CANADA-NOVA SCOTIA
OFFSHORE PETROLEUM BOARD

Resource Assessment of Undeveloped Significant Discoveries on the Scotian Shelf

March 2014

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Note: *The purpose of this publication is to document an independent resource assessment of the hydrocarbon resource within the undeveloped Significant Discoveries offshore Nova Scotia. The information contained in this publication, while believed to be accurate, is not warranted to be so and the Canada-Nova Scotia Offshore Petroleum Board assumes no responsibility for damages arising from the use or reliance on any such information. This publication is not to be considered as a statement of policy or position of the Board or of the governments of Canada or Nova Scotia. In addition, it should be appreciated that many of the statements contained herein, particularly with respect to technical matters, are based on assumptions, opinions or interpretations. The descriptions of the regulatory issues are of necessity generalized and incomplete and are subject to change, and for a precise statement of the law reference should be made to the applicable legislation and regulations.*

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Abstract

Objective

To date, twenty-three (23) Significant Discovery (SD) declarations have been made offshore Nova Scotia, of which eight (8) have been declared Commercial Discoveries (CD) by the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB). The purpose of this report is to provide an updated, comprehensive, analysis and assessment of the discovered hydrocarbons for the remaining fifteen (15) undeveloped SDs.

Background

In March 1997, the CNSOPB published the *Technical Summaries of Scotian Shelf Significant and Commercial Discoveries,* which contained the first published resource assessment of the existing 22 SDs. This report was updated in 2000 to reflect an adjustment at Primrose. Calculations of original hydrocarbon in place (OHIP) were undertaken using the following standard volumetric equation, employed within a Monte Carlo style probabilistic simulation using the @Risk™ software:

$$OHIP = A * h * \phi * (1 - S_w) * FVF$$

$OHIP$ = Original Hydrocarbons (Gas/Oil) in Place (m^3)
A = Areal extent of the accumulation (km^2 * 1,000,000)
h = Average Net Pay for the reservoir zone (m)
ϕ = Average Porosity (Fraction)
S_w = Average Water Saturation (Fraction)
FVF = Formation Volume Factor (m^3/m^3)

Each input variable was defined as triangular distributions based on minimum (P100), most likely (P50) and maximum (P00) interpreted values. The CNSOPB analysis of input parameters included the compilation of all available industry and government data related to the SDs and CDs. Industry data originated from regulatory submissions related to SD and CD approvals while government data included previous analysis and assessment work completed by the previous federal regulator the Canada Oil & Gas Lands Administration (COGLA) in the 1970s and 1980s.

In the 2000 assessment, no new seismic interpretation was undertaken by the CNSOPB, but limited petrophysical and reservoir analysis was carried out. The SD structures had only been mapped using 2D seismic data at that time, and most fields contained only one well, therefore, the areal extent of each pool was the variable with the greatest uncertainty. Reasonable ranges for pool areas were determined by reviewing available structure maps, well tests and petrophysical data. The remaining variables were better constrained by formation evaluation data such as logs, cores, and DST reports. Results were published as P90, P50, P10, and Mean values.

2014 Assessment Method

By 2014, the addition of Deep Panuke brought the total number of SDs to 23, with eight of these having been declared as CDs. Good quality 3D seismic data was available over most of the SDs and a new assessment of the remaining 15 SDs was completed. This report is far more comprehensive than previous publications. In-house work completed by CNSOPB staff included:

1. Interpretation and mapping of digital 3D seismic data over all fields except Banquereau (2D was used) and Primrose (insufficient seismic available),
2. Loading and editing of digital logs for all wells,
3. Review of DST data and wireline formation pressures,
4. Petrophysical analysis and reservoir property summation of all wells,
5. Leak point analysis on all reservoirs,
6. Hydrocarbon recovery factor analysis,
7. Resource assessment utilizing values derived from steps 1–6.

A Monte Carlo style probabilistic simulation of the OHIP calculation, as described above for the 2000 report, was also used for the 2014 assessment. Recovery factors were based on production data from analogous producing fields. The assumed depletion scenario for each field included at least one production well in each major fault compartment. All input data, methods, and results were fully documented.

Results

For each SD, a detailed description of the structure, reservoir, formation evaluation and resource assessment is provided. In-place and recoverable hydrocarbon volume tables are listed for each zone and field totals are summarized on charts. The recoverable hydrocarbons for all 15 SDs are displayed in Table 1.

The 2014 assessment resulted in a total mean recoverable gas estimate of 1,949 Bcf for all 15 fields which was a decrease of 14% (313 Bcf) from the 2000 report. While there were modest decreases in total estimated gas volumes, there were significant changes within individual fields (Fig. 1). The largest reduction occurred at Chebucto, resulting from a reduced areal extent based on the petrophysical evaluation and seismic mapping. The Uniacke volumes decreased for similar reasons. The largest increase occurred at Onondaga, mainly due to the addition of the central fault block area. An increase at Glenelg resulted from the inclusion of new gas zones. Overall, seven fields increased in mean recoverable gas volume, while eight decreased.

Table 1 Summary of Recoverable Hydrocarbons (Imperial units).

Field	Recoverable Gas (BCF)				Recoverable Oil (MMB)				Recoverable Condensate (MMB)			
	P90	P50	Mean	P10	P90	P50	Mean	P10	P90	P50	Mean	P10
Arcadia	130	158	**160**	193					1.3	1.6	**1.6**	2.0
Banquereau	143	170	**172**	202					0.7	0.8	**0.9**	1.1
Chebucto	53	66	**67**	82					0.4	0.5	**0.5**	0.6
Citnalta	149	172	**173**	198					8.3	9.8	**9.9**	11.6
Glenelg	473	508	**509**	546					3.3	3.6	**3.6**	4.0
Intrepid	48	54	**54**	61					0.4	0.5	**0.5**	0.6
Olympia	126	143	**144**	163					2.0	2.4	**2.5**	3.0
Onondaga	172	304	**288**	369					1.2	2.1	**2.1**	2.8
Primrose	100	127	**129**	162	0.7	1.0	**1.1**	1.5	0.5	0.7	**0.7**	1.0
South Sable	7	8	**9**	11					0.2	0.3	**0.3**	0.3
Uniacke	17	20	**21**	24					1.0	1.2	**1.2**	1.4
West Olympia	20	30	**31**	42					0.5	0.8	**0.8**	1.2
West Sable	81	93	**93**	105	12.3	15.0	**15.2**	18.3	2.5	3.1	**3.1**	3.9
West Venture C-62	26	31	**31**	36					0.1	0.2	**0.2**	0.2
West Venture N-91	52	68	**70**	89					0.3	0.4	**0.4**	0.5
Total	1819	1955	**1949**	2068	13.4	16.1	**16.3**	19.3	25.9	28.0	**28.2**	30.2

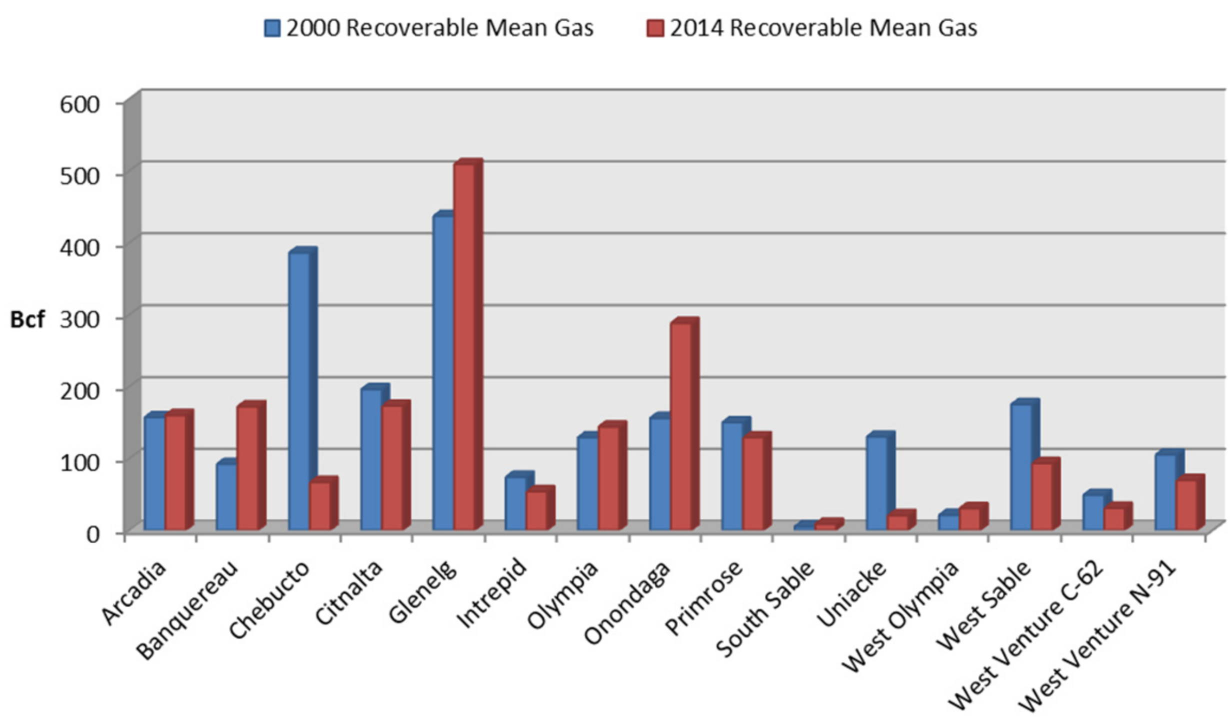

Figure 1 Comparison of 2014 and 2000 results for mean recoverable gas.

Conclusions

For most fields, the seismic mapping and petrophysical analysis provided a consistent description of reservoir leak points. This demonstrates the superior resolution of the 3D seismic used, as compared to the 2D seismic that was available for the 2000 report. Detailed seismic mapping using 3D data, combined with comprehensive petrophysical analysis and better constrained recovery factors, has resulted in a significantly improved understanding of the hydrocarbon volumes in these 15 SDs.

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1 Introduction

Purpose

The purpose of this technical report is to provide updated resource assessments of the 15 undeveloped Significant Discoveries (SDs) located offshore Nova Scotia. The previous assessment published by the CNSOPB, *Technical Summaries of Scotian Shelf, Significant and Commercial Discoveries*, was released in 1997 and updated in 2000 to reflect an adjustment to the Primrose field. Since the 2000 report was released, 3D seismic data has become available over all SDs except Banquereau and Primrose. While the 2000 assessment relied heavily on information from industry and the previous federal regulator Canada Oil & Gas Lands Administration (COGLA), the 2014 assessment utilizes seismic interpretation and mapping, petrophysical analysis, reservoir studies and volumetric calculations completed in-house by CNSOPB staff.

Background

Significant and Commercial Discovery Declarations are based on the following Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Acts definitions:

Significant Discovery is defined in Part II, section 49 in the Canada – Nova Scotia Offshore Petroleum Resources Accord Implementation Act (July 21, 1988) as *"a discovery indicated by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons in that feature and, having regard to geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has potential for sustained production."*

Commercial Discovery is defined as *"a discovery of petroleum that has been demonstrated to contain petroleum reserves that justify the investment of capital and effort to bring the discovery to production."*

The Nova Scotia Offshore Area covers approximately 401,650 km^2, extending from the low water mark to the outer limits of the continental margin. Since petroleum exploration began in the late 1950's, 400,955 km of 2D seismic and 37,585 km^2 of 3D seismic has been acquired. Of the 207 wells drilled since 1967, 127 were exploration, 27 delineation, 52 development and one service relief. To date, twenty-three (23) SD declarations have been approved offshore Nova Scotia (Table 1.1). Associated with these 23 discoveries or fields are thirty-five (35) Significant Discovery Licences (SDLs) which describes the field portion held by each interest holder. Eight (8) of the SD areas have been declared Commercial Discoveries (CDs) by the CNSOPB. With the exception of the Banquereau SD, all are within 50 km of Sable Island, which is located approximately 170 km offshore (Fig 1.1).

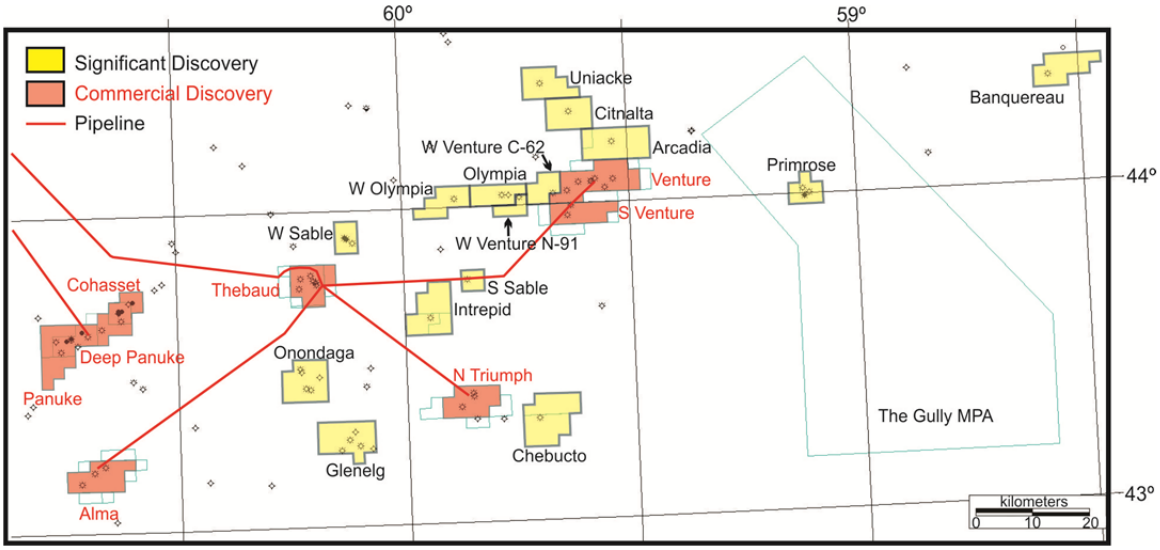

Figure 1.1 Map displaying Significant and Commercial Discoveries.

Petroleum production offshore Nova Scotia began in 1992 with Lasmo's (later PanCanadian) development of the Cohasset and Panuke oil fields (COPAN Project). These two fields – along with Balmoral, a small satellite field associated with Cohasset – produced a total of 44.5 million barrels of light oil from 1992 – 1999. The Sable Offshore Energy Project (SOEP) began producing natural gas in December 1999. The SOEP Development Plan Application included the development of six gas fields, however to date only five fields have been developed. As of December 31, 2013, SOEP had produced approximately 1.9 trillion cubic feet of gas. In June, 2009 the CNSOPB declared Encana's Deep Panuke field a CD, with gas production commencing in August 2013.

The locations of existing SDs that have been converted to Commercial Discoveries are displayed in red (Fig. 1.1) with the undeveloped SDs shown in yellow. The remaining unshaded areas (blue outlines) are the remnants of SD areas that were not converted to Commercial Discovery (CD) areas. The red lines indicate the existing subsea pipeline systems.

A listing of the 23 SDs declared offshore Nova Scotia (Table 1.1) shows that all discoveries, based on the termination date of the discovery well, occurred between 1969 and1988, except for Deep Panuke which was in 1999. The eight SDs highlighted in red were declared CDs and are either currently producing, or have been produced and abandoned. Historical production information is available on the CNSOPB website (www.cnsopb.ns.ca). This report includes a resource assessment of the remaining 15 undeveloped SDs, including Glenelg that was included in the SOEP Development Plan Application, but is currently undeveloped.

Table 1.1 Significant Discovery statuses as of March, 2014.

Significant Discovery	Discovery Date	Water Depth (m)	Number of Wells*	Status as of Mar. 2014
Alma	Jul. 5, 1984	68	7	Producing (SOEP)
Arcadia	Jul. 19, 1983	56	1	Undeveloped
Banquereau	Aug. 1, 1982	83	1	Undeveloped
Chebucto	Aug. 3, 1984	109	1	Undeveloped
Citnalta	Apr. 29, 1974	95	1	Undeveloped
Cohasset	Apr. 27, 1973	41	21	Abandoned (COPAN)
Deep Panuke	Apr. 12, 1999	44	9	Producing (Deep Panuke)
Glenelg	Nov. 7, 1983	84	6	Undeveloped**
Intrepid	Aug. 15, 1979	44	1	Undeveloped
North Triumph	Jan. 31, 1986	74	4	Producing (SOEP)
Olympia	Jan. 10, 1983	40	1	Undeveloped
Onondaga	Nov. 11, 1969	58	5	Undeveloped
Panuke	Aug. 6, 1986	47	12	Abandoned (COPAN)
Primrose	Apr. 21, 1973	91	3	Undeveloped
South Sable	Jul. 8, 1988	35	1	Undeveloped
South Venture	Jan. 2, 1983	24	4	Producing (SOEP)
Thebaud	Oct. 13, 1972	26	10	Producing (SOEP)
Uniacke	Apr 4, 1984	153	1	Undeveloped
Venture	Jun 16, 1979	20	12	Producing (SOEP)
West Olympia	Nov. 9, 1985	38	1	Undeveloped
West Sable	Oct. 15, 1971	N/A***	9	Undeveloped
West Venture C-62	Mar. 23, 1985	16	1	Undeveloped
West Venture N-91	Jul. 7, 1985	38	1	Undeveloped

* Total well count includes sidetracks.

** The Glenelg field was included as one of the six gas fields, originally slated for development, in SOEP Development Plan Application. At present the field remains undeveloped.

*** The West Sable wells were drilled on Sable Island.

A schematic illustration of the lithostratigraphic location and field average net pay thicknesses of the SD reservoirs (Fig. 1.2) shows that most of the gas has been discovered in clastic reservoirs of the Early Cretaceous Missisauga Formation. The Deep Panuke field is located in the Late Jurassic carbonates of the Abenaki Formation.

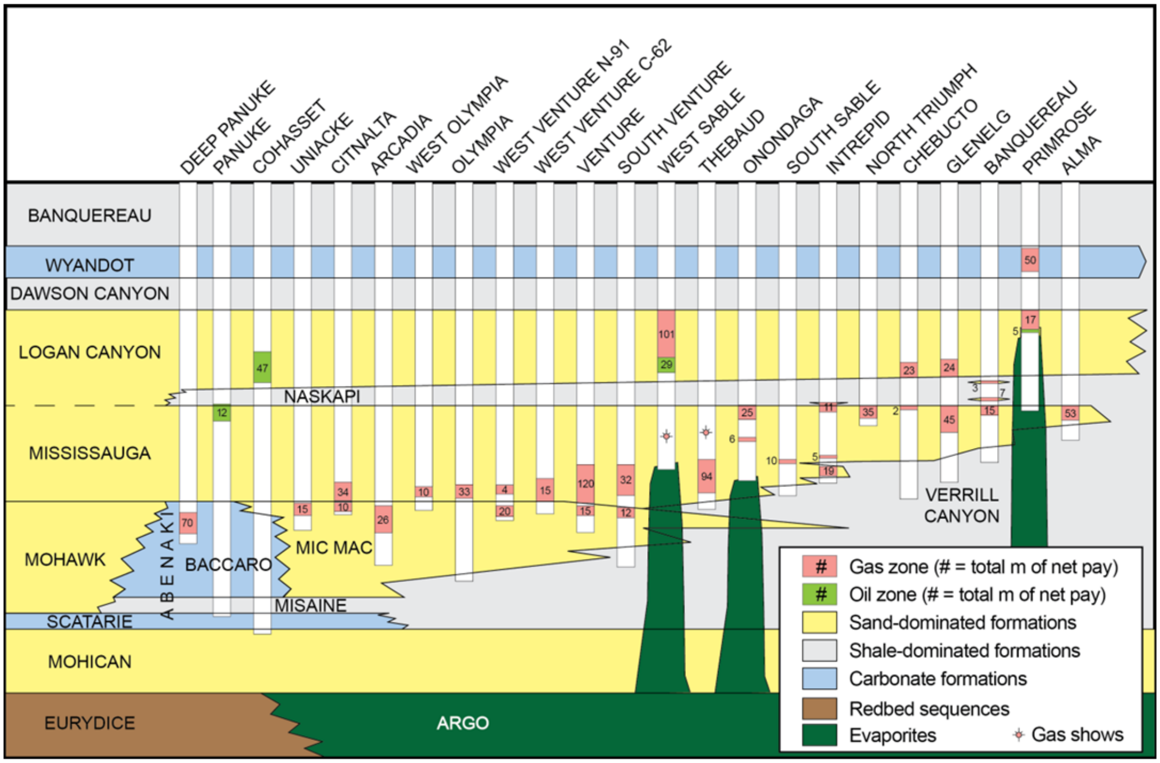

Figure 1.2 Significant Discovery field average net pay thicknesses and stratigraphic positions. (Modified after CNSOPB, 1991)

2014 Resource Assessment

For this assessment, the CNSOPB interpreted and mapped 3D seismic data over all SDs except Primrose and Banquereau. Banquereau was remapped using available 2D seismic but data coverage over Primrose was too sparse to adequately define the structure, therefore, the original mapping submitted by Shell was utilized. Primrose is now within the Gully Marine Protected Area that was created in 2004 under the federal government's "Canada Ocean's Act".

The lithostratigraphic chart (Fig 1.2) includes the geological time scale, global sea level changes, long term stratigraphic sequences and depositional settings on the shelf. To date, all declared SDs are located on the Scotian Shelf.

All maps in this report are a north-up orientation. The data used is based on industry seismic and well data that has been submitted to the Board and is no longer privileged.

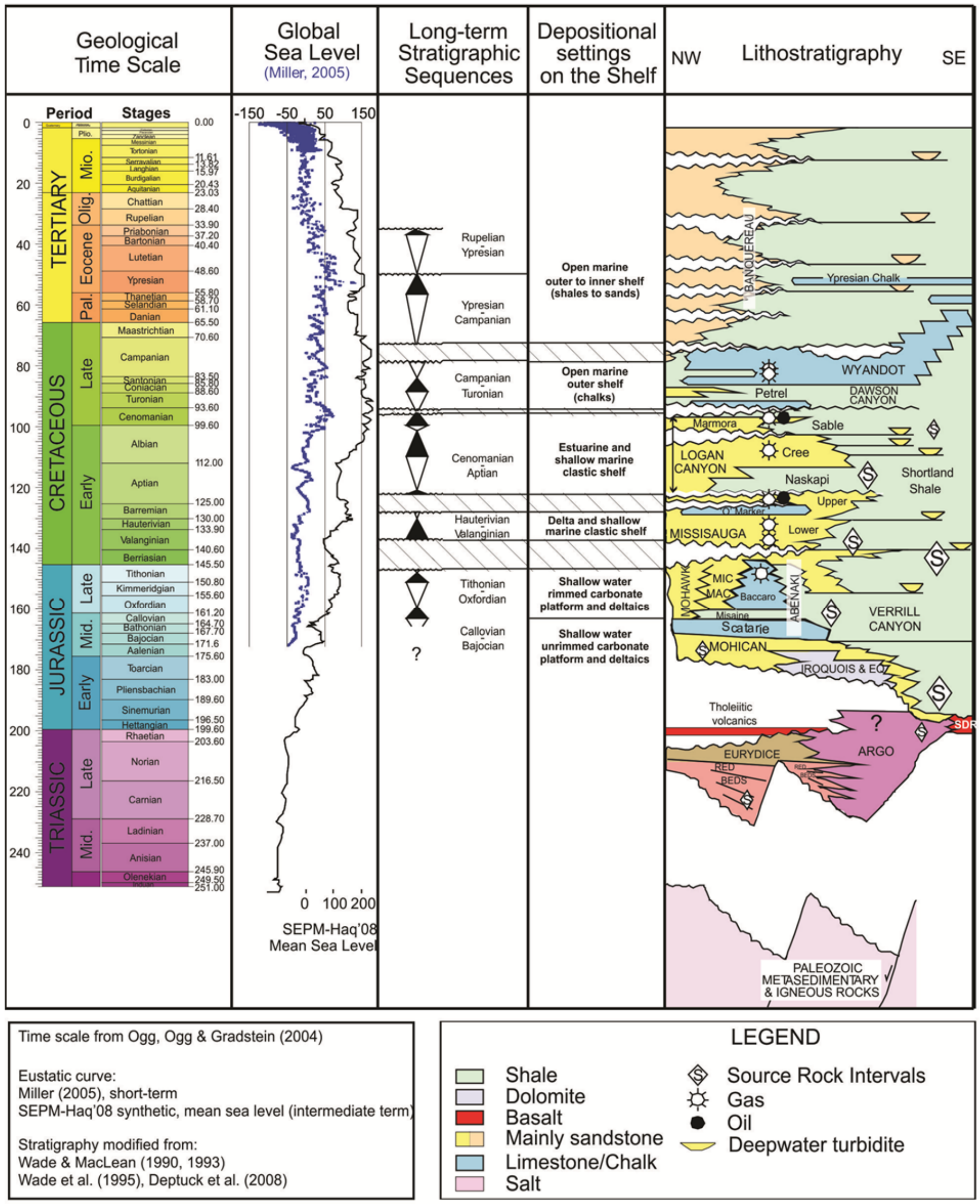

Figure 1.2 Stratigraphic chart, Scotian Basin (CNSOPB, 2002; modified by OETRA, 2011)

2 Methodology

2.1 Abbreviations

BB	Billion barrels (10^9)
BBL	Barrel
Bcf	Billion cubic feet (10^9)
BOE	Barrels of Oil Equivalent
BOEB	Billion of Oil Equivalent Barrels
Bpd	Barrels per day
CGR	Condensate Gas Ratio
DST	Drillstem test
E3M3/D	Thousand cubic meters per day
E6	Million
E9	Billion
FVF	Formation Volume Factor
GDT	Gas Down To
GWC	Gas-Water-Contact
h	height
MB	Thousand barrels (10^3)
Mcf	Thousand cubic feet (10^3)
mD	Millidarcies
MMB	Million barrels (10^6)
m^3	Cubic Meters
MMscf	Million standard cubic feet (10^6)
m MD	Meters Measured Depth
m TVD	Meters True Vertical Depth
MMscf/d	Million standard cubic feet per day
OGIP	Original-Gas-In-Place
OOIP	Original-Oil-In-Place
Sh	Hydrocarbon saturation
Sw	Water Saturation
Tcf	Trillion cubic feet (10^{12})
Vsh	Shale Volume
WUT	Water-Up-To

2.2 Seismic Time to Depth Map Conversion

Seismic derived velocity data was not available to the CNSOPB so a simple "layer cake" depth conversion method was used to convert all time maps to depth. This method involves converting individual isochrons to thicknesses and adding them together. The layers used for the calculations were:

1. Sea Level datum → Sea Floor
2. Seafloor → Top Wyandot Fm. (Late Cretaceous)
3. Top Wyandot → O-Marker (Missisauga Fm. (Early Cretaceous))
4. O-Marker → Reservoir Horizon

For each structure, an isochron map was produced from each of these intervals. An average velocity was calculated that would provide the best conversion of each isochron map to the corresponding measured thickness at the well or wells on the structure. This method provides a perfect well tie for single well structures but does not incorporate lateral velocity variations. The small areal extent of each map minimizes the error induced by this limitation.

Most undeveloped SDs are penetrated by a single well. This only provides one data point per zone for each well log derived parameter such as porosity, net pay and water saturation. In order to account for geological variations over a pool area, all parameters were assigned a range of inputs that were used to complete a probabilistic analysis of the in-place and recoverable hydrocarbon volumes for each field.

2.3 Assessment Calculation Input Variables

Calculations of original hydrocarbon in-place were undertaken using the following standard volumetric equation, employed within a Latin Hypercube (Monte Carlo style) probabilistic simulation using the @Risk™ software package.

$$OHIP = A * h * \phi * (1 - S_w) * FVF$$

$OHIP$ = Original Hydrocarbon (Gas/Oil) in Place (m^3)
A = Areal extent of the accumulation (Km^2 * 1,000,000)
h = Average Net Pay for the reservoir zone (m)
ϕ = Average Porosity (Fraction)
S_w = Average Water Saturation (Fraction)
FVF = Formation Volume Factor for the hydrocarbon (m^3/m^3)

The input variables used in the @Risk™ probabilistic simulation software were defined as triangular distributions based on minimum (P100), most likely (P50) and maximum (P00) justifiable values.

In order to calculate the in-place and recoverable hydrocarbon volumes for each reservoir zone, an analysis of the available well and seismic data was undertaken in the following manner:

1) Seismic interpretation using the most recent SEGY data available to the CNSOPB was conducted. This included:
    a. Interpreting and mapping of the key horizon(s) at or near the main reservoir zones for each field.
    b. Mapping intra-field and bounding faults.
    c. Time to depth conversion of the horizon maps to generate depth structure maps.

2) A petrophysical analysis of all wells in each field was completed that included:
    a. Splicing, editing and depth shifting well log data.
    b. Identification of significant hydrocarbon-bearing reservoir zones.
    c. Analysis of available core data to determine porosity/permeability relationships, assist in log calibration and to identify appropriate net pay cutoffs.
    d. Pressure/Depth analysis using available well test data and wireline pressure measurements (e.g. MDT, RFT). This data was used to determine formation pressures and to help define fluid contacts.
    e. A review of all well test data was conducted that included the following: type of fluid recovered from each zone (e.g. gas, oil, water), flow rates and formation water salinity. The fluids recovered during testing were also used to help constrain fluid contacts.
    f. Petrophysical analysis was conducted to determine, for each zone: net reservoir and net pay thickness, porosity, water saturation and volume of shale.
    g. Selection of appropriate net pay cutoffs and tabulation of the results.

3) For each zone, depth maps and the results of the petrophysical evaluation were analyzed to interpret the areal extent of the hydrocarbon accumulation.

4) Formation Volume Factors (FVFs) were determined using available well data.

5) Recovery factors were assigned to provide a reasonable estimate of the technically recoverable reserves in each zone. It should be noted, that while a zone may contain technically recoverable hydrocarbons, these reserves may not be economically recoverable.

6) In-place and recoverable hydrocarbon volumes along with associated condensate and solution gas were calculated using @Risk™ probabilistic software.

7) In-place and recoverable hydrocarbons were tabulated.

On the in-place and recoverable hydrocarbon volume tables, four output values are labeled as P90/Low, P50/Med, P10/High, and Mean. P90 represents a value with a 90% chance of being equaled or exceeded, at P50 there is a 50% chance that the indicated value will be equaled or exceeded, and at P10 there exists a 10% chance that the indicated value will be equaled or exceeded. The Mean is the expected value; the sum of all samples divided by the total number of samples, and as such also represents the most likely value or the Best Current Estimate (BCE). The input parameters required for each zone for the volumetric calculations are discussed below.

Area

The first step in determining the areal extent of each zone was to project interpreted fluid contacts onto the nearest depth structure map. Where zonal fluid contacts (e.g. GWC) could not be accurately determined from well logs alone, fluid levels were "bracketed" to define the extent of each accumulation, e.g. WUT (WUT), gas-down-to (GDT) etc. Where available, well test data was also reviewed to ensure the interpreted fluid contacts were consistent with DST recoveries. The interpreted fluid contacts were used in conjunction with mapped spill-points to determine the P50 or most likely area for each zone. For most zones, the P100 area (minimum) was determined by subtracting 10% from the P50 area and the P00 area (maximum) was defined by adding 10% to the P50 area. The 10% increase and decrease to the P50 area was assigned to allow for mapping uncertainty.

Net Pay Thickness

The net pay of each zone was calculated from the petrophysical analysis. Since many of the fields have only a single well penetration, there is considerable uncertainty in the net pay values across the field. For these fields, the petrophysically calculated value was typically used as the P50 net pay input parameter. For fields with multiple wells, the P50 value was defined by averaging net pay values across the field. For all fields, calculated well values, seismically mapped zone extents and interpreted depositional environments, (e.g. channel or sheet sand) were reviewed to determine ranges for P100 and P00 net pay input values. In many cases, P100 and P00 net pay inputs were varied symmetrically around the P50 value. Hydrocarbon zones with total net pay of less than 1 m were not included in the resource assessment.

Average Porosity

Porosity was calculated using the density, density/neutron and sonic logs. The preferred porosity was generally the core-adjusted density porosity. Where bad hole conditions (e.g. washout) had an impact on density readings, the sonic log was used to calculate porosity. Where gas crossover was noted, the density/neutron cross-plot porosity was used. For fields with only one well, the petrophysically calculated values were typically used as the P50 porosity input. For fields with multiple wells, P50 values were assigned by "averaging" porosity values across the field. Calculated well values, interpreted depositional environments, and facies were reviewed to determine the degree of porosity variation for the P100 and P00 input values. In many cases, the P100 and P00 porosity inputs were varied symmetrically around the P50 value.

Average Water Saturation

Formation water resistivity (Rw) was typically determined from the analysis of formation water samples recovered from well tests and wireline formation testers. Water saturation (Sw) was calculated using the Archie water saturation equation. The P50 Sw input values were assigned by considering factors such as the petrophysically calculated well values, interpreted reservoir quality distributions, well location(s) on the structure and hydrocarbon column heights. The P100 and P00 Sw input parameters were varied depending on the degree of uncertainty in the above factors. In zones with a lower degree of uncertainty, the P100 and P00 variations were relatively minor (i.e. P50 Sw value +/- 5 saturation units). Larger variations were assigned where the level of uncertainty was greater.

Formation Volume Factors/Shrinkage Factors

Formation Volume Factors (FVFs) are based on hydrocarbon composition, reservoir pressure and temperature and standard pressure and temperature. The P50 values were derived by correlations based on specific gravity, reservoir pressure and reservoir temperature obtained from well tests. The P100 and P00 inputs where assigned based on uncertainties in composition and the other primary variables.

Recovery Factor

In assigning the P50 recovery factors (RFs) a number of factors were considered including, the conceptual depletion plan (typically one well per major fault compartment), reservoir quality and distribution, structural relief, hydrocarbon column height, proximity of fluid contacts in both vertical and horizontal directions and the degree of reservoir compartmentalization (field complexity). The P100 and P00 RF input parameters were varied depending on the degree of uncertainty in the above factors.

In-Place and Recoverable Hydrocarbons

Using the assigned input parameters, described above, the hydrocarbon volume is calculated probabilistically for each zone. The mean and standard deviation resulting from the above probabilistic calculations, of each zone, is used in a log-normal distribution to probabilistically calculate the total in-place and recoverable hydrocarbons for each field.

Probability Parameter Input Template Example

The following table is an example of the @Risk™ input parameters for Zone 5 in the Arcadia field. Values in blue are variables unique to each zone and are provided in the appropriate sections. Values in red remain constant for all calculations.

Field: Arcadia

Zone: 5

Reservoir Parameters	Probability			
	1	0.5	0	MEAN
Total Field Area (km^2)	19.6	21.75	23.9	21.75
Net Pay (m)	6	11	14	10.333333
Porosity	0.08	0.1	0.12	0.1
Hydrocarbon Saturation	0.4	0.5	0.6	0.5
Depth of Reservoir (m)	5150	5175	5200	5175
Z	1.067	1.04	1.015	1.0406667
Gas Volume Factor	388.2	399.5	410.5	399.2
Fraction of Pore Volume Oil Bearing	0	0	0	0.000
GOR (m3/m3)	299.58	301.03	302.48	301.03
Formation Volume Factor (Oil)	1.963	1.968	1.972	1.968
Liquids Yield (BBL/MMCF)	8	10	12	10
Oil Recovery Factor	0.15	0.3	0.45	0.3
Gas Recovery Factor	0.3	0.5	0.65	0.4833333
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

Risk Parameters		
Play Adequacy	100	1

Other Parameters				
Pressure gradient (kPa / m)	12.657	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	3.4	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	177.4	178.25	179.1	178.25
Reservoir Pressure (kPa)	65284.85	65601.28	65917.70	65601.28

3 Significant Discovery Field Assessments

3.1 Arcadia - Significant Discovery

3.1.1. Overview

The Arcadia field is located approximately 30 km northeast of Sable Island. (Fig. 1.1) The field was discovered in 1983 and this assessment is based on the discovery well.

Discovery Well

Well:	Arcadia J-16
Company:	Mobil et al.
Spud:	27-Jan-83
Well Termination:	19-Jul-83
Total Depth:	6005 m
Water Depth:	55.5 m
Latitude:	44° 05' 43.58" N
Longitude:	59° 31' 58.19" W
Target:	Drilled to test for hydrocarbons in the Late Jurassic to Early Cretaceous sands incorporated in a large rollover anticline associated with a down-to-the-basin growth fault

Additional Wells

No delineation drilling conducted.

