified and evaluated.

1. Oil Production Estimates and Benefits of Excelaron's 160-Acre, 12-Well Project Have Been Overstated by Excelaron

In order to evaluate United Hunter's resources, GCA provided an estimate of the "Contingent Resources" (oil) in the Huasna field. First, it is important to note that GCA classified the resources as "Contingent Resources," defined as "those quantities of petroleum estimated, as of a given date, to be *potentially* recoverable from known accumulations using established technology or technology under development, but which are ***not* currently considered to be *commercially* recoverable** due to one or more contingencies." GCA cited five main contingencies, the first of which is "Establishing production in commercial quantities *using primary or secondary methods*."

Specifically, GCA estimates recoverable oil for the life of the project to range from 900,000 to 4.1 million barrels of oil, with a **best estimate of 2.1 million** barrels of oil. This **estimate is based on 60 wells** not 12. In sharp contrast, **Excelaron asserted at the Planning Commission hearing that it will recover 6 million** barrels of oil over the life of the project with **12 wells.** The GCA Analysis proves that to be impossible.

This assertion is based on a transcript of a video recording taken of the March 8, 2012, San Luis Obispo County Planning Commission Hearing, a portion of which is provided below:

<u>Commissioner Jim Irving</u>:

"...is there recoverable oil, economically recoverable oil, here?"

Dr. Arthur Halleran:

> "…and I had this field studied, this field by the way by Gaffney Cline report which is very credible engineering firm in Houston, Texas, who have a lot of expertise on Monterey um give it a most likely case of 100 million barrels in place. So the pool extends from pad 2, pad 1, all under, underneath it…Injecting hot water you can recover uh, like I say, 5, 4, 5, 6% depending upon the spacing of the wells. So 6% of the a 100 million barrels is **6 million**."

Notably, the GCA report is cited to shareholders, media and potential investors, yet has not been provided to county staff or representatives in support of Excelaron's project or its assertions to the Planning Commission.

A closer review of the GCA report also reveals that an estimate of 2.1 million barrels of oil over the life of a Huasna field project is overly optimistic. This is because the estimate is based on analog data from dissimilar oilfields and relies on the assumption that oil is evenly distributed throughout the Monterey formation, an assumption not supported by historical well log data from the Huasna field[1].

GCA estimates recovery of 24 barrels of oil per acre-foot volume of Monterey formation. However, the project description in the EIR states production volume will be limited by the proposed hot water injection method, which is only effective to a radius of 150 feet from the wellbore and to a depth of 2,000 feet below ground surface. Using GCA's optimistic recovery estimate, the *upper limit* of production for 12 vertical wells using hot water injection would be **700,661 barrels of oil over the life of the project**. This is a far cry from the 6 million barrels of oil publicly proclaimed by Mr. Halleran to the Planning Commissioners on March 8, 2012, and represents ***only 10.7 barrels of oil per day*** for each of the 12 wells over the life of the project[2].

The average production of heavy oil from fractured Monterey shale formation in eight Santa Barbara and Monterey County oilfields was 6.9 barrels of oil per day per well, independently demonstrating that the GCA numbers appear inflated[3].

Based on the more realistic, but still "best case" estimate of 700,661 barrels of oil over the 20-year life of the project, **oil production and tax revenue will be *less than one-tenth* of that purported by Excelaron**[4].

2. The Conditional Use Permit Represents Only One Phase in Excelaron's Strategy to Develop a Much Larger Field with Far Greater Adverse Environmental Impacts

Excelaron has a strategy to expand the field from 160 acres and 12 wells to one that encompasses all properties "for which United Hunter holds variable interests and has verbal agreements on the remaining interest with the other mineral rights owners in which they concur to allow leasing of those interest once the first phase of development is permitted by the regulatory authorities." Excelaron currently holds oil and gas leases on 1,057 acres, with an unknown number of verbal agreements for additional acres[5].

Excelaron's strategy is to develop this field in two phases. The Conditional Use Permit, properly rejected by the Planning Commission, to develop 160 acres and 12 wells is only the first phase. These facts appear nowhere in the lengthy record presented by Excelaron and reflect a material misrepresentation of the scope of the project by the company and its representatives.

3. Excelaron's Two-Phase Field Development Scheme Prevents the True Adverse Environmental Impacts From Being Identified and Evaluated

Excelaron's field development and expansion strategy is outlined in detail in the GCA report. The second contingency in the list of GCA's five main contingencies to recovering commercial quantities of oil, is "securing the necessary permits from the regulatory authorities, which requires environmental impact compliance and approval." Based on the environmental issues Based on the environmental issues involved, Excelaron made the assessment that development of the field would only **"be feasible *provided* that it is approached in *stages*."** Therefore, Excelaron made the calculation to break development of the field into two stages, 160 acres in the first stage and the remainder of the field in the second stage.

The method of extraction was also strategically selected. According to the report, the hot water method of extraction was chosen because it "maximizes the volume of injected thermal fluid in relation to the heat generation facilities," thus triggering fewer environmental compliance criteria that would have to be met ***in order to get a permit***. As the GCA report candidly admits, it would also allow an approach that is "***perceived*** to adopt a maximum recovery by the least possible surface impact principle."

Yet, as the report goes on to demonstrate, full production will rely not only on development of the entire Huasna field of up to 600 acres and 60 wells, it will also require an increase in the temperature of the injection water/steam and horizontal drilling, none of which are included in the Conditional Use Permit or addressed in the EIR.

CONCLUSION

The true significant adverse impacts to the Huasna Valley and the environment of producing commercial quantities of oil have not been identified or evaluated, especially as they relate to field size, number of wells, steam injection, heat generation facilities, and horizontal drilling.

The Planning Commission made the correct decision to uphold the recommendation of county staff to deny this project. The Board of Supervisors should affirm that decision. If it acts otherwise, it will establish an entitlement for oil processing and transportation volumes that contemplate, and would accommodate future expansion not considered by the EIR. In addition, impacts from the 12 well, first phase project will alter the baseline for environmental analysis of future expansion. This expansion, as envisioned by Excelaron and delineated in the GCA report, is a field encompassing 600+ acres and 60 wells, with the facilities, extraction methods and wells necessary to produce 1,000 barrels of oil per day.

Impacts for Excelaron's project are currently known only for 12 vertical wells, using hot water extraction, methods that could produce a maximum of only 96 barrels of oil per day.

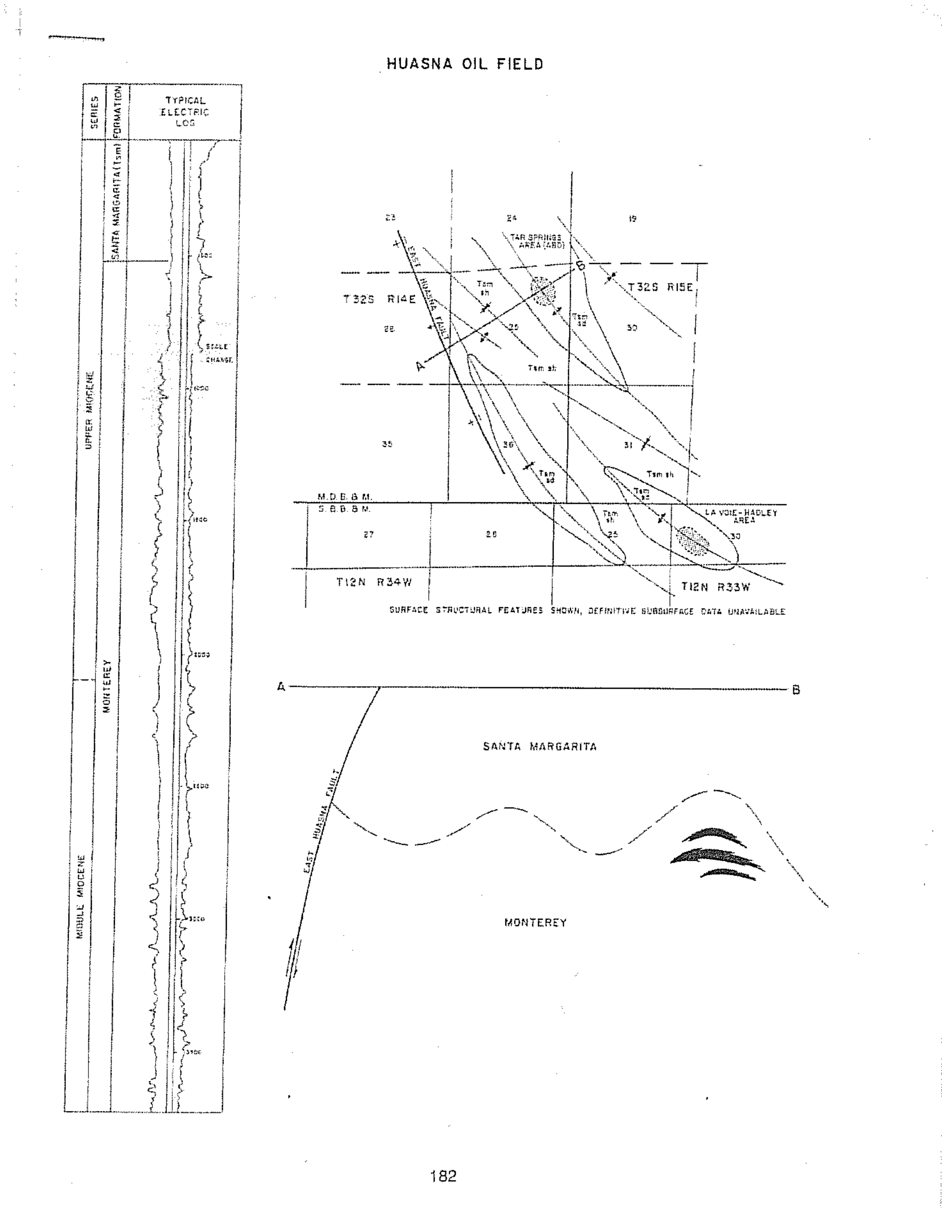
On March 8, 2012, the San Luis Obispo County Planning Commission properly concluded that a 160-acre, 12-well project is not compatible with the SLO County General Plan and not in keeping with the rural character of the Huasna Valley. This conclusion applies 10-fold to Excelaron's ultimate project goal as described in the GCA report.

Please uphold the recommendation of SLO County Planning staff and the decision of the Planning Commission and deny Excelaron's appeal of the Planning Commission's decision.