3.1.2. Structure

The Arcadia structure results from a rollover anticline bounded by two down-to-basin growth faults as shown on the seismic line (Fig. 3.1.1). There are six reservoir zones, all within the Late Jurassic Mic Mac Formation. Two surfaces were mapped and used to represent the structural configuration of all six gas bearing zones. The Zone 3 horizon (orange), with corresponding depth map (Fig. 3.1.2), was used to determine closure areas for Zones 1, 2, and 3. The Zone 5 horizon (red), with corresponding depth map (Fig. 3.1.3), was used to calculate closure areas for Zones 4, 5, and 6.

Structural closure at all levels is dependent on high-side fault seal to the south, and a structural saddle spill point to the west. The P50 area contour for each map is shown in purple. The well was drilled down dip from the crest and near the western structural spill point.

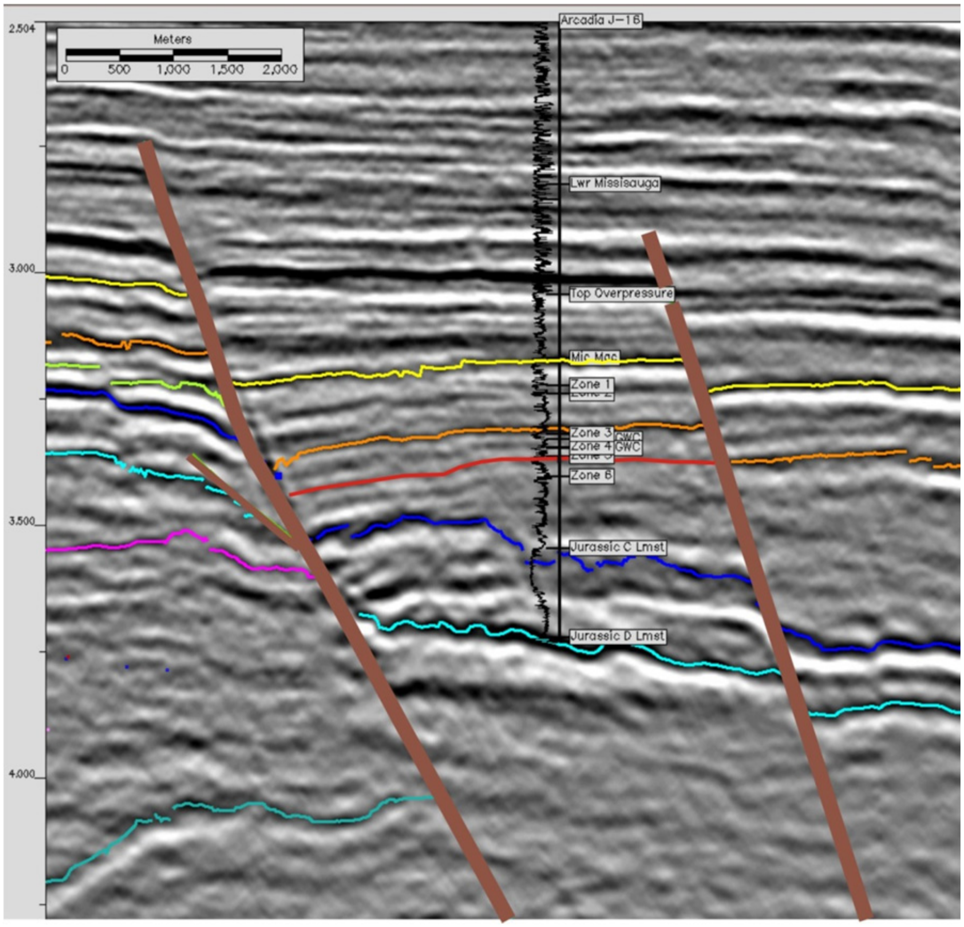

Figure 3.1.1 Arcadia seismic time line showing gamma ray log.

Seismic data quality through the deeper reservoir sections (red horizon) is poor near the fault (Fig. 3.1.1) and this structural uncertainty is reflected in the range of probabilistic input parameters chosen.

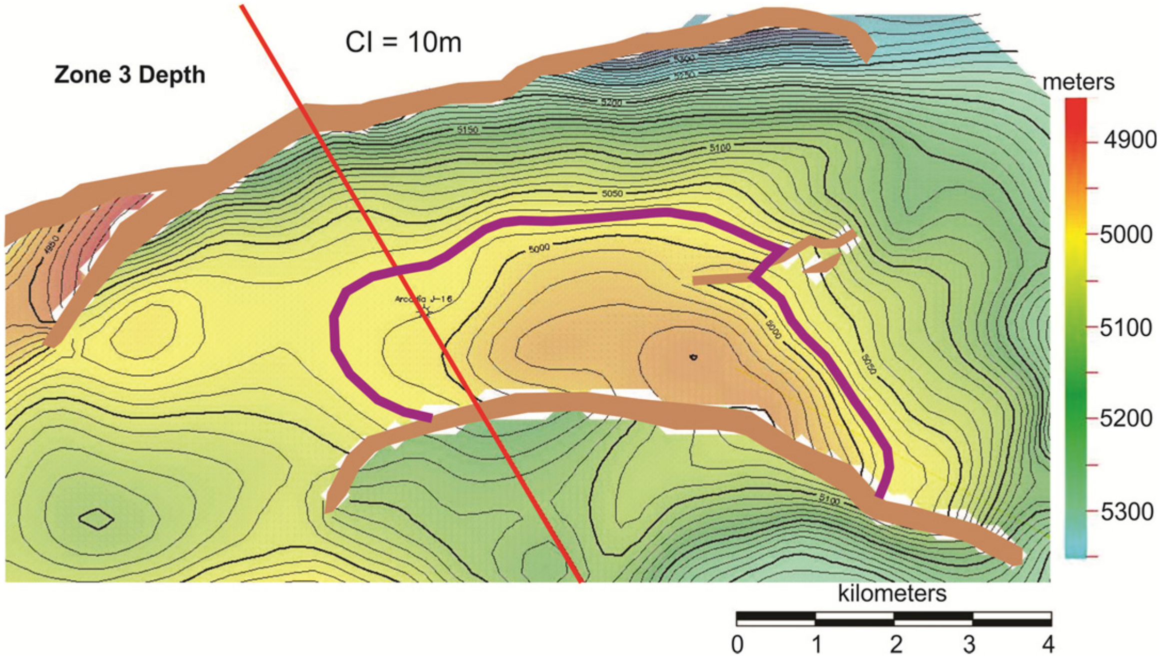

Figure 3.1.2 Arcadia Zone 3 depth map used for Zones 1–3.

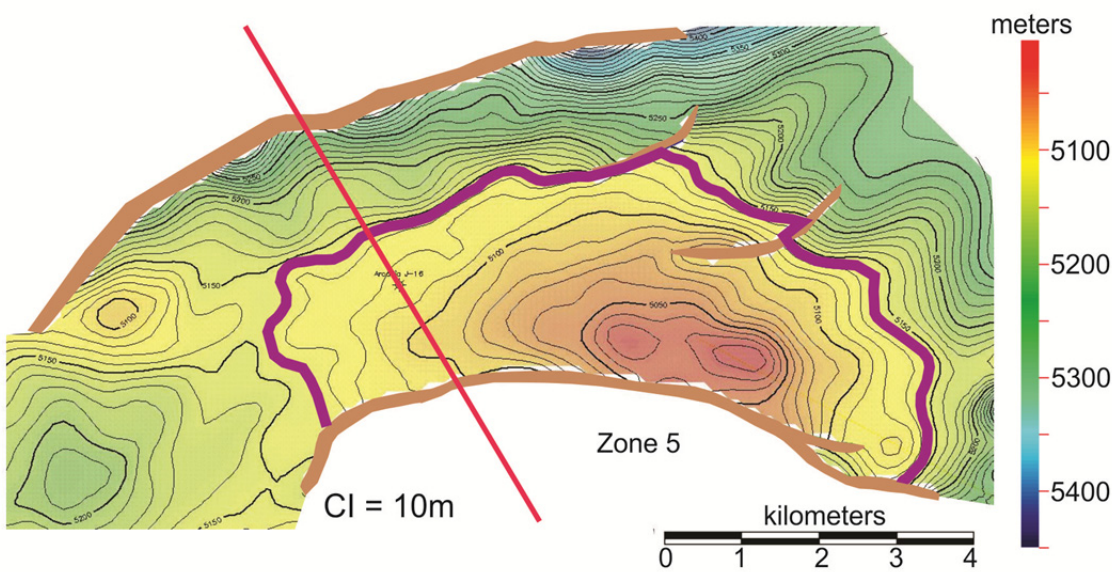

Figure 3.1.3 Arcadia Zone 5 depth map used for Zones 4–6.

3.1.3. Reservoir Description

The Arcadia J-16 exploratory well is located in the western portion of the Arcadia field. Six gas bearing reservoir sands were encountered over a 380 meter thick section, and are stratigraphically located within the Late Jurassic Mic Mac Formation. Structural mapping and well data interpretations suggest that the reservoir strata is equivalent to that of the Venture field immediately to the south, although direct sand-to-sand correlations are uncertain. The reservoir sands are very fine to medium grained, well sorted, siliceous and calcareous and generally have coarsening upward profiles. These reservoirs consist of stacked sequences of cyclic deltaic and shoreface sands interfingering with marine and prodelta shales. These capping shales and intermittent tight limestones provide effective top seals within the succession. Log profiles and cores of the Mic Mac reservoir strata reflect delta front, channel and shoreface deposition with tidal facies also present. The geometry of the reservoir sands are interpreted to have good lateral continuity along strike though they may thin and deteriorate toward the field's southern margin. The Arcadia gas reservoirs are deep and exist under hard overpressure conditions.

3.1.4. Formation Evaluation

Four of the six Arcadia gas zones were flow tested (Table 3.1.1). Gas flow rates varied from 5 to 14 MMscf/d. The Arcadia reservoirs have low to modest porosities, with an unstressed core porosity range of 0.06–0.16. Core permeabilities are generally between 0.03 and 1 mD with values up to 45 mD. Due to relatively low porosity and permeability of the Arcadia zones, calculated net pays are relatively modest and water saturations are elevated. Log defined gas-water contacts were identified in Zones 3 and 4 while other zones are gas-down-to (GDT) base of porosity in the sand. Results of the Arcadia J-16 petrophysical assessment are shown below (Table 3.1.2; Figs. 3.1.4–3.1.6).

Table 3.1.1 Arcadia J-16 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	5606-5620	N/A (tight)	Mic Mac	No Rec			No Rec		
DST 2	5227-5235	6	Mic Mac	No Rec			No Rec		
DST 5	5165-5175	5	Mic Mac	399	14	12	14.1	88.1	75.5
DST 6	5031-5041	N/A (wet)	Mic Mac			1824			11,473
DST 8	4892-4901	2	Mic Mac	161		7	5.7		44
DST 9	4857-4864	1	Mic Mac	147	1	5	5.2	6.3	31.4
DST 10	4640-4645	N/A (wet)	Missisauga			175			1,101

Table 3.1.2 Arcadia J-16 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	Gross Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	4857.5	4891.5	34.0	2.0	0.069	0.54
Zone 2	4891.5	4902.0	10.6	4.4	0.082	0.43
Zone 3	5071.0	5089.3	18.3	4.0	0.103	0.54
Zone 4	5117.5	5126.0	8.5	1.8	0.079	0.54
Zone 5	5147.3	5180.0	32.7	11.6	0.096	0.53
Zone 6	5217.8	5240.0	22.3	1.8	0.098	0.56
Net Pay Cutoffs: Porosity >=0.08, GR <=40, Sw <=0.70						

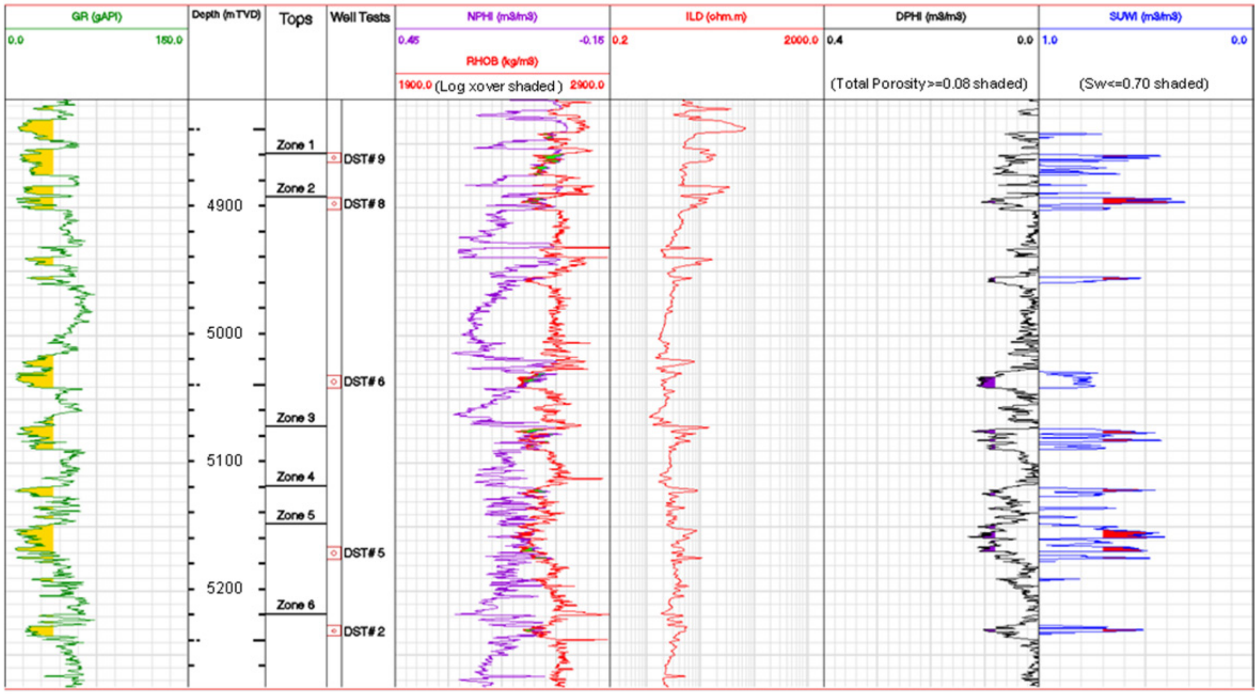

Figure 3.1.4 Arcadia J-16 petrophysical results plot: all zones.

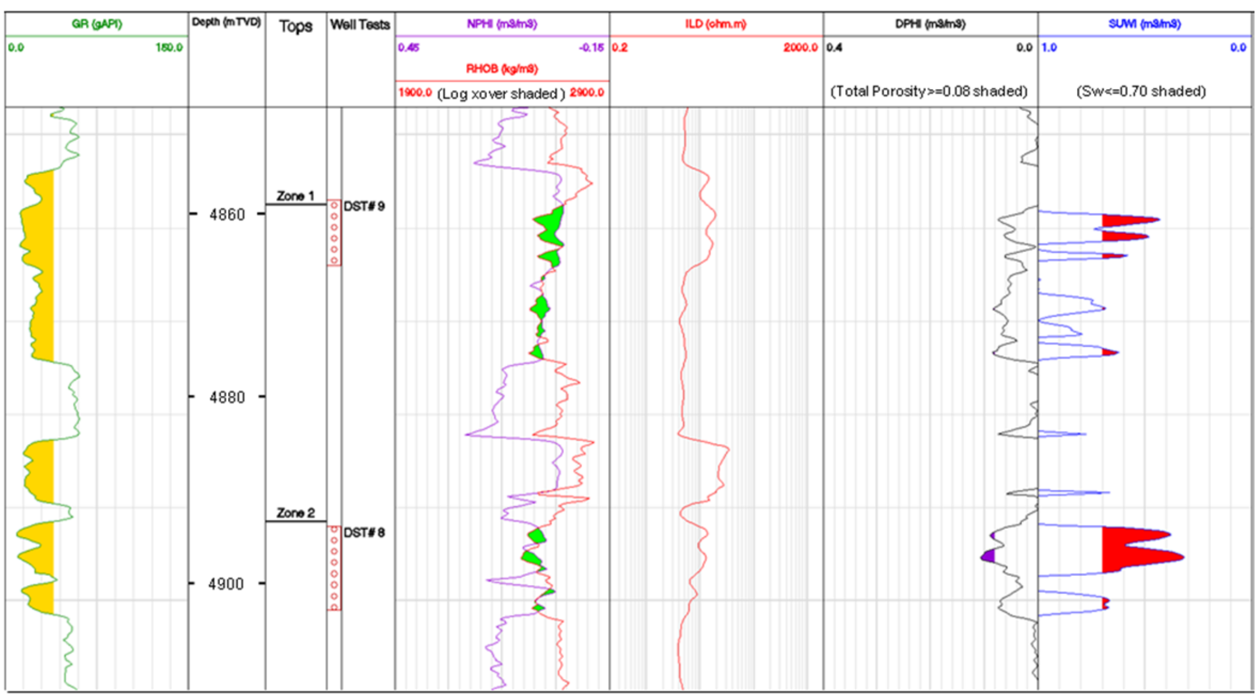

Figure 3.1.5 Arcadia J-16 petrophysical results plot: Zones 1 and 2.

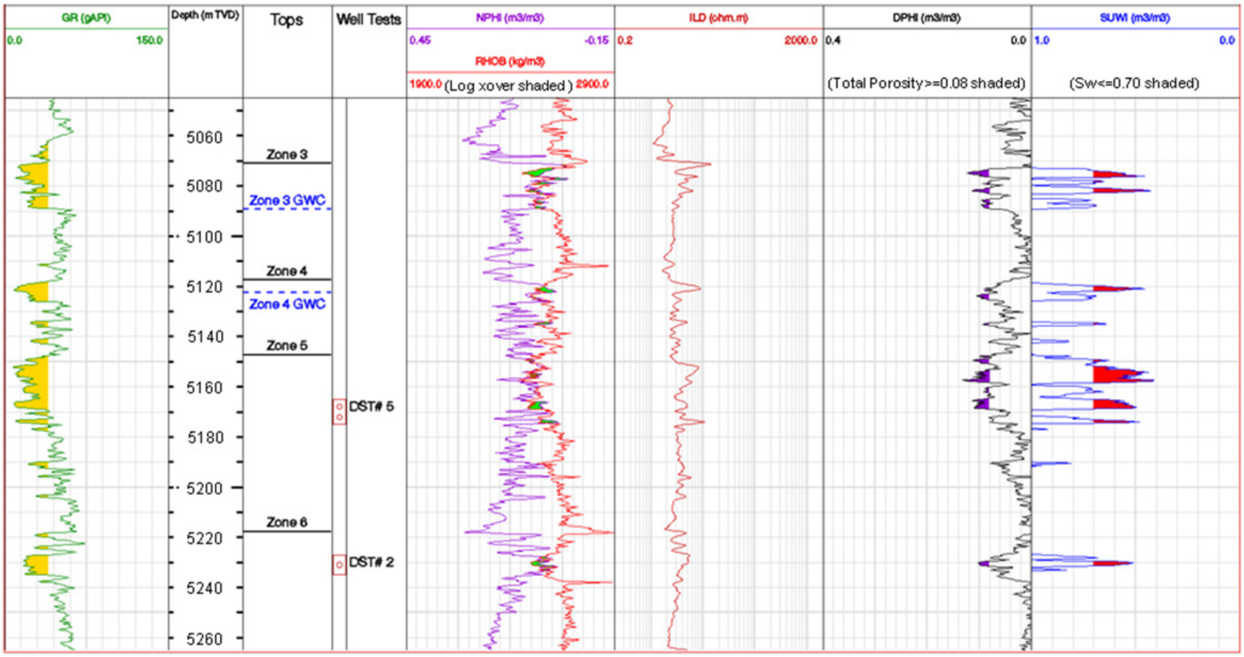

Figure 3.1.6 Arcadia J-16 petrophysical results plot: Zones 3–6.

3.1.5. Resource Assessment

For Arcadia Zones 1–3, the Zone 3 depth map was used to define reservoir extent. This map was selected due to proximity and conformability to the zones. For Zones 4–6, the Zone 5 depth map was used to determine area.

Zones 1 and 2 contain GDT on logs while Zone 3 has an observed GWC. These fluid levels were projected on to the Zone 3 depth map and coincided with the structural spill point to the west. This closing contour was used to define the P50 area for Zones 1–3. The minimum and maximum areas for these zones were assigned by varying the P50 value +/-10% to allow for mapping uncertainty.

Zone 4 has an observed GWC while Zones 5 and 6 are GDT on logs. These fluid levels were projected on to the Zone 5 depth map and were found to be consistent with the structure being filled to the western spill point. This closing contour was used to define the P50 area for Zones 4–6. Minimum and maximum areas for these zones were assigned by varying the P50 value +/-10% to allow for mapping uncertainty.

A few wet sands are present in the Arcadia reservoir interval between Zones 1 and 6. These sands may be gas bearing updip but are outside of closure and wet at the J-16 well location. Because updip gas presence in these sands is uncertain, it was not included in the resource assessment.

P50 input parameters for net pay, porosity and hydrocarbon saturation were based on petrophysically-calculated well values. Net pay and porosity inputs were generally assigned more upside as these parameters are expected to improve distally towards the north bounding fault. Given the low porosity and permeability of Arcadia sands, assigned zonal recovery factors (RFs) ranged from 25 to 65% with P50 values at or near 50%.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.1.3).

Table 3.1.3 Arcadia probabilistic volume calculation variables.

Zone 1	P100	P50	P00	Mean
Area (km^2)	12.1	13.4	14.7	13.4
Net Pay (m)	1.0	2.0	4.0	2.33
Porosity (fraction)	0.06	0.07	0.09	0.0733
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	385	395	405	395
CGR (BBL/MMCF)	8.0	10	12	10
Gas Recovery Factor	0.25	0.45	0.55	0.4167

Zone 2	P100	P50	P00	Mean
Area (km^2)	12.1	13.4	14.7	13.4
Net Pay (m)	2.0	4.0	7.0	4.33
Porosity (fraction)	0.06	0.08	0.11	0.0833
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	387	397	407	397
CGR (BBL/MMCF)	8.0	10.0	12.0	10.0
Gas Recovery Factor	0.30	0.50	0.60	0.4667

Zone 3	P100	P50	P00	Mean
Area (km^2)	12.1	13.4	14.7	13.4
Net Pay (m)	2.0	4.0	7.0	4.33
Porosity (fraction)	0.08	0.10	0.13	0.1033
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	396	406	416	406
CGR (BBL/MMCF)	8.0	10.0	12.0	10.0
Gas Recovery Factor	0.35	0.55	0.65	0.5167

Zone 4	P100	P50	P00	Mean
Area (km^2)	19.6	21.8	24.0	21.8
Net Pay (m)	1.0	2.0	4.0	2.33
Porosity (fraction)	0.06	0.08	0.11	0.0833
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	398	408	419	408
CGR (BBL/MMCF)	8.0	10.0	12.0	10.0
Gas Recovery Factor	0.30	0.50	0.60	0.4667

Zone 5	P100	P50	P00	Mean
Area (km^2)	19.6	21.8	24.0	21.8
Net Pay (m)	6.0	12.0	14.0	10.667
Porosity (fraction)	0.08	0.10	0.13	0.1033
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	399	410	420	409
CGR (BBL/MMCF)	8.0	10.0	12.0	10.0
Gas Recovery Factor	0.35	0.55	0.65	0.5167
Zone 6	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	19.6	21.8	24.0	21.8
Net Pay (m)	1.0	2.0	4.0	2.33
Porosity (fraction)	0.08	0.10	0.13	0.1033
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	403	413	423	413
CGR (BBL/MMCF)	8.0	10.0	12.0	10.0
Gas Recovery Factor	0.35	0.55	0.65	0.5167

3.1.6. Results

The probabilistic assessment results for the Arcadia field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.1.4 and 3.1.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.1.7 and 3.1.8).

Table 3.1.4 Arcadia probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP (E9m^3)	7.50	8.95	10.7	9.03
OGIP (Bcf)	265	316	378	319
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.255	0.394	0.592	0.411
OGIP (Bcf)	9.00	13.9	20.9	14.5
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.671	1.03	1.51	1.06
OGIP (Bcf)	23.7	36.2	53.4	37.6
Zone 3	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.872	1.31	1.87	1.35
OGIP (Bcf)	30.8	46.1	66.2	47.5
Zone 4	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.476	0.748	1.14	0.784
OGIP (Bcf)	16.8	26.4	40.4	27.7
Zone 5	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	3.14	4.36	5.86	4.45
OGIP (Bcf)	111	154	207	157
Zone 6	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.609	0.940	1.42	0.983
OGIP (Bcf)	21.5	33.2	50.1	34.7

Table 3.1.5 Arcadia probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	3.68	4.47	5.47	4.53
Rec. Gas (Bcf)	130	158	193	160
Rec. Condensate ($E6m^3$)	0.205	0.252	0.310	0.255
Rec. Condensate (MMB)	1.29	1.58	1.95	1.60
Zone 1	**P90**	**P50**	**P10**	**Mean**
Rec. ($E9m^3$)	0.100	0.162	0.255	0.171
Rec. (Bcf)	3.52	5.71	8.99	6.03
Rec. Condensate ($E6m^3$)	0.00557	0.00903	0.0145	0.00960
Rec. Condensate (MMB)	0.0350	0.0567	0.0908	0.0603
Zone 2	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.300	0.476	0.722	0.496
Rec. Gas (Bcf)	10.6	16.8	25.5	17.5
Rec. Condensate ($E6m^3$)	0.0165	0.0264	0.0412	0.0279
Rec. Condensate (MMB)	0.104	0.166	0.259	0.175
Zone 3	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.433	0.668	0.991	0.697
Rec. Gas (Bcf)	15.3	23.6	35.0	24.6
Rec. Condensate ($E6m^3$)	0.0240	0.0374	0.0564	0.0392
Rec. Condensate (MMB)	0.151	0.235	0.354	0.246
Zone 4	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.212	0.345	0.549	0.365
Rec. Gas (Bcf)	7.48	12.2	19.4	12.9
Rec. Condensate ($E6m^3$)	0.0117	0.0194	0.0309	0.0205
Rec. Condensate (MMB)	0.0736	0.122	0.194	0.129
Zone 5	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	1.55	2.25	3.11	2.30
Rec. Gas (Bcf)	54.7	79.3	110	81.1
Rec. Condensate ($E6m^3$)	0.0853	0.126	0.177	0.129
Rec. Condensate (MMB)	0.536	0.792	1.11	0.811
Zone 6	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.303	0.481	0.750	0.507
Rec. Gas (Bcf)	10.7	17.0	26.5	17.9
Rec. Condensate ($E6m^3$)	0.0167	0.0269	0.0425	0.0285
Rec. Condensate (MMB)	0.105	0.169	0.267	0.179

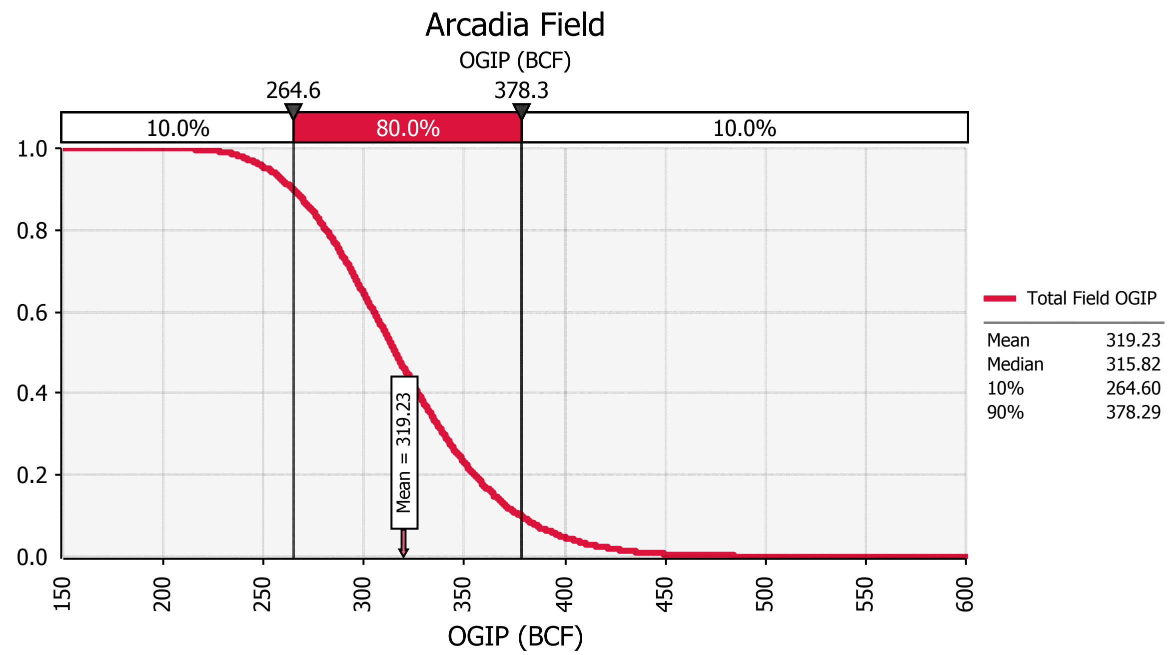

Figure 3.1.7 Arcadia OGIP descending cumulative probability chart.

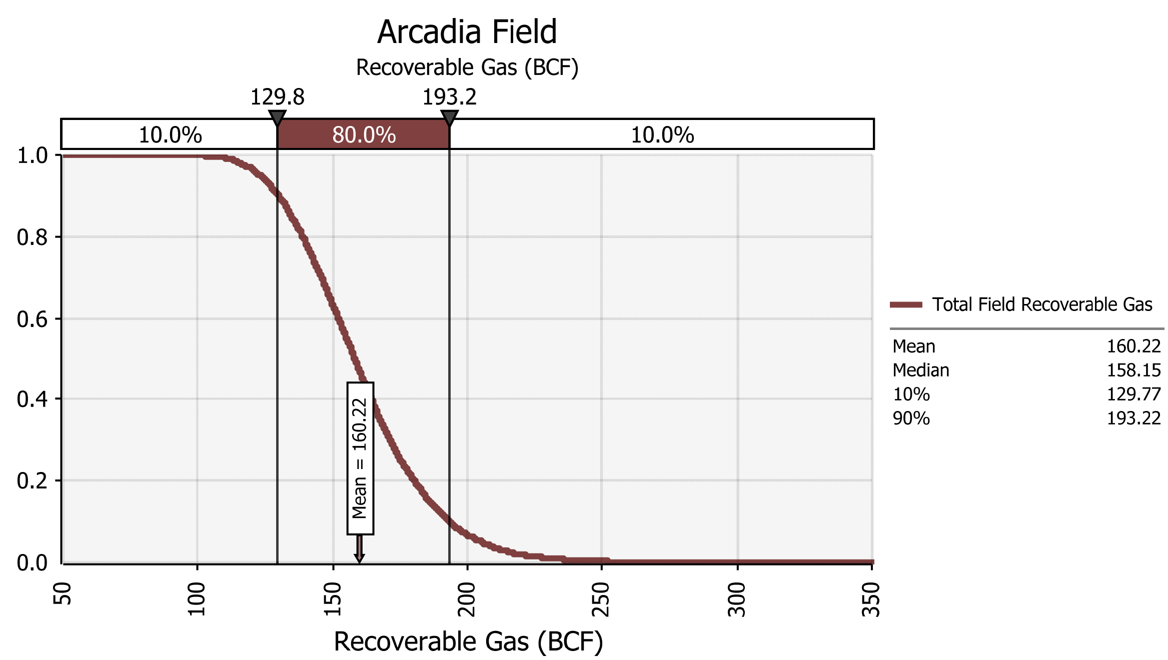

Figure 3.1.8 Arcadia recoverable gas descending cumulative probability chart.

3.2 Banquereau - Significant Discovery

3.2.1. Overview

The Banquereau field is located approximately 110 km east of Sable Island (Fig. 1.1). The field was discovered in 1982 and this assessment is based on the discovery well.

Discovery Well

Well:	Banquereau C-21
Company:	Petro-Canada et al.
Spud:	02-Dec-81
Well Termination:	01-Aug-83
Total Depth:	4991 m
Water Depth:	83m
Latitude:	44°10’07.52”N
Longitude:	58°34’00.24”W
Target:	Drilled to test for the presence of hydrocarbons in a rollover anticline associated with down-to-the-basin faults.

Additional Wells

No delineation drilling was conducted.

3.2.2. Structure

Only 2D seismic data was available over this structure which was created via motion along a major growth fault at the basin hinge zone formed by the underlying South Griffin Ridge (Fig. 3.2.1). Faulting penetrates into Tertiary age strata and soles into Jurassic marine shales of the Verrill Canyon Formation. The Top Missisauga horizon (yellow) has been used to create the Top Missisauga depth map (Fig. 3.2.2). Banquereau is a low relief, narrow, elongate anticlinal feature bounded to the north by this down-to-the-basin fault. The P50 area contour (purple) outlines the field extent as defined by the well’s gas column which would require structural and fault dependent closure. The reservoir is limited by an inferred leak point along the fault.

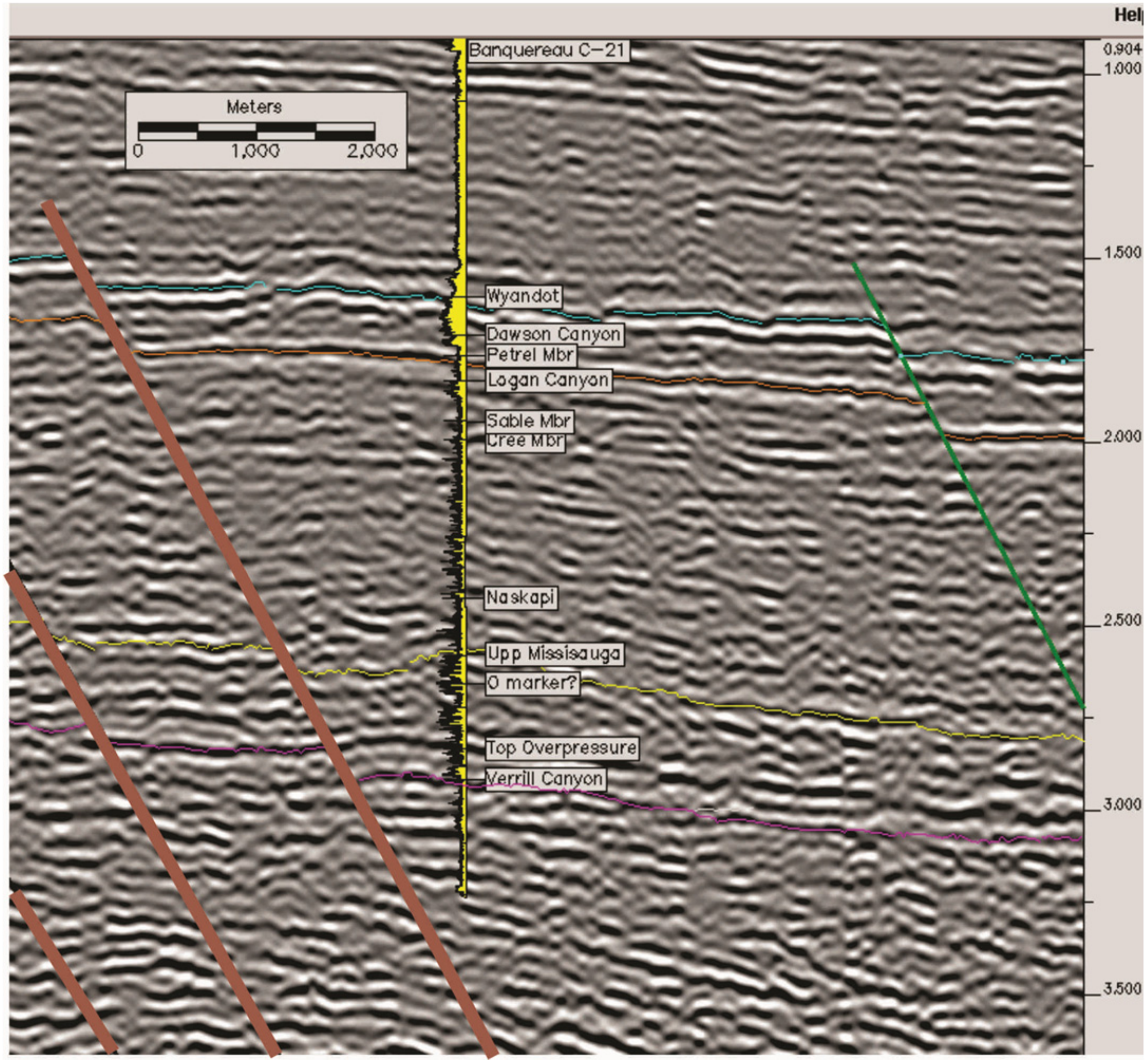

Figure 3.2.1 Banquereau 2D seismic time line showing gamma ray log.

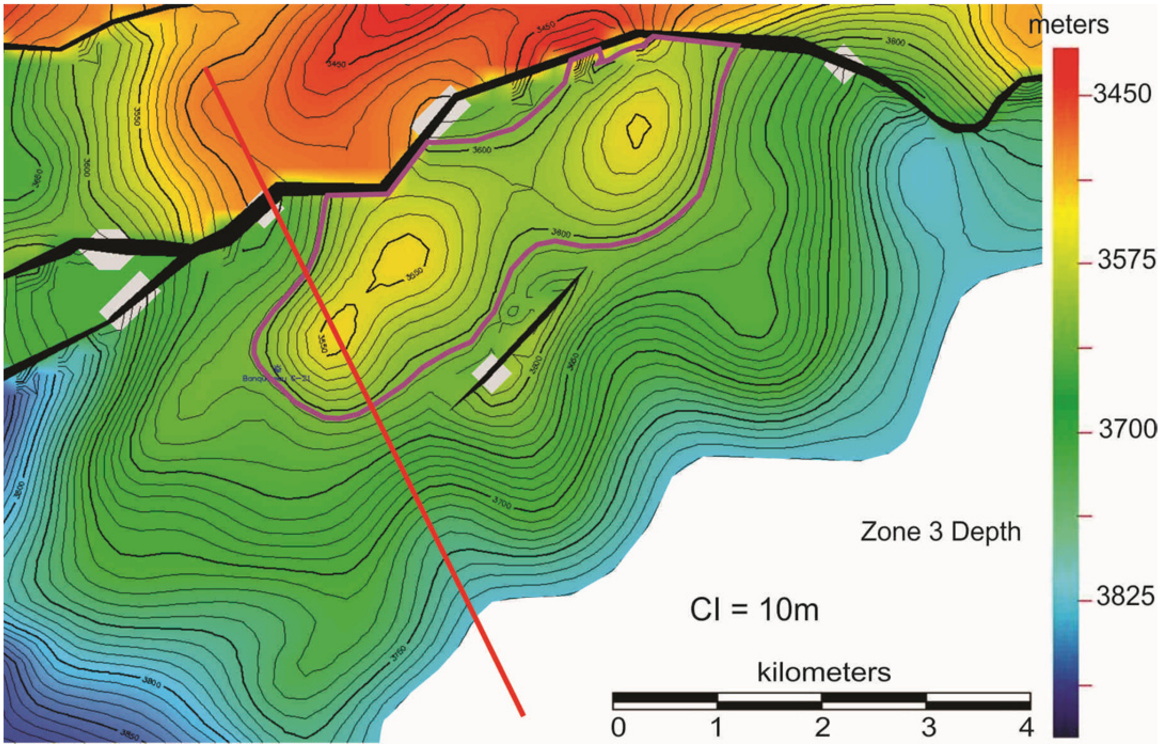

Figure 3.2.2 Banquereau Top Missisauga depth map used for Zones 1–3.

3.2.3. Reservoir Description

The Banquereau gas reservoirs are located within the Early Cretaceous (Aptian) Naskapi member of the Logan Canyon Formation, and at the top of the Missisauga Formation. The well was drilled on the flank of the structure encountering three gas zones, two in the Naskapi and one in the upper Missisauga.

The reservoir zones in the Banquereau field consist of delta front, channel and strandplain-shoreface depositional facies in a shale dominated marine setting. The sands are generally very fine to medium grained, well sorted, siliceous and variably argillaceous. They are interpreted to thicken toward the north bounding fault and have good lateral continuity. The Banquereau reservoirs are normally pressured and the top of overpressure is located within the deeper Verrill Canyon shales.

3.2.4. Formation Evaluation

Two of the three Banquereau gas zones were flow-tested (Table 3.2.1). Zone 1 flowed mostly water with minor gas with a GWC near the top of the perforations. Zone 3 flowed gas at 20 MMscf/d. All three gas zones have log and/or DST defined GWCs. The zones have fair-to-good average net pay porosity ranging from 0.12 to 0.17. The results of the Banquereau C-21 petrophysical assessments are shown below (Table 3.2.2; Figs. 3.2.3–3.2.5).

Table 2.1 Banquereau C-21 significant tests.

Test#	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	4035-4046.5	tight	Missisauga	TSTM			TSTM		
DST 2	3585-3596	3	Missisauga	566	15	6	20.0	100	37.7
DST 3	3360-3372.5	1	Logan Canyon	22		93	0.8	0	585
DST 4	4949-4991	tight	Missisauga	No flow to surface			No flow to surface		

Table 3.2.2 Banquereau C-21 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	Gross Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	3358.3	3372.9	14.6	2.6	0.123	0.50
Zone 2	3424.2	3444.5	12.4	6.7	0.167	0.46
Zone 3	3575.0	3635.6	30.0	15.4	0.169	0.33
Net Pay Cutoffs: Porosity >=0.10, Vsh <=40, Sw <=0.60						

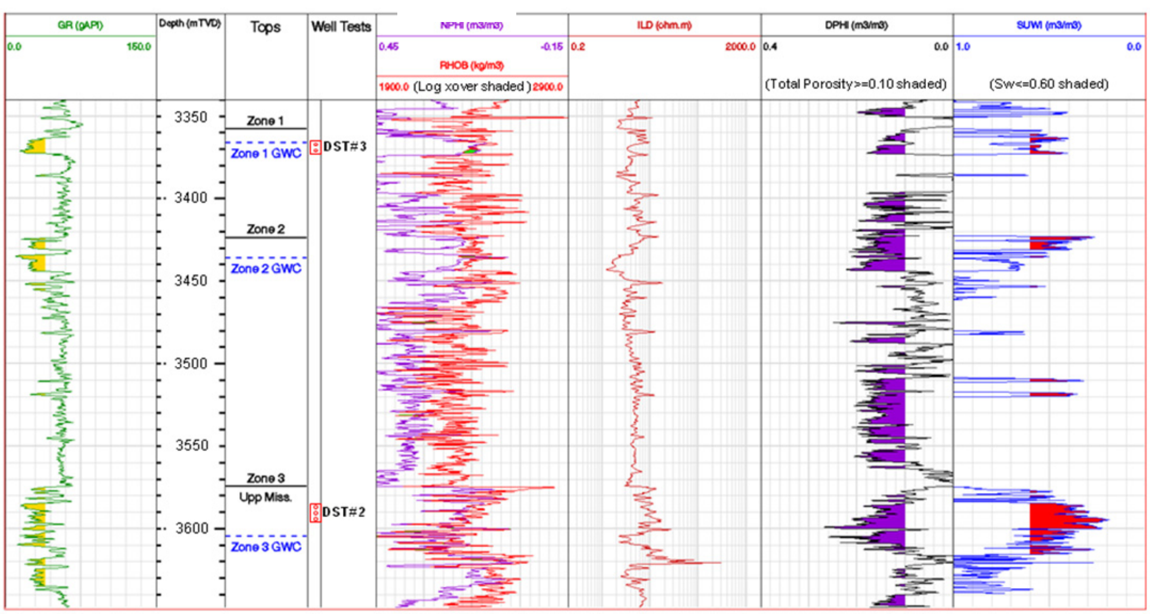

Figure 3.2.3 Banquereau C-21 petrophysical results plot: all zones.

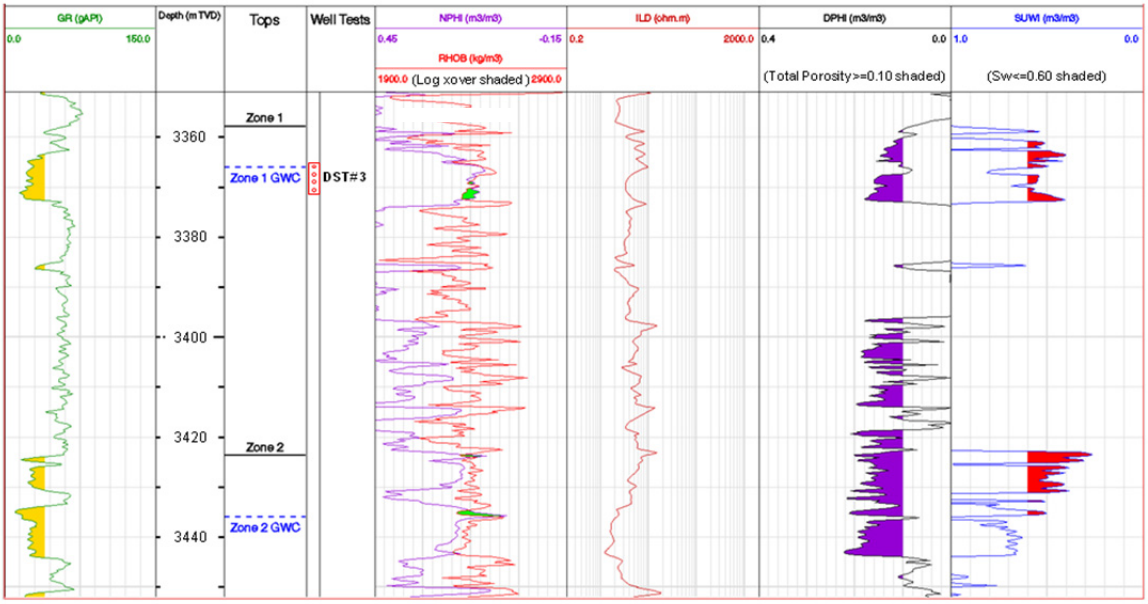

Figure 3.2.4 Banquereau C-21 petrophysical results plot: Zones 1 & 2.

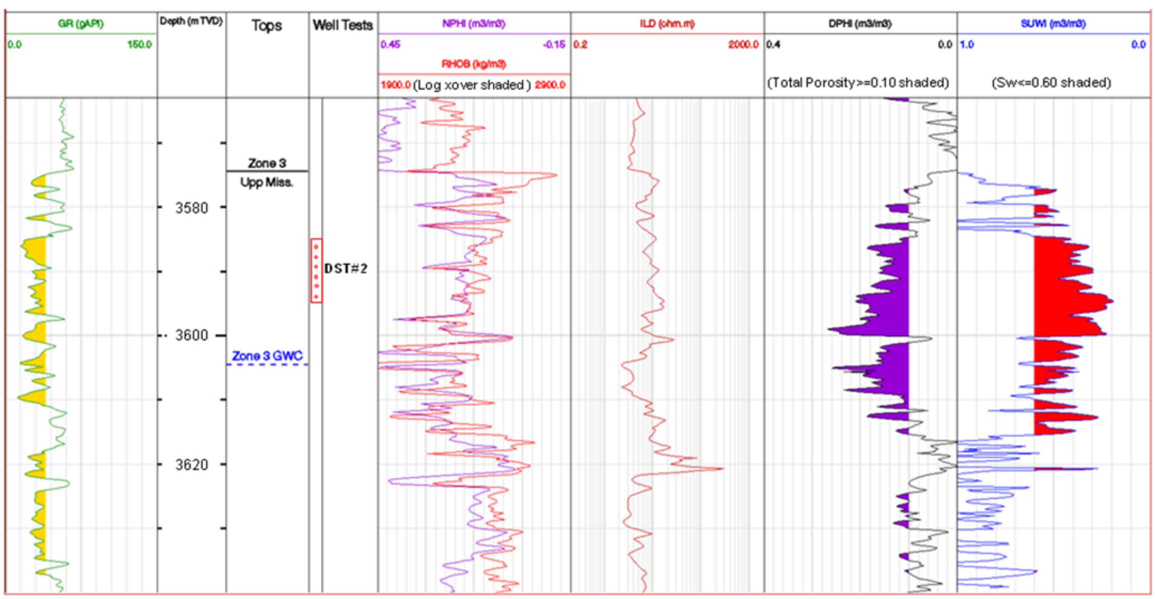

Figure 3.2.5 Banquereau C-21 petrophysical results plot: Zone 3.

3.2.5. Resource Assessment

The Top Missisauga depth map (Fig. 3.2.2) was used to define the structure for Zones 1, 2, and 3. Interpreted GWCs were projected on to the structure map to define the P50 area for each zone. Zone 3 had a greater gas column height than the other two zones which resulted in a larger P50 area. Based on uncertainty due to sparser 2D lines spacing, the P100 area was determined by decreasing the P50 area by 25% and the P00 area was defined by increasing the P50 area by 10%. This 2D line spacing results in a less constrained and possibly more optimistic area so more downside uncertainty was applied.

P50 input parameters for net pay, porosity and hydrocarbon saturation were based on petrophysically-calculated well values. P100 and P00 inputs for these parameters were varied symmetrically around P50 value.

Assigned zonal recovery factors for Banquereau were varied due to differences in sand thickness, reservoir quality and GWC elevation. Assigned P50 recovery factors varied from 50% for Zone 1, with the smallest gas column and poorest reservoir quality, to 65% for Zone 3 with the largest column and very good porosity. P100 and P00 inputs for recovery factor were varied symmetrically around the P50 value.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.2.3).

Table 3.2.3: Banquereau probabilistic volume calculation variables.

Zone 1	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	6.90	7.70	8.50	7.70
Net Pay (m)	1.5	2.5	3.5	2.5
Porosity (fraction)	0.10	0.12	0.14	0.12
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	263	268	273	268
CGR (BBL/MMCF)	3.0	5.0	7.0	5.0
Gas Recovery Factor	0.50	0.60	0.70	0.60

Zone 2	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	6.90	7.70	8.50	7.70
Net Pay (m)	5.0	7.0	9.0	7.0
Porosity (fraction)	0.14	0.17	0.20	0.17
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	267	272	277	272
CGR (BBL/MMCF)	3.0	5.0	7.0	5.0
Gas Recovery Factor	0.50	0.60	0.70	0.60

Zone 3	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	11.5	12.8	14.1	12.8
Net Pay (m)	12	15	18	15
Porosity (fraction)	0.14	0.17	0.20	0.17
Sh (1-Sw) (fraction)	0.55	0.65	0.75	0.65
Gas FVF	275	280	285	280
CGR (BBL/MMCF)	3.0	5.0	7.0	5.0
Gas Recovery Factor	0.55	0.65	0.75	0.65

3.2.6. Results

The probabilistic assessment results for the Banquereau field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.2.4 and 3.2.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.2.6 and 3.2.7).

Table 3.2.4: Banquereau probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP ($E9m^3$)	6.48	7.59	8.89	7.65
OGIP (Bcf)	229	268	314	270
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.226	0.306	0.402	0.311
OGIP (Bcf)	7.97	10.8	14.2	11.0
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.07	1.36	1.72	1.38
OGIP (Bcf)	37.6	47.9	60.6	48.6
Zone 3	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	4.81	5.91	7.18	5.97
OGIP (Bcf)	170	209	254	211

Table 3.2.5 Banquereau probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	6.48	7.60	8.89	7.66
Rec. Gas (Bcf)	143	170	202	172
Rec. Condensate ($E6m^3$)	0.105	0.134	0.171	0.136
Rec. Condensate (MMB)	0.661	0.840	1.08	0.858
Zone 1	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.111	0.153	0.205	0.155
Rec. Gas (Bcf)	3.90	5.39	7.22	5.49
Rec. Condensate ($E6m^3$)	0.00287	0.00421	0.00604	0.00436
Rec. Condensate (MMB)	0.0180	0.0265	0.0380	0.0274
Zone 2	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.627	0.811	1.04	0.826
Rec. Gas (Bcf)	22.1	28.7	36.9	17.5
Rec. Condensate ($E6m^3$)	0.0159	0.0226	0.0312	0.0232
Rec. Condensate (MMB)	0.100	0.142	0.196	0.146
Zone 3	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	3.08	5.91	7.18	5.97
Rec. Gas (Bcf)	109	135	167	137
Rec. Condensate ($E6m^3$)	0.0773	0.107	0.143	0.109
Rec. Condensate (MMB)	0.486	0.672	0.903	0.685

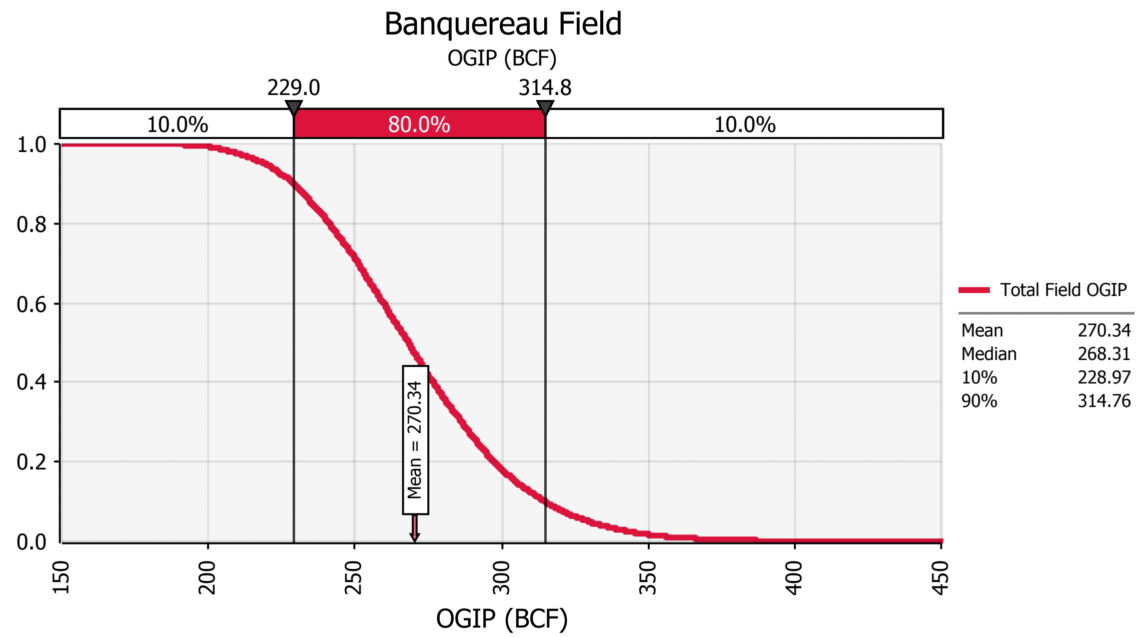

Figure 3.2.6 Banquereau OGIP descending cumulative probability chart.

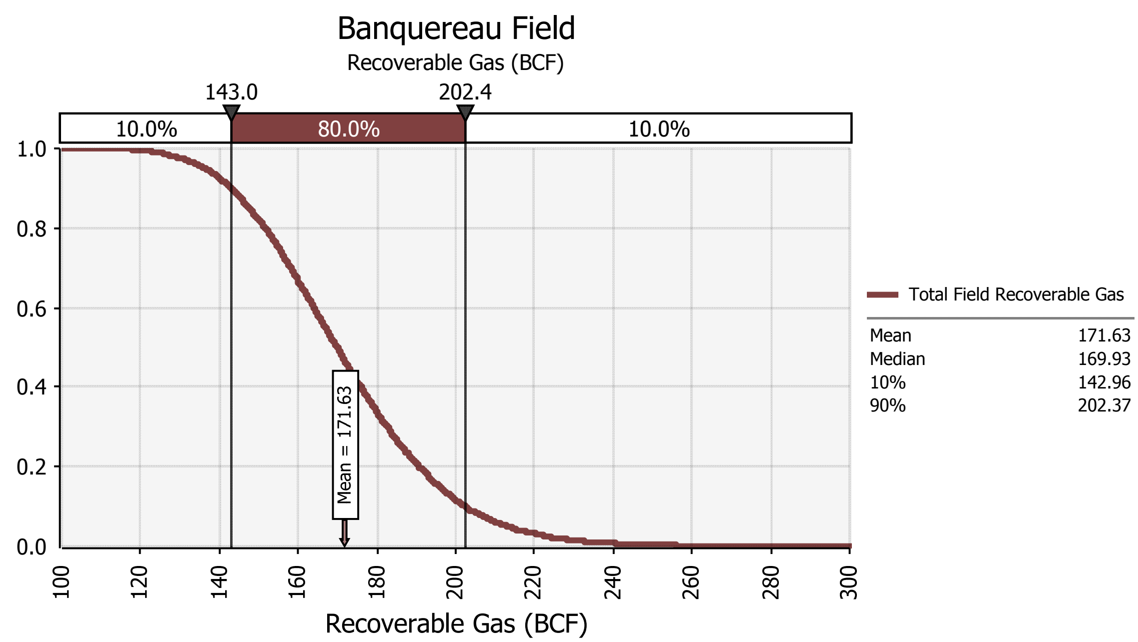

Figure 3.2.7 Banquereau recoverable gas descending cumulative probability chart.

3.3 Chebucto - Significant Discovery

3.3.1. Overview

The Chebucto gas field is located approximately 40 km south-east of Sable Island (Fig. 1.1). The field was discovered in 1984 and this assessment is based on the discovery well.

Discovery Well

Well:	Chebucto K-90
Company:	Husky-Bow Valley et al.
Spud:	06-Jan-84
Well Termination:	02-Aug-84
Total Depth:	5235 m
Water Depth:	86.2 m
Latitude:	43°39'44.74"N
Longitude:	59°42'52.05"W
Target:	Drilled to test for the presence of hydrocarbons in a large structural closure against a major down-to-the-basin fault.

Additional Wells

No delineation drilling was conducted.

3.3.2. Structure

The Chebucto structure is a rollover anticline associated with a down-to-basin growth fault that soles out along salt as shown on the seismic line (Fig. 3.3.1). The two seismic horizons interpreted to represent the reservoir zones were Zone 1 (red) and Zone 2 (orange). The structure is deeply incised by a lower Cretaceous canyon complex, one level of which is shown by the purple seismic horizon. Sands in the three Chebucto pay zones were created from depositional processes related to infilling of the canyon systems

The large north bounding fault and associated smaller crestal faults are evident on the Zone 1 depth structure map (Fig. 3.3.2). The P50 area (purple) indicates sealing crestal faults with a leak point at the intersection with the west bounding fault.

The Zone 2 depth map (Fig. 3.3.3) was used for the Zone 2 and 3 volumetric calculations. The P50 area contour (purple) has an inferred leak point at the east bounding fault.

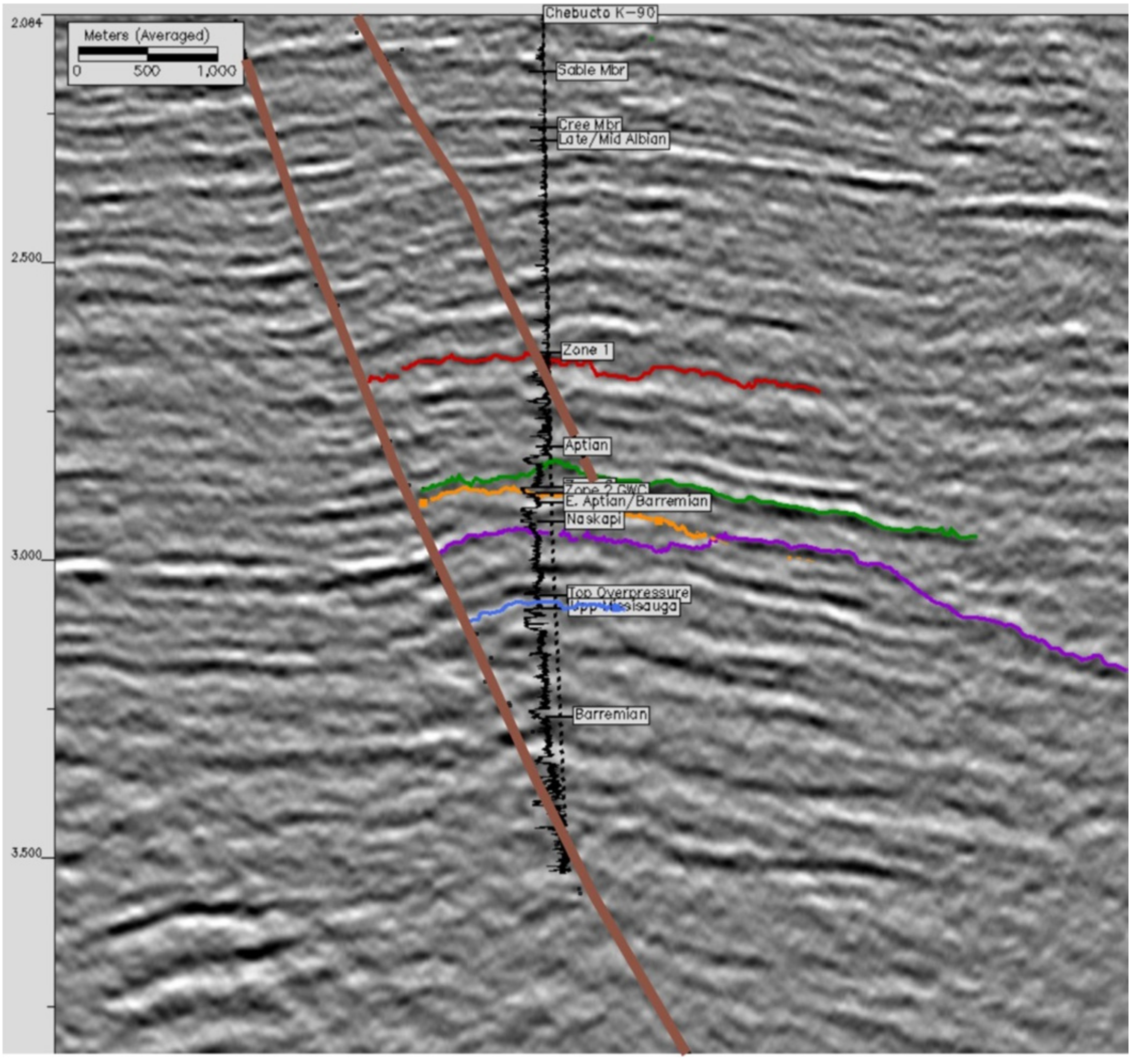

Figure 3.3.1 Chebucto seismic time line showing gamma ray log.

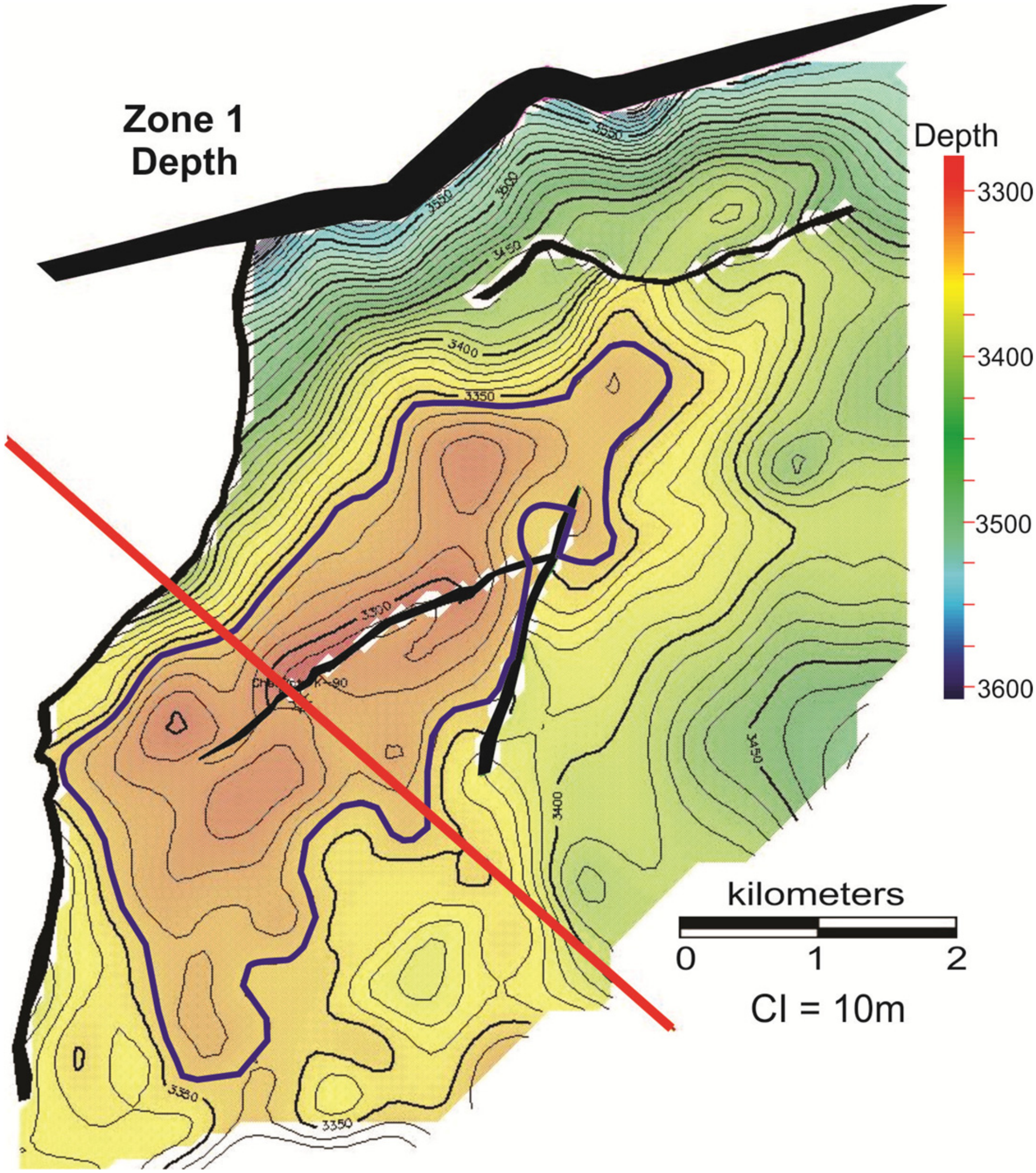

Figure 3.3.2 Chebucto Zone 1 depth map.

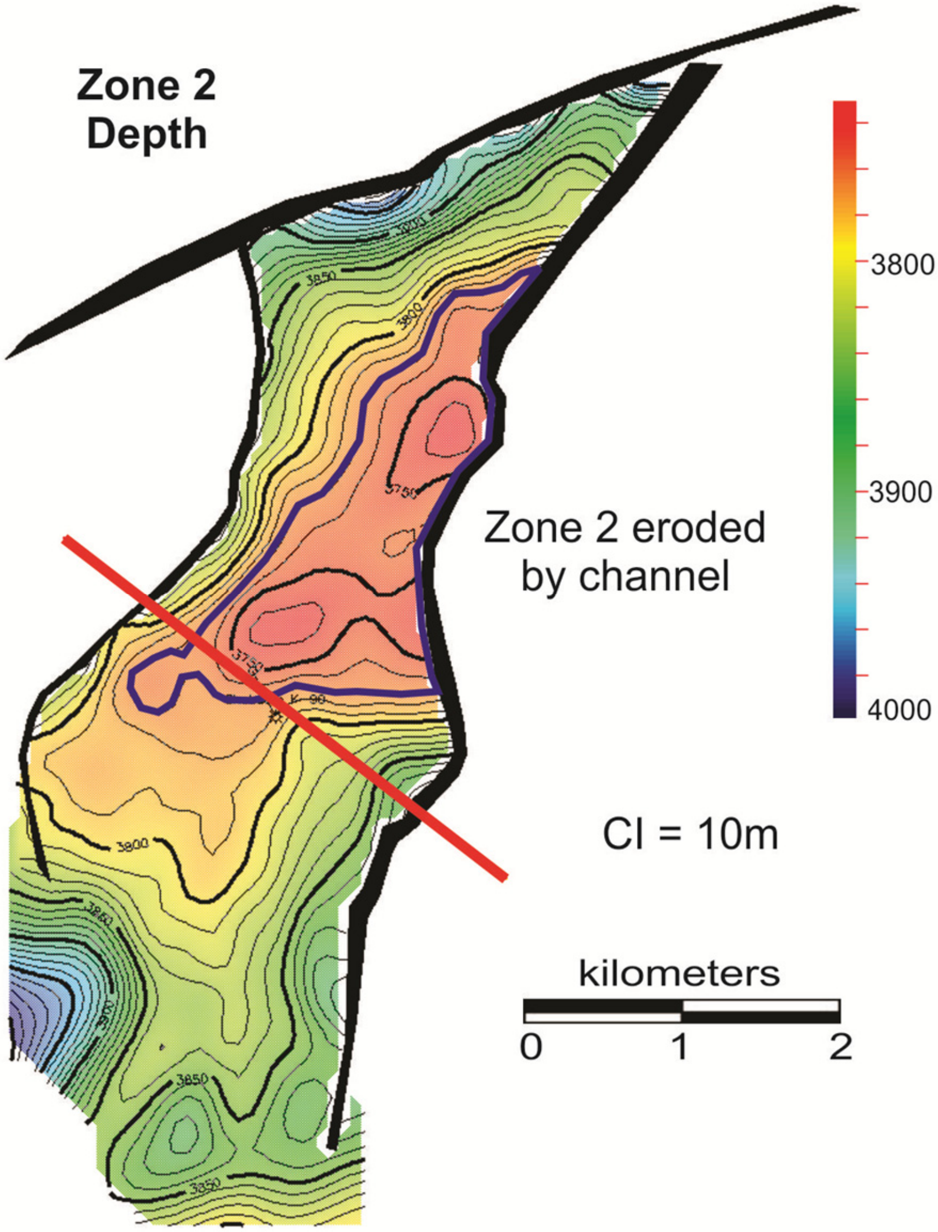

Figure 3.3.3 Chebucto Zone 2 depth map used for Zones 2 and 3.

3.3.3. Reservoir Description

The Chebucto gas reservoirs are located within strata of the Early Cretaceous (Albian) Cree member of the Logan Canyon Formation, and at the top of the Missisauga Formation (Aptian). The well was drilled near the structural crest of the field and encountered three significant hydrocarbon bearing sands. The two shallowest sands are normally pressured while the deepest gas sand, in the upper Missisauga, is slightly overpressured.

The Chebucto reservoir sands consist of isolated sequences of delta front, channel and strandplain-shoreface depositional facies in a shale dominated marine setting. They generally coarsen upward, are very fine to fine grained, well sorted, siliceous, calcareous and variably argillaceous and dolomitic.

3.3.4. Formation Evaluation

All three of the Chebucto K-90 gas zones were flow tested with rates ranging from 7.7 to 20.7 MMscf/d (Table 3.3.1) with Zones 2 and 3 both producing considerable water. Zone 2 has an interpreted GWC at base perforations while Zone 3 has a GWC in the middle of the DST perforation interval. All three gas zones have log, wireline pressure tester (RFT), and/or DST defined GWCs. The zones have good to very good average porosity (0.16–0.19) and calculated permeabilities from 5 to 20 mD based on logs and DST results. Results of the Chebucto K-90 petrophysical assessment are shown below (Table 3.3.2; Figs. 3.3.4–3.3.7).