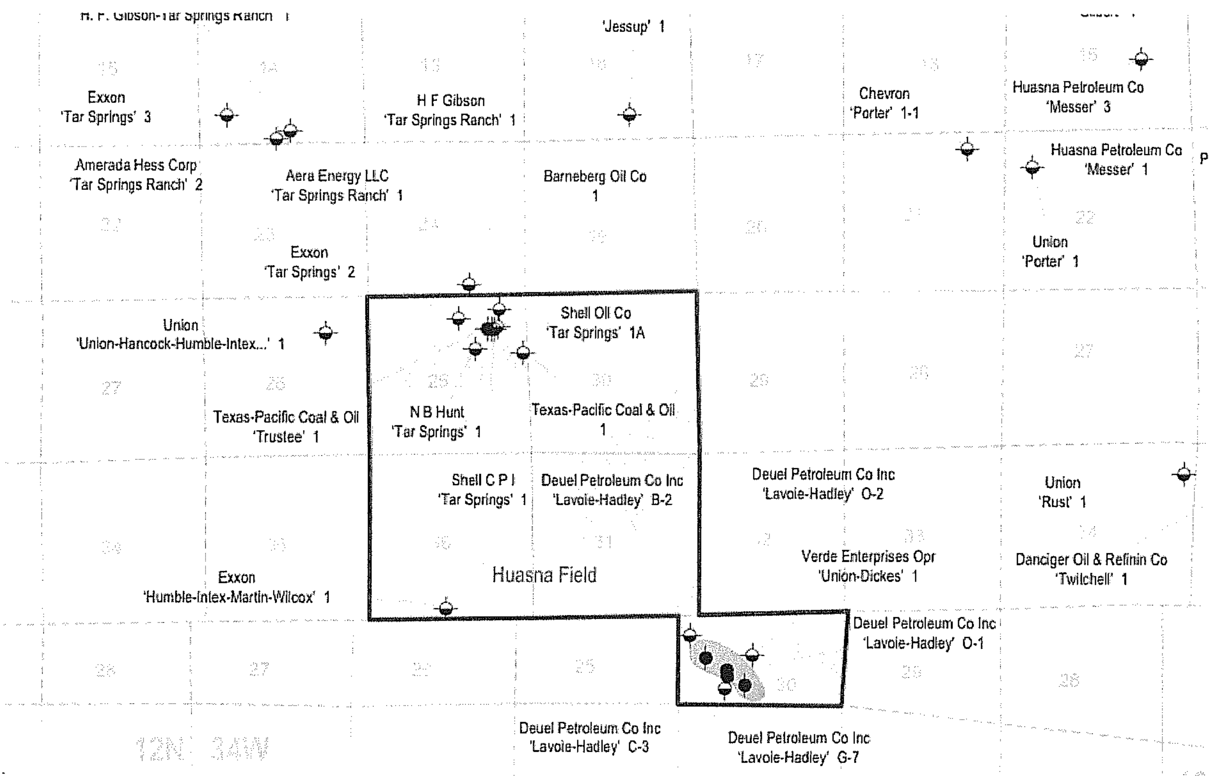
Notes

[1] "Huasna is not an analog of Santa Maria. It is farther east (closer to the San Andreas), has already been subject to higher tectonic forces to heat and squeeze out residual hydrocarbons, and may have been leaking oil for a longer interval." (Private communication with Dr. Robert Curry, April 27, 2012)

Division of Oil, Gas, and Geothermal Resources (DOGGR) records indicate oil-bearing intervals in two small anticlinal folds in the Monterey formation. DOGGR Field records list the extent of reserves at 10 and 40 acres – not 160, 400, or 600 acres as claimed in the GCA report.



There have been 16 wells drilled within the designated "Huasna Oilfield." Eleven of those wells failed to produce any oil. Multiple dry wells were drilled surrounding the producing wells on each anticline structure, delimiting the small oil bearing regions shown on the above DOGGR field map. There exists no evidence in the DOGGR files to suggest that oil is distributed uniformly through a volume of the Monterey formation extending up to 600 acres in surface area and 2,000 feet deep. It is more likely that what little oil was in the Huasna field was extracted during the 1960's. Well logs from the LaVoie-Hadley wells show production of only a few barrels of oil during a 30-day period when they were tested in the 1980's.



On-line DOGGR oil well map. Oil wells are represented by circles: Half-circles are dry holes, full circles produced oil. The red boundary defines the designated Huasna Oilfield, which simply outlines map sections connecting the two productive anticlinal regions. According to DOGGR staff, the designation only signifies a demonstrated resource and carries no legal significance.

[2] Excelaron project production calculation:

Assumptions:

- Recoverable oil volume = 24 barrels per acre-foot volume of Monterey Formation[a].
- Volume of Monterey formation = cylinder of radius 150 feet and height 1,500 feet[b].
- Oil is evenly distributed throughout this volume of Monterey formation[c].

$$\text{Limit of recoverable oil per well} = (24\ \text{barrels/acre-ft})\cdot\pi\cdot(150\text{ft})^2\cdot(1{,}500\text{ft}) = 58{,}388\ \text{barrels}$$

Before analyzing the validity of this number, consider what this limit means in terms of the overall productivity of Excelaron's proposed 12 well project. Twelve wells, producing at the maximum limit of the proposed hot water method would produce 700,656 barrels of oil over the 20-year lifetime of the project, which yields the following production figures:

Ideal-Case Scenario Upper Limit of Production for the Excelaron Project

35,033 Barrels of oil per year
96 Barrels of oil per day[d]
10.7 Barrels of oil per well per day[e]

Does the 58,388 barrels of oil per well ideal-case scenario upper limit of recoverable oil using hot water injection make sense? Once again, this calculation assumes that oil is evenly distributed throughout the volume of Monterey formation, an assumption that is not supported by historical well log evidence. In addition, the total production of the historical wells at Excelaron's proposed project site over a three-year period in the 1960's using both acid and cyclic steam extraction methods is substantially less than would be expected for a limit of recoverable oil of 58,388 barrels per well:

Well Number	Date Drilled	Max Depth	Total Production with Acid & Cyclic Steam (in barrels)
SD-1	1939	5,591	0
UD-1	1958	7,705	0
LVH-01	1965	2,986	3,605
LVH-02	1965	1,340	15,072
LVH-B3	1966	828	0
LVH-C3	1966	1,086	242
LVH-G7	1966	1,134	1,134

The GCA report states, "Fractured shale formations like the Monterey have been shown to recover 30-40% of the oil in place with continuous steam injection and <u>20-30% with cyclic injection</u>. Using thermal calculations, it is estimated that with hot water the expected recoveries will be in the 4-6% range."

With cyclic steam stimulation the best cumulative total production out of seven historic wells drilled at Excelaron's project site is 20,053 barrels. Had the operator used cyclic hot water injection (5% recovery) instead of cyclic steam (25% recovery) they would have extracted a total of only 4,011 barrels and an average of 573 barrels per well. It appears that the upper limit of 58,388 barrels of recoverable oil using hot water extraction does not accurately reflect the reality.

of the field. In addition, since three out of seven wells drilled on the project site produced no oil, the assumption of uniform distribution of recoverable oil throughout the volume of Monterey Formation appears to be an invalid assumption.

Notes for Excelaron Project Production Calculation

[a] From GCA Report.
[b] Assumes vertical wells and dimensions specified in the EIR sections 2.2.1 and 2.2.3.
[c] This assumption is not supported by historical well log evidence. Thus this calculated estimate of recoverable oil represents only an ideal-case scenario upper limit for the hot water extraction method and does not reflect the likely amount of recoverable oil.
[d] This assumes the facility operates 365 days per year and does not take into account required facility shutdown during times of flooding of the Porter Ranch Road.
[e] This assumes a 75% operational cycle for the wells – the average operational cycle for oilfields with less than 50 wells in California is 37.2% (see DOGGR online production and injection data at http://www.conservation.ca.gov/dog/Pages/Index.aspx).

[3] See DOGGR online production and injection data for the following fields (Cat Canyon, Santa Maria, Barham Ranch, Careaga Canyon, Lompoc, Orcutt, McCool Ranch, and Casmalia) at http://www.conservation.ca.gov/dog/Pages/Index.aspx.

2011 OIL PRODUCTION RECORDS

Extraction of Heavy Oil from Monterey Shale in California Oilfields

County	Field Name	# of Drilled Wells	# of Active Wells	Average Daily Oil Production per well (Barrels)
Monterey	McCool Ranch	29	20	9.6
Santa Barbara	Lompoc	181	156	19.5
Santa Barbara	Orcutt	840	495	14.1
Santa Barbara	Casmalia	351	267	4.7
Santa Barbara	Santa Maria	807	635	8.5
Santa Barbara	Cat Canyon	2,925	1,757	5.1
Santa Barbara	Careaga Canyon	19	14	12.2
Santa Barbara	Barham Ranch	36	33	10.1

Average Daily Oil Production for all wells = 6.9 barrels per well per day

(Note that the number of wells drilled always exceeds the number of active wells.)

[4] Excelaron's stated annual production is 365,000 barrels per year, which is ten times higher than the ideal-case scenario upper limit of production for the hot water method of 35,033 barrels per year.

[5] Excelaron LLC holds Oil and Gas Leases recorded with the County of San Luis Obispo on the following parcels totaling 1,057 surface acres: 048-151-001, 085-231-002, 048-141-001, 085-231-008, 085-012-039, 085-271-004.

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GDV/bgh/C1893.00/gcah.237.10

October 27, 2010

Mr. Arthur Halleran - CEO
United Hunter Oil & Gas Corporation
700 - 4th Ave SW - Suite 310
Calgary, Alberta
Canada, T2P 3J4

E-mail: arthur.halleran@yahoo.ca

Huasna Field Resource Evaluation

Dear Mr. Halleran:

Gaffney, Cline & Associates (GCA) presents this evaluation in response to the inquiry by United Hunter Oil & Gas Corporation (United Hunter) to provide an estimate of United Hunter's Resources in the Huasna field, San Luis Obispo County in California. These resources are classified in accordance with the reserve and resource definitions set out in the Canadian Oil and Gas Evaluation Handbook (COGEH), Second Edition released September 1, 2007, which also forms part of Canadian National Instrument 51-101.

BACKGROUND

The Huasna field is the most prominent accumulation in the Huasna basin in San Luis Obispo County, California. Huasna is a fault related anticline structure that has produced heavy oil from the Monterey Formation, which outcrops also to the surface. The oil column has been reported from depths of about 270 feet to 3,000 feet and consists of fractured shale in the Monterey Formation with 8.5° to 13° API oil. Seven wells were drilled in the field between the years 1937 and 1965. The first well drilled in 1937 tested extra heavy oil. Drilling and production resumed in the late 1950's reaching peak production in 1966. The field was then shut in with a cumulative production of only about 23,000 bbl of oil. The field has basically been idle since, with the exception of a brief production campaign in the mid 80's. Currently all wells are abandoned.

RESERVE AND RESOURCE ESTIMATE

GCA has reviewed all data provided by United Hunter and is of the opinion that any remaining recoverable hydrocarbon volumes should be classified as Contingent Resources under COGEH. The main contingencies are:

- Establishing production in commercial quantities using primary or secondary methods;
- Securing the necessary permits to develop the field;
- Securing funds and services in order to drill and complete new wells;
- Constructing processing and transportation facilities; and
- Securing sales contracts for the oil that can be produced.

ITEM #20
MEETING DATE: May 15, 2012
PRESENTED BY: Ron Skinner
RECEIVED PRIOR TO MEETING
POSTED ON: May 10, 2012

There is no certainty that it will be commercially viable to produce any portion of the resources.

In estimating the Contingent Resource volumes, GCA has made volumetric estimates of the in-place volumes using the existing petrophysical and geological information and using appropriate analogs in absence of direct inferences. GCA has used simple thermal balance analytical models that provide a basis for an incremental oil recovery that may result from the hot water stimulation process that United Hunter plans to test and implement. At this stage there is limited information available from United Hunter on the Huasna field as the past development offers little in terms of assessing reservoir quality and long term productivity. It is expected that once the development starts, the new wells will offer modern logs, production tests and cores that will help in reducing the recoverable volume uncertainty. The main uncertainties in estimating the Contingent Resources in the Huasna field are:

- **Reservoir properties.** The available information from existing wells dates to the 1960's and does not offer a reliable means to estimate pay intervals, rock porosity and fluid saturations. The first new development wells will offer better log and core suites that would eventually allow a better estimate of the in place volumes. Such data will also be required to estimate the pay zones within the Monterey that will be targeted for an efficient development.
- **Fluid properties.** Although the Huasna field has produced a mix of bitumen (8.5^{o} API) and heavy oil (13^{o} API) and some fluid samples were taken and analyzed lately, there is variation on how the oil properties are distributed within the reservoir. The new development wells might be able to provide better data that could allow a better assessment of that oil distribution.
- **Oil recovery.** The primary recovery will depend on the rock and fluid characteristics and the presence or not of a water drive. The magnitude and orientation of natural fractures which contribute greatly to the productivity of Monterey under primary and secondary drives might be determined by the new development wells if the appropriate suite of logs and surveillance are carried out. The applicability of hot water stimulation was estimated in broad terms by analytical methods, but it could be determined with higher certainty by field trials as the development progresses.

Given the uncertainties involved in the estimation of the in-place volumes and the expected recoveries, GCA has adopted a probabilistic approach which is based on determining meaningful ranges of expected values as they are used in that assessment. The ranges of the input variables used in the probabilistic estimation are presented in the following table:

Table 1: Probabilistic Input

	Low	Most Likely	High
Area, acres	**160**	**400**	**600**
Net Thickness, feet	**200**	**500**	**960**
Porosity	**8%**	**12%**	**18%**
Oil Saturation	**45%**	**50%**	**60%**
Bo (rbbl/STB)[1]	**1.01**	**1.02**	**1.05**
Recovery Factor	**4.2%**	**5.2%**	**6.0%**

In the probabilistic estimate, all input variables are independent of one another except the net thickness, which is perceived to relate to the area in that the largest net thickness values are expected to be found in the smallest development area. That development area contains the existing abandoned wells and is at the structurally highest position. As there are still uncertainties regarding the net pay thickness that correlation is perceived to be relatively weak with a -0.5 coefficient. The following table summarizes the probabilistic estimation results:

Table 2: Probabilistic Output

	P90	P50	P10
Oil in Place, MMBbl	**44.6**	**96.0**	**174.0**
Recoverable, MMBbl	**2.2**	**4.9**	**9.0**

The estimated Contingent Resources are reported here for two separate areas. The first covers the 160 acres that contain the existing wells and is the target of the first phase of development that United Hunter plans to undertake. The second represents the remainder of the field area for which United Hunter holds variable interests and has verbal agreements on the remaining interests with the other mineral rights owners in which they concur to allow leasing of those interests once the first phase of development is permitted by the regulatory authorities. United Hunter's net interest is based on its 65% working interest in the 160 acre parcel and a 12% royalty deduction. The working and royalty interests are presumed to be the same on the remaining acreage as advised by United Hunter. The volumes represent crude oil in Millions of barrels (MMBbl) reported at standard conditions[2].

Table 3: Contingent Resources as of July 31, 2010,
Net to United Hunter's Interest. Crude Oil in MMBbl

	1C	2C	3C
160 acres owned	**0.5**	**1.2**	**2.3**
Remainder	**0.7**	**1.5**	**2.8**

[1] rbbl/STB is defined as reservoir barrels per stock tank barrels of oil
[2] Standard conditions at 14.7 psia pressure and 60 °F temperature.

In order to assess the oil in place and potential recovery within the 160 acre parcel, the following probabilistic input and output is shown in tables 4 and 5:

Table 4: Probabilistic Input, 160 acres

	Low	Most Likely	High
Area, acres	160	160	160
Net Thickness, feet	200	500	960
Porosity	8%	12%	18%
Oil Saturation	45%	50%	60%
Bo (rbbl/STBO)	1.01	1.02	1.05
Recovery Factor	4.2%	5.2%	6.0%

Table 5: Probabilistic Output, 160 acres

	P90	P50	P10
Oil in Place, MMBbl	18.2	42.2	78.5
Recoverable, MMBbl	0.9	2.1	4.1

This assessment will likely become more definitive once new information is gathered from a new well drilling campaign, which should result in acquiring appropriate modern well logs, cores and successful production tests. At this point, lack of such information is reflected in the wide variation between the low and the high estimates as they are presented. That gap is expected to narrow as development advances and new data become available.

The reported resources are based on estimates and other information provided by United Hunter to GCA through September 2010, and included such tests, procedures and adjustments as were considered necessary. All questions that arose during the course of the evaluation were resolved to our satisfaction.

It is GCA's opinion that the resource estimates of total remaining recoverable hydrocarbon liquid volumes as of July 31, 2010 are, in the aggregate, reasonable and have been prepared in accordance with the reserve and resource definitions set out in the Canadian Oil and Gas Evaluation Handbook COGEH, Second Edition released September 1, 2007, which also forms part of Canadian National Instrument 51-101.

This assessment has been conducted within the context of GCA's understanding of United Hunter's petroleum property rights as represented by United Hunter'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 evaluators. The firm's officers and employees have no direct or indirect interest holding(s) in the property unit evaluated. 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 United Hunter and should not be used for purposes other than those for which it is intended.

Yours sincerely,

GAFFNEY, CLINE & ASSOCIATES, INC.

George Vassilellis

Attachments
Appendices: I: Technical Discussion
II: COGEH Definitions

APPENDICES

APPENDIX I:

Technical Discussion

Technical Discussion

GEOLOGY

The Santa Maria Basin Province includes the area from the Santa Lucia and the San Rafael Mountains on the southwestern flank of the southern Coast Ranges to the northern Santa Ynez Mountains in the Western Transverse Ranges. It includes northern Santa Barbara County, western San Luis Obispo County and southwestern Monterey County.

The Santa Maria Basin occupies the central part of the province. Large folds in the central part of the basin (Casmalia-Orcutt Anticline, San Antonio-Los Alamos Valley Syncline, Lompoc-Purisima Anticline and Santa Rita Syncline) are associated with north-verging reverse faults of the Pliocene and Quaternary age. The thickness of the deformed basin fill approaches 15,000 feet in growth synclines in the footwalls of the reverse fault system. Oil accumulations are mostly trapped in the Miocene Monterey Formation anticlines, in fractured Monterey truncated by an unconformity along the northeastern flank of the basin, or in Pliocene sandstone lenses above an unconformity on the northeastern basin margin.

The Huasna basin is located northeast of the Santa Maria Basin. It lies between the West Huasna fault on the west and the East Huasna fault zone on the east. The basin is a synclinal depocenter filled with Pliocene and Miocene aged section similar to that of the Santa Maria Basin, but it contains a greater amount of sandstones. Synclinal and anticlinal structures are oriented northwest-southeast within the Huasna basin. It is described as being located in the Santa Maria Basin Margin Play areas (Tennyson, 1995). Oil accumulations in the Monterey and tar sands are present in smaller volumes in the Huasna Basin than those in the prolific Santa Maria Basin (Tennyson, 1995).

In the Huasna basin, the Monterey total thickness is usually about 2000 feet, although it ranges from 0 to 4000 feet. The Monterey net thickness ranges between 200 and 1000 feet and net pay thickness, although somewhat uncertain, probably ranges up to a few hundred feet (Tennyson, 1995). Net pay thicknesses of 200 to 400 feet and 290 to 500 feet were reported in the offshore Point Arguello field and onshore Jesus Maria field, respectively (Tennyson, 1995). Based on the California Department of Conservation DOGGR (Division of Oil, Gas and Geothermal Resources) oil field records for the Santa Maria Field-Main Area and Orcutt field, the net thickness was reported at 950 to 960 feet.

Porosity in the Monterey formation is reported to range from 6 to 33 percent and permeability is probably in the range of 10 to 15 millidarcies (mD) (Tennyson, 1995).

Monterey Formation

The Monterey rocks were originally deposited by a hemipelagic “rain” of fine-grained (silt- and mud-sized particles) in most of the Neogene (Pliocene and Miocene age) marine basins in California. The predominant original constituent of the Monterey formation is biogenous-silica (diatom frustules) which is highly soluble and geochemically unstable, and this leads to patterns of silica-phase diagenesis that affect reservoir characteristics. Other original components include biogenous calcite (coccoliths and foraminifera) and fine grained terrigenous detritus (illite-smectite clay, feldspar and quartz). In some rocks, organic matter is a major primary constituent. In some areas, interbedded clastic sediments deposited by turbidity currents are locally important in the Monterey (Isaacs, 1981, 1984).

There are three mineralogical phases of silica-diagenetic observed the Monterey formation: 1) opal-A, a hydrated form of amorphous biogenous silica mostly composed of

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diatoms; 2) opal-CT, a metastable form composed of interlayered α-cristobalite and α-tridymite silica; and 3) diagenetic quartz, results from dissolution and re-precipitation of opal-CT with increasing temperature (depth). Silica phases are generally transformed by nearly in-situ solution-precipitation which is accompanied by abrupt step-reduction in porosity (Isaacs, 1981, 1984). The boundaries between the silica-phases are represented by transition intervals (up to 1200 feet) between abrupt step-reduction in porosity at the transitions of opal-A to opal-CT and of opal-CT to diagenetic quartz).

Each silica diagenetic phase is represented by an array of rock types and properties: 1) opal-A rocks are friable, highly porous (60 -70%) diatomaceous rock, 2) opal-CT rocks are cohesive, moderately porous (20-35%) and include chert, porcelanite and siliceous shale/mudstone; and 3) diagenetic quartz rocks are cohesive with low porosity (0-20%) and include chert porcelanite and siliceous shale/mudstone. Understanding these three rock types and their boundaries are essential for meaningful correlation and rock property determination within the Monterey formation. Patterns of carbonate diagenesis also influence rock types and reservoir physical properties (Isaacs, 1984). For example, dolostones are important reservoir rock types in the Santa Maria Basin.

Fracture intensity is related to rock type. Outcrop studies of fractures show that fracture intensity in the Monterey formation is higher in the diagenetic-quartz bearing rocks than in the opal-CT bearing rocks. In general, fracture intensity decreases for the following sequence of rock types: chert, porcelanite, dolostone and marl (Isaacs, 1984).