Table 3.3.1 Chebucto K-90 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	4609-4621	tight	Missisauga	No Flow To Surface			No Flow To Surface		
DST 2	4287-4299	tight	Missisauga	No Flow To Surface			No Flow To Surface		
DST 3	4262-4276	wet	Missisauga	0.4	0	275	0.014	0	1728
DST 4	4227-4238	3	Missisauga	416	14	227	14.7	89	1425
DST 5	4166-4177	tight	Logan Canyon	No Flow To Surface			No Flow To Surface		
DST 6	3866-3877	wet	Logan Canyon	TSTM	0	40	TSTM	0	252
DST 7	3798-3815	2	Logan Canyon	586	25	80	20.7	159	504
DST 8	3352-3357	1	Logan Canyon	No Flow To Surface			No Flow To Surface		
DST 8A	3352-3357	1	Logan Canyon	218	9	6	7.7	56	38

Table 3.3.2 Chebucto K-90 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	Gross Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	3341.8	3376.0	34.2	6.5	0.157	0.39
Zone 2	3797.6	3815.0	17.5	16.1	0.161	0.30
Zone 3	4225.3	4243.0	17.7	1.6	0.189	0.49
Net Pay Cutoffs: Porosity >=0.10, Vsh <=40, Sw <=0.65						

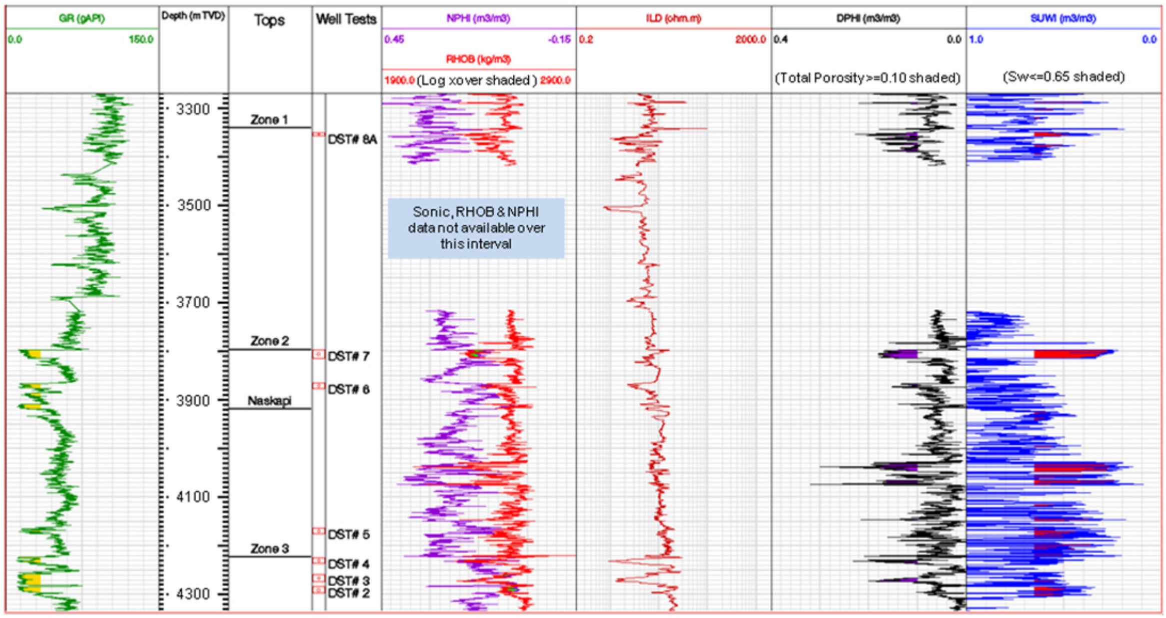

Figure 3.3.4 Chebucto K-90 petrophysical results plot: all zones.

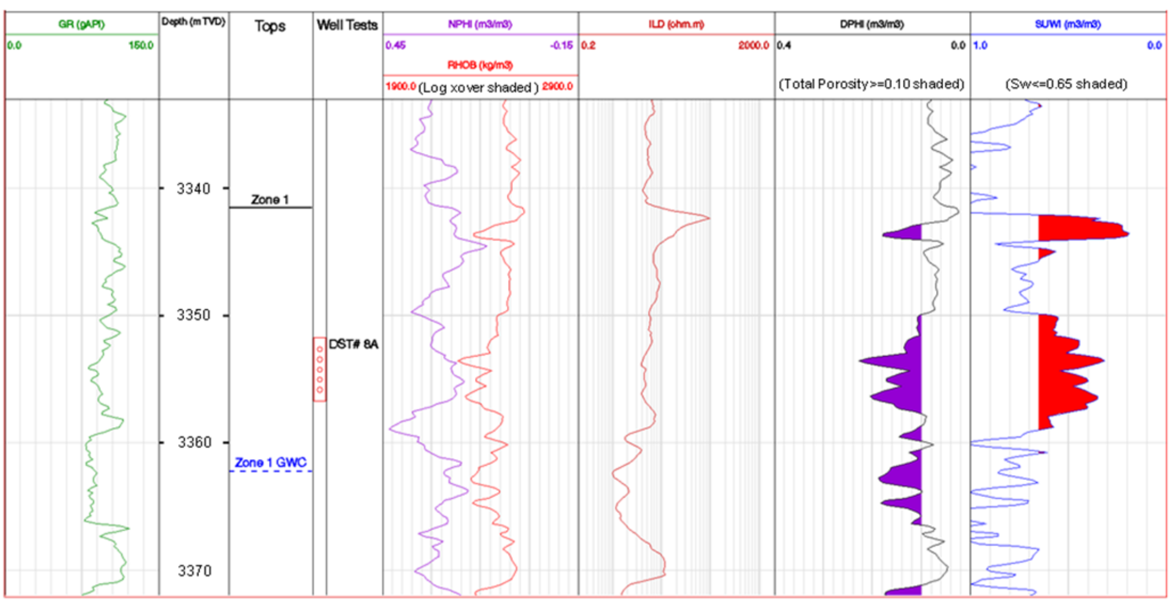

Figure 3.3.5 Chebucto K-90 petrophysical results plot: Zone 1.

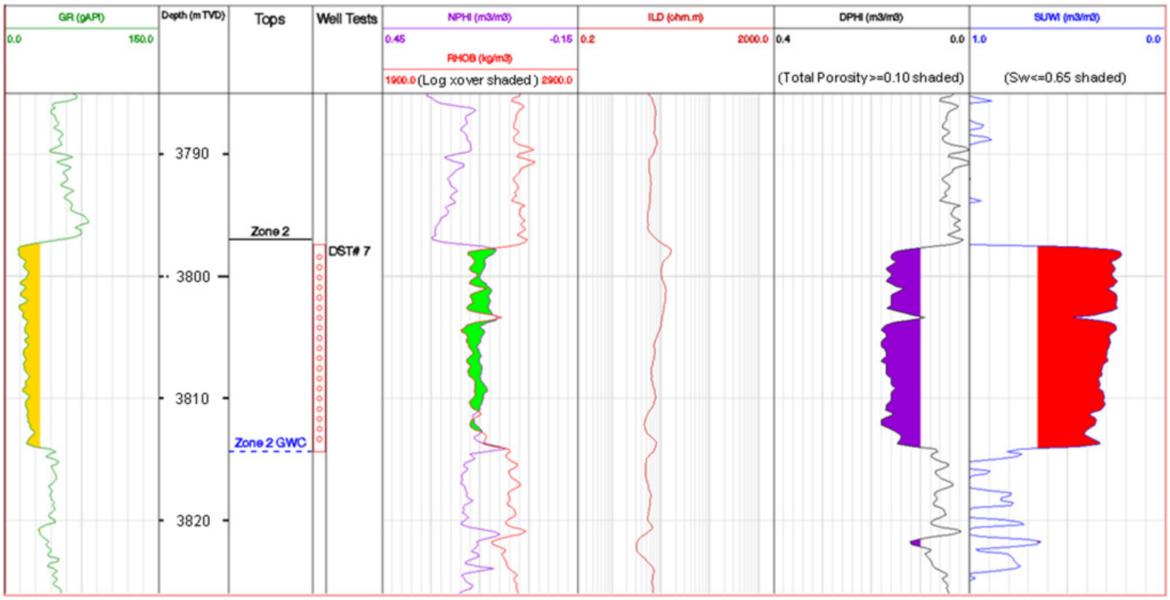

Figure 3.3.6 Chebucto K-90 petrophysical results plot: Zone 2.

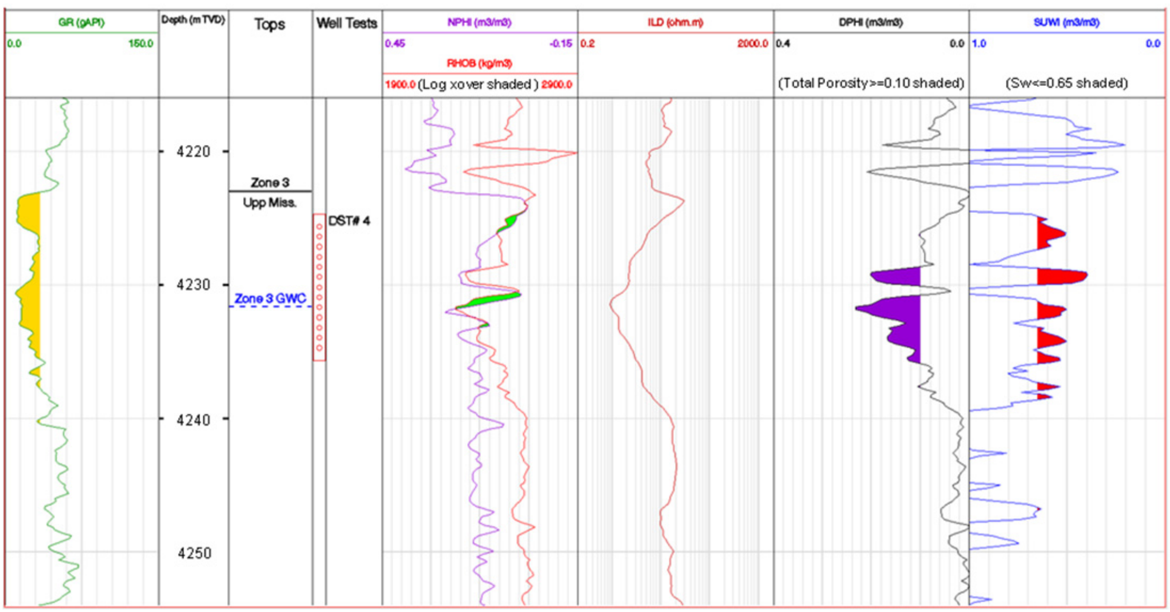

Figure 3.3.7 Chebucto K-90 petrophysical results plot: Zone 3.

3.3.5. Resource Assessment

Wireline pressure tester data was used to define the P50 GWC for Zone 1. When projected on to the Zone 1 depth map, this contact coincides with the mapped limit of simple closure. The mapped spill point for this zone is located at the west-bounding fault. The minimum area was assigned using the log-defined GWC which is approximately 20 m above the RFT contact. Maximum area was defined by increasing the P50 value by 10% to allow for mapping uncertainty.

A large channel to the east of the Chebucto structural high is interpreted to have eroded out the eastern portion of the Zone 2 reservoir. The log and DST defined GWC at the base of the sand is used to define the P50 area. The minimum area was defined by decreasing the P50 value by 10% to allow for mapping uncertainty. The maximum area was determined by assuming that the channel does not cut out the eastern portion of the Zone 2 reservoir.

Zone 3 has a log and DST-defined GWC that was projected onto the Zone 2 map to define the P50 area. The minimum area was determined by decreasing the P50 value by 10%. Due to poor seismic data quality, there is considerable mapping uncertainty in this interval making it difficult to confidently map a maximum area for the zone. As a result, the maximum area was arbitrarily set at twice the P50 value. Given the elevation of the GWC, the Zone 3 hydrocarbon volume appears to be limited to the crest of the structure resulting in a P50 area of only 1 km^2, a maximum of 2 km^2 and a minimum area of 0.9 km^2.

P50 input parameters for net pay, porosity and hydrocarbon saturation were based on petrophysically-calculated well values. Minimum and maximum inputs for these parameters were varied symmetrically around the P50 value.

Assigned zonal recovery factors for Chebucto were varied due to differences in sand thickness, reservoir quality and the position of the GWC. Assigned P50 recovery factors were varied from 50-70%. Zone 1 contains a shaly sand with considerable porosity variability so the assigned recovery factors were weighted toward the low side. For Zones 2 and 3, minimum and maximum recovery factors were varied symmetrically around the P50.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.3.3).

Table 3.3.3 Chebucto probabilistic volume calculation variables..

Zone 1	P100	P50	P00	Mean
Area (km^2)	3.40	8.70	9.60	7.23
Net Pay (m)	4.0	7.0	10.0	7.0
Porosity (fraction)	0.14	0.16	0.18	0.16
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	252	259	266	259
CGR (BBL/MMCF)	4.0	7.0	10	7.0
Gas Recovery Factor	0.55	0.65	0.75	0.65

Zone 2	P100	P50	P00	Mean
Area (km^2)	2.20	2.50	4.50	3.07
Net Pay (m)	12.0	16.0	20.0	16.0
Porosity (fraction)	0.14	0.16	0.18	0.16
Sh (1-Sw) (fraction)	0.65	0.70	0.75	0.70
Gas FVF	263	270	277	270
CGR (BBL/MMCF)	5.0	8.0	11	8.0
Gas Recovery Factor	0.6	0.7	0.8	0.7

Zone 3	P100	P50	P00	Mean
Area (km^2)	0.90	1.00	2.00	1.30
Net Pay (m)	1.0	2.0	3.0	2.0
Porosity (fraction)	0.17	0.19	0.21	0.19
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	295	302	309	302
CGR (BBL/MMCF)	3.0	6.0	9.0	6.0
Gas Recovery Factor	0.40	0.50	0.60	0.50

3.3.6. Results

The probabilistic assessment results for the Chebucto field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.3.4 and 3.3.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.3.8 and 3.3.9).

Table 3.3.4 Chebucto probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP (E9m^3)	2.25	2.78	3.45	2.82
OGIP (Bcf)	79.5	98.1	122	99.6
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.813	1.24	1.73	1.26
OGIP (Bcf)	28.7	43.7	61.2	44.5
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	1.12	1.44	1.92	1.48
OGIP (Bcf)	39.4	50.9	67.8	52.4
Zone 3	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.0476	0.0716	0.106	0.0751
OGIP (Bcf)	1.69	2.53	3.74	2.64

Table 3.3.5 Chebucto probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	1.50	1.87	2.33	1.90
Rec. Gas (Bcf)	52.9	66.1	82.3	67.0
Rec. Condensate (E6m^3)	0.0601	0.0787	0.102	0.0801
Rec. Condensate (MMB)	0.378	0.495	0.643	0.504
Zone 1	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.523	0.801	1.14	0.821
Rec. Gas (Bcf)	18.5	28.3	40.2	29.0
Rec. Condensate (E6m^3)	0.0191	0.0312	0.0469	0.0323
Rec. Condensate (MMB)	0.120	0.196	0.295	0.203
Zone 2	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.773	1.01	1.35	1.04
Rec. Gas (Bcf)	27.3	35.6	47.8	36.7
Rec. Condensate (E6m^3)	0.0320	0.0452	0.0636	0.0467
Rec. Condensate (MMB)	0.201	0.284	0.400	0.294
Zone 3	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.0235	0.0357	0.0538	0.0374
Rec. Gas (Bcf)	0.830	1.26	1.90	1.32
Rec. Condensate (E6m^3)	0.000714	0.00118	0.00191	0.00126
Rec. Condensate (MMB)	0.00449	0.00742	0.0120	0.00791

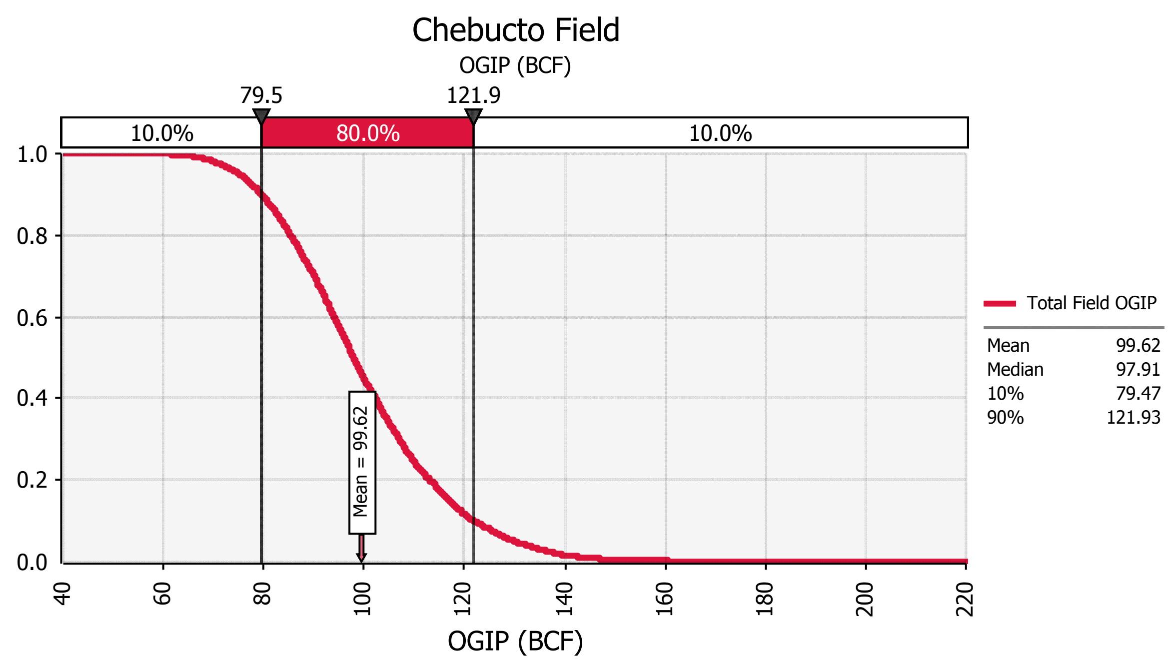

Figure 3.3.8 Chebucto OGIP descending cumulative probability chart.

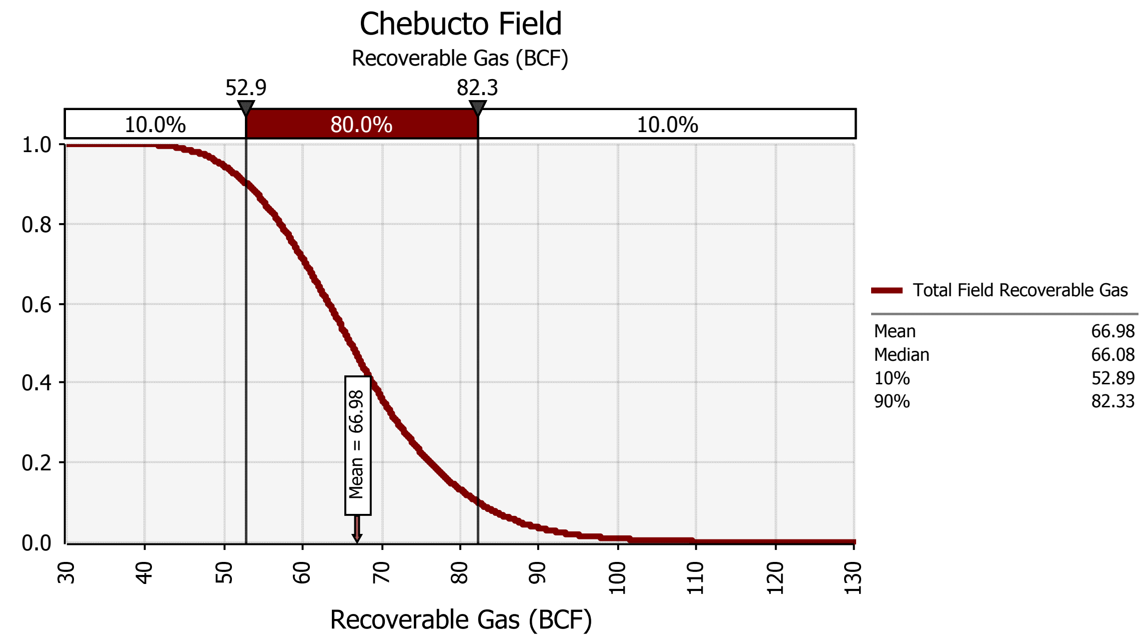

Figure 3.3.9 Chebucto recoverable gas descending cumulative probability chart.

3.4 Citnalta - Significant Discovery

3.4.1. Overview

The Citnalta gas field is located approximately 30 km north-east of Sable Island (Fig. 1.1). The field was discovered in 1974 and this assessment is based on the discovery well.

Discovery Well

Well:	Citnalta I-59
Company:	Mobil-Tetco-Texaco
Spud:	04-Feb-74
Well Termination:	29-Apr-74
Total Depth:	4575 m
Water Depth:	94.48 m
Latitude:	44°08'42.58"N
Longitude:	59°37'32."W
Target:	Drilled to test for the presence of hydrocarbons in the sands of a large rollover anticline associated with a north bounding down-to-basin listric fault.

Additional Wells

No delineation drilling was conducted.

3.4.2. Structure

The Citnalta structure is a salt-cored rollover anticline on the down thrown side of a down-to-basin growth fault as shown on the seismic time dip section (Fig. 3.4.1). There are five reservoir zones. Zones 1, 2, 3, and 4 represented by the Zone 3 seismic horizon (orange) and the Zone 5 horizon (red), which is just below the Mic Mac horizon (yellow)

The P50 area contour (purple) on the Zone 3 depth map (Fig. 3.4.2) results from a projected GWC, suggesting that the gas column is limited to simple anticlinal closure for Zones 1 to 4. The reservoir leaks where it contacts the fault.

The P50 area contour (purple) on the Zone 5 depth map (Fig. 3.4.3) resulted from a GDT approximately 55 m below the structural top depth at the well location. This demonstrates that some degree of fault dependent closure exists before the leak point is reached.

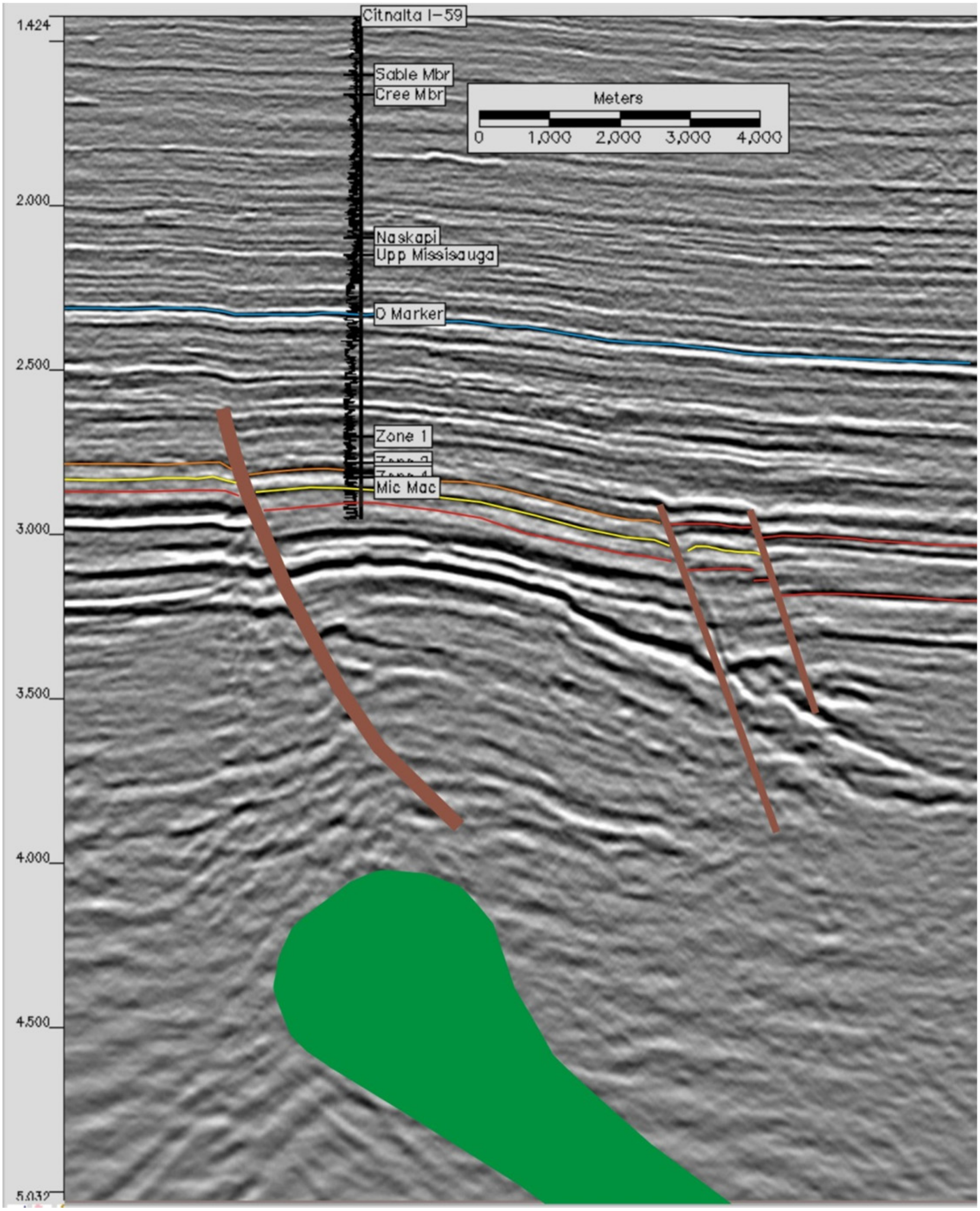

Figure 3.4.1 Citnalta seismic time line showing gamma ray log.

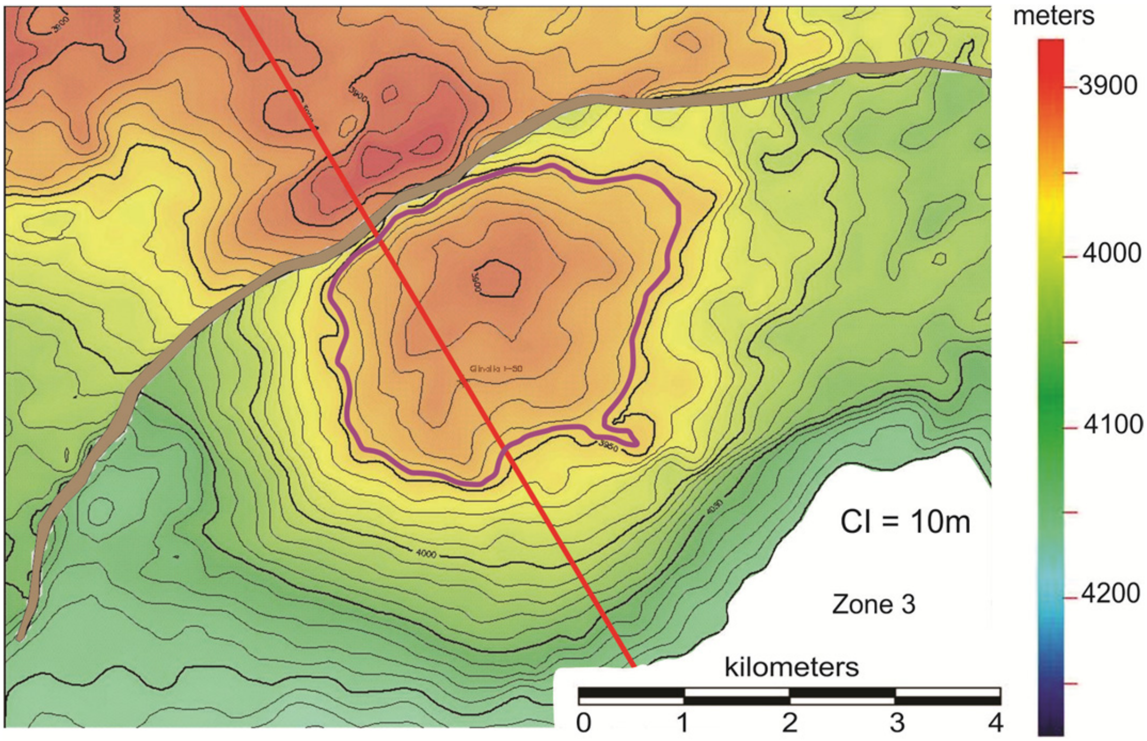

Figure 3.4.2 Citnalta Zone 3 depth map used for Zones 1–4.

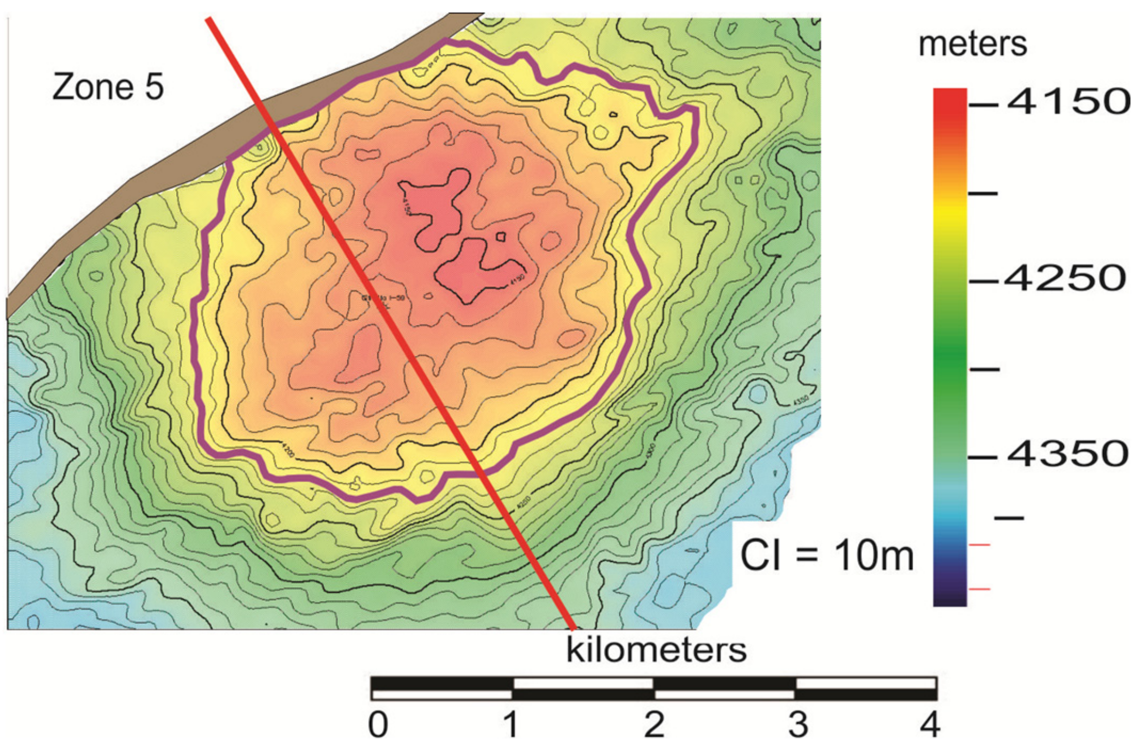

Figure 3.4.3 Citnalta Zone 5 depth map.

3.4.3. Reservoir Description

The Citnalta reservoir sands are located within the Early Cretaceous-Late Jurassic (Berriasian-Tithonian) lower Missisauga and Late Jurassic (Oxfordian-Kimmeridgian) upper Mic Mac Formations. The well encountered five gas bearing reservoir sands over a 500 meter interval.

The Citnalta gas reservoirs are normally hydropressured and consist of stacked sequences of cyclic deltaic and shoreface sands capped by marine and prodelta shales. The sands are generally very fine to medium grained, well sorted, with siliceous and calcareous cements with low to modest average porosities which range from 0.09–0.15.

3.4.4. Formation Evaluation

Three of the five Citnalta gas zones were tested (Zones 1, 2 and 4) with a flow rate range of 2.7–11.0 MMscf/d (Table 3.4.1). The zones vary in reservoir quality and thickness, having low to modest net pay average porosity that ranges from 0.09 to 0.15. Zones 1 and 2 have an interpreted log defined GWC while the other zones have gas down to base porosity. Results of the Citnalta I-59 petrophysical assessment are shown below (Table 3.4.2; Figs. 3.4.4–3.4.7).

Table 3.4.1 Citnalta I-59 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
PD 1	4054-4059	4	Missisauga	77	10	0	2.7	65	0
PD 2	3951-3958	2	Missisauga	168	70	0	5.9	442	0
PD 3	3777-3782	1	Missisauga	312	131	4	11.0	824	25

Table 3.4.2 Citnalta I-59 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	3768.8	3790.0	21.2	6.1	0.119	0.42
Zone 2	3939.8	4008.7	68.9	15.8	0.151	0.40
Zone 3	4008.7	4033.0	31.3	10.4	0.131	0.42
Zone 4	4040.0	4062.0	72.1	7.9	0.091	0.48
Zone 5	4200.5	4257.5	57.0	9.8	0.097	0.26
Cutoffs: PHI >= 0.08, Gr <= 40, Sw <= 0.60						

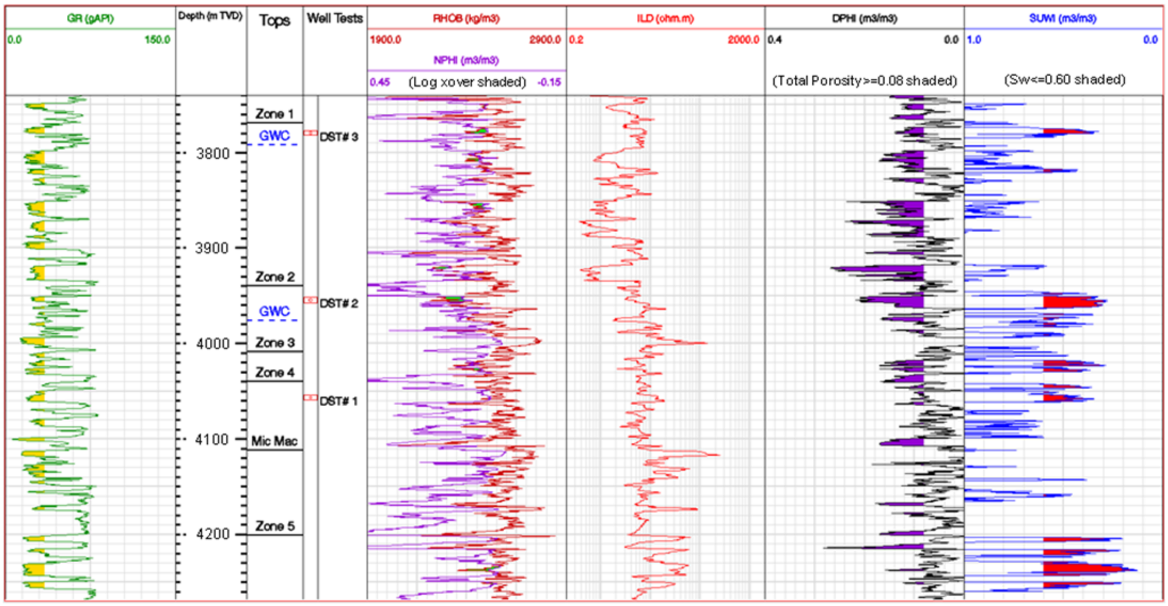

Figure 3.4.4 Citnalta I-59 petrophysical results plot: all zones.

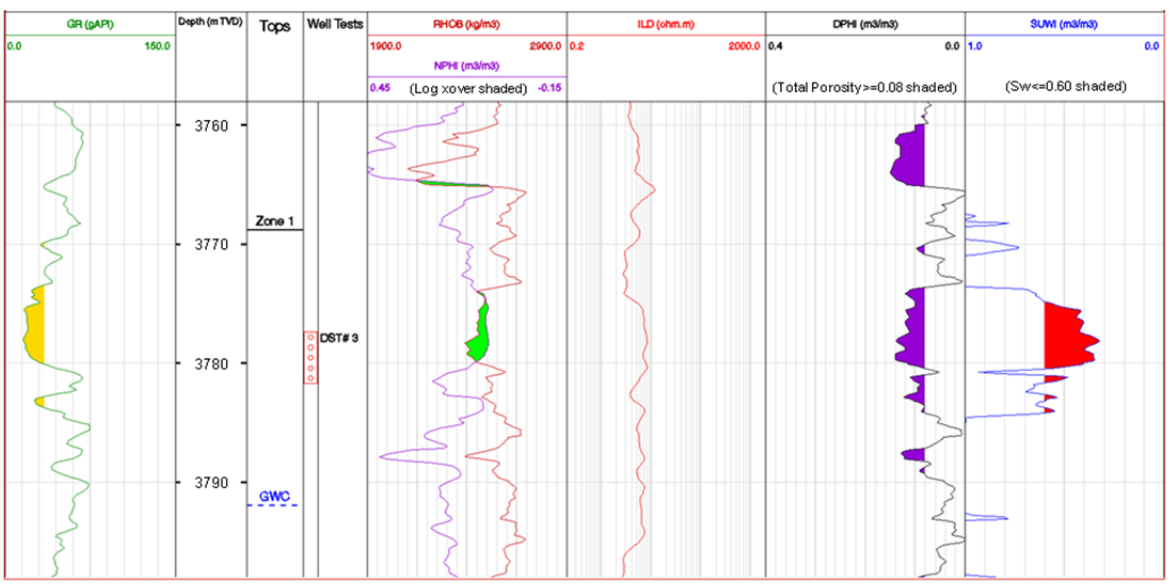

Figure 3.4.5 Citnalta I-59 petrophysical results plot: Zone 1.