Dilation brecciation due to dolomitzation has been proposed as a mechanism for fracturing, petroleum expulsion and dolomization in the Monterey formation (Roehl, 1983). Dilation breccia is a distinct form of non-depositional breccias, and it may occur in many tectonic provinces. Tectonic stresses cause an initial compression and subsequent dilation (elastic) of rock microcracks (microfractures) and imperfections. These microcracks are propagated inelastically with continued stress to develop into major fracture networks. Fracturing associated with the excess pore fluid pressures triggers flow of connate fluids into newly fractured strata. The resulting reduction in fluid pressure and temperature causes precipitation of the "fracture-healing" dolomite. The dilation process is repeated. Reportedly, the majority of fractured "hard rocks" in mudlog descriptions are cherts or dolomites (Isaacs, 1984). It has been observed that minor amounts of limestone, and locally dolomite, occur in the Monterey and that extremely brittle cherts are restricted to carbonate-bearing strata (Isaacs, 1984). These reported descriptions and observations lend support to the dilation brecciation theory.

Oil In Place

The Husana oil field is located within the Huasna Basin (Figure 1 and 2). The generalized stratigraphic section for the Huasna Basin is shown in Figure 3. Oil in place estimates were made based on Huasna oil field well data and analog information from the Santa Maria Basin oil fields. The analog Santa Maria Basin SW-NE cross section and Huasna Oil Field well log for the Monterey formation are shown in Figure 4. This cross section and well log are from the California DOGGR state database.

Over the period from 1937 to 1966, a range of conventional core, sidewall core and cuttings rock samples were collected in the Monterey formation over a depth range of 400 to 5000 drilled measured depth from 6 wells SD_1, LVH_O1, LVH_O2, LVH_B2, LVH_C3 and UD_1_30 (Figure 2). Overall the Monterey formation was described as hard fractured dark brown to grey shale with oil or tar present on fracture surfaces with calcareous, dolomitic and/or sandy lithologies occasionally identified in the rock samples. Core analyses were not performed on these samples.

The core data, drill stem tests (DSTs) and production information indicated a wide depth range of oil and tar shows and oil productivity within the Monterey. The conventional core of wells SD_1 and UD_1_30 and sidewall cores of well LVH_B2 indicated oil shows in the Monterey formation. The drill cuttings samples that were collected over most of the Monterey formation for wells LVH_O1, LVH_O2 and LVH_C3 did not indicate any oil shows even at the tested intervals. Thus, drilling cuttings cannot be relied upon for identifying oil shows.

Overall for these 6 wells, the elevations of the Highest Know Oil (HKO) and Lowest Know Oil (LKO) were at 1057 feet above mean sea level and 1722 feet below mean sea level (TVDSS), respectively, which gives a potential oil column interval of 2779 feet. This oil column interval is based on HKO and LKO correlations between SD_1 and LVH_1. It appears there is a potential for the Monterey formation to outcrop in the ridge areas near these wells.

Summary of Highest Known Oil (HKO), Lowest Known Oil (LKO) and Water Level (WL)							
Wellname	HKO, MD	HKO, TVDSS	LKO, MD	LKO, TVDSS	WL, MD	WL, TVDSS	Comments -- HKO, LKO, WL
LVH_G7	unk	unk	unk	unk	unk	unk	no cuttings/core/ DST
SD_1	655	1057	3189	-1477	4449	-2737	HKO, LKO based on DST & a WL based on DST
LVH_O1	1561	-301	2982	-1722	unk	unk	HKO, LKO based on Production thru Perfs
LVH_O2	845	15	1313	-453	unk	unk	HKO, LKO based on prod perfs and TD
UD_1_30	unk	unk	4408	-3548	5150	-4290	LKO based DST & a WL based on logs (both possible but questionable)
LVH_C3	511	530.5	1086	-44.5	unk	unk	DST at 1966 4 bopd above Mont., TD=1086 for LKO may be questionable
LVH_B2	412	536	828	120	unk	unk	Cuttings desc, tar on fractures surfaces in the Monterey

Note, tar specs were identified on cuttings sampled in LVH_B2 from shallower depths than the identified stratigraphic top of the Monterey formation. In well UD_1_30, the LKO was based DST results and a possible WL at 5150 ft-MD (4290 TVDSS) was based on a declining resistivity gradient and resistivity values at 1 ohm-m. Note, the TVDSS depth corrections were made by taking the difference between the well log drilled depth and the KB elevation provided by the client, as directional survey data was not available.

The available raw resistivity response curves of the 7-well data set may show some invasion, because of some separation displayed between the shallow and deep depth-of-investigation resistivity curves. Resistivity response generally ranged between 10 and 20 ohm-m and peaked near 100 ohm-m. Without specified stratigraphic correlation markers in the Monterey formation, a depth datum of 0 feet TVDSS was used to align the well logs as show in the A-B cross section (Figure 6). Note, the A-B cross section index location is shown in Figure 5.

Neither calibrated neutron nor density well logs were available for the 7-well data set. Although, an un-calibrated legacy neutron well log in API units was available for well LVH_C3, it was not useable to estimate porosity. Using analog information from the Santa Maria Basin area and based on the conservative estimates of porosity for the expected diagenetic silica-phase (Opal-CT from 1800 to 4000 feet drilled depth and diagenetic-quartz at depths greater than 4000 feet drilled depth) and/or dolostone, an average total porosity (matrix and fracture) was estimated to range between 8 and 18 percent bulk volume. When core analysis data is available, a key input in the estimation of porosity for diagenetic silica is the grain density which may vary from 2.10 to 2.65 g/cc.

Mid-range oil saturation values of 45 to 60 percent pore volume (water saturation of 55 to 40 percent pore volume) were estimated from which to estimate the original oil in place (OOIP). Experience in the Santa Maria Basin indicates a mid-range oil saturation estimate is reasonable based on available data and at this initial level of reservoir characterization. Typically, oil saturations for the Monterey formation are determined from core analyses (RCAL and SCAL) for each rock type. Core analyses are used with modern well logs to develop predictive water saturation models (hence oil saturations) for each rock type.

The development area is 160 acres and includes the previously drilled wells that produced oil from the Monterey formation. Based on regional geological map interpretations, the 160 acres is located within the crestal area of the La Voie-Hadley (LVH) anticline (Figure 2). The remaining acreage of the lease area is designated as the potential development area.

Within the LVH anticline of the remaining acreage, the most likely and high areas of 400 and 600 acres, respectively, were estimated based on extending the pay interval down structure to deeper depths within the estimated oil column thickness. . These data were used in a probabilistic approach to improve the estimated ranges of expected values in this assessment.

Although drill stem tests bracket roughly a 2,300 feet oil column, there is no proof, or firm basis to state that the entire column is productive. As discussed previously, there are conventional cores and sidewall cores that indicate reasonable oil saturation, but they do not cover the entire column. The drill cuttings which have wider sampling do not indicate any oil shows even at the tested intervals and cannot be relied on. Furthermore the well logs do not include density measurements that would help in characterizing potential pay. Based on analog data referred to in the Geology section of this report, net pay thickness for a matrix and fracture Monterey reservoir was estimated to range between 200 and 960 feet with the most likely estimate at 500 feet. The net pay thickness uncertainty will be fairly addressed by the drilling of new wells that will acquire modern logs and new cores and fluid samples.

The range of input variables for the probabilistic estimation is shown in Table 1 and output is shown in Table 2 of this report. Assuming the most productive and best reservoir quality would be located in the crestal structural position of the anticline, a relationship may exist between the smallest area of development (160 acres) and the thickest net pay. As part of the probabilistic estimation, a correlation test was performed which indicated a possible weak negative correlation at a -0.5 correlation coefficient.

Development Plan

United Hunter Oil & Gas Corporation (United Hunter) plans to drill 12 new wells within the next 5 years in order to obtain new subsurface information and to initiate production using intermittent hot water injection. In this approach hot water will be injected in each well for intermittent periods followed by periods of production. These wells will be drilled and completed as vertical or near vertical, and will be logged using the appropriate modern logs. Fresh cores and fluid samples will taken and analyzed. United Hunter plans to use reservoir modeling that will involve the construction of a geological model and reservoir simulation using thermal and dual permeability formulations to assess the recovery potential and to optimize vertical and horizontal spacing in conjunction with injection rates and schedule. The intent is to develop the field on 10 acre spacing, although some of the first wells will be drilled further apart for delineation purposes. That implies that once the field development gets under way, there could be up to 60 of new wells required.

The major obstacle in carrying out this development concept, apart from drilling new wells to acquire modern logs and core data that will help in characterizing the field properties better, is securing the necessary permits from the regulatory authorities, which requires environmental impact compliance and approval.

United Hunter's assessment is that such a development is feasible provided that it is approached in stages. This will enable United Hunter to demonstrate their operational integrity and the oil recovery potential. In that regard, United Hunter has chosen to commence production operations with injection of very low quality steam that will be in the liquid (hot water) phase by the time it contacts the formation.

The practice of injecting hot water was used in the industry long before high quality steam injection was widely implemented. In this particular case the hot water injection is selected as it maximizes the volume of injected thermal fluid in relation to the heat generation facilities, which require several environmental compliance criteria to be met before they are permitted and commissioned.

In that sense the Huasna field development under this approach is perceived to adopt a maximum recovery by the least possible surface impact principle. In practice, vertical and directional wells will be drilled from central locations that at subsurface will project a 10 acre spacing pattern. Hot water injection will be applied at about 2400 bbl/day rates during the first stage of development which will include up to 12 wells.

The hot water will be injected in each well sequentially allowing wells to alternate through injection and production cycles. Recent fluid sampling has shown that increasing the temperature of the fluid by a modest amount from 900 F to 1400 F reduces oil viscosity from 100,000 centipoises (cp) to 2,000 cp.

Applied at intervals no thicker than 300-400 feet is typically accomplished by injecting at the deepest interval first and then plugging and later completing upwards at shallower depths.

Fractured shale formations like the Monterey have been shown to recover 30-40% of the oil in place with continuous steam injection and 20-30% with cyclic injection. Using thermal calculations, it is estimated that with hot water the expected recoveries will be in the 4-6% range. The wells that have been drilled and produced in Huasna under primary depletion are estimated to have recovered about 2% of the oil in place. At this stage in absence of more field data it is not possible to apply reservoir simulation estimates that will also include the displacement potential from water injection, which could potentially help in recovering more oil provided that there is hydraulic communication between wells.

GCA estimated recoverable oil based on Huasna's performance for primary recovery and by making separate thermal estimates using analytical tools. As a point of reference, GCA compared the estimated recoverable oil in terms of bbl/ac-ft, with other fields that produce heavy oil from the same formation such as Orcutt, and Santa Maria , but cannot be considered direct analogs as they produce less viscus oil. Recoverable oil per unit rock volume in Orcutt and Sanata Maria range between 50 to 150 bbl/ac-ft. Oil gravity in the Monterey formation in California is generally between 12 and 18 API o (Regan, 1953). In the Santa Maria basin, oil gravity within different horizons of the Monterey formation can range from 8 to 23 API o (Isaacs, 1984). According to our estimates, the recoverable oil is estimated at 24 bbl/ac-ft, which is reasonable to expect for the heavier oil gravities found in Huasna.

Figure 1: Oil Field Map showing Santa Maria Basin Fields and Huasna Oil Field

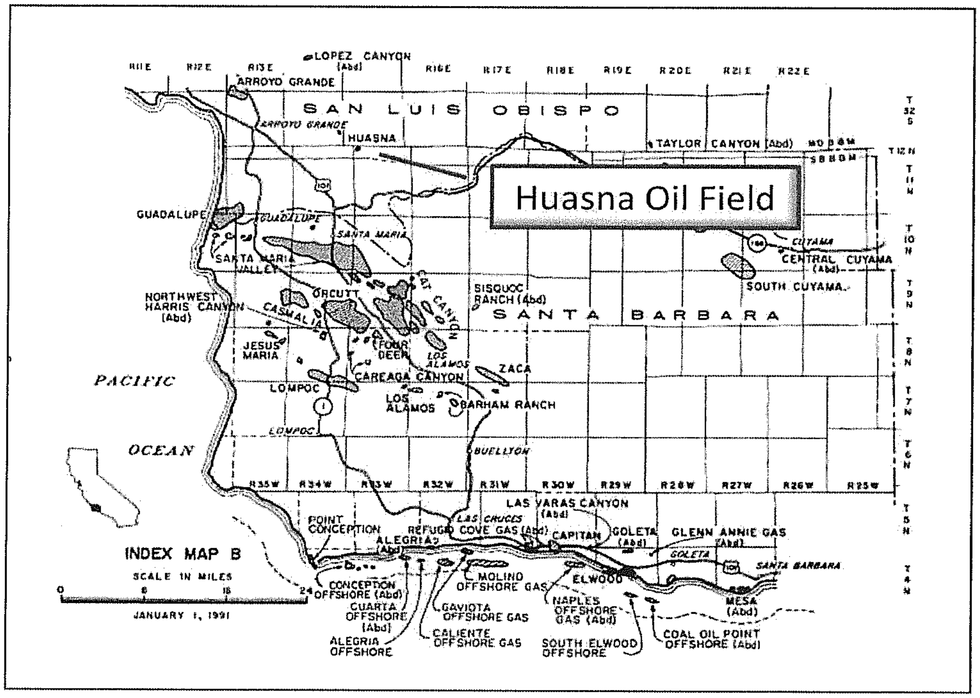


Figure 2: Huasna Oil Field Well Locations, and Synclinal and Anticlinal Structures

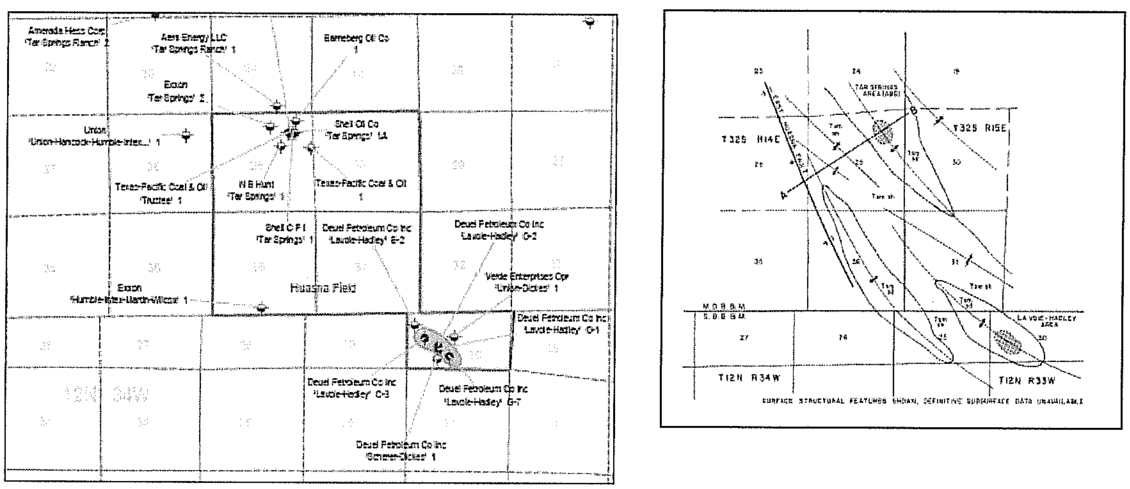
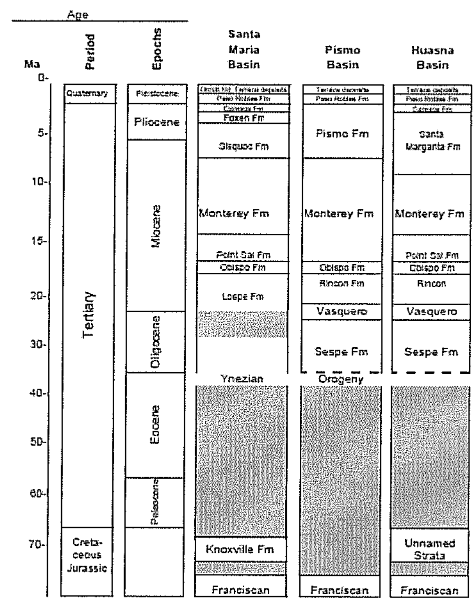


Figure 3: Stratigraphic Correlation Section

Department of Water Resources, Southern District, Water Resources of the Arroyo Grande - Nipomo Mesa Area, 2002

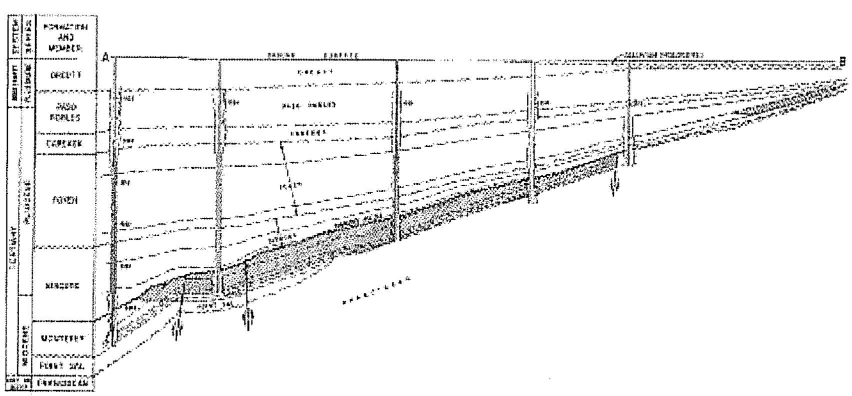
FIGURE 3 - STRATIGRAPHIC CORRELATION DIAGRAM*



*Stratigraphy shown is through only Pleistocene epoch. Diagram modified from Namson and Davis, 1990; Santa Maria Basin (Namson and Davis, 1990; Stanley and Surdam, 1984), Pismo Basin (Stanley and Surdam, 1984; Hall, 1973), and Huasna Basin (Hall and Corbato, 1967)

Figure 4: Analog Santa Maria and Huasna Oil Field Well Logs for Monterey Formation

Santa Maria Basin (SW to NE) and Huasna Basin



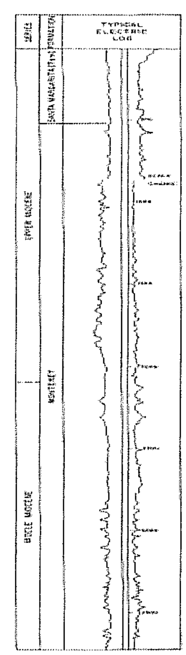


Figure 5: Current Development Area (160 ac) within Potential Development Area (beige) and A-B Cross Section Index Location

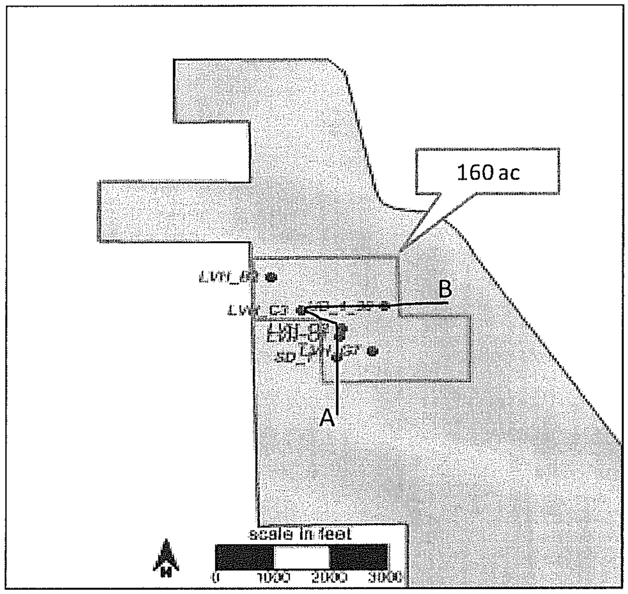
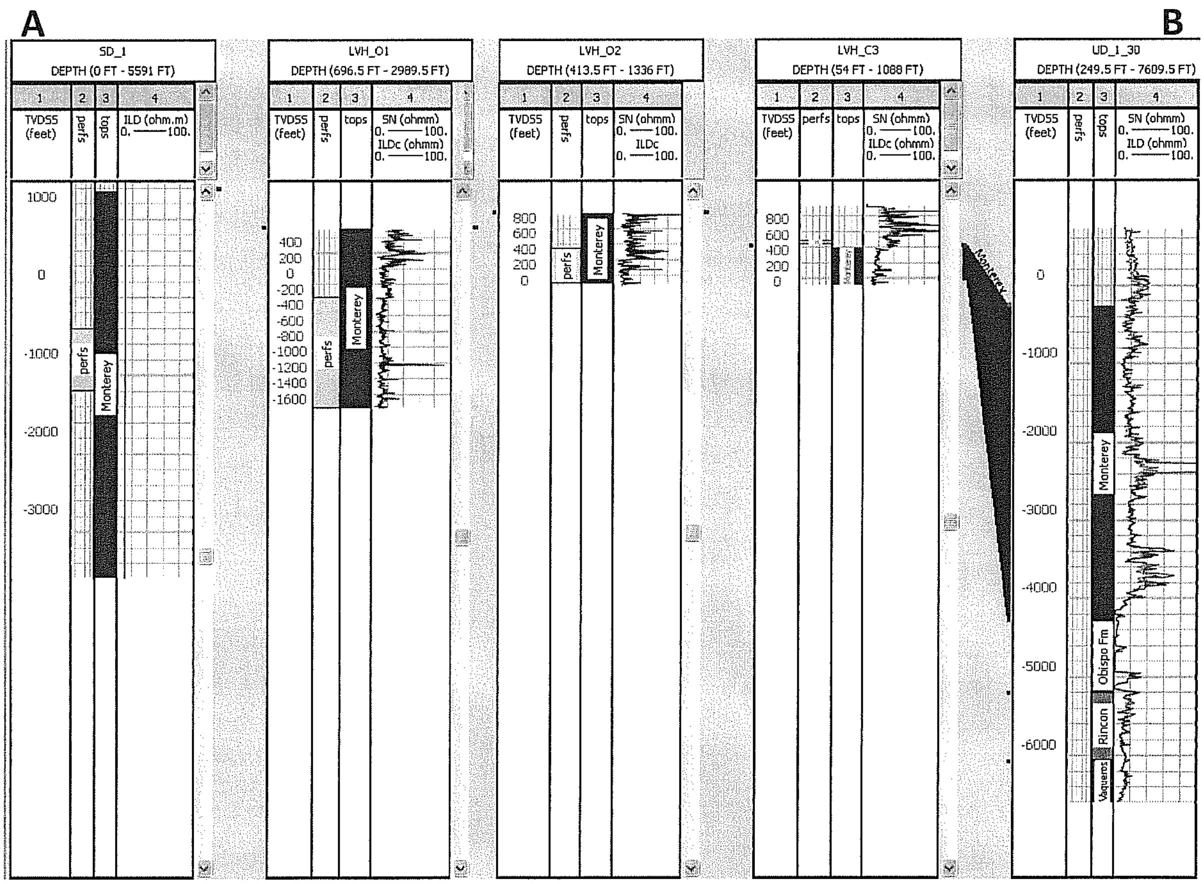