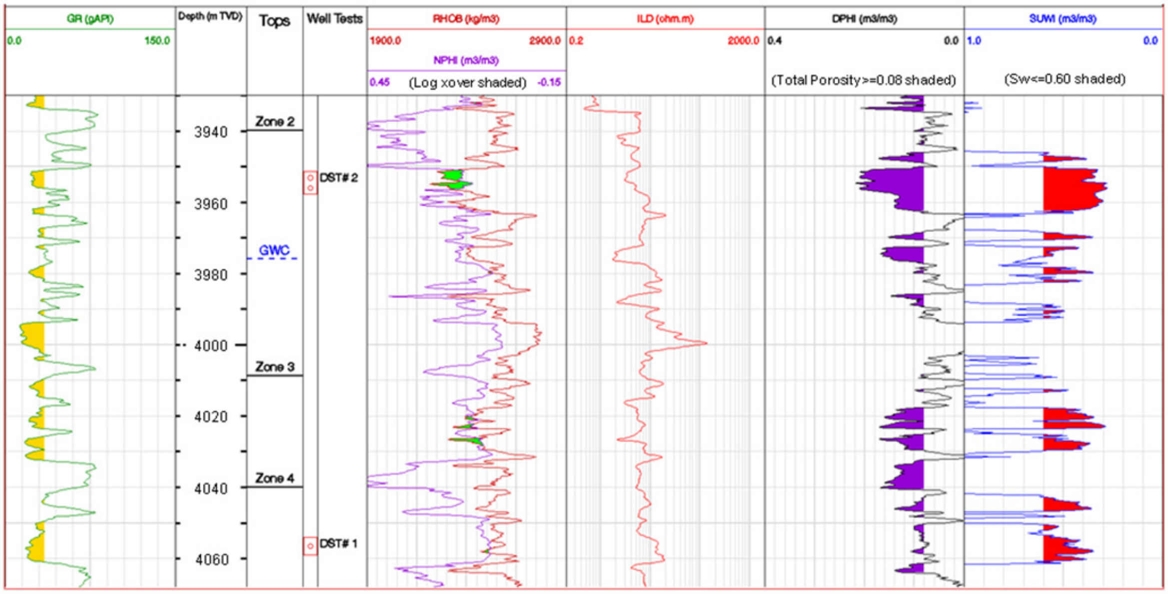

Figure 3.4.6 Citnalta I-59 petrophysical results plot: Zones 2–4.

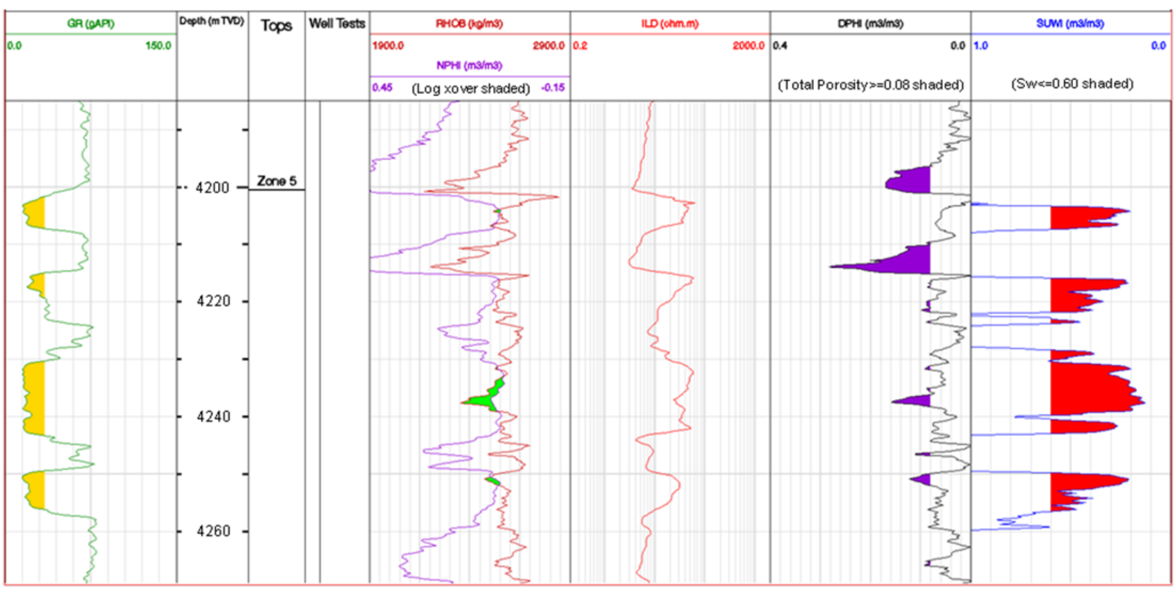

Figure 3.4.7 Citnalta I-59 petrophysical results plot: Zone 5.

3.4.5. Resource Assessment

The shape of the Citnalta Zone 3 depth map (Fig. 3.4.2) was used to determine areal extents for Zones 1–4. The P50 area for Zone 1 was determined by projecting the interpreted GWC, at the base of the zone, onto the Zone 3 depth map. The minimum area was defined by reducing the P50 value by 10% to allow for mapping uncertainty. The maximum area was defined as the mapped limit of simple closure prior to an interpreted leak point at the intersection with the north bounding fault.

The P50 area for Zone 2 was defined by transposing the log GWC onto the Zone 3 depth map. The elevation of this contact is consistent with the mapped limit of simple closure. The minimum and maximum values were assigned by varying the P50 area +/-10% to allow for mapping uncertainty.

For both Zones 3 and 4 the P50 area was defined using the limit of simple closure on the Zone 3 depth map, with the leak point at the north bounding fault. Both zones are GDT on logs; therefore the minimum area was determined by projecting the elevation of the GDT, for each zone, onto the Zone 3 map. The maximum area was assigned by increasing the P50 area by 10%.

Zone 5 is a DT on logs. Given the height of the gas column it appears the north bounding fault is providing some fault seal as the gas extends beyond the limits of simple closure. The P50 area for Zone 5 was determined by projecting the log GDT onto the Zone 5 depth map (Fig. 3.4.3). The minimum and maximum values were assigned by varying the P50 area +/-10% to allow for mapping uncertainty.

A few wet sands were encountered within the Citnalta I-59 gas bearing interval. While these structurally conformable sands are wet at the well location, they may be gas-bearing updip. The presence of updip gas in these zones is uncertain; therefore they were excluded from the resource assessment.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50 value. For zones with low to fair porosity and/or short gas columns the assigned hydrocarbon saturations were skewed toward the downside.

Given the generally low to modest reservoir quality of the Citnalta reservoirs, the assigned P50 recovery factors ranged from 50 to 70%. The minimum and maximum values were varied symmetrically around the P50. For zones with variable reservoir quality, these ranges were broadened to account for the additional uncertainty.

All key input parameters used for the probabilistic volume calculations are listed below (Table 3.4.3).

Table 3.4.3 Citnalta probabilistic volume calculation variables.

Zone 1	P100	P50	P00	Mean
Area (km^2)	5.4	6.0	8.2	6.53
Net Pay (m)	4.0	6.0	8.0	6.0
Porosity (fraction)	0.10	0.12	0.14	0.12
Sh (1-Sw) (fraction)	0.50	0.60	0.65	0.583
Gas FVF	269	277	285	277
CGR (BBL/MMCF)	70	75	80	75
Gas Recovery Factor	0.50	0.60	0.70	0.60

Zone 2	P100	P50	P00	Mean
Area (km^2)	7.4	8.2	9.0	8.2
Net Pay (m)	9.0	13	17	13
Porosity (fraction)	0.14	0.17	0.20	0.17
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	278	286	295	286
CGR (BBL/MMCF)	70	75	80	75
Gas Recovery Factor	0.60	0.70	0.80	0.70

Zone 3	P100	P50	P00	Mean
Area (km^2)	6.0	8.2	9.0	7.73
Net Pay (m)	6.0	9.0	12	9.0
Porosity (fraction)	0.11	0.14	0.17	0.14
Sh (1-Sw) (fraction)	0.50	0.60	0.65	0.583
Gas FVF	281	290	299	290
CGR (BBL/MMCF)	25	50	75	50
Gas Recovery Factor	0.55	0.65	0.75	0.65

Zone 4	P100	P50	P00	Mean
Area (km^2)	6.0	8.2	9.2	7.73
Net Pay (m)	2.0	6.0	10	6.0
Porosity (fraction)	0.07	0.09	0.11	0.09
Sh (1-Sw) (fraction)	0.40	0.50	0.55	0.483
Gas FVF	283	291	300	291
CGR (BBL/MMCF)	20	24	28	24
Gas Recovery Factor	0.35	0.50	0.65	0.5

Zone 5	P100	P50	P00	Mean
Area (km^2)	7.7	8.6	9.5	8.6
Net Pay (m)	6.0	10	14	10
Porosity (fraction)	0.08	0.10	0.12	0.10
Sh (1-Sw) (fraction)	0.60	0.70	0.75	0.683
Gas FVF	291	300	309	300
CGR (BBL/MMCF)	20	24	28	24
Gas Recovery Factor	0.35	0.50	0.65	0.50

3.4.6. Results

The probabilistic assessment results for the Citnalta field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.4.4 and 3.4.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.4.8 and 3.4.9). Citnalta has the largest condensate resources of the 15 undeveloped fields, therefore, recoverable condensate liquids are also included (Fig. 3.4.10).

Table 3.4.4 Citnalta probabilistic OGIP.

Sum of all zones	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	6.91	7.84	8.95	7.90
OGIP (Bcf)	244	277	316	279
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.57	0.75	0.97	0.76
OGIP (Bcf)	20.3	26.5	34.2	26.9
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	2.40	3.09	3.91	3.11
OGIP (Bcf)	84.8	109	138	110
Zone 3	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.23	1.63	2.11	1.65
OGIP (Bcf)	43.5	57.4	74.6	58.4
Zone 4	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.35	0.57	0.85	0.59
OGIP (Bcf)	12.4	20.3	30.0	20.8
Zone 5	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	1.30	1.75	2.27	1.77
OGIP (Bcf)	46.0	61.7	80.0	62.5

Table 3.4.5 Citnalta probabilistic recoverable resources.

Sum of all zones	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	4.25	4.87	5.61	4.90
Rec. Gas (Bcf)	150	172	198	173
Rec. Condensate ($E6m^3$)	1.320	1.556	1.844	1.574
Rec. Condensate (MMB)	8.30	9.79	11.6	9.90
Zone 1	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.34	0.45	0.59	0.46
Rec. Gas (Bcf)	12.0	15.9	20.7	16.1
Rec. Condensate ($E6m^3$)	0.143	0.189	0.248	0.192
Rec. Condensate (MMB)	0.898	1.19	1.56	1.21
Zone 2	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	1.67	2.15	2.75	2.19
Rec. Gas (Bcf)	58.8	76.0	97.0	77.2
Rec. Condensate ($E6m^3$)	0.698	0.905	1.159	0.921
Rec. Condensate (MMB)	4.39	5.69	7.29	5.79
Zone 3	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.79	1.06	1.39	1.08
Rec. Gas (Bcf)	27.8	37.3	49.0	38.0
Rec. Condensate ($E6m^3$)	0.192	0.293	0.423	0.302
Rec. Condensate (MMB)	1.21	1.84	2.66	1.90

Zone 4	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	0.17	0.29	0.43	0.29
Rec. Gas (Bcf)	6.05	10.1	15.3	10.4
Rec. Condensate ($E6m^3$)	0.0227	0.0383	0.0585	0.0397
Rec. Condensate (MMB)	0.143	0.241	0.368	0.250
Zone 5	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.62	0.87	1.17	0.89
Rec. Gas (Bcf)	21.9	30.6	41.3	31.3
Rec. Condensate ($E6m^3$)	0.0825	0.117	0.159	0.119
Rec. Condensate (MMB)	0.519	0.733	1.00	0.750

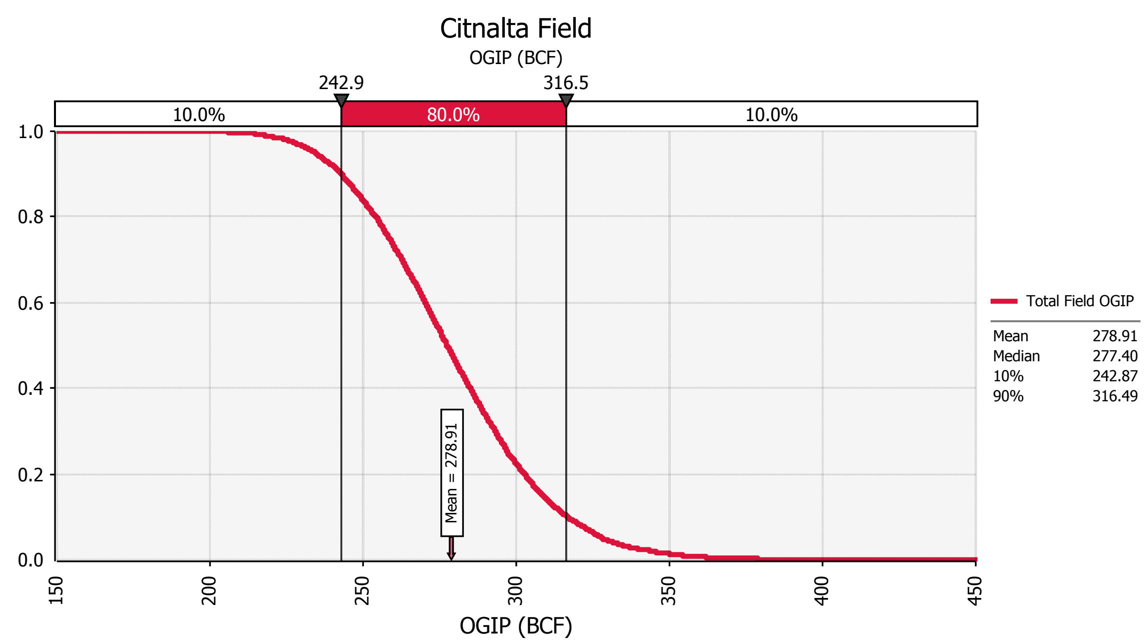

Figure 3.4.8 Citnalta OGIP descending cumulative probability chart.

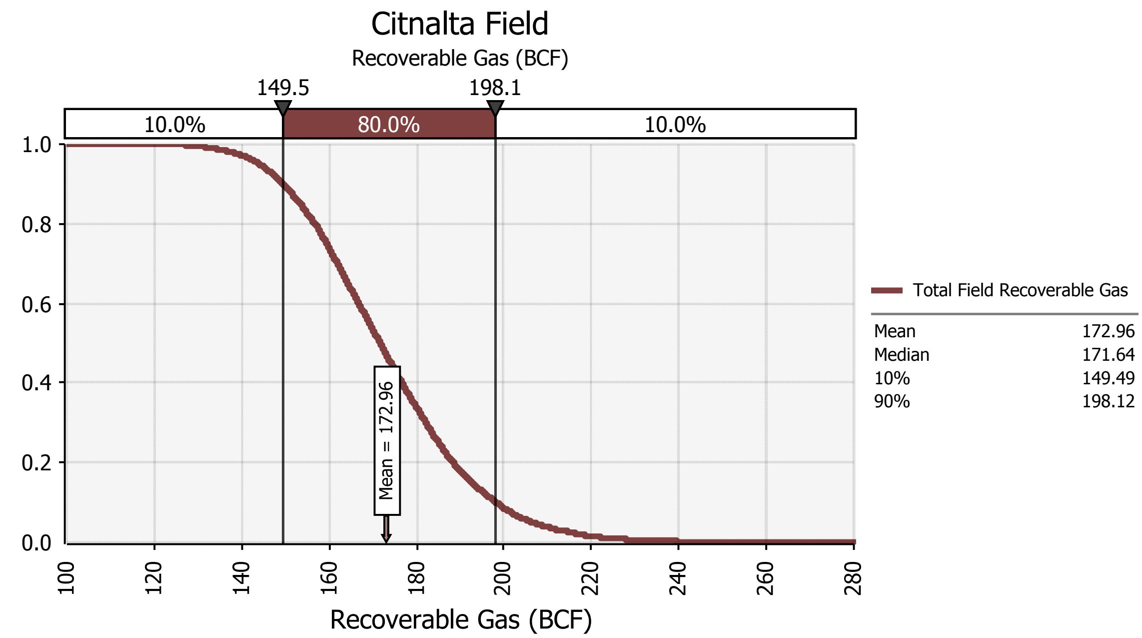

Figure 3.4.9 Citnalta recoverable gas descending cumulative probability chart

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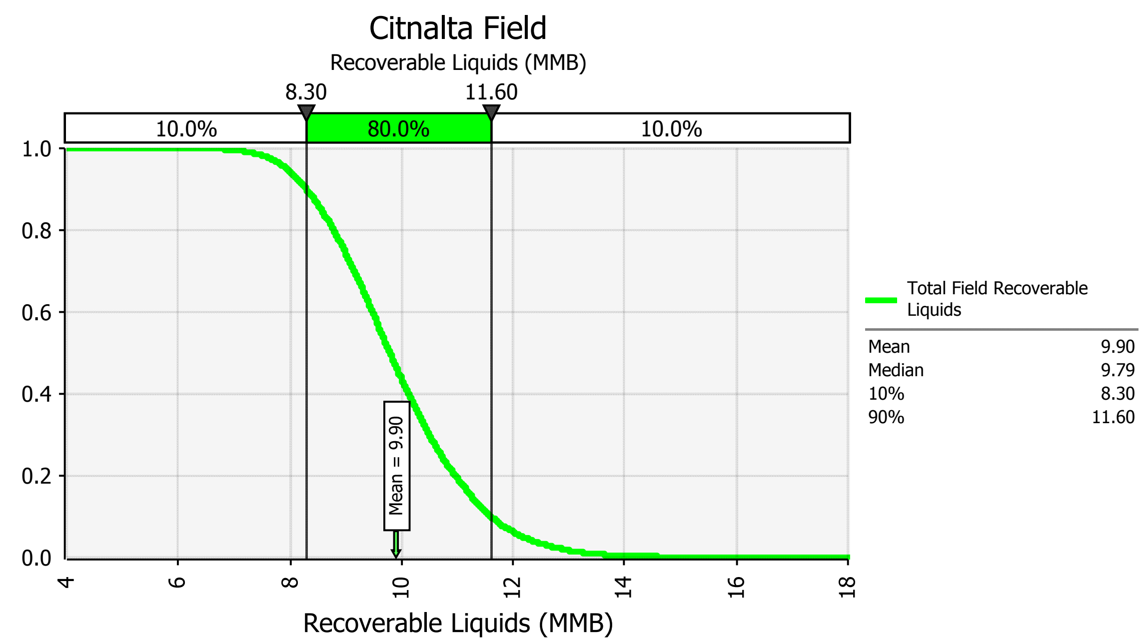

Figure 3.4.10 Citnalta recoverable condensate liquids descending cumulative probability chart.

3.5 Glenelg - Significant Discovery

3.5.1. Overview

The Glenelg gas field is located approximately 40 km south of Sable Island (Fig. 3.1.1). The field was discovered in 1983 and delineated by four wells, one of which was sidetracked. The hydrocarbon accumulation is located within Early Cretaceous age sediments in the distal portion of the Sable Delta.

Discovery Well

Well:	Glenelg J-48
Company:	Shell, Petro-Canada
Spud:	22-Feb-83
Well Termination:	08-Nov-83
Total Depth:	5148 m
Water Depth:	83.7 m
Latitude:	43°37’38.57”N
Longitude:	60°06’24.84”W
Target:	Drilled to test for the presence of hydrocarbons within Cretaceous age sandstones trapped within a rollover anticline.

Additional Wells

The Glenelg field was delineated by the following four additional wells and one sidetrack, located within 4 km of the discovery well location:

- Shell Petro-Canada et. al Glenelg E-58 & E-58A (E-58A sidetrack)
- Shell PCI et al. Glenelg N-49
- Shell Petro-Canada et al. Glenelg H-38
- ExxonMobil et al. Glenelg H-59

3.5.2. Structure

The Glenelg structural complex is a series of fault-bounded, rollover anticlinal features, associated with east-west trending listric faults that sole into deep underlying salt as shown on the seismic line (Fig. 3.5.1). The Upper Missisauga horizon is shown in yellow.

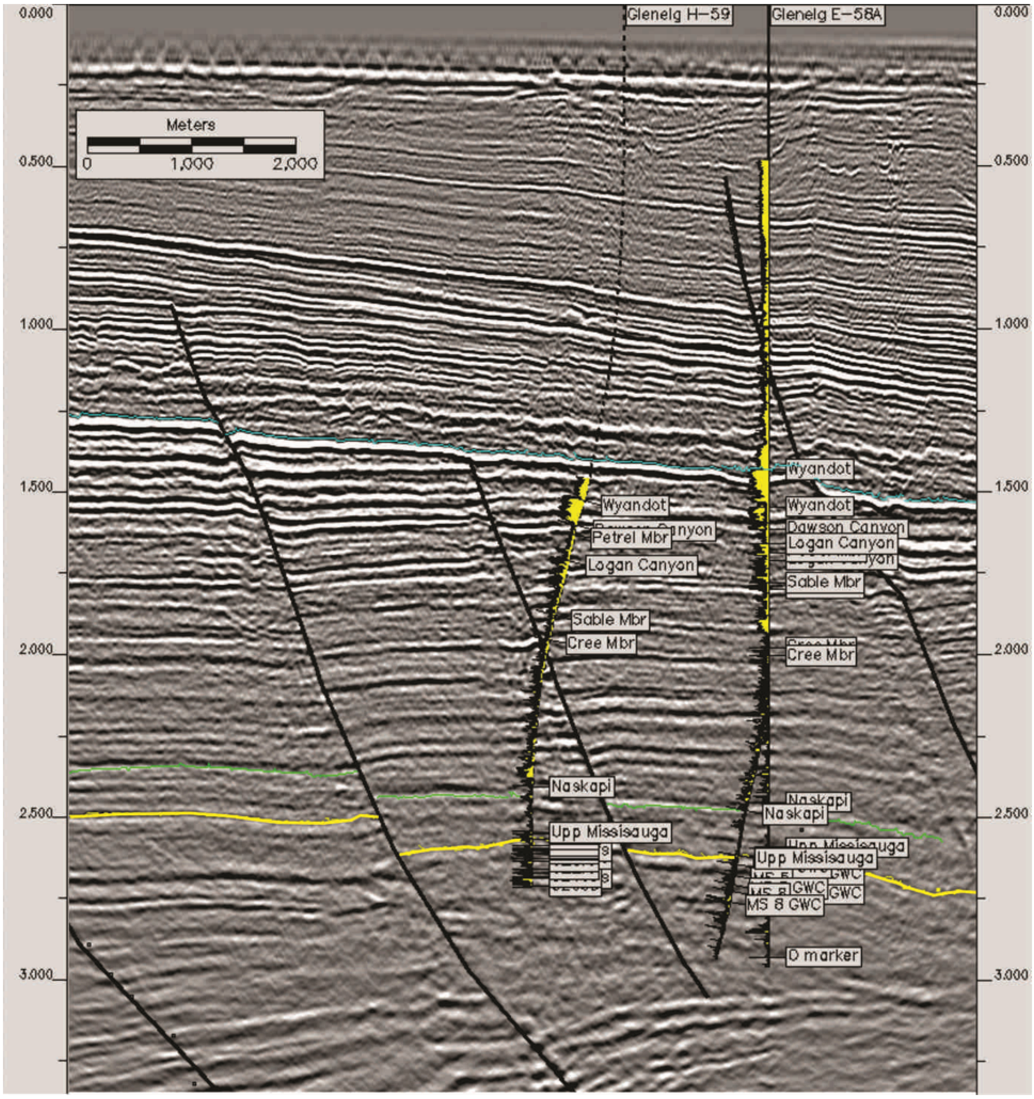

Figure 3.5.1 Glenelg seismic time line showing gamma ray logs.

On the Upper Missisauga depth map (Fig. 3.5.2), the north bounding fault and a secondary large en echelon fault, form the northern and southern boundaries of this complex series of structures. Faulting associated with these structures penetrates upwards through most of the overlying strata and in some cases approaches the seafloor.

There are five main fault compartments between the north and south-bounding faults. At the Upper Missisauga level, four of the fault compartments have well penetrations and contain proven hydrocarbons. The central fault compartment, bounded by north-south trending faults is currently untested. Glenelg H-38 was drilled on the southern side of the south-bounding fault, penetrating the hanging wall and encountering two minor gas sands in the Logan Canyon Formation. Trapping mechanisms are combinations of fault seal, dip closure, and possible stratigraphic seal. In most cases, intra-field faults are sealing however some gas zones extend across fault blocks and share common GWCs, indicating that not

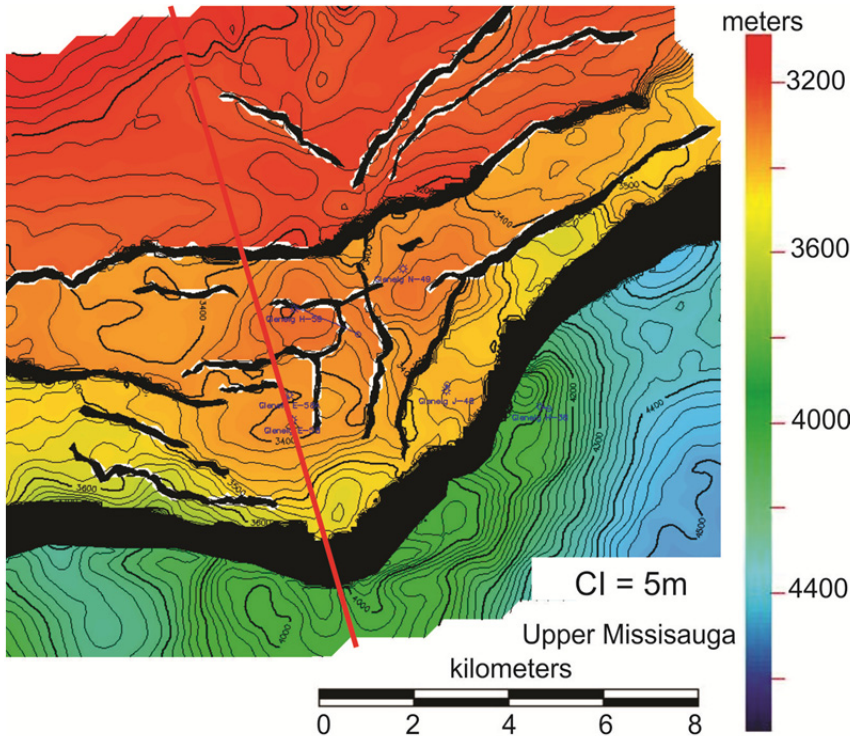

Figure 3.5.2 Glenelg Upper Missisauga depth map used for all zones.

all faults seal. Numerous splay faults add a significant degree of complexity to this discovery. These complex faults trend roughly parallel and perpendicular to the main north- and south-bounding faults. The map does not represent all of the faulting in this region as many more sub-seismic scale faults are suspected to exist. There are 19 P50 pool areas calculated from this map for the resource assessment presented below. These were not included on this map.

3.5.3. Reservoir Description

The Glenelg field occupies a distal position along the southwestern flank of the Sable Delta complex. In this region, various phases of progradation of the Early Cretaceous Sable Delta are manifested as numerous stacked cycles of sand and significant volumes of marine shales. The overall sand-shale ratio of the Missisauga Formation, the main reservoir interval at Glenelg, is therefore lower than the equivalent section in the central portion of the Sable Subbasin.

The reservoir sands at Glenelg are located within fluvial-deltaic and shallow marine sandstones of the upper Missisauga (Barremian) and Logan Canyon (Albian) Formations. The Logan Canyon gas sands are fine to coarse grained, subrounded to subangular and medium to well sorted. Two thin Logan Canyon gas sands were encountered at Glenelg H-38, which penetrated a small isolated fault-dependent closure in the hanging wall of the Glenelg south bounding fault. Five Logan Canyon gas sands were encountered in Glenelg J-48 but their hydrocarbon charge is limited to the J-48 fault block, as they are wet in the offset wells.

The majority of Glenelg's gas reserves are located in the Upper Missisauga Formation. These sands are fine to coarse grained, subrounded to subangular and poorly to well sorted. The sands within the top 200 m of the Upper Missisauga can be reliably correlated across the field, however deeper in the section the channelized nature of the sands makes well-to-well correlations challenging. Thirteen gas pools, all with separate gas-water contacts, have been identified in the Upper Missisauga. Four of these pools extend across two or more fault blocks while the remaining nine pools are limited to a single fault block.

3.5.4. Formation Evaluation

In Glenelg a total of 20 separate gas pools have been identified, all with separate gas-water contacts. These contacts were defined by log and/or wireline pressure data and supported by DST data where available. The only Logan Canyon (LC) gas pool with significant reserves is the LC 6. The LC 6 is also the only Logan Canyon pool that was tested (Glenelg J-48, DST# 9) and flowed gas at a rate of 30 MMscf/d. The reservoir properties of the Logan Canyon sands are good to excellent with average porosities ranging from 0.14 to 0.29. Core permeabilities are highly variable and generally range from poor (<1 mD) to very good (>700 mD).

The main gas reserves in Glenelg are located in the Upper Missisauga (MS) which contains 13 separate gas pools (MS1–MS 13). The most recent Glenelg well, drilled in 2003, is Glenelg H-59. Log and wireline pressure data acquired in H-59 indicated that the gas zone at the top of the Upper Missisauga had a GWC that was 78m higher than the equivalent zone in the N-49 and E-58 fault blocks. An analysis of the log and pressure data clearly indicated that the hydrocarbon zones encountered in H-59 were separate gas pools, limited to the H-59 fault block. Only two significant gas pools were encountered in H-59 (MS 1 & MS 4). The other pools (MS 6 & MS 9) encountered thin gas pay and contained very minor gas volumes.

The petrophysical analysis of the Glenelg wells indicated that four of the 13 Upper Missisauga gas pools (MS 2, MS 3, MS 5 & MS 8) extend across two or more fault blocks. The other nine gas pools are limited to a single fault block. Many of the Upper Missisauga pools were tested with gas rates ranging from 4.4 to 31.2 MMscf/d (Table 3.5.1). The reservoir properties of the Upper Missisauga sands are fair to very good with average porosities ranging from 0.12 to 0.19. Core permeabilities are highly variable and range from poor (<1 mD) to excellent (>8000 mD).

Results of the petrophysical assessment of the Glenelg field are shown below (Table 3.5.2; Figs. 3.5.3–3.5.9).

Table 3.5.1 Glenelg field significant tests.

Well	Test #	Depth (m)	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
J-48	DST 1	5075-5107	Verrill Canyon			11.5			72
J-48	DST 2	3950-3955	Upper Missisauga	127		Trace	4.5		Trace
J-48	DST 3	3806-3815	Upper Missisauga	Rec. Form Fluid			Rec. Form Fluid		
J-48	DST 4	3767-3773	Upper Missisauga	125		88.4	4.4		554
J-48	DST 5	3746-3758	Upper Missisauga	801	18	8.5*	28.3	113	53*
J-48	DST 7	3608-3615	Upper Missisauga	99	Trace	Trace	3.5	Trace	Trace
J-48	DST 8	3491-3495.5	Upper Missisauga	594		Trace	21.0		Trace
J-48	DST 9	3062-3065	Logan Canyon	849	65	8.5*	30.0	410	53*
E-58A	DST 1	3702-3713	Upper Missisauga	663	62		23.4	387	
E-58A	DST 2	3567-3578	Upper Missisauga	314	minor		11.0	minor	
N-49	DST 1	3597.5-3602.5	Upper Missisauga	596	20		21.1	126	
N-49	DST 2	3476-3485	Upper Missisauga	884	24		31.2	151	
N-49	DST 3	3390.5-3401.5	Upper Missisauga	483	12		17.0	73	

* Mud filtrate

Table 3.5.2 Glenelg field petrophysical summary.

Well	Zone	Top (m MD)	Base (m MD)	GR Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Glenelg E-58	MS 2	3380.2	3424.0	43.8	Tight	N/A	N/A
Glenelg E-58	MS 5	3500.0	3545.2	45.2	4.3	0.144	0.58
Glenelg E-58	MS 8	3619.3	3661.0	41.7	3.7	0.138	0.31
Glenelg E-58	MS 11	3873.1	3889.5	16.5	3.3	0.131	0.39
Glenelg E-58	MS 12	3944.9	3950.5	5.6	1.5	0.115	0.30
Glenelg E-58A	MS 2	3413.4	3471.5	56.1	Tight	N/A	N/A
Glenelg E-58A	MS 5	3539.5	3597.3	55.7	7.8	0.144	0.44
Glenelg E-58A	MS 8	3645.7	3718.5	69.5	12.5	0.137	0.14
Glenelg H-59	MS 1	3747.4	3811.3	63.8	14.8	0.161	0.29
Glenelg H-59	MS 4	3862.3	3913.4	51.1	13.3	0.150	0.33
Glenelg H-59	MS 6	3930.1	3933.4	3.3	1.5	0.143	0.42
Glenelg H-59	MS 9	4029.2	4034.7	5.6	2.4	0.146	0.42
Glenelg J-48	LC 2	2739.0	2766.1	27.1	1.5	0.176	0.44
Glenelg J-48	LC 3	2786.6	2791.1	4.6	3.9	0.235	0.51
Glenelg J-48	LC 4	2969.2	2975.6	6.4	0.6	0.197	0.40
Glenelg J-48	LC 5	3008.5	3015.1	6.6	4.7	0.214	0.57
Glenelg J-48	LC 6	3047.5	3073.5	26.1	13.2	0.213	0.40
Glenelg J-48	MS 3	3490.5	3512.2	21.7	2.7	0.167	0.23
Glenelg J-48	MS 8	3605.4	3658.2	52.9	6.6	0.141	0.32
Glenelg J-48	MS 10	3743.7	3779.3	35.6	19.0	0.138	0.42
Glenelg J-48	MS 13	3948.8	3968.6	19.8	7.8	0.141	0.45
Glenelg N-49	MS 2	3349.8	3419.3	69.5	16.9	0.191	0.31
Glenelg N-49	MS 3	3455.3	3510.3	55.1	17.0	0.178	0.25
Glenelg N-49	MS 5	3522.9	3540.5	17.6	2.6	0.158	0.44
Glenelg N-49	MS 7	3566.0	3607.0	41.0	12.2	0.160	0.34
Glenelg H-38	LC 1	1942.0	1947.7	5.7	4.9	0.292	0.29
Glenelg H-38	LC 7	3314.7	3322.2	7.5	5.5	0.141	0.39
Cutoffs: Vsh <=0.40, Por. >=0.10, Sw <=0.65				**Zones: LC = Logan Canyon / MS = Missisauga**			

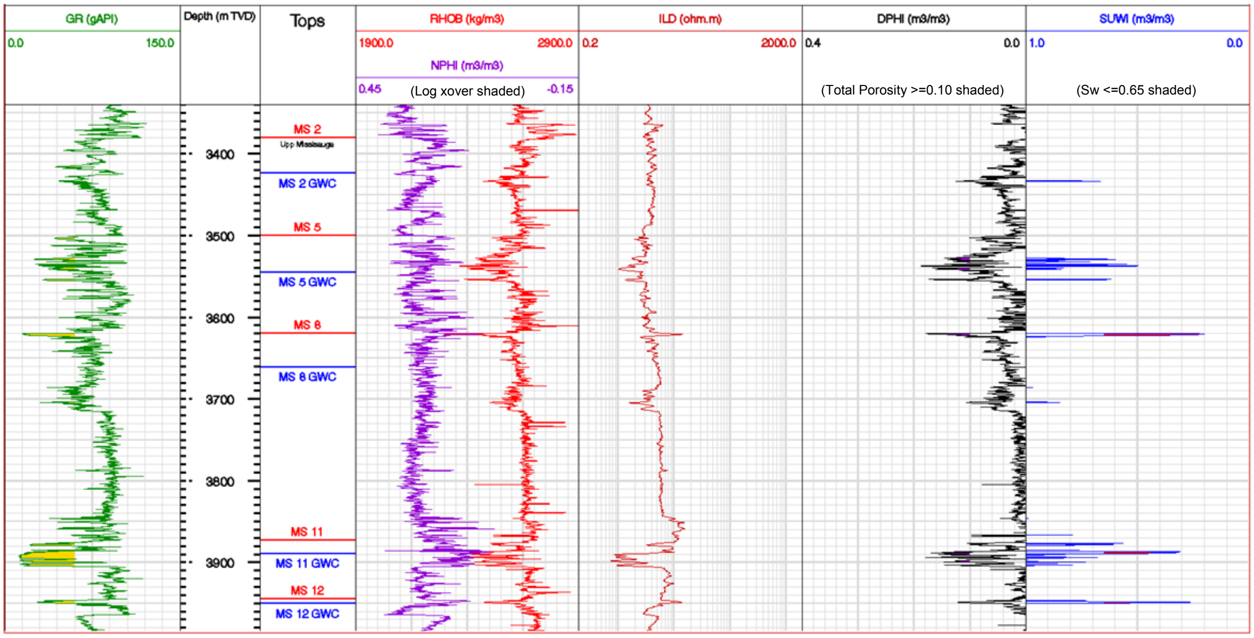

Figure 3.5.3 Glenelg E-58 petrophysical results plot: Missisauga gas zones.