Figure 6: A-B Cross Section Wells: SD_1, LVH_O1, LVH_O2, LVH_C3, UD_1_30



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APPENDIX II:
COGEH Definitions

DEFINITIONS OF OIL AND GAS RESOURCES AND RESERVES

CSA Staff Notice 51-324 - Glossary to NI 51-101 *Standards of Disclosure for Oil and Gas Activities* sets out the reserves and resources definitions derived from Section 5 of volume 1 of the Canadian Oil and Gas Evaluation Handbook (COGEH).

To further assist users of NI 51-101, an updated version of Section 5 of volume 1 of the COGEH, "Definitions of Resources and Reserves", is attached. (The copyright holders of COGEH have given the Alberta Securities Commission, and users of NI 51-101, authority to reproduce Section 5 of volume 1 of COGEH.) This version reflects updated resource classification and terminology that is provided in the recently published second edition of COGEH.

The COGEH itself can be obtained from the Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum, Calgary Chapter at www.petsoc.org.

SECTION 5

DEFINITIONS OF RESOURCES AND RESERVES

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5.1 Preface

5.1.1 Background

The Petroleum Society of CIM (Petroleum Society) Standing Committee on Reserves Definitions (Standing Committee) released revised *Definitions and Guidelines For Estimating and Classifying Oil and Gas Reserves* in January 2002. Later in 2002 these reserves definitions were adopted as the foundation for reserves estimation in the Canadian Oil and Gas Evaluation Handbook (COGEH).

The authors of COGEH and the Standing Committee each developed separate definitions of resources, incorporating terminology and concepts published in February 2000 by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), and the American Association of Petroleum Geologists (AAPG) (hereafter referred to as the 2000 SPE Resources Definitions). The COGEH version was published in COGEH in 2002, with the Standing Committee version being published in the second edition of the Petroleum Society's Monograph No. 1, *Determination of Oil and Gas Reserves*, in 2004.

The Standing Committee has now reviewed its definitions for both resources and reserves. Simultaneously, the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE) reviewed the 2000 SPE Resources Definitions and released revised definitions in April 2007 in its *Petroleum Resources Management System* (SPE-PRMS) document. This revision to COGEH has given due consideration to the SPE-PRMS and has resulted in notable changes to resources definitions, with only minor editorial changes to the previous reserves definitions and guidance.

There is now a broad alignment between the COGEH and SPE-PRMS definitions and guidelines, but some minor differences remain. Currently neither the sponsors of COGEH nor those of SPE-PRMS have fully endorsed all aspects of the other party's definitions, nor has such endorsement been requested.

5.1.2 Introduction

Petroleum is defined as a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid, or solid phase. The term "resources" encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Accordingly, total resources is equivalent to total Petroleum Initially-In-Place (PIIP). It is recommended

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that the term "total PIIP" be used rather than "total resources" in order to avoid any confusion that may result from the mixed historical usage of the term "resources" to mean the recoverable portion of PIIP or total PIIP.

The concept that a recovery or development *project* is required in order to recover resources from a petroleum accumulation is fundamental to the SPE-PRMS. One or more exploration, delineation, or development projects may be applied to an accumulation, and each project will provide additional technical data and/or recover an estimated portion of the PIIP. In the early stage of exploration or development, project definition will not be of the detail expected in later stages of maturity. For the purposes of government/regulatory resource management or for basin potential studies, projects will typically be defined with lesser precision. Regardless of the end use of estimates, a basic requirement for the assignment of recoverable resources in any category is that it must be possible to define a technically feasible recovery project.

Figure 5-1, taken from the SPE-PRMS, illustrates the main resources classification system. Additional operational subcategories may also be optionally used (see Section 5.3.4 a).

The vertical axis of Figure 5-1 represents the chance of commerciality. The key vertical categories relate to the quantities that are estimated to be remaining and recoverable; that is

- reserves, which are discovered and commercially recoverable;
- contingent resources, which are discovered and potentially recoverable but sub-commercial;
- prospective resources, which are undiscovered and potentially recoverable.

The range of uncertainty indicated on the horizontal axis of Figure 5-1 reflects that remaining recoverable quantities can only be estimated, not measured. Three uncertainty categories, or scenarios, are identified for estimates of recoverable resources — low estimate, best estimate, and high estimate (abbreviations for contingent resources are 1C, 2C, and 3C, respectively) — with the corresponding reserves categories of proved (1P), proved + probable (2P), and proved + probable + possible (3P).

Formal definitions for each element of Figure 5-1 are provided in Section 5.2.

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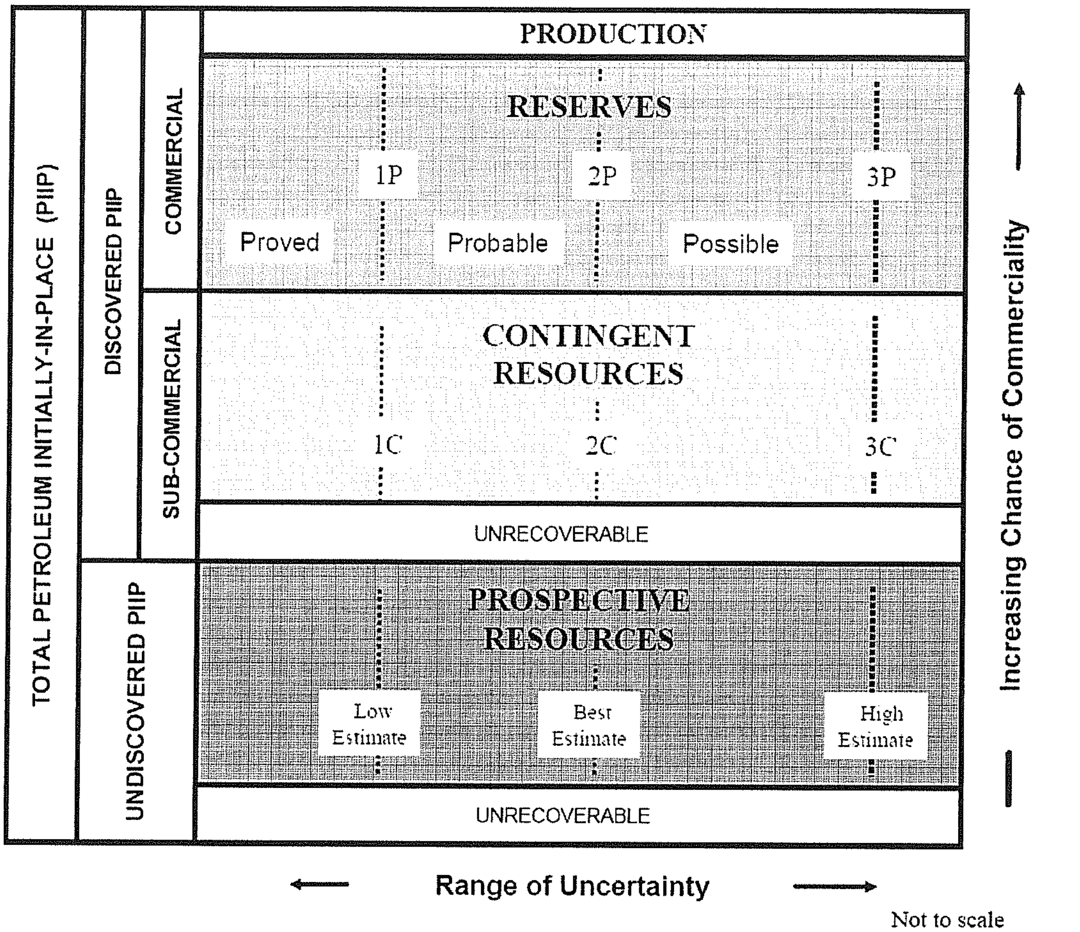

Figure 5-1 Resources classification framework (SPE-PRMS, Figure 1.1).

5.2 Definitions of Resources

The following definitions relate to the subdivisions in the resources classification framework of Figure 5-1 and use the primary nomenclature and concepts contained in the 2007 SPE-PRMS, with direct excerpts shown in italics.

Total Petroleum Initially-In-Place (PIIP) 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 (equivalent to discovered resources) *is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production*. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

Production is the cumulative quantity of petroleum that has been recovered at a given date.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status. Refer to the full definitions of reserves in Section 5.4.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. *Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.*

Unrecoverable is that portion of Discovered or Undiscovered PIIP 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 the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) *is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered.* The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

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 subclassified based on project maturity.

Unrecoverable: see above.

Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification. However, in some instances (e.g., basin potential studies) it may be desirable to refer to certain subsets of the total PIIP. For such purposes the term "resources" should include clarifying adjectives "remaining" and "recoverable," as appropriate. For example, the sum of reserves, contingent resources, and prospective resources may be referred to as "remaining recoverable resources." However, contingent and prospective resources estimates involve additional risks, specifically the risk of not achieving commerciality and exploration risk, respectively, not applicable to reserves estimates. Therefore, when resources categories are combined, it is important that each component of the summation also be provided, and it should be made clear whether and how the components in the summation were adjusted for risk.