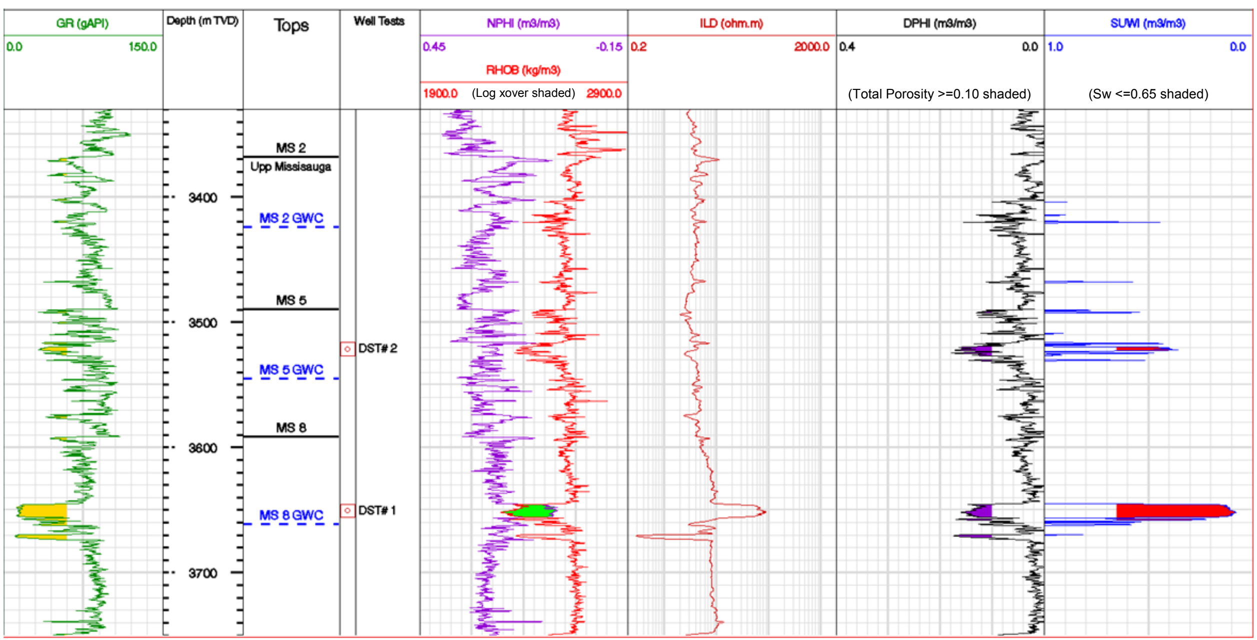

Figure 3.5.4 Glenelg E-58A petrophysical results plot: Missisauga gas zones.

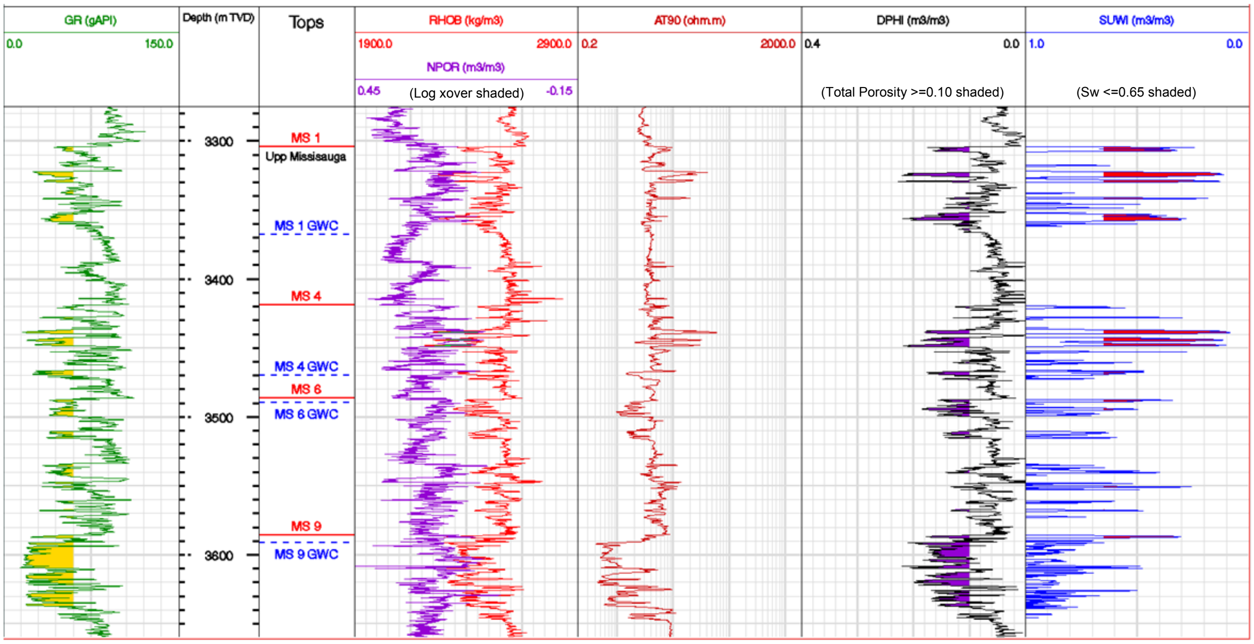

Figure 3.5.5 Glenelg H-59 petrophysical results plot: Missisauga gas zones.

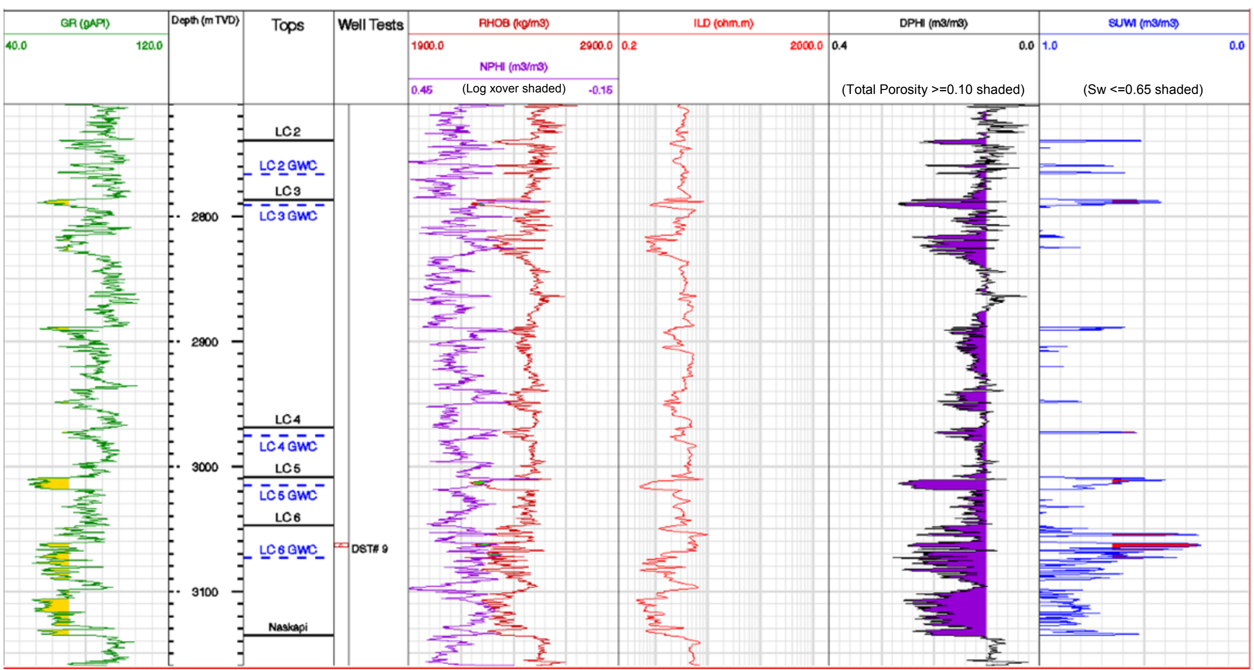

Figure 3.5.6 Glenelg J-48 petrophysical results plot: Logan Canyon gas zones.

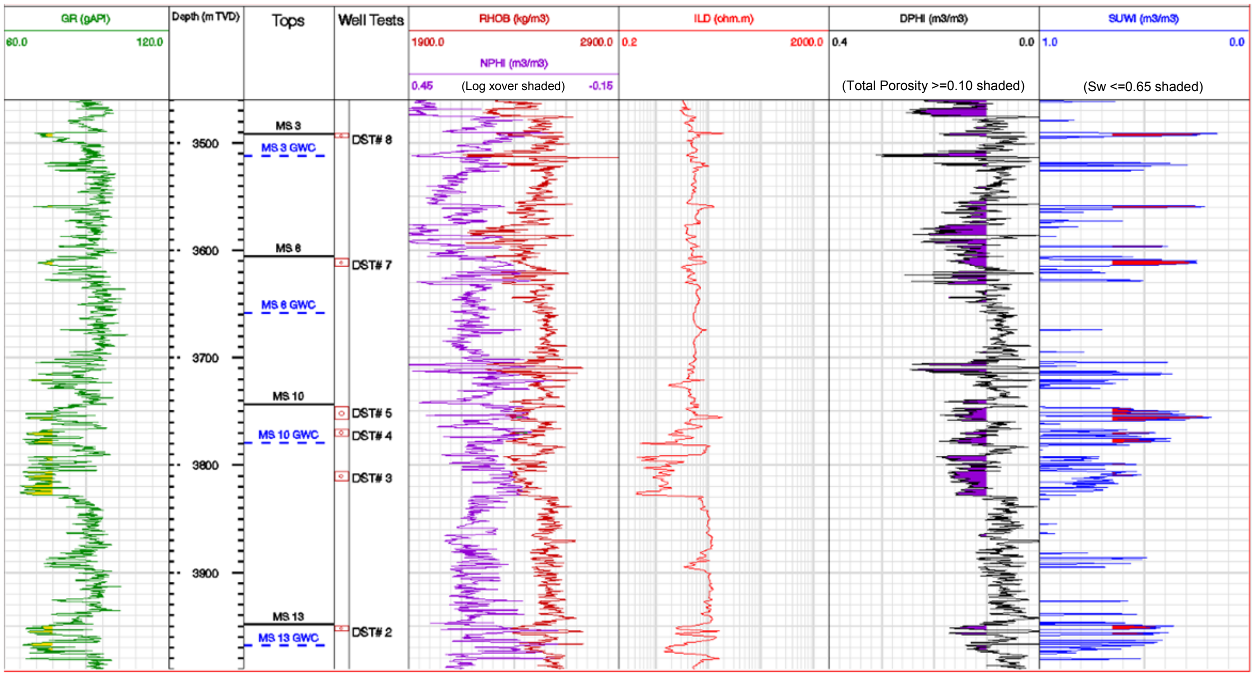

Figure 3.5.7 Glenelg J-48 petrophysical results plot: Missisauga gas zones.

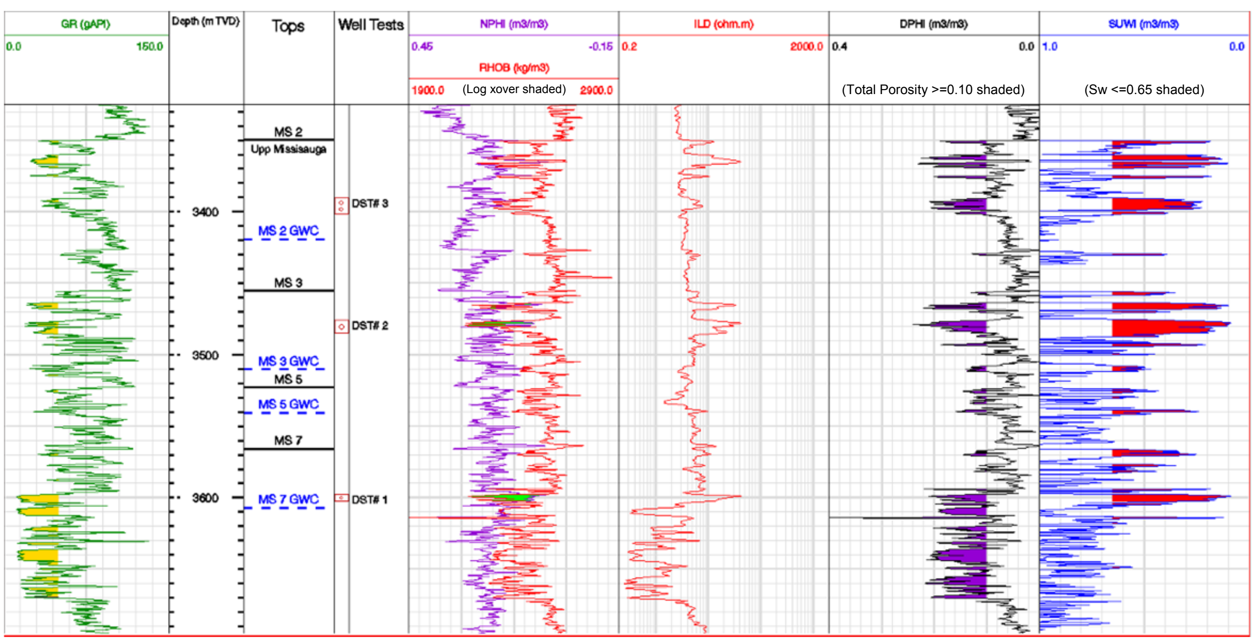

Figure 3.5.8 Glenelg N-49 petrophysical results plot: Missisauga gas zones.

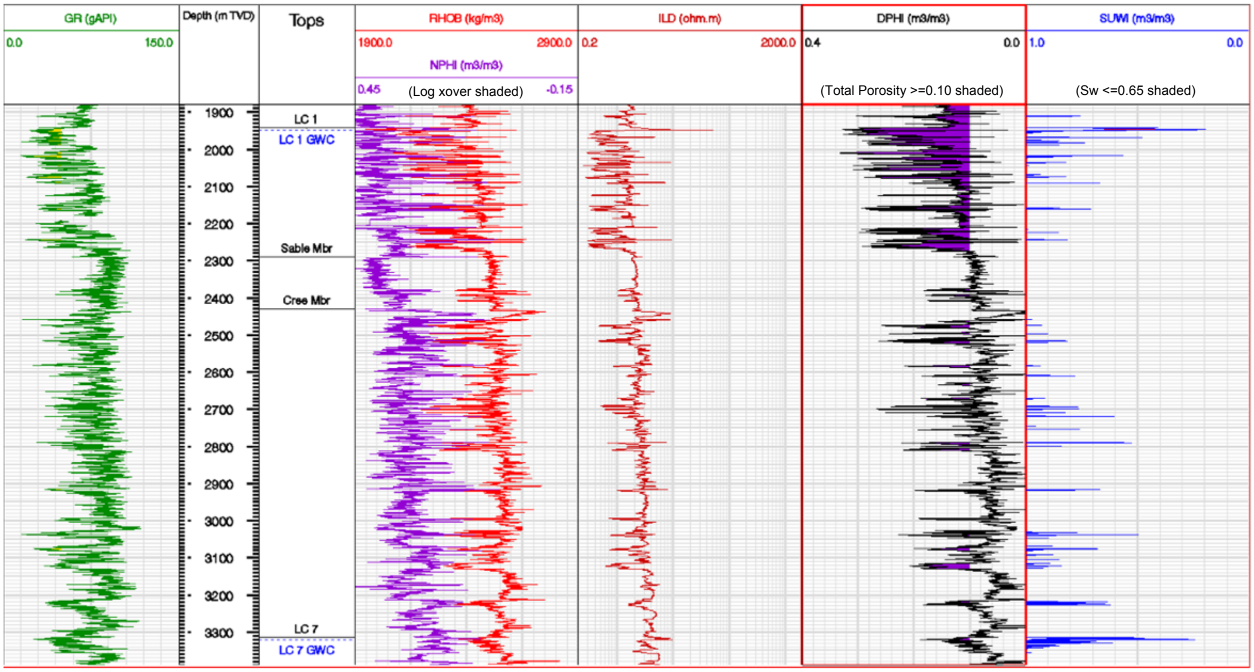

Figure 3.5.9 Glenelg H-38 petrophysical results plot: Logan Canyon gas zones.

3.5.5. Resource Assessment

A resource assessment of all Glenelg gas pools was conducted with the exception of pools MS 6, MS 9, and MS 12, which contain very minor gas volumes. For assessment purposes, Logan Canyon zones with thin gas pay and similar areal extents were grouped together as follows: LC 1 & LC 7 and LC 3 – LC 5; all other Glenelg pools were assessed individually. All Glenelg pools have GWCs that are defined by log and/or pressure data, constraining their areal extents.

The P50 area for each pool was defined by projecting the interpreted GWC onto the Glenelg Upper Missisauga depth map (Fig. 3.5.2). Minimum and maximum areas were determined by varying the P50 value +/-10% to allow for mapping uncertainty.

P50 probabilistic input parameters for net pay, porosity and hydrocarbon saturation were based on petrophysically-calculated well values. Minimum and maximum inputs for these parameters were varied symmetrically around the P50 value. With the exception of area and net pay, the assigned input parameters for Central fault block reservoirs were the same as those used for the N-49 fault block.

The reservoir characteristics of the Glenelg sandstones are generally good to excellent. However, zones with limited areal extent, thin gas columns and/or lower quality reservoir were assigned more conservative recovery factors. Assigned P50 recovery factors for the Logan Canyon pools varied from 50 to 70%. Higher recovery factors were typically used for the Upper Missisauga as

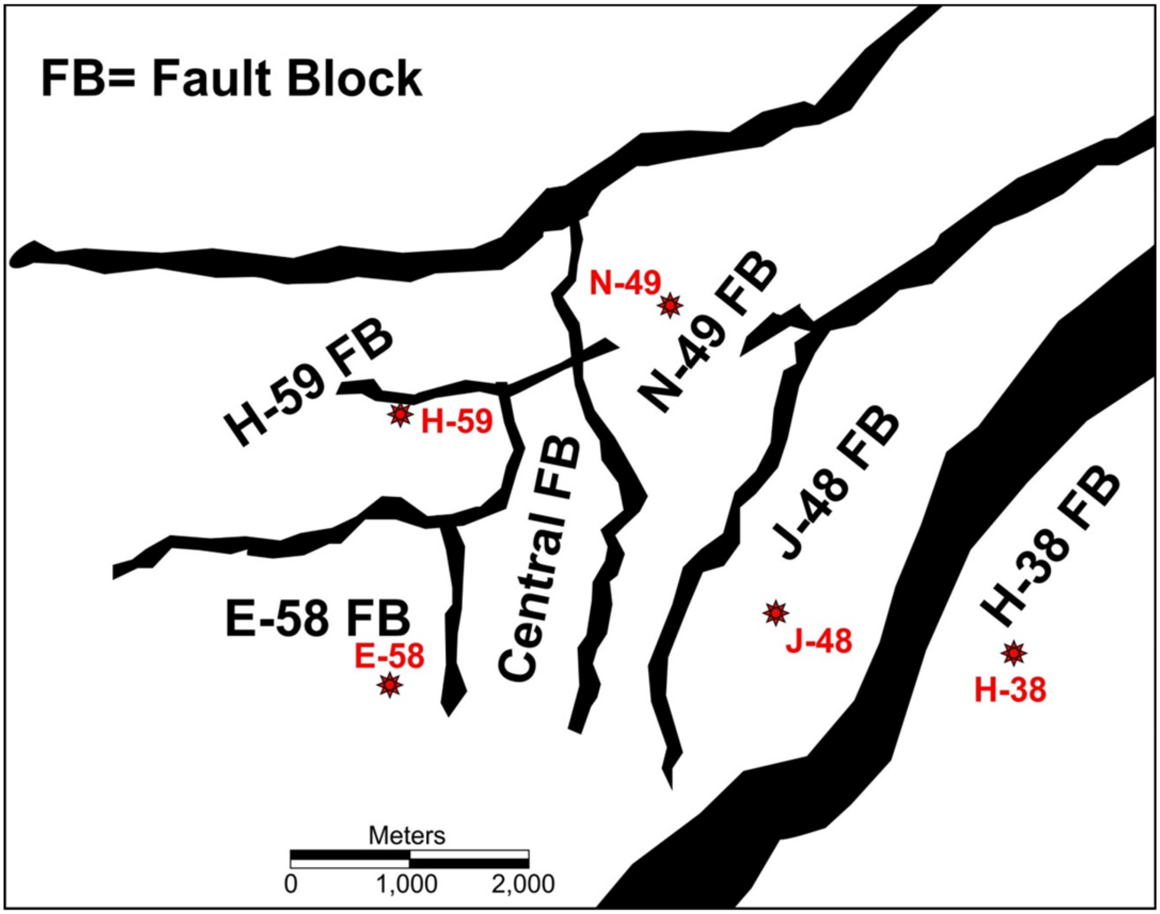

Figure 3.5.10 Glenelg fault blocks used for probabilistic resource calculation.

pool areas and gas column heights are generally larger than those in the Logan Canyon. For the Upper Missisauga gas pools, the assigned P50 recovery factors ranged from 60 to 75%, and the minimum and maximum inputs were varied symmetrically around the P50 value.

Probabilistic results for the Glenelg Field are presented for the entire field and by individual fault blocks (Fig. 3.5.10) defined by the Glenelg Upper Missisauga depth map (Fig. 3.5.2).
All key input parameters used for the probabilistic volume calculations are listed below (Table 3.5.3).

Table 3.5.3 Glenelg probabilistic volume calculation variables.

MS 2 (N-49 Fault Block)	P100	P50	P00	Mean
Area (km2)	6.8	7.5	8.3	7.5
Net Pay (m)	14	17	20	17
Porosity (fraction)	0.17	0.19	0.21	0.19
Sh (1-Sw) (fraction)	0.60	0.70	0.80	0.70
Gas FVF	252	259	266	259
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.65	0.75	0.85	0.75

MS 3 (N-49 Fault Block)	P100	P50	P00	Mean
Area (km2)	5.9	6.5	7.2	6.5
Net Pay (m)	4.0	10	16	10
Porosity (fraction)	0.15	0.17	0.19	0.17
Sh (1-Sw) (fraction)	0.60	0.70	0.80	0.70
Gas FVF	257	264	271	264
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.55	0.65	0.75	0.65

MS 5 (N-49 Fault Block)	P100	P50	P00	Mean
Area (km2)	3.0	3.3	3.6	3.3
Net Pay (m)	2.0	5.0	8.0	5.0
Porosity (fraction)	0.13	0.15	0.17	0.15
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	260	266	272	266
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.5	0.6	0.7	0.6

MS 7 (N-49 Fault Block)	P100	P50	P00	Mean
Area (km2)	4.9	5.5	6.1	5.5
Net Pay (m)	9.0	12	15	12
Porosity (fraction)	0.14	0.16	0.18	0.16
Sh (1-Sw) (fraction)	0.55	0.65	0.75	0.65
Gas FVF	262	269	276	269
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.60	0.70	0.80	0.70

LC 2 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km^2)	4.3	4.8	5.3	4.8
Net Pay (m)	1.0	2.0	3.0	2.0
Porosity (fraction)	0.16	0.18	0.20	0.18
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	215	222	229	222
CGR (BBL/MMCF)	10	14	18	14
Gas Recovery Factor	0.40	0.50	0.60	0.50

LC 3 – LC 5 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km^2)	1.0	1.1	1.2	1.1
Net Pay (m)	6.0	9.0	12	9.0
Porosity (fraction)	0.18	0.21	0.24	0.21
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	217	228	239	228
CGR (BBL/MMCF)	10	14	18	14
Gas Recovery Factor	0.50	0.60	0.70	0.60

LC 6 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km^2)	4.3	4.8	5.3	4.8
Net Pay (m)	10	13	16	13
Porosity (fraction)	0.18	0.21	0.24	0.21
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	233	240	247	240
CGR (BBL/MMCF)	10	14	18	14
Gas Recovery Factor	0.60	0.70	0.80	0.70

MS 3 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km^2)	1.9	2.1	2.3	2.1
Net Pay (m)	4.0	10	16	10
Porosity (fraction)	0.15	0.17	0.19	0.17
Sh (1-Sw) (fraction)	0.60	0.70	0.80	0.70
Gas FVF	257	264	271	264
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.55	0.65	0.75	0.65

MS 8 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km^2)	4.9	5.4	5.9	5.4
Net Pay (m)	3.0	8.0	13	8.0
Porosity (fraction)	0.12	0.14	0.16	0.14
Sh (1-Sw) (fraction)	0.60	0.70	0.80	0.70
Gas FVF	266	272	279	272
CGR (BBL/MMCF)	12	17	22	17
Gas Recovery Factor	0.5	0.6	0.7	0.6

MS 10 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km2)	4.0	4.5	5.0	4.5
Net Pay (m)	16	19	21	18.7
Porosity (fraction)	0.13	0.15	0.17	0.15
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	271	278	285	278
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.60	0.70	0.80	0.70

MS 13 (J-48 Fault Block)	P100	P50	P00	Mean
Area (km2)	1.9	2.1	2.3	2.1
Net Pay (m)	5.0	8.0	11	8.0
Porosity (fraction)	0.12	0.14	0.16	0.14
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	281	288	295	288
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.55	0.65	0.75	0.65

MS 1 (H-59 Fault Block)	P100	P50	P00	Mean
Area (km2)	4.3	4.8	5.3	4.8
Net Pay (m)	10	13	16	13
Porosity (fraction)	0.18	0.21	0.24	0.21
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	250	257	264	257
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.60	0.70	0.80	0.70

MS 4 (H-59 Fault Block)	P100	P50	P00	Mean
Area (km2)	2.5	2.8	3.1	2.8
Net Pay (m)	10	13	16	13
Porosity (fraction)	0.13	0.15	0.17	0.15
Sh (1-Sw) (fraction)	0.55	0.65	0.75	0.65
Gas FVF	254	261	268	261
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.60	0.70	0.80	0.70

MS 2 (Central Fault Block)	P100	P50	P00	Mean
Area (km2)	2.	2.8	3.1	2.8
Net Pay (m)	6.0	9.0	12	9.0
Porosity (fraction)	0.17	0.19	0.21	0.19
Sh (1-Sw) (fraction)	0.60	0.70	0.80	0.70
Gas FVF	252	259	266	259
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.65	0.75	0.85	0.75

MS 5 (Central Fault Block)	P100	P50	P00	Mean
Area (km2)	2.6	2.9	3.2	2.9
Net Pay (m)	2.0	5.0	8.0	5.0
Porosity (fraction)	0.13	0.15	0.17	0.15
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	260	266	272	266
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.50	0.60	0.70	0.60

MS 5 (E-58 Fault Block)	P100	P50	P00	Mean
Area (km2)	4.0	4.4	4.8	4.4
Net Pay (m)	2.0	5.0	8.0	5.0
Porosity (fraction)	0.13	0.15	0.17	0.15
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	259	266	272	266
CGR (BBL/MMCF)	3	5	7	5
Gas Recovery Factor	0.50	0.60	0.70	0.60

MS 8 (E-58 Fault Block)	P100	P50	P00	Mean
Area (km2)	3.9	4.3	4.7	4.3
Net Pay (m)	3.0	8.0	13	8.0
Porosity (fraction)	0.12	0.14	0.16	0.14
Sh (1-Sw) (fraction)	0.60	0.70	0.80	0.70
Gas FVF	265	272	279	272
CGR (BBL/MMCF)	12	17	22	17
Gas Recovery Factor	0.50	0.60	0.70	0.60

LC 1 & LC 7 (H-38 Fault Block)	P100	P50	P00	Mean
Area (km^2)	0.9	1.0	1.1	1.0
Net Pay (m)	7.0	10	13	10
Porosity (fraction)	0.18	0.21	0.24	0.21
Sh (1-Sw) (fraction)	0.55	0.65	0.75	0.65
Gas FVF	203	210	217	210
CGR (BBL/MMCF)	10	14	18	14
Gas Recovery Factor	0.50	0.60	0.70	0.60

3.5.6. Results

The probabilistic assessment results for the Glenelg field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.5.4 and 3.5.5). Descending cumulative probability charts for in-place and recoverable gas, for the entire field and by individual fault block, appear below (3.5.11–3.5.24).

Table 3.5.4 Glenelg probabilistic OGIP.

Sum of all Fault Blocks and Zones	P90	P50	P10	Mean
OGIP ($E9m^3$)	19.6	20.9	22.5	21.0
OGIP (Bcf)	693	740	795	742
N-49 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	7.59	8.58	9.71	8.64
OGIP (Bcf)	268	303	343	305
J-48 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	5.95	6.60	7.36	6.63
OGIP (Bcf)	210	233	260	234

H-59 Fault Block - Sum of all Zones	P90	P50	P10	Mean
OGIP ($E9m^3$)	2.53	2.92	3.40	2.95
OGIP (Bcf)	89.4	103	120	104
E-58 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.03	1.33	1.74	1.36
OGIP (Bcf)	36.2	46.9	61.3	48.0
Central Fault Block – Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.951	1.14	1.38	1.16
OGIP (Bcf)	33.6	40.4	48.7	40.9
H-38 Fault Block – Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.228	0.283	0.351	0.286
OGIP (Bcf)	8.05	10.0	12.4	10.1
Zone MS 2 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	3.71	4.36	5.13	4.39
OGIP (Bcf)	131	154	181	155
Zone MS 3 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.33	2.02	2.78	2.04
OGIP (Bcf)	47.0	71.5	98.3	72.2
Zone MS 5 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.213	0.323	0.456	0.331
OGIP (Bcf)	7.51	11.4	16.1	11.7
Zone MS 7 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.50	1.83	2.22	1.85
OGIP (Bcf)	52.8	64.7	78.4	65.3
Zone LC 2 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.148	0.208	0.279	0.212
OGIP (Bcf)	5.23	7.35	9.85	7.47
Zones LC 3 to LC 5 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.181	0.235	0.297	0.238
OGIP (Bcf)	6.38	8.29	10.5	8.39
Zone LC 6 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.52	1.87	2.29	1.89
OGIP (Bcf)	53.7	66.1	80.8	66.8
Zone MS 3 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.430	0.654	0.903	0.660
OGIP (Bcf)	15.2	23.1	31.9	23.3
Zone MS 8 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.736	1.14	1.58	1.16
OGIP (Bcf)	26.0	40.4	55.9	40.8
Zone MS 10 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.75	2.10	2.47	2.11
OGIP (Bcf)	61.7	74.0	87.3	74.4
Zone MS 13 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.280	0.368	0.476	0.374
OGIP (Bcf)	9.88	13.0	16.8	13.2

Zone MS 1 – H-59 Fault Block	P90	P50	P10	Mean
OGIP ($E9m^3$)	1.63	2.00	2.44	2.02
OGIP (Bcf)	57.6	70.8	86.3	71.5
Zone MS 4 – H-59 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.753	0.920	1.12	0.929
OGIP (Bcf)	26.6	32.5	39.4	32.8
Zone MS 2 – Central Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.682	0.864	1.06	0.869
OGIP (Bcf)	24.1	30.5	37.5	30.7
Zone MS 5 – Central Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.184	0.286	0.399	0.289
OGIP (Bcf)	6.51	10.1	14.1	10.2
Zone MS 5 – E-58 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.283	0.433	0.606	0.439
OGIP (Bcf)	10.0	15.3	21.4	15.5
Zone MS 8 – E-58 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.583	0.906	1.26	0.917
OGIP (Bcf)	20.6	32.0	44.5	32.4
Zones LC 1 & LC 7– H-38 Fault Block	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.226	0.283	0.354	0.286
OGIP (Bcf)	7.97	10.0	12.5	10.1

Table 3.5.5 Glenelg probabilistic recoverable resources.

Sum of all Fault Blocks and Zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	13.4	14.4	15.5	14.4
Rec. Gas (Bcf)	473	508	546	509
Rec. Condensate ($E6m^3$)	0.521	0.574	0.636	0.577
Rec. Condensate (MMB)	3.28	3.61	4.00	3.63
N-49 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	5.35	6.09	6.94	6.12
Rec. Gas (Bcf)	189	215	245	216
Rec. Condensate ($E6m^3$)	0.142	0.170	0.204	0.172
Rec. Condensate (MMB)	0.893	1.07	1.28	1.08
J-48 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	3.94	4.39	4.93	4.42
Rec. Gas (Bcf)	139	155	174	156
Rec. Condensate ($E6m^3$)	0.211	0.248	0.291	0.250
Rec. Condensate (MMB)	1.33	1.56	1.83	1.57
H-59 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	1.75	2.05	2.40	2.07
Rec. Gas (Bcf)	61.8	72.3	84.9	73.0
Rec. Condensate ($E6m^3$)	0.0429	0.0571	0.0715	0.0580
Rec. Condensate (MMB)	0.270	0.359	0.450	0.365

E-58 Fault Block - Sum of all Zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	0.606	0.796	1.05	0.816
Rec. Gas (Bcf)	21.4	28.1	37.0	28.8
Rec. Condensate ($E6m^3$)	0.0410	0.0577	0.0820	0.0601
Rec. Condensate (MMB)	0.258	0.363	0.516	0.378
Central Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.668	0.816	0.991	0.827
Rec. Gas (Bcf)	23.6	28.8	35.0	29.2
Rec. Condensate ($E6m^3$)	0.0175	0.0227	0.0294	0.0232
Rec. Condensate (MMB)	0.110	0.143	0.185	0.146
H-38 Fault Block - Sum of all Zones	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.134	0.170	0.214	0.172
Rec. Gas (Bcf)	4.74	5.99	7.56	6.09
Rec. Condensate ($E6m^3$)	0.0100	0.0132	0.0175	0.0135
Rec. Condensate (MMB)	0.0632	0.0833	0.110	0.0852
Zone MS 2 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	2.73	3.28	3.91	3.29
Rec. Gas (Bcf)	96.3	116	138	116
Rec. Condensate ($E6m^3$)	0.0677	0.0940	0.119	0.0925
Rec. Condensate (MMB)	0.426	0.591	0.746	0.582
Zone MS 3 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.858	1.31	1.82	.133
Rec. Gas (Bcf)	30.3	46.3	64.3	46.9
Rec. Condensate ($E6m^3$)	0.0227	0.0361	0.0534	0.0374
Rec. Condensate (MMB)	0.143	0.227	0.336	0.235
Zone MS 5 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.126	0.195	0.274	0.198
Recoverable Gas (Bcf)	4.46	6.87	9.66	6.99
Rec. Condensate ($E6m^3$)	0.00334	0.00534	0.00803	0.00555
Rec. Condensate (MMB)	0.0210	0.0336	0.0505	0.0349
Zone MS 7 – N-49 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	1.03	1.28	1.58	1.29
Rec. Gas (Bcf)	36.5	45.3	55.8	45.7
Rec. Condensate ($E6m^3$)	0.0261	0.0356	0.0475	0.0364
Rec. Condensate (MMB)	0.164	0.224	0.299	0.229
Zone LC 2 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.0728	0.104	0.142	0.106
Rec. Gas (Bcf)	2.57	3.66	5.00	3.73
Rec. Condensate ($E6m^3$)	0.00549	0.00808	0.0114	0.00832
Rec. Condensate (MMB)	0.0345	0.0508	0.0720	0.0523
Zones LC 3 to LC 5 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.107	0.140	0.182	0.143
Rec. Gas (Bcf)	3.77	4.95	6.44	5.04
Rec. Condensate ($E6m^3$)	0.00801	0.0109	0.0148	0.0112
Rec. Condensate (MMB)	0.0504	0.0687	0.0932	0.0705

Zone LC 6 – J-48 Fault Block	P90	P50	P10	Mean
Rec. Gas (E9m^3)	1.05	1.31	1.62	1.33
Rec. Gas (Bcf)	37.1	46.2	57.1	46.8
Rec. Condensate (E6m^3)	0.0784	0.102	0.133	0.104
Rec. Condensate (MMB)	0.493	0.642	0.836	0.654
Zone MS 3 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.278	0.425	0.589	0.430
Rec. Gas (Bcf)	9.81	15.0	20.8	15.2
Rec. Condensate (E6m^3)	0.00727	0.0116	0.0173	0.0121
Rec. Condensate (MMB)	0.0457	0.0732	0.109	0.0759
Zone MS 8 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.436	0.682	0.960	0.694
Rec. Gas (Bcf)	15.4	24.1	33.9	24.5
Rec. Condensate (E6m^3)	0.0405	0.0644	0.0941	0.0661
Rec. Condensate (MMB)	0.255	0.405	0.592	0.416
Zone MS 10 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	1.20	1.46	1.76	1.48
Rec. Gas (Bcf)	42.5	51.7	62.0	52.1
Rec. Condensate (E6m^3)	0.0300	0.0407	0.0536	0.0413
Rec. Condensate (MMB)	0.189	0.256	0.337	0.260
Zone MS 13 – J-48 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.179	0.239	0.311	0.243
Rec. Gas (Bcf)	6.33	8.45	11.0	8.58
Rec. Condensate (E6m^3)	0.00464	0.00661	0.00928	0.00682
Rec. Condensate (MMB)	0.0292	0.0416	0.0584	0.0429
Zone MS 1 – H-59 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	1.12	1.40	1.73	1.42
Rec. Gas (Bcf)	39.7	49.4	61.0	50.1
Rec. Condensate (E6m^3)	0.0285	0.0390	0.0525	0.0397
Rec. Condensate (MMB)	0.179	0.245	0.330	0.250
Zone MS 4 – H-59 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.521	0.643	0.790	0.648
Rec. Gas (Bcf)	18.4	22.7	27.9	22.9
Rec. Condensate (E6m^3)	0.0130	0.0180	0.0238	0.0183
Rec. Condensate (MMB)	0.0819	0.113	0.150	0.115
Zone MS 2 – Central Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.507	0.646	0.804	0.651
Rec. Gas (Bcf)	17.9	22.8	28.4	23.0
Rec. Condensate (E6m^3)	0.0128	0.0180	0.0242	0.0183
Rec. Condensate (MMB)	0.0808	0.113	0.152	0.115
Zone MS 5 – Central Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.110	0.171	0.241	0.174
Rec. Gas (Bcf)	3.87	6.05	8.52	6.15
Rec. Condensate (E6m^3)	0.00289	0.00472	0.00703	0.00488
Rec. Condensate (MMB)	0.0182	0.0297	0.0442	0.0307

Zone MS 5 – E-58 Fault Block	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	0.169	0.259	0.368	0.264
Rec. Gas (Bcf)	5.96	9.15	13.0	9.33
Rec. Condensate ($E6m^3$)	0.00444	0.00714	0.0108	0.00741
Rec. Condensate (MMB)	0.0279	0.0449	0.0680	0.0466
Zone MS 8 – E-58 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.345	0.544	0.765	0.552
Rec. Gas (Bcf)	12.2	19.2	27.0	19.5
Rec. Condensate ($E6m^3$)	0.0320	0.0512	0.0750	0.0526
Rec. Condensate (MMB)	0.201	0.322	0.472	0.331
Zones LC 1 & LC 7– H-38 Fault Block	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.133	0.170	0.215	0.172
Rec. Gas (Bcf)	4.71	6.02	7.59	6.09
Rec. Condensate ($E6m^3$)	0.0100	0.0133	0.0175	0.0135
Rec. Condensate (MMB)	0.0627	0.0834	0.110	0.0852

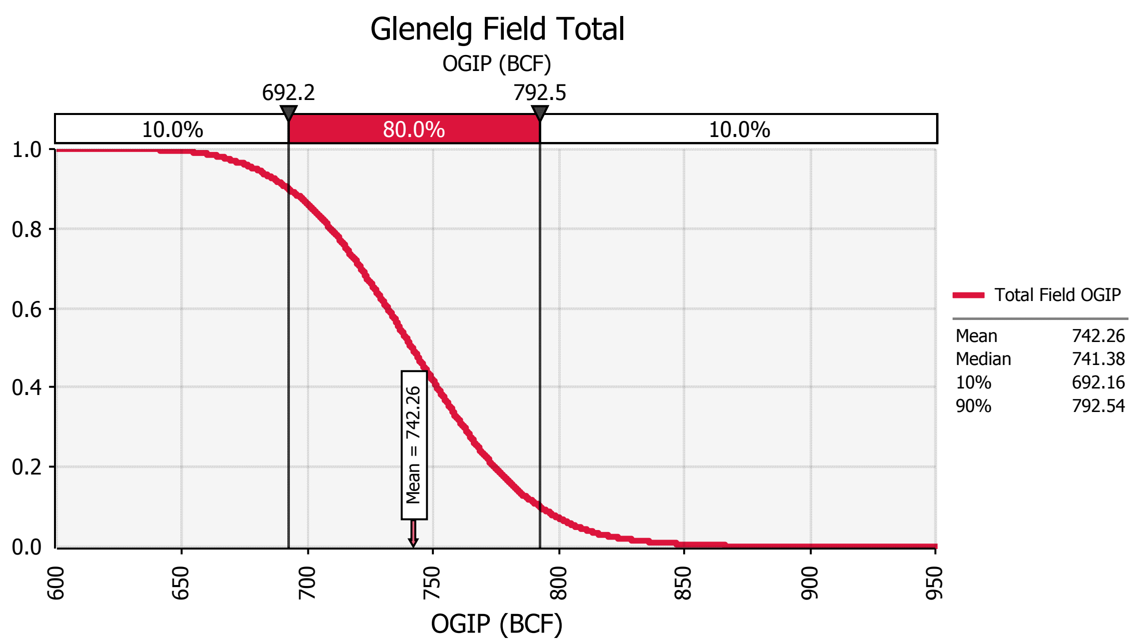

Figure 3.5.11. Glenelg OGIP descending cumulative probability chart (including all zones from all fault blocks).

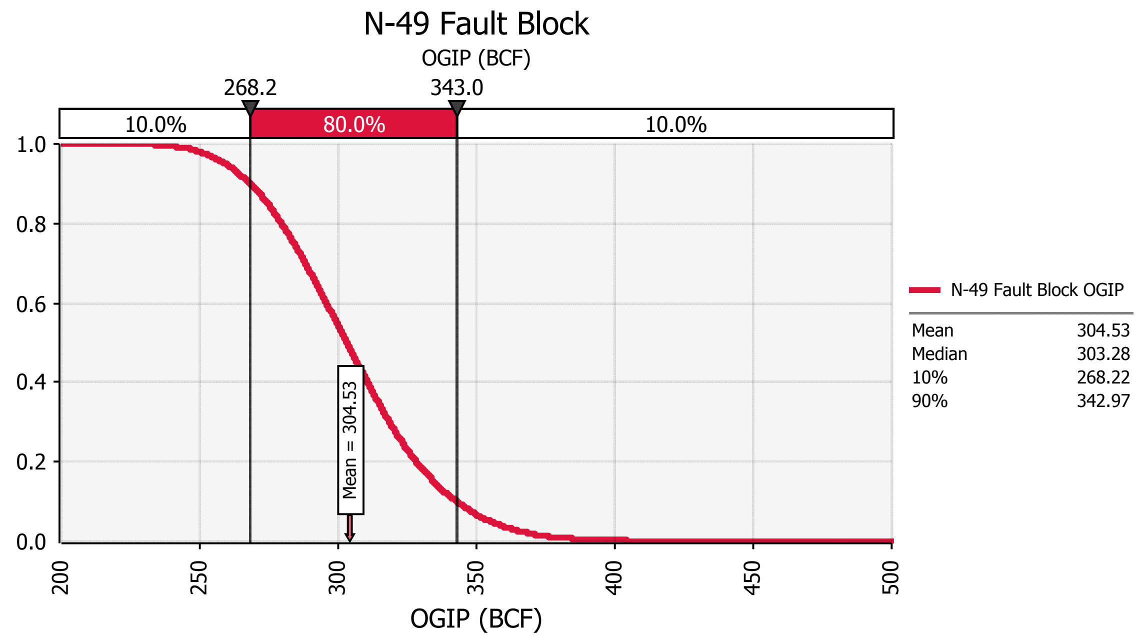

Figure 3.5.12 Glenelg OGIP descending cumulative probability chart for N-49 fault block.

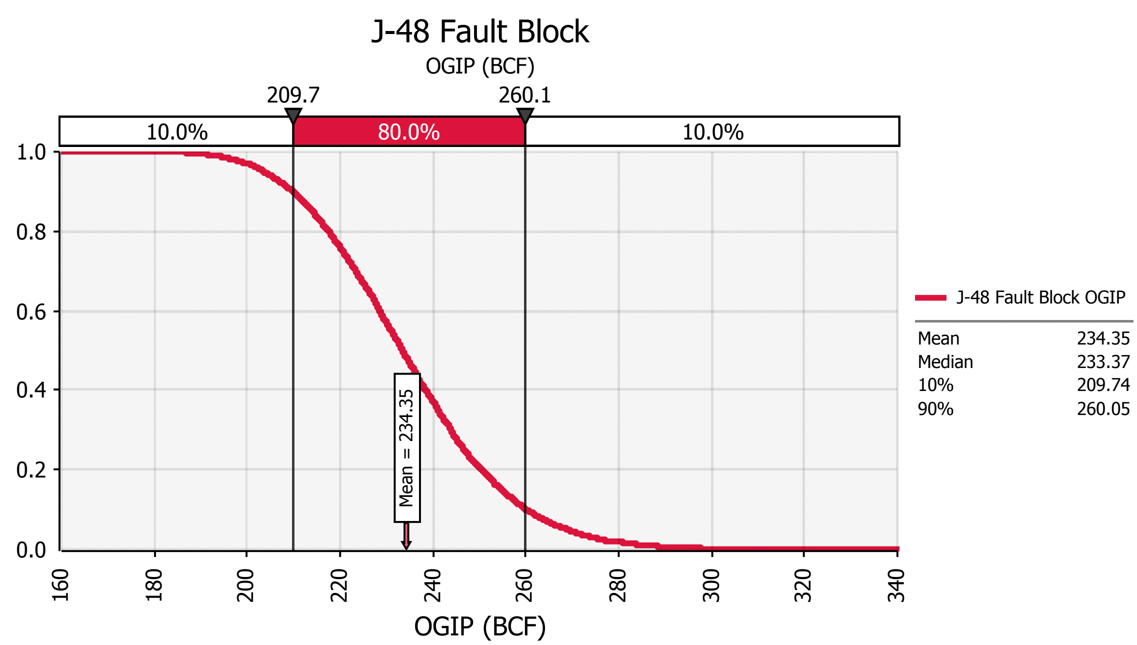

Figure 3.5.13 Glenelg OGIP descending cumulative probability chart for J-48 fault block.

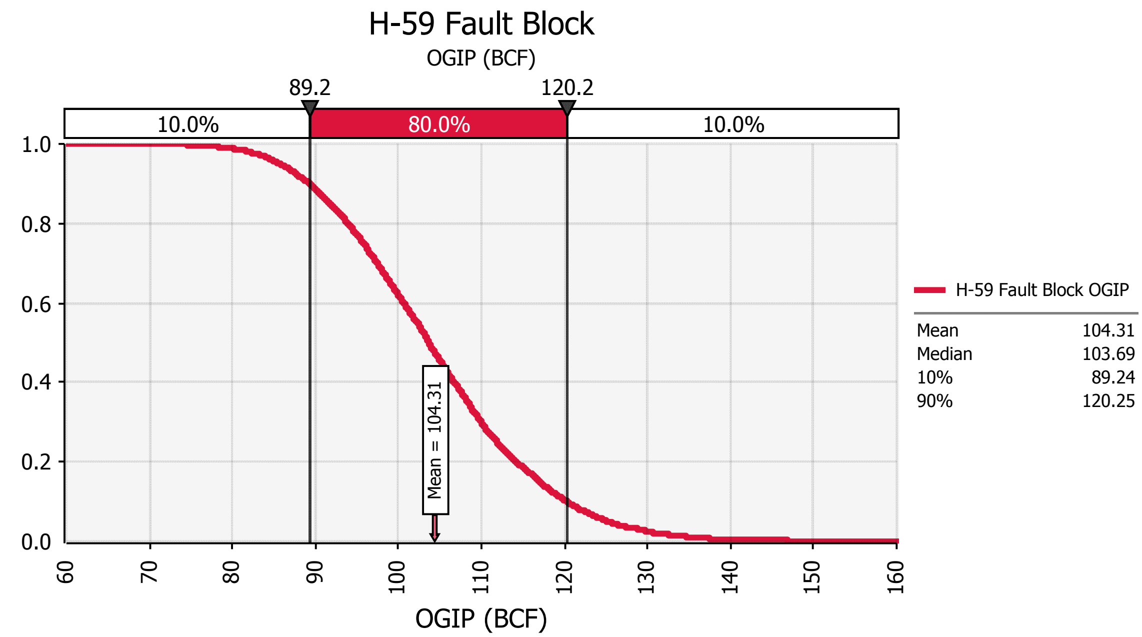

Figure 3.5.14 Glenelg OGIP descending cumulative probability chart for H-59 fault block.

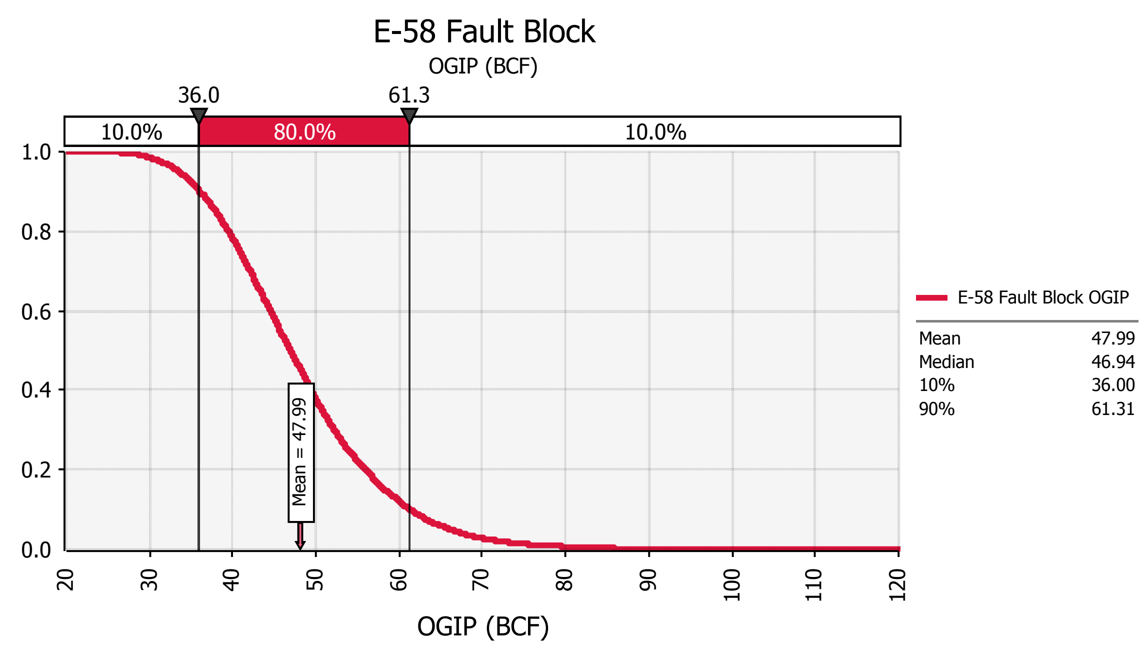

Figure 3.5.15 Glenelg OGIP descending cumulative probability chart for E-58 fault block.

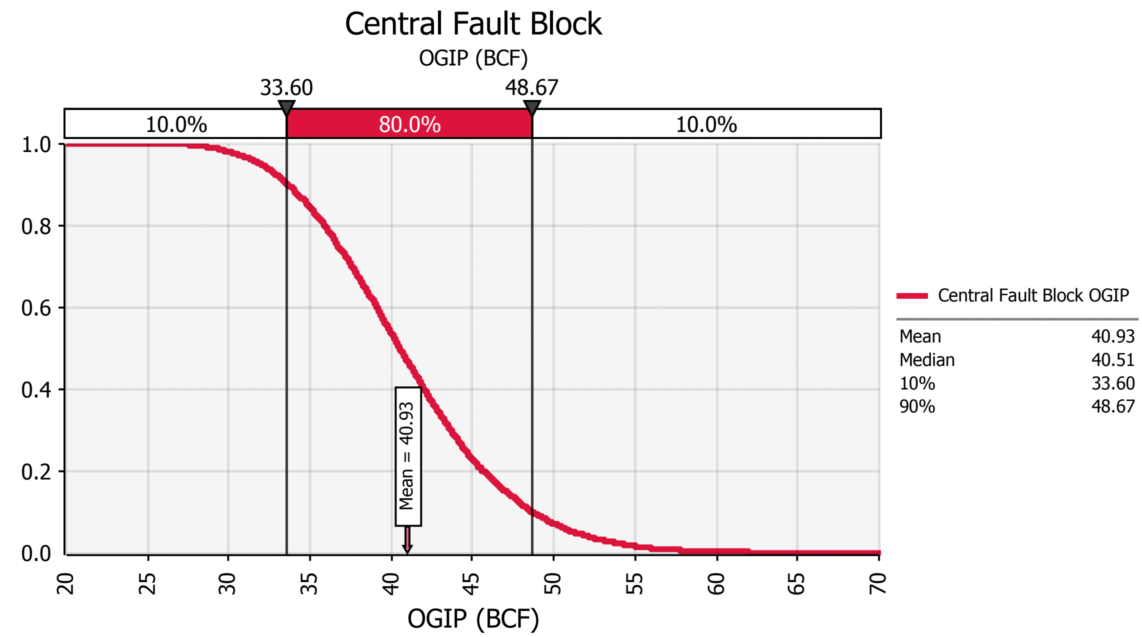

Figure 3.5.16 Glenelg OGIP descending cumulative probability chart for Central fault block.

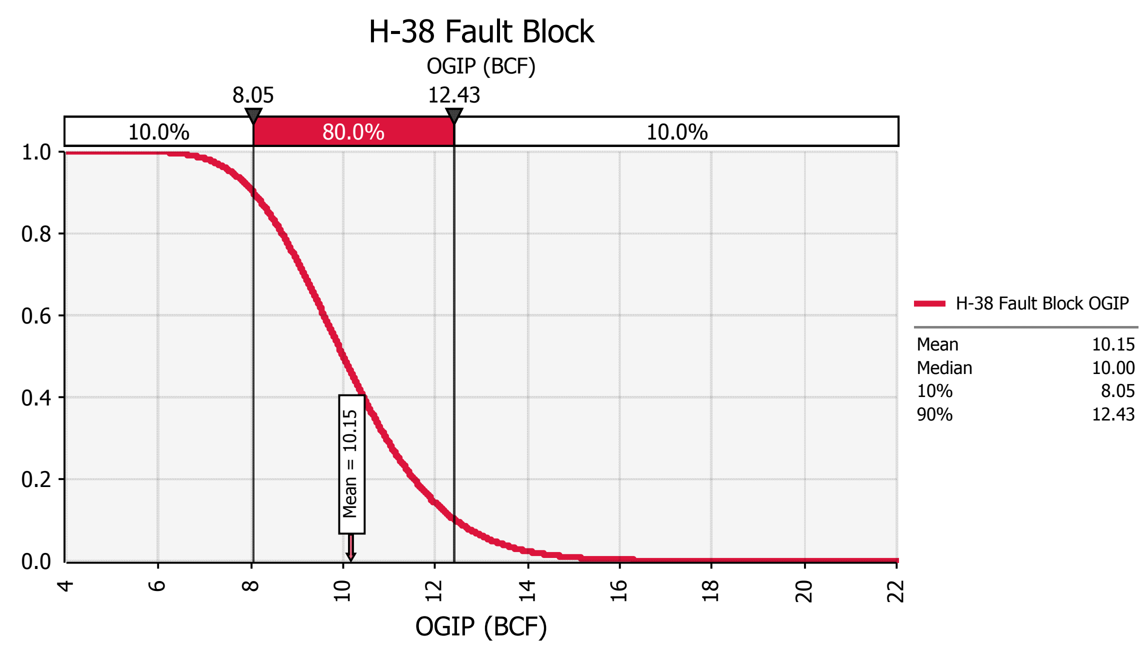

Figure 3.5.17 Glenelg OGIP descending cumulative probability chart for H-38 fault block.

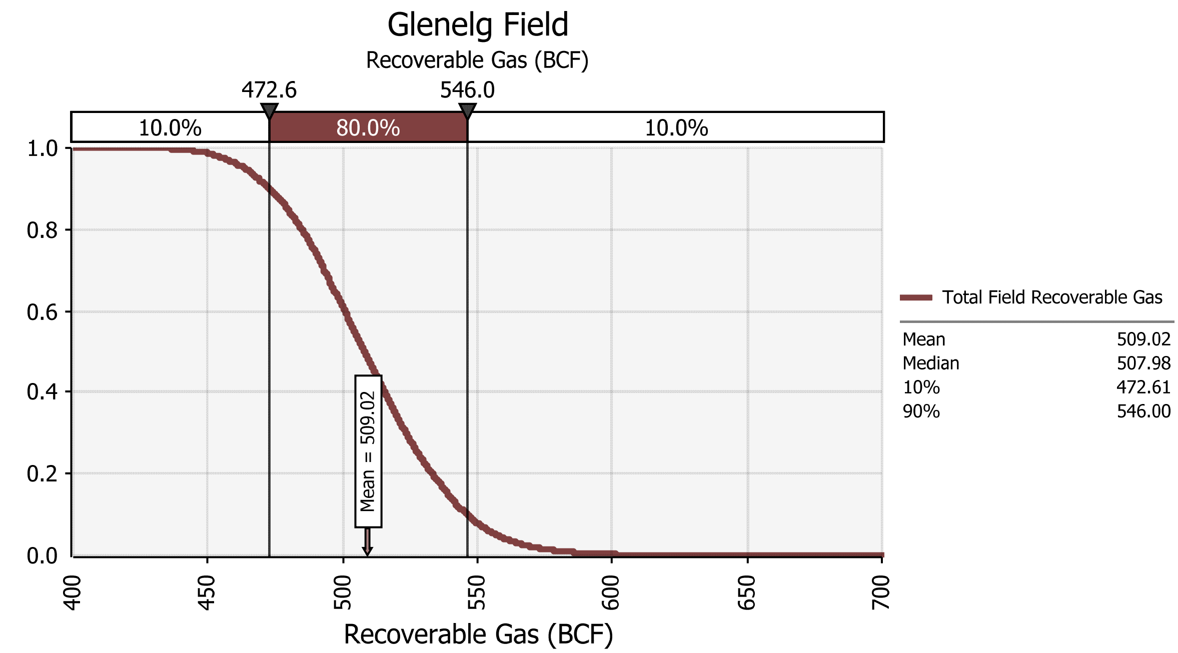

Figure 3.5.18 Glenelg recoverable gas descending cumulative probability chart (including all zones from all fault blocks).

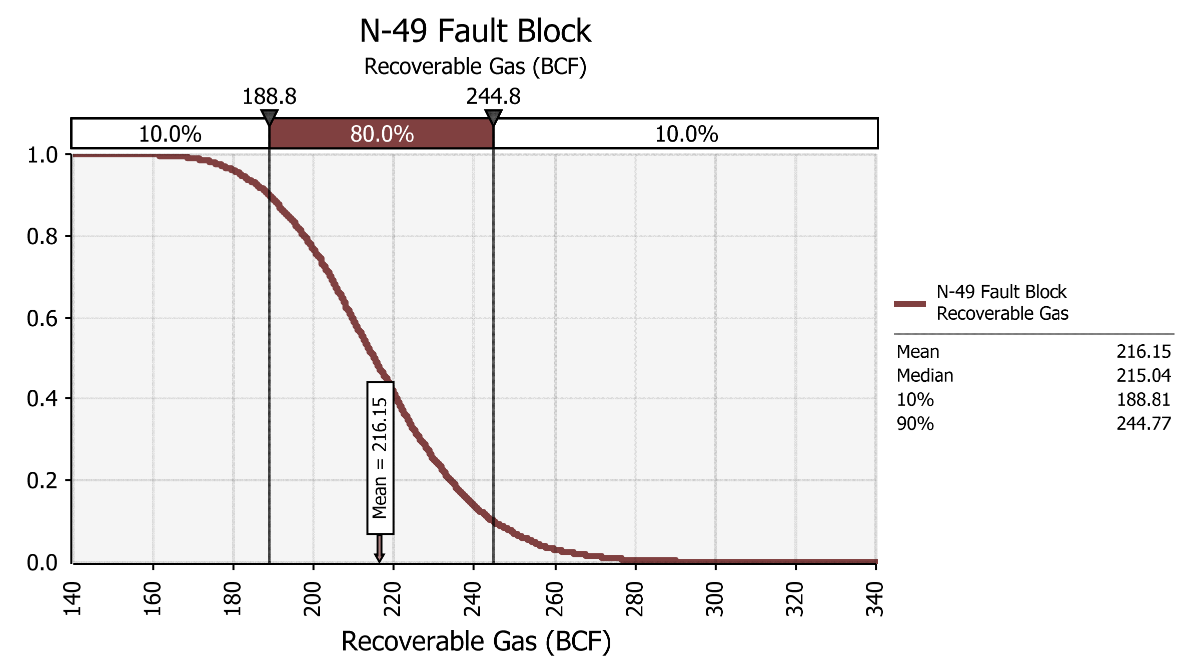

Figure 3.5.19 Glenelg recoverable gas descending cumulative probability chart for N-49 fault block.

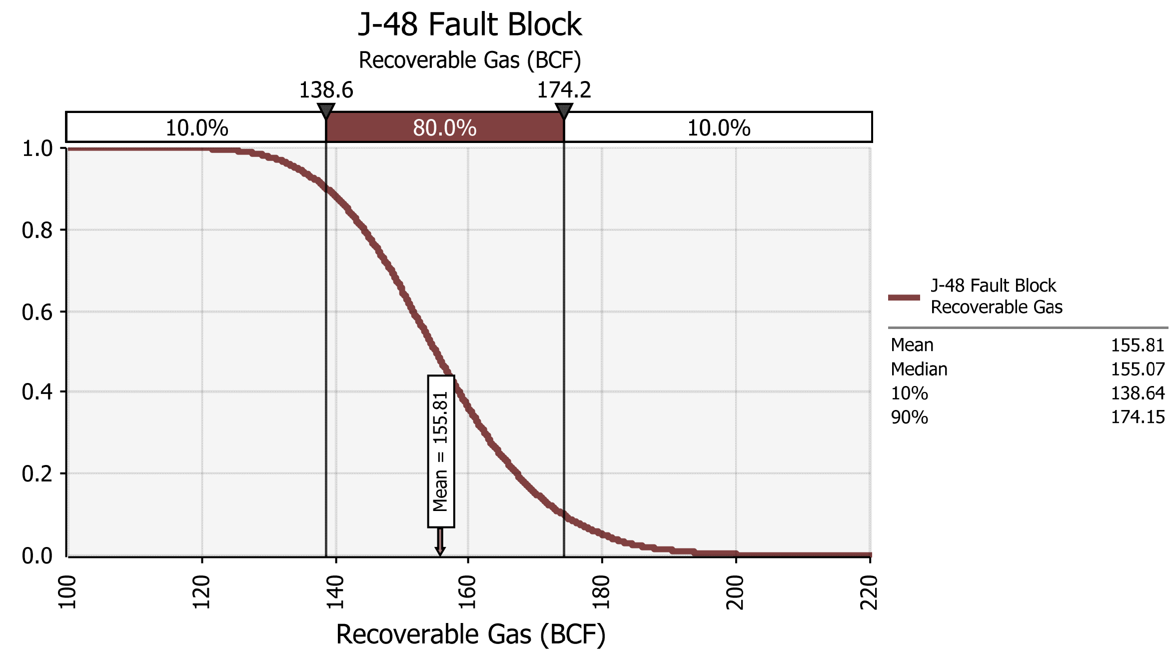

Figure 3.5.20 Glenelg recoverable gas descending cumulative probability chart for J-48 fault block.

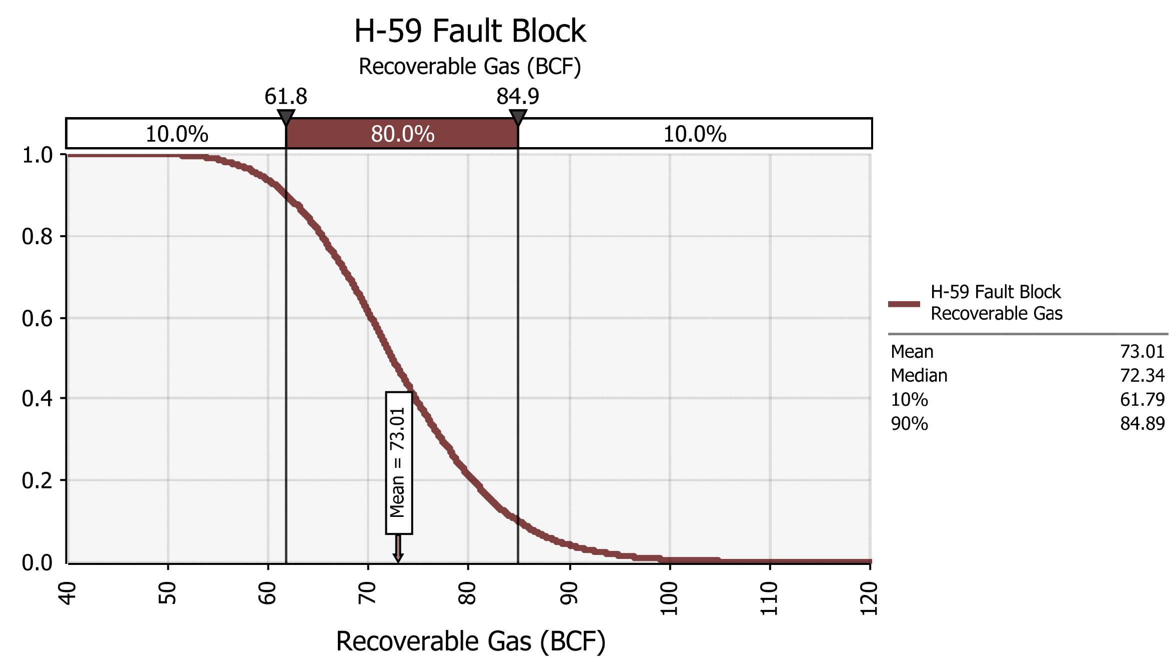

Figure 3.5.21 Glenelg recoverable gas descending cumulative probability chart for H-59 fault block.

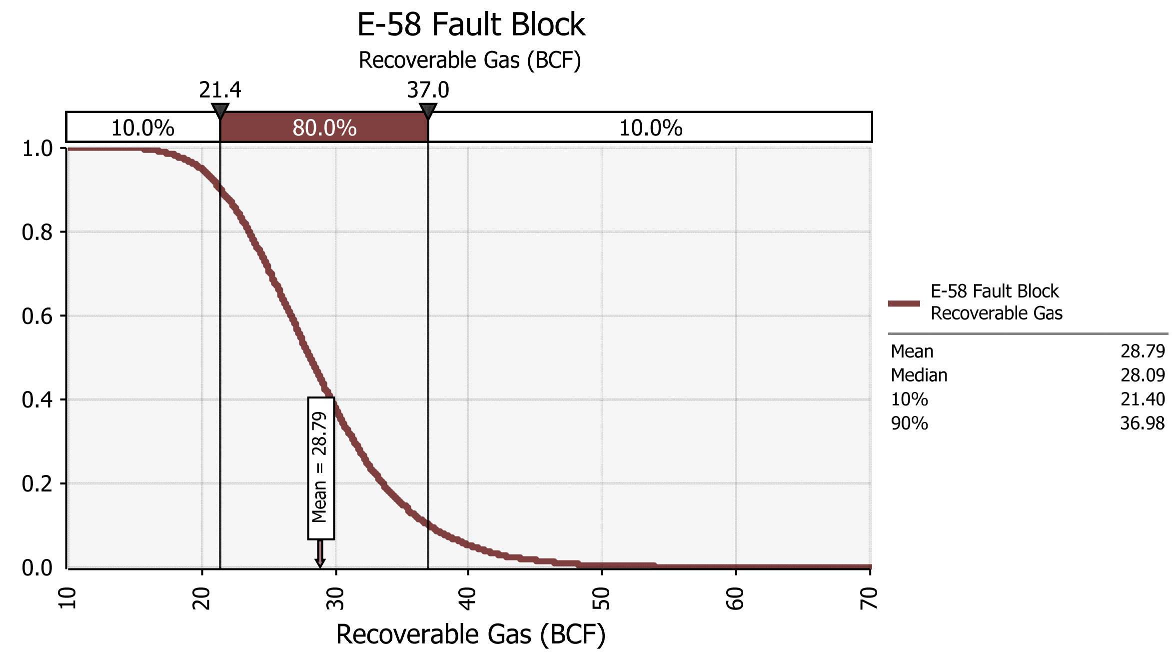

Figure 3.5.22 Glenelg recoverable gas descending cumulative probability chart for E-58 fault block.

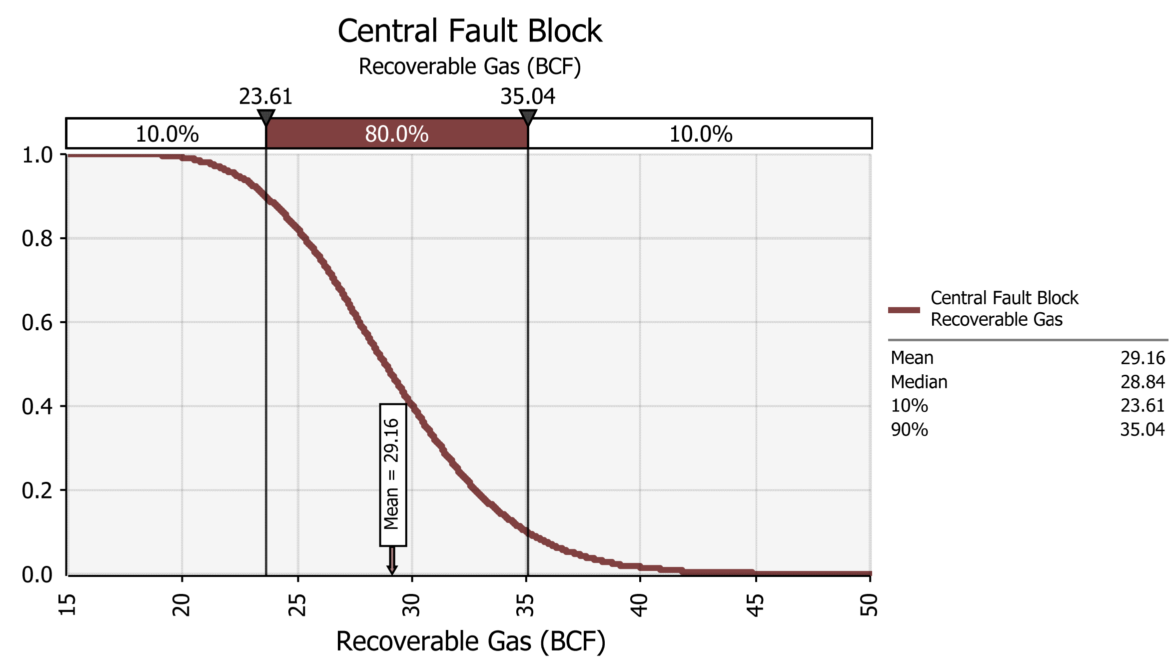

Figure 3.5.23 Glenelg recoverable gas descending cumulative probability chart for Central fault block.