5.3 Classification of Resources

For petroleum quantities associated with simple conventional reservoirs, the divisions between the resources categories defined in Section 5.2 may be quite clear, and in such instances the basic definitions alone may suffice for differentiation between categories. For example, the drilling and testing of a well in a simple structural accumulation may be sufficient to allow classification of the entire estimated recoverable quantity as contingent resources or reserves. However, as the industry trends toward the exploitation of more complex and costly petroleum sources, the divisions between resources categories are less distinct, and accumulations may have several categories of resources simultaneously. For example, in extensive "basin-center" low-permeability gas plays, the division between all categories of remaining recoverable quantities, i.e., reserves, contingent resources, and prospective resources, may be highly interpretive. Consequently, additional guidance is necessary to promote consistency in classifying resources. The following provides some

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clarification of the key criteria that delineate resources categories. Subsequent volumes of COGEH provide additional guidance.

5.3.1 Discovery Status

As shown in Figure 5-1, the total petroleum initially in place is first subdivided based on the discovery status of a petroleum accumulation. Discovered PIIP, production, reserves, and contingent resources are associated with known accumulations. Recognition as a known accumulation requires that the accumulation be penetrated by a well and have evidence of the existence of petroleum. COGEH Volume 2, Sections 5.3 and 5.4, provides additional clarification regarding drilling and testing requirements relating to recognition of known accumulations.

5.3.2 Commercial Status

Commercial status differentiates reserves from contingent resources. The following outlines the criteria that should be considered in determining commerciality:

- economic viability of the related development project;
- a reasonable expectation that there will be a market for 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, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated;
- a reasonable expectation that all required internal and external approvals will be forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approvals for expenditures, etc.;
- evidence to support a reasonable timetable for development. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a maximum time frame for classification of a project as commercial, 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.

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COGEH Volume 2, Sections 5.5 to 5.8, provides addition details relating to the foregoing aspects of commerciality relating to classification as reserves versus contingent resources.

5.3.3 Commercial Risk

In order to assign recoverable resources of any category, a development plan consisting of one or more projects needs to be defined. In-place quantities for which a feasible project cannot be defined using established technology or technology under development are classified as unrecoverable. In this context "technology under development" refers to technology that has been developed and verified by testing as feasible for future commercial applications to the subject reservoir. In the early stage of exploration or development, project definition will not be of the detail expected in later stages of maturity. In most cases recovery efficiency will be largely based on analogous projects.

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources, and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality." The chance of commerciality varies in different categories of recoverable resources as follows:

- **Reserves:** To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.
- **Contingent Resources:** Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.
- **Prospective Resources:** Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation the chance of commerciality is the product of

two risk components — the chance of discovery and the chance of development.

5.3.4 Economic Status, Development, and Production Subcategories

a. Economic Status

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to subclassify contingent resources by economic status:

Economic Contingent Resources are those contingent resources that are currently economically recoverable.

Sub-Economic Contingent Resources are those contingent resources that are not currently economically recoverable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is "undetermined" (i.e., "contingent resources – economic status undetermined").

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e., specified economic conditions, which are generally accepted as being reasonable (refer to COGEH Volume 2, Section 5.8).

b. Development and Production Status

Resources may be further subclassified based on development and production status. For reserves, the terms "developed" and "undeveloped" are used to express the status of development of associated recovery projects, and "producing" and "non-producing" indicate whether or not reserves are actually on production (see Section 5.4.2).

Similarly, project maturity subcategories can be identified for contingent and prospective resources; the SPE-PRMS (Section 2.1.3.1) provides examples of subcategories that could be identified. For example, the SPE-PRMS identifies the highest project maturity subcategory as "development pending," defined as "a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future."

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5.3.5 Uncertainty Categories

Estimates of resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project. Consequently, estimates of resources should generally be quoted as a range according to the level of confidence associated with the estimates. An understanding of statistical concepts and terminology is essential to understanding the confidence associated with resources definitions and categories. These concepts, which apply to all categories of resources, are outlined in Sections 5.5.1 to 5.5.3.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

- **Low Estimate:** This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.

- **Best Estimate:** This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.

- **High Estimate:** This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

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5.4 Definitions of Reserves

The following reserves definitions and guidelines are designed to assist evaluators in making reserves estimates on a reasonably consistent basis, and assist users of evaluation reports in understanding what such reports contain and, if necessary, in judging whether evaluators have followed generally accepted standards.

The guidelines outline

- general criteria for classifying reserves,
- procedures and methods for estimating reserves,
- confidence levels of individual entity and aggregate reserves estimates,
- verification and testing of reserves estimates.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable, and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgement combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. These concepts are presented and discussed in greater detail within the guidelines in Section 5.5.

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

5.4.1 Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;

- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

a. Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

b. Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.

c. Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

Other criteria that must also be met for the classification of reserves are provided in Section 5.5.4.

5.4.2 Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

a. Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be

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currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production but are shut in and the date of resumption of production is unknown.

b. Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

5.4.3 Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Section 5.4.1 are applicable to "individual reserves entities," which refers to the lowest level at which reserves calculations are performed, and to "reported reserves," which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves,
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable reserves,
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved + probable + possible reserves.

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A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3.

5.5 General Guidelines for Estimation of Reserves

The following is a summary of fundamental guidelines that should be followed by reserves evaluators. These general guidelines provide guidance that should aid in improving consistency in reserves reporting, but provide only a brief summary of the issues that may arise in applying the reserves definitions. It must be recognized that reserves definitions and associated guidelines cannot address all possible scenarios, nor can they remove the conditions of uncertainty that are inherent in all reserves estimates. It is the responsibility of the reserves evaluator to exercise sound professional judgement and apply these guidelines appropriately and objectively.

5.5.1 Uncertainty in Reserves Estimation

Reserves estimation has characteristics that are common to any measurement process that uses uncertain data. An understanding of statistical concepts and the associated terminology is essential to understanding the confidence associated with reserves definitions and categories.

Uncertainty in a reserves estimate arises from a combination of error and bias:

- Error is inherent in the data that are used to estimate reserves. Note that the term "error" refers to limitations in the input data, not to a mistake in interpretation or application of the data. The procedures and concepts dealing with error lie within the realm of statistics and are well established.

- Bias, which is a predisposition of the evaluator, has various sources that are not necessarily conscious or intentional.

In the absence of bias, different qualified evaluators using the same information at the same time should produce reserves estimates that will not be significantly different, particularly for the aggregate of a large number of estimates. The range within which these estimates should reasonably fall depends on the quantity and quality of the basic information and the extent of analysis of the data.

5.5.2 Deterministic and Probabilistic Methods

Reserves estimates may be prepared using either deterministic or probabilistic methods.

a. Deterministic Method

The deterministic approach, which is the one most commonly employed worldwide, involves the selection of a single value for each parameter in the reserves calculation. The discrete value for each parameter is selected based on the estimator's determination of the value that is most appropriate for the corresponding reserves category.

b. Probabilistic Method

Probabilistic analysis involves describing a range of possible values for each unknown parameter. This approach typically consists of employing computer software to perform repetitive calculations (e.g., Monte Carlo simulation) to generate the full range of possible outcomes and their associated probability of occurrence.

c. Comparison of Deterministic and Probabilistic Estimates

Deterministic and probabilistic methods are not distinct and separate. A deterministic estimate is a single value within a range of outcomes that could be derived by a probabilistic analysis. There should be no significant difference between reported reserves estimates prepared using deterministic and probabilistic methods.

d. Application of Guidelines to the Probabilistic Method

The following guidelines include criteria that provide specific limits to parameters for proved reserves estimates. For example, volumetric estimates are restricted by the lowest known hydrocarbon (LKH). Inclusion of such specific limits may conflict with standard probabilistic procedures, which require that input parameters honour the range of potential values.

Nonetheless, it is required that the guidelines be met regardless of analysis method. Accordingly, when probabilistic methods are used, constraints on input parameters may be required in certain instances. Alternatively, a deterministic check may be made in such instances to ensure that aggregate estimates prepared using probabilistic methods do not exceed those prepared using a deterministic approach including all appropriate constraints.

5.5.3 Aggregation of Reserves Estimates

Reported reserves typically comprise the aggregate of estimates prepared for a number of individual wells, reservoirs, and/or properties/fields.

When deterministic methods are used, reported reserves will be the simple arithmetic sum of all estimates within each reserves category. Evaluators and users of reserves information must understand the effect of summation on the confidence level of estimates. The confidence level associated with the arithmetic sum for a number of individual estimates may be different from that of each of the individual estimates. Arithmetic summation of independent high-probability estimates will result in a total with a higher confidence level; arithmetic summation of low-probability estimates will yield a total with a lower confidence level.

Because the definitions and guidelines require a conservative approach in the estimation of proved reserves, the minimum probability target for proved reported reserves will be satisfied with a deterministic approach as long as there are enough independent entity estimates in the aggregate. Where a very small number of entities dominate in the reported reserves, a specific effort to meet the probability criteria may be required in preparing deterministic estimates of proved reserves. Since proved + probable reserves prepared by deterministic methods will approximate mean values, the probability associated with the estimates will essentially be unaffected by aggregation.

When probabilistic techniques are used in reserves estimation, statistically based mathematical aggregation is performed within the probabilistic model. It is critical that such models appropriately include all dependencies between variables and components within the aggregation. Where dependencies and specific criteria contained in the guidelines have been treated appropriately, reserves for the various categories would be defined by the minimum probability requirements contained in Section 5.4.3, subject to the following considerations.

Reported reserves for a company will typically not be the aggregate results from a single probabilistic model, since reserves estimates are used for a variety of purposes, including planning, reserves reconciliation, accounting, securities disclosure, and asset transactions. These uses will generally necessitate tabulations of reserves estimates at lower aggregation levels than the total reported reserves. For these reasons and due to the lack of general acceptance of probabilistic aggregation up to

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the company level, reserves should not be aggregated probabilistically beyond the field (or property) level.

Statistical aggregation of a tabulation of values, which does not result in a straightforward arithmetic addition, is not accepted for most reporting purposes. Consequently, discrete estimates for each reserves category resulting from separate probabilistic analyses, which may, as appropriate, include aggregation up to the field or property level, should be summed arithmetically. As a result, reported reserves will meet the probability requirements in Section 5.4.3 regardless of dependencies between separate probabilistic analyses and may be summed with deterministic estimates within each reserves category.

It is recognized that the foregoing approach imposes an additional measure of conservatism when proved reserves are derived from a number of mathematically independent probabilistic analyses, because the sum of independent 90 percent confidence level estimates has an associated confidence level of greater than 90 percent. Nonetheless, this is considered to be an acceptable consequence given the need for a discrete accounting of component proved reserves estimates.

Conversely, this approach will cause the sum of proved + probable + possible reserves derived from a number of probabilistic analyses to fail to meet the 10 percent minimum confidence level requirement. Given the limited application for proved + probable + possible reported reserves, this is also considered to be an acceptable consequence.

5.5.4 General Requirements for Classification of Reserves

The following general conditions must be satisfied in the estimation and classification of reserves. More detailed guidance can be found in Chapter 5 of COGEH Volume 2.

a. Ownership Considerations

Assigning reserves to a company requires the company to own the subsurface mineral rights or have the contractual right to exploit and produce. This may be ascertained by reviewing land records and verified in financial records.

Internationally, in Production Sharing Contracts, the company will not usually own the mineral rights, but reserves may be assigned if the company has the right to extract the oil or gas. Further qualifications are

- the right to take volumes in kind,

- exposure to market and technical risk,
- the opportunity for reward through participation in producing activities.

Reserves would not be booked for companies participating in projects where their rights are limited to purchasing volumes or service agreements that do not contain aspects of technical and price risk and reward. Pure service contracts are an example of this type.

Company gross reserves are the working interest share of reserves prior to deduction of payments to others such as royalties (burdens).

Company royalty interest reserves are the net reserves received as a result of a royalty or carried interest.

Company interest reserves are the sum of company gross plus company royalty interest reserves. To avoid double accounting of reserves reported by a company, company royalty interest reserves must include only royalty volumes derived from non-related working interest owners.

Company net reserves are the working interest reserves after payment of burdens. Received royalty interests and carried interests are included in net reserves. Internationally, net reserves are after payments to governments. Depending on the PSC, they may be before or after payment of income tax.

b. Drilling Requirements

Proved, probable, or possible reserves may be assigned only to known accumulations that have been penetrated by a wellbore. Potential hydrocarbon accumulations that have not been penetrated by a wellbore may be assigned to prospective resources.

c. Testing Requirements

Confirmation of commercial productivity of an accumulation by production or a formation test is required for classification of reserves as proved. In the absence of production or formation testing, probable and/or possible reserves may be assigned to an accumulation on the basis of well logs and/or core analysis that indicates that the zone is hydrocarbon bearing and is analogous to other reservoirs in the immediate area that have demonstrated commercial productivity by actual production or formation testing.

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d. Regulatory Considerations

In general, proved, probable, or possible reserves may be assigned only in instances where production or development of those reserves is not prohibited by governmental regulation. This provision could, for instance, preclude the assignment of reserves in designated environmentally sensitive areas. Reserves may be assigned in instances where regulatory restraints may be removed subject to satisfaction of minor conditions. In such cases the classification of reserves as proved, probable, or possible should be made with consideration given to the risk associated with project approval.

e. Infrastructure and Market Considerations

In order to assign reserves there should be an identifiable transportation infrastructure and a market to sell the oil or gas. The market requirement could vary from highly transparent spot markets such as exist in North America or the UK to long-term contracts in more remote areas of the world. If there is no existing market, the evaluator has to assess the level of confidence that one will be available within a reasonable time frame.

If there is no infrastructure in place, or the company has no ownership in nearby infrastructure, the evaluator has to assess the level of confidence that access to suitable infrastructure will be available within a reasonable time frame.

f. Timing of Production and Development

Non-producing reserves should be planned to be developed within a reasonable time frame. For projects requiring minor capital expenditures, two years is a recommended guideline unless the non-producing reserves are awaiting depletion of another producing zone or production levels are constrained by facility or market limitations. For larger capital expenditures, three years is a recommended guideline for assigning proved reserves and five years for assigning probable reserves. Exceptions to these guidelines are possible but should be clearly documented.

For producing reserves, extrapolating reserves over very long periods should take into account the uncertainties in forecasting volumes, fiscal terms, market factors, and infrastructure. It is recommended that reserves be limited to less than a 50-year forecast period unless there are clear reasons to extend beyond this.

g. Economic Requirements

Proved, probable, or possible reserves may be assigned only to those volumes that are economically recoverable. The fiscal conditions under which reserves estimates are prepared should generally be those considered to be a reasonable outlook on the future. Securities regulators or other agencies may require that constant or other prices and costs be used in the estimation of reserves and value. In such instances the estimated reserves quantities must be recoverable under those conditions and should also be recoverable under fiscal conditions considered to be a reasonable outlook on the future. In any event, the fiscal assumptions used in the preparation of reserves estimates must be disclosed.

Undeveloped recoverable volumes must have a sufficient return on investment to justify the associated capital expenditure in order to be classified as reserves as opposed to contingent resources.

5.5.5 Procedures for Estimation and Classification of Reserves

The process of reserves estimation falls into three broad categories: volumetric, material balance, and decline analysis. Selection of the most appropriate reserves estimation procedures depends on the information that is available. Generally, the range of uncertainty associated with an estimate decreases and confidence level increases as more information becomes available and when the estimate is supported by more than one estimation method. Regardless of the estimation method(s) employed, the resulting reserves estimate should meet the certainty criteria in Section 5.4.

a. Volumetric Methods

Volumetric methods involve the calculation of reservoir rock volume, the hydrocarbons in place in that rock volume, and the estimation of the portion of the hydrocarbons in place that ultimately will be recovered. For various reservoir types at varied stages of development and depletion, the key unknown in volumetric reserves determinations may be rock volume, effective porosity, fluid saturation, or recovery factor. Important considerations affecting a volumetric reserves estimate are outlined below:

- **Rock Volume:** Rock volume may simply be determined as the product of a single well drainage area and wellbore net pay or by more complex geological mapping. Estimates must take into account geological characteristics, reservoir fluid properties, and the drainage area that could be expected for the well or wells. Consideration must be given to any limitations indicated by geological and geophysical data or interpretations, as well as pressure depletion or boundary conditions exhibited by test data.

- **Elevation of Fluid Contacts:** In the absence of data that clearly define fluid contacts, the structural interval for volumetric calculations of proved reserves should be restricted by the lowest known structural elevation of occurrence of hydrocarbons (LKH) as defined by well logs, core analyses, or formation testing.

- **Effective Porosity, Fluid Saturation, and Other Reservoir Parameters:** These are determined from logs and core and well test data.

- **Recovery Factor:** Recovery factor is based on analysis of production behaviour from the subject reservoir, by analogy with other producing reservoirs, and/or by engineering analysis. In estimating recovery factors the evaluator must consider factors that influence recoveries, such as rock and fluid properties, PIIP, drilling density, future changes in operating conditions, depletion mechanisms, and economic factors.

b. Material Balance Methods

Material balance methods of reserves estimation involve the analysis of pressure behaviour as reservoir fluids are withdrawn, and they generally result in more reliable reserves estimates than volumetric estimates. Reserves may be based on material balance calculations when sufficient production and pressure data are available. Confident application of material balance methods requires knowledge of rock and fluid properties, aquifer characteristics, and accurate average reservoir pressures. In complex situations, such as those involving water influx, multi-phase behaviour, multi-layered or low-permeability reservoirs, material balance estimates alone may provide erroneous results.

Computer reservoir modelling can be considered a sophisticated form of material balance analysis. While modelling can be a reliable predictor of reservoir behaviour, the input rock properties, reservoir geometry, and fluid properties are critical. Evaluators must be aware of the limitations of predictive models when using these results for reserves estimation.

The portion of reserves estimated as proved, probable, or possible should reflect the quantity and quality of the available data and the confidence in the associated estimate.

c. Production Decline Methods

Production decline analysis methods of reserves estimation involve the analysis of production behaviour as reservoir fluids are withdrawn. Confident application of decline analysis methods requires a sufficient period of stable operating conditions after the wells in a reservoir have established drainage areas. In estimating reserves, evaluators must take into consideration factors affecting production decline behaviour, such as reservoir rock and fluid properties, transient versus stabilized flow, changes in operating conditions (both past and future), and depletion mechanism.

Reserves may be assigned based on decline analysis when sufficient production data are available. The decline relationship used in projecting production should be supported by all available data.

The portion of reserves estimated as proved, probable, or possible should reflect the confidence in the associated estimate.

d. Future Drilling and Planned Enhanced Recovery Projects

The foregoing reserves estimation methodologies are applicable to recoveries from existing wells and enhanced recovery projects that have been demonstrated to be economically and technically successful in the subject reservoir by actual performance or a successful pilot. The following criteria should be considered when estimating incremental reserves associated with development drilling or implementation of enhanced recovery projects. In all instances the probability of recovery of the associated reserves must meet the criteria for commerciality (Section 5.3.2), the general requirements (Section 5.5.4), and certainty criteria contained in Section 5.4.

If interpretations are such that no proved or probable reserves are assigned to a development project involving significant future capital expenditures, then the potentially recoverable quantities should be classified as contingent resources rather than stand-alone possible reserves.

i. Additional Reserves Related to Future Drilling

Additional reserves associated with future commercial drilling projects in known accumulations may be assigned where economics support, and regulations do not prohibit, the drilling of the location.

Aside from the criteria stipulated in Section 5.4, factors to be considered in classifying reserves estimates associated with future drilling as proved, probable, or possible include

- whether the proposed location directly offsets existing wells or acreage with proved or probable reserves assigned,
- the expected degree of geological continuity within the reservoir unit containing the reserves,
- the likelihood that the location will be drilled.

In addition, where infill wells will be drilled and placed on production, the evaluator must quantify well interference effects, that portion of recovery that represents accelerated production of developed reserves, and that portion that represents incremental recovery beyond those reserves recognized for the existing reservoir development.

ii. Reserves Related to Planned Enhanced Recovery Projects

Reserves that can be economically recovered through the future application of an established enhanced recovery method may be classified as follows.

Proved reserves may be assigned to planned enhanced recovery projects when the following criteria are met:

- Repeated commercial success of the enhanced recovery process has been demonstrated in reservoirs in the area with analogous rock and fluid properties.
- The project is highly likely to be carried out in the near future. This may be demonstrated by factors such as the commitment of project funding.
- Where required, either regulatory approvals have been obtained or no regulatory impediments are expected, as clearly demonstrated by the approval of analogous projects.

Probable reserves may be assigned when a planned enhanced recovery project does not meet the requirements for classification as proved; however, the following criteria are met:

- The project can be shown to be practically and technically reasonable.

- Commercial success of the enhanced recovery process has been demonstrated in reservoirs with analogous rock and fluid properties.

- It is reasonably certain that the project will be implemented.

Additional possible reserves may be assigned in a planned enhanced recovery project considering factors such as greater effective hydrocarbons in place or greater recovery efficiencies than those estimated in the proved + probable reserves scenario. As previously noted, stand-alone possible reserves should not be assigned to a potential future enhanced recovery project where conditions are such that no proved or probable reserves could be assigned. In such cases the potentially recoverable quantities would be classified as contingent resources, with a corresponding low, best, and high estimate.

5.5.6 Validation of Reserves Estimates

A practical method of validating that reserves estimates meet the definitions and guidelines is through periodic reserves reconciliation of both entity and aggregate estimates. The tests described below should be applied to the same entities or groups of entities over time, excluding revisions due to differing economic assumptions:

- Revisions to proved reserves estimates should generally be positive as new information becomes available.

- Revisions to proved + probable reserves estimates should generally be neutral as new information becomes available.

- Revisions to proved + probable + possible reserves estimates should generally be negative as new information becomes available.

These tests can be used to monitor whether procedures and practices employed are achieving results consistent with certainty criteria contained in Section 5.4. In the event that the above tests are not satisfied on a consistent basis, appropriate adjustments should be made to evaluation procedures and practices.