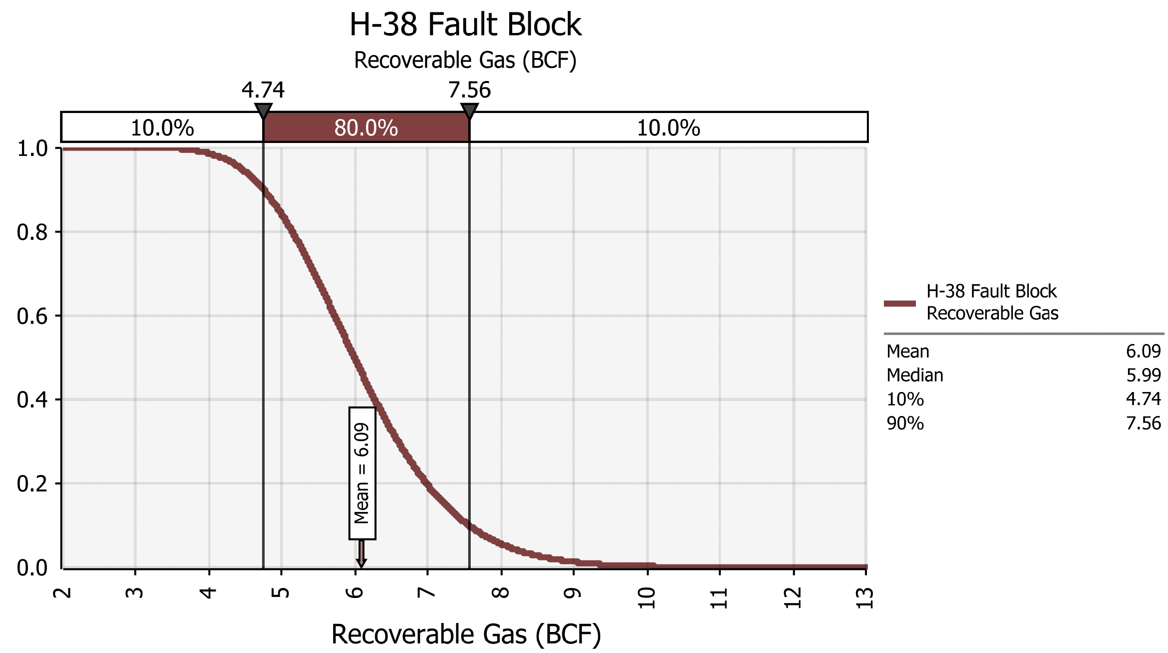

Figure 3.5.24 Glenelg recoverable gas descending cumulative probability chart for H-38 fault block.

3.6 Intrepid - Significant Discovery

3.6.1. Overview

The Intrepid gas field is located approximately 19 km south of Sable Island (Fig. 1.1). The field was discovered in 1979 and this assessment is based on the discovery well.

Discovery Well

Well:	Intrepid L-80
Company:	Texaco & Shell
Spud:	18-May-74
Well Termination:	14-Aug-74
Total Depth:	4162 m
Water Depth:	43.58 m
Latitude:	43°49'35.78"N
Longitude:	59°56'43.83"W
Target:	Drilled to test for the presence of hydrocarbons in the sands of a large rollover anticline bounded to the north and south by large down-to-basin faults.

Additional Wells

No delineation drilling was conducted.

3.6.2. Structure

The Intrepid structure is a salt-cored rollover anticline on the downthrown side of a down-to-basin growth fault as shown on the seismic line (Fig. 3.6.1). This growth fault is a reaction to underlying salt movement. The well is drilled near the up thrown side of a crestal fault that resulted from deeper salt movement. Two key seismic horizons are the Upper Missisauga Zone 2 (red), and O-Marker (blue), which is just above the deeper gas zones.

The seven reservoir zones are represented by these two mapped seismic horizons. The Zone 2 depth map (Fig. 3.6.2) is used for Zones 1 and 2 and the O-Marker depth map (Fig. 3.6.3) is used for Zones 3, 4, 5, 6, and 7. The P50 area contour (purple) on each map indicates that both closures seal along the crestal fault and leak at structural spill points to the north.

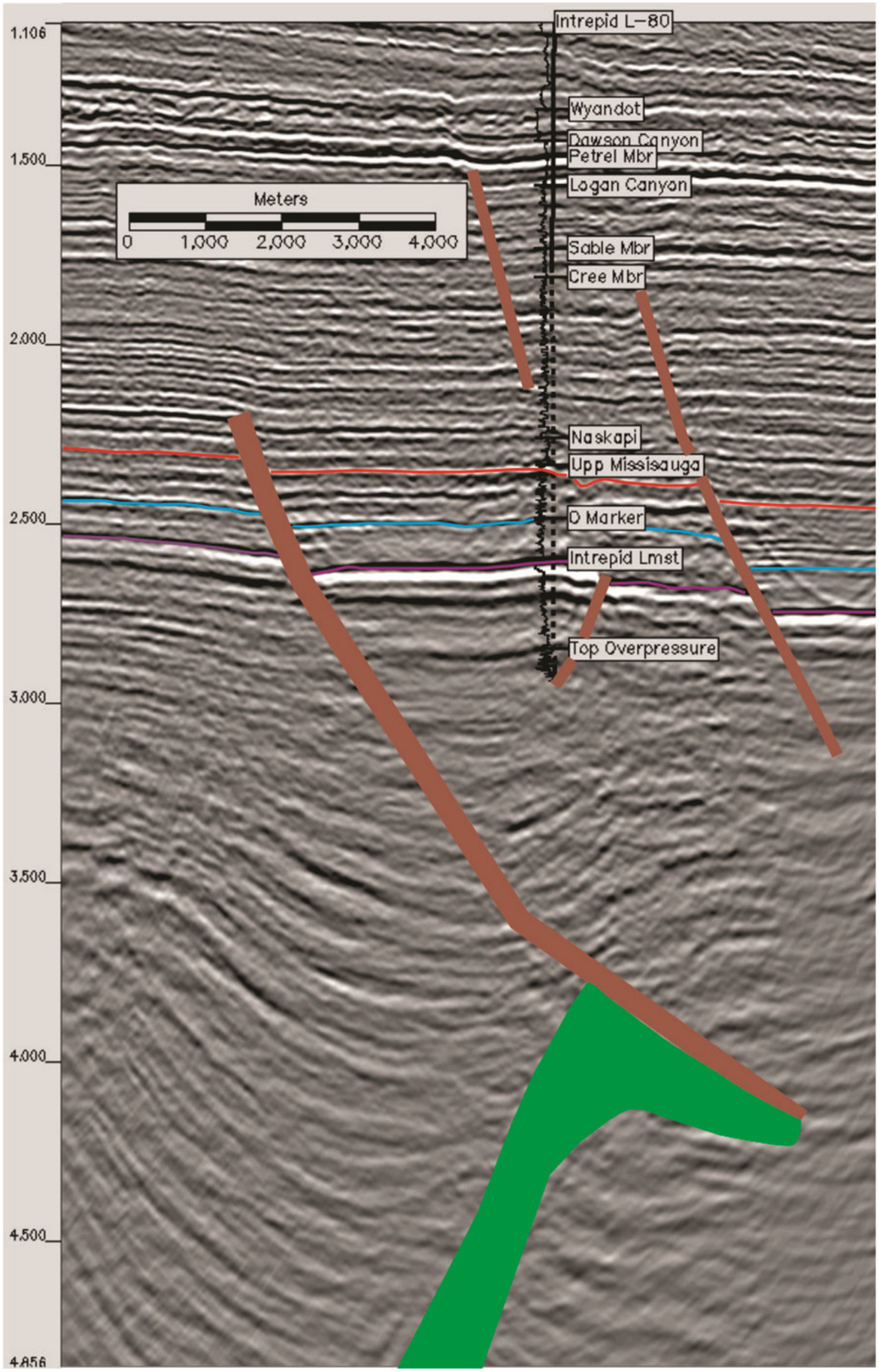

Figure 3.6.1 Intrepid seismic time line showing gamma ray log.

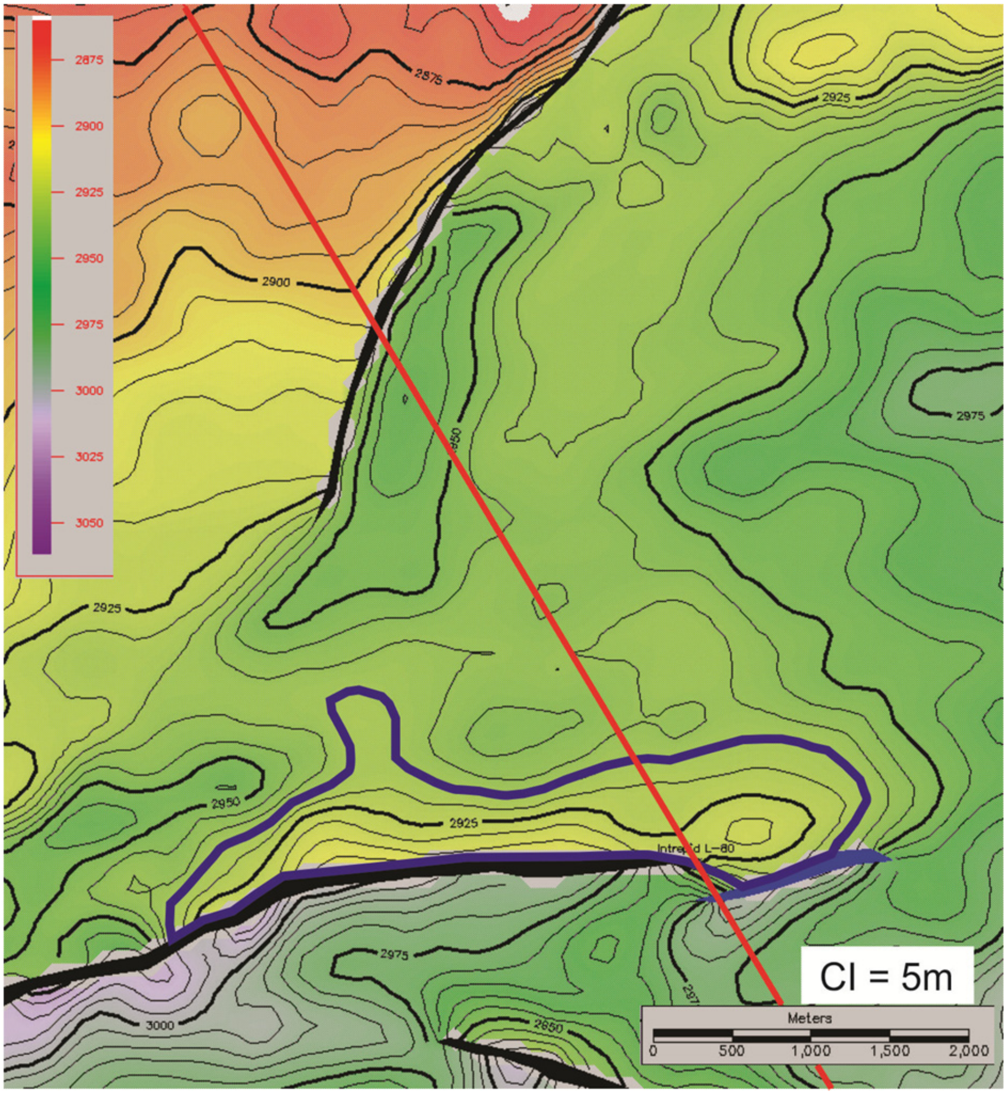

Figure 3.6.2 Intrepid Zone 2 depth map used for Zones 1 and 2.

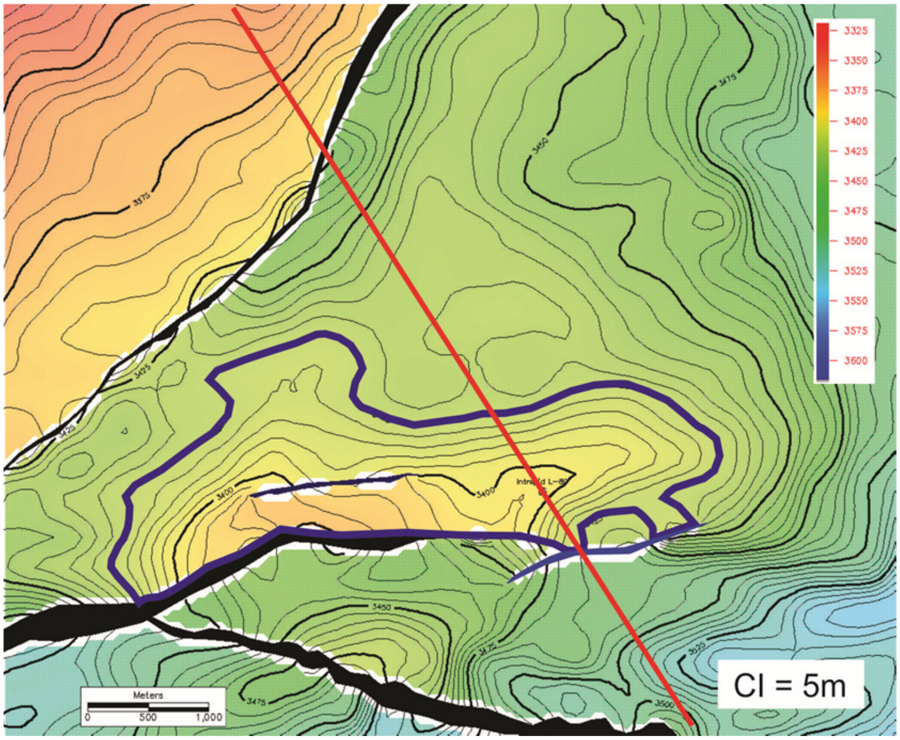

Figure 3.6.3 Intrepid O-Marker depth map used for Zones 3–7.

3.6.3. Reservoir Description

The Intrepid gas reservoirs are found within the Early Cretaceous strata of the Middle and Upper members of the Missisauga Formation (Berriasian-Barremian), and the Naskapi shale member of the Logan Canyon Formation (Aptian). The well was drilled near the crest of the structure and encountered numerous reservoir quality sands. The reservoirs are all normally pressured with the top of overpressure interpreted to occur approximately 100 m below the deepest gas zone.

Reservoir sands consist of stacked sequences of delta front, channel and strandplain-shoreface facies in a dominantly marine setting. The sands are medium to coarse grained (occasionally pebbly), moderate to well-sorted, siliceous and variably argillaceous and dolomitic.

3.6.4. Formation Evaluation

Four of the seven Intrepid gas zones were tested with flow rates ranging from 1.7 to 7.7 MMscf/d (Table 3.6.1). The reservoir characteristics of the gas zones vary from fair to very good with average porosities ranging from 0.12 to 0.20. Log and/or DST defined GWCs were interpreted in all sands except Zones 4–6. Although no clear contact is present, the lower portions of Zones 4–6 appear to be transitional indicating the GWC is near the base of these sands. The Intrepid L-80 petrophysical assessment results are detailed below (Table 3.6.2; Figs. 3.6.4 to 3.6.6).

Table 3.6.1 Intrepid L-80 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	3965-3968	wet	Missisauga	Rec Salt Water			Rec Salt Water		
DST 2	3953-3956	wet	Missisauga	Rec Gassy Salt Water			Rec Gassy Salt Water		
DST 3	3841-3845	7	Missisauga	47			1.7		
DST 4	3447-3501	tight	Missisauga	No Rec.			No Rec.		
DST 5	3383-3389	3	Missisauga	120	11	144	4.2	69	906
DST 6	3045-3054	wet	Missisauga	Rec Salt Water			Rec Salt Water		
DST 7	2937-2941	2	Missisauga	130	4	30	4.6	25	189
DST 8	2908-2911	1	Logan Canyon	217	11	25	7.7	69	157

Table 3.6.2 Intrepid L-80 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	2905.4	2911.5	6.1	4.4	0.204	0.46
Zone 2	2935.0	2961.3	26.3	7.3	0.202	0.39
Zone 3	3379.0	3396.5	17.5	4.6	0.126	0.50
Zone 4	3647.9	3661.6	13.7	0.5	0.116	0.53
Zone 5	3692.2	3699.0	6.8	3.4	0.140	0.44
Zone 6	3715.6	3750.0	34.4	4.3	0.125	0.46
Zone 7	3840.3	3884.3	44.0	6.2	0.119	0.45
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60						

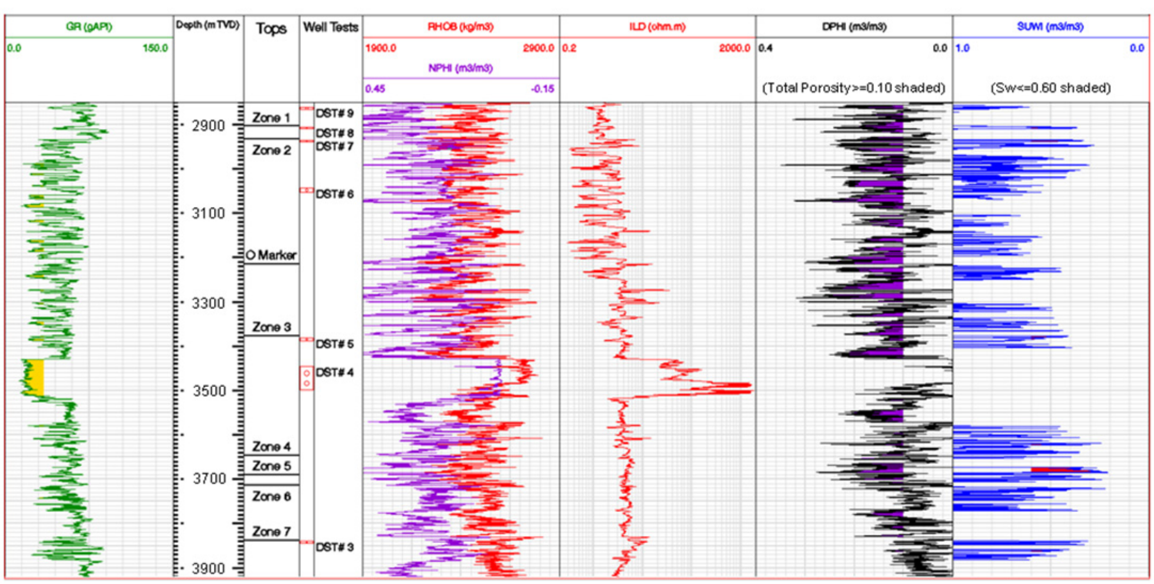

Figure 3.6.4 Intrepid L-80 petrophysical results plot: all zones.

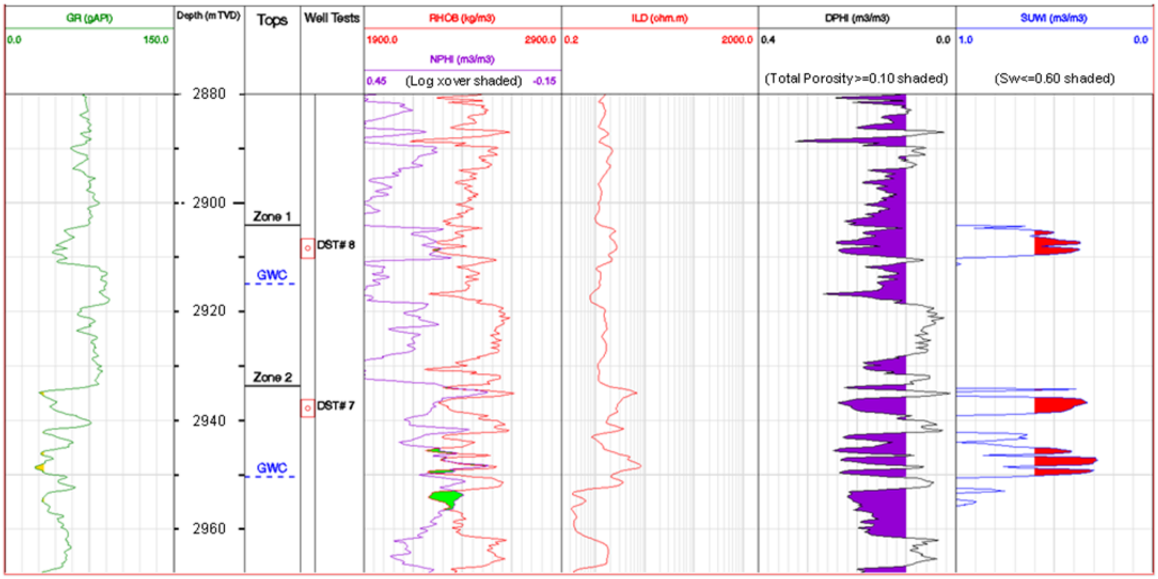

Figure 3.6.5 Intrepid L-80 petrophysical results plot: Zones 1 & 2.

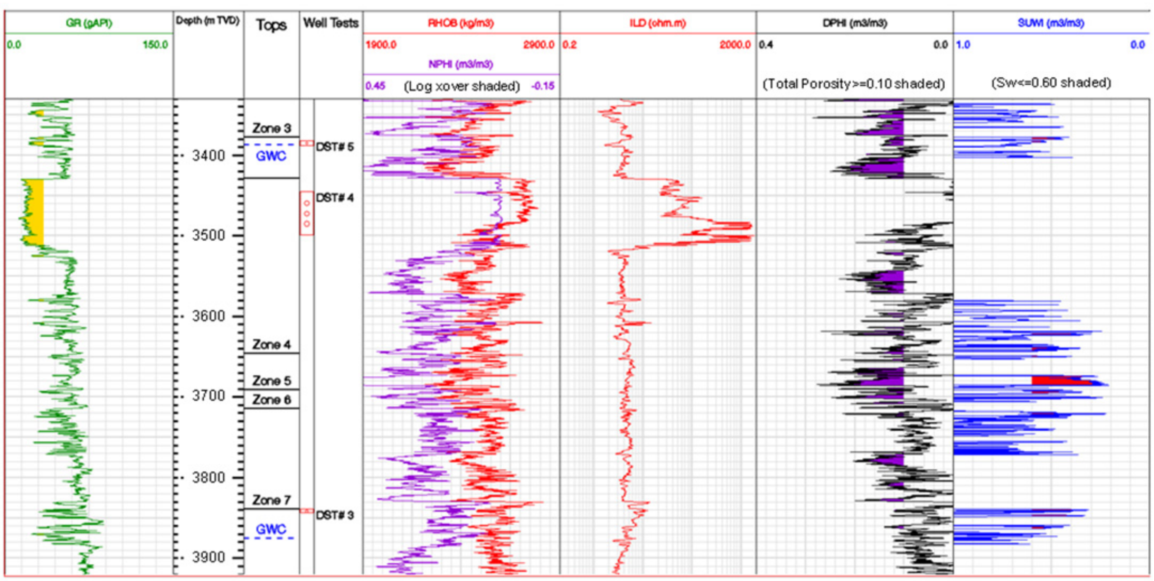

Figure 3.6.6 Intrepid L-80 petrophysical results plot: Zones 3 – 7.

3.6.5. Resource Assessment

The P50 area for Zones 1 and 2 was determined by projecting the interpreted GWC for these zones onto the Zone 2 depth map (Fig.6.2). The P50 area for Zone 3 was determined by projecting the interpreted GWC onto the Intrepid limestone depth map (Fig. 3.6.4). Zones 4–6 are all gas-bearing down to the base of porosity. Therefore, the mapped spill point was used to determine the P50 area for these zones. The P50 area for Zone 7 was determined by projecting the interpreted GWC onto the O-Marker depth map. For all zones the minimum and maximum areas were assigned by varying the P50 area +/-10%.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50.

Given the modest column height, variable porosity and generally small pool size, of the Intrepid gas zones, the assigned P50 recovery factors ranged from 50–65%. The minimum and maximum recovery factors were varied symmetrically around the P50 value.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.6.3).

Table 3.6.3 Intrepid probabilistic volume calculation variables.

Zone 1	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	1.6	1.8	2.0	1.8
Net Pay (m)	3.0	4.0	5.0	4.0
Porosity (fraction)	0.18	0.20	0.22	0.20
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas **FVF**	241	248	255	248
CGR (BBL/MMCF)	7	9	11	9
Gas Recovery Factor	0.55	0.65	0.75	0.4167

Zone 2	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	2.3	2.6	2.9	2.6
Net Pay (m)	5.0	7.0	9.0	7.0
Porosity (fraction)	0.18	0.20	0.22	0.20
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	243	250	257	250
CGR (BBL/MMCF)	5	11	17	11
Gas Recovery Factor	0.55	0.65	0.75	0.65

Zone 3	**P100**	**P50**	**P00**	**Mean**
Area (km^2)	2.4	2.7	3.0	2.7
Net Pay (m)	3.0	5.0	7.0	5.0
Porosity (fraction)	0.11	0.13	0.15	0.11
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	250	257	264	257
CGR (BBL/MMCF)	10	16	22	16
Gas Recovery Factor	0.35	0.55	0.65	0.5167

Zones 4 & 5	P100	P50	P00	Mean
Area (km^2)	5.1	5.7	6.3	5.7
Net Pay (m)	2.0	4.0	6.0	4.0
Porosity (fraction)	0.10	0.12	0.14	0.14
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	257	268	279	268
CGR (BBL/MMCF)	5	11	17	11
Gas Recovery Factor	0.40	0.50	0.60	0.50

Zone 6	P100	P50	P00	Mean
Area (km^2)	5.1	5.7	6.3	5.7
Net Pay (m)	2.0	4.0	6.0	4.0
Porosity (fraction)	0.11	0.13	0.15	0.13
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	265	275	285	275
CGR (BBL/MMCF)	5	11	17	11
Gas Recovery Factor	0.45	0.55	0.65	0.55

Zone 7	P100	P50	P00	Mean
Area (km^2)	7.0	7.8	8.6	7.8
Net Pay (m)	4.0	6.0	8.0	6.0
Porosity (fraction)	0.10	0.12	0.14	0.12
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	272	281	290	281
CGR (BBL/MMCF)	2	5	8	5
Gas Recovery Factor	0.45	0.55	0.65	0.55

3.6.6. Results

The probabilistic assessment results for the Intrepid field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.6.4 and 3.6.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.6.7 and 3.6.8).

Table 3.6.4 Intrepid probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP ($E9m^3$)	2.36	2.65	2.97	2.66
OGIP (Bcf)	83.2	93.5	105	93.9
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.159	0.195	0.238	0.197
OGIP (Bcf)	5.60	6.89	8.39	6.95
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.433	0.541	0.668	0.547
OGIP (Bcf)	15.3	19.1	23.6	19.3
Zone 3	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.165	0.222	0.292	0.226
OGIP (Bcf)	5.84	7.84	10.3	7.99

Zones 4 & 5	P90	P50	P10	Mean
OGIP ($E9m^3$)	0.250	0.362	0.493	0.368
OGIP (Bcf)	8.83	12.8	17.4	13.0
Zone 6	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.311	0.442	0.597	0.450
OGIP (Bcf)	11.0	15.6	21.1	15.9
Zone 7	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.660	0.861	1.09	0.869
OGIP (Bcf)	23.3	30.4	38.6	30.7

Table 3.6.5 Intrepid probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	1.35	1.52	1.72	1.53
Rec. Gas (Bcf)	47.6	53.8	60.7	54.0
Rec. Condensate ($E6m^3$)	0.0677	0.0800	0.0946	0.0808
Rec. Condensate (MMB)	0.426	0.503	0.595	0.508
Zone 1	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.101	0.127	0.156	0.128
Rec. Gas (Bcf)	3.58	4.47	5.52	4.52
Rec. Condensate ($E6m^3$)	0.00493	0.00636	0.00811	0.00647
Rec. Condensate (MMB)	0.0310	0.0400	0.0510	0.0407
Zone 2	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.277	0.351	0.439	0.357
Rec. Gas (Bcf)	9.78	12.4	15.5	12.6
Rec. Condensate ($E6m^3$)	0.0142	0.0215	0.0304	0.0219
Rec. Condensate (MMB)	0.0893	0.135	0.191	0.138
Zone 3	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.0977	0.133	0.178	0.136
Rec. Gas (Bcf)	3.45	4.70	6.27	4.79
Rec. Condensate ($E6m^3$)	0.00808	0.0118	0.0167	0.0122
Rec. Condensate (MMB)	0.0508	0.0745	0.105	0.0767
Zones 4 & 5	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.123	0.180	0.250	0.184
Rec. Gas (Bcf)	4.35	6.37	8.84	6.50
Rec. Condensate ($E6m^3$)	0.00661	0.0109	0.0169	0.0114
Rec. Condensate (MMB)	0.0416	0.0686	0.106	0.0715
Zone 6	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.168	0.243	0.334	0.247
Rec. Gas (Bcf)	5.94	8.57	11.8	8.74
Rec. Condensate ($E6m^3$)	0.00661	0.0109	0.0169	0.0114
Rec. Condensate (MMB)	0.0566	0.0922	0.141	0.0961
Zone 7	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.357	0.470	0.609	0.479
Rec. Gas (Bcf)	12.6	16.6	21.5	16.9
Rec. Condensate ($E6m^3$)	0.00811	0.0131	0.0192	0.0135
Rec. Condensate (MMB)	0.0510	0.0821	0.121	0.0846

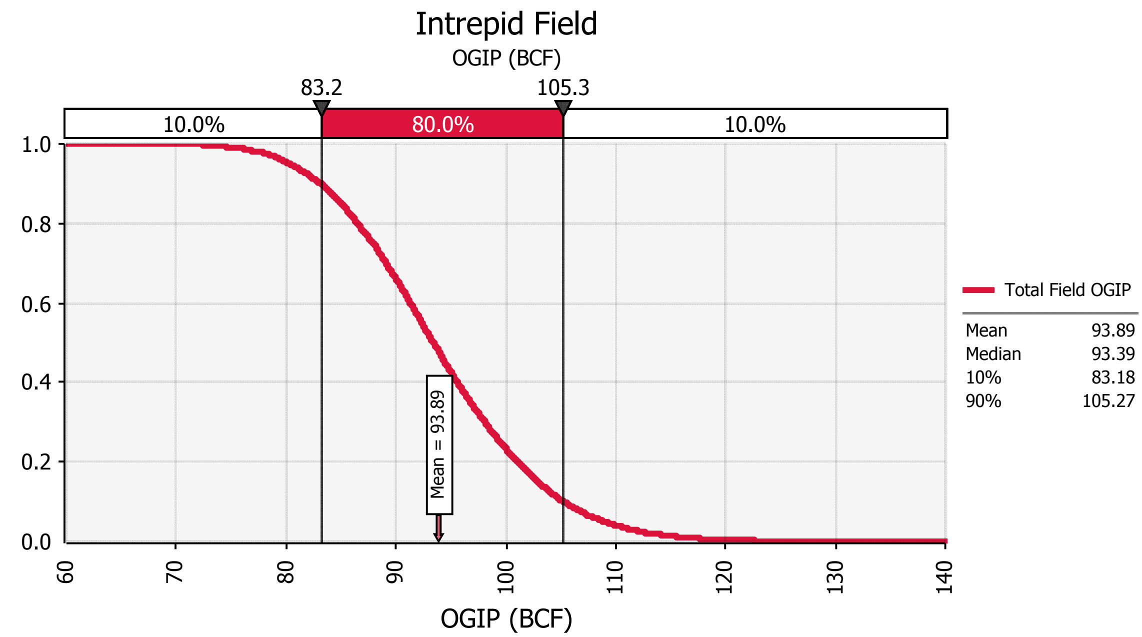

Figure 3.6.7 Intrepid OGIP descending cumulative probability chart.

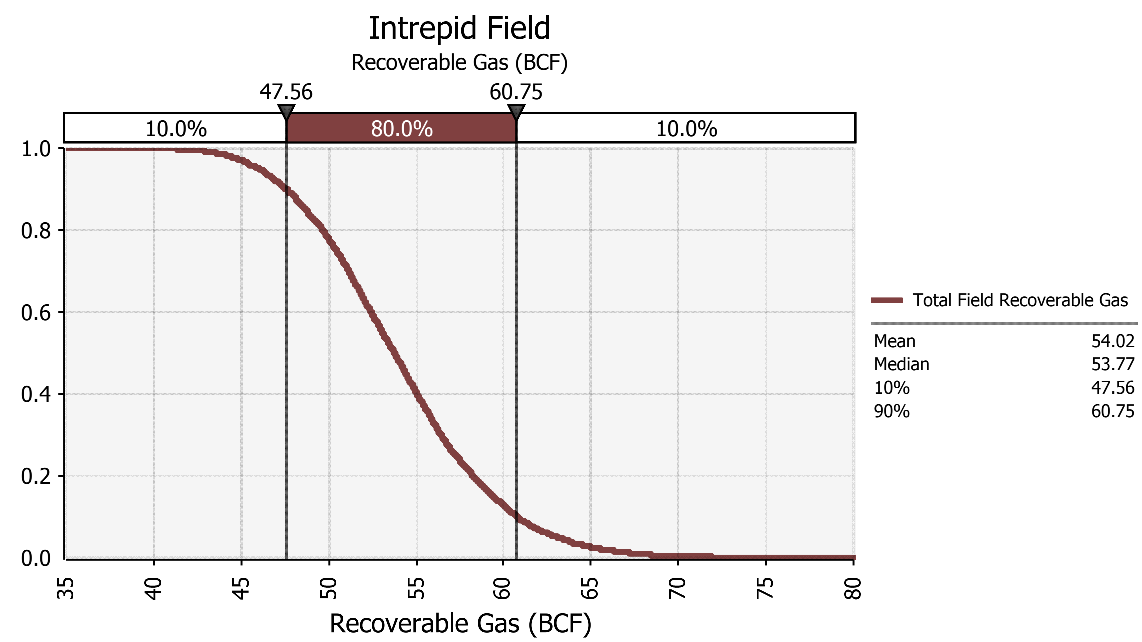

Figure 3.6.8 Intrepid recoverable gas descending cumulative probability chart.

3.7 Olympia - Significant Discovery

3.7.1. Overview

The Olympia gas field is located 5 km due north of the eastern end of Sable Island (Fig. 1.1). The field was discovered in 1983 and this assessment is based on the discovery well.

Discovery Well

Well:	Olympia A-12
Company:	Mobil Texaco PEX
Spud:	23-April-82
Well Termination:	10-Jan-83
Total Depth:	6064 m
Water Depth:	40 m
Latitude:	44°01’03.27”N
Longitude:	59°46’44.09”W
Target:	Drilled to test for the presence of hydrocarbons in the sands of a rollover anticline against a down-to-basin fault.

Additional Wells

No delineation drilling was conducted.

3.7.2. Structure

The Olympia structure is situated along a fault trend with West Olympia, West Venture and Venture. The structure is a rollover anticline associated with a growth fault resulting from underlying salt movement, and the well is drilled near its faulted crest as shown on the seismic line (Fig. 3.7.1). There are four gas zones located between the 4 Sand (red) and the 9 Limestone (blue) seismic horizons. The 4 Sand depth map (Fig. 3.7.2) is used for the 4b Sand volumetric calculations and the 9 Limestone map (Fig. 3.7.3) for Sands 6 Upper (6u), 6 Middle (6m), and 7. The P50 area contour (purple) shown on both maps requires fault seal along the eastern boundaries and spills to the south.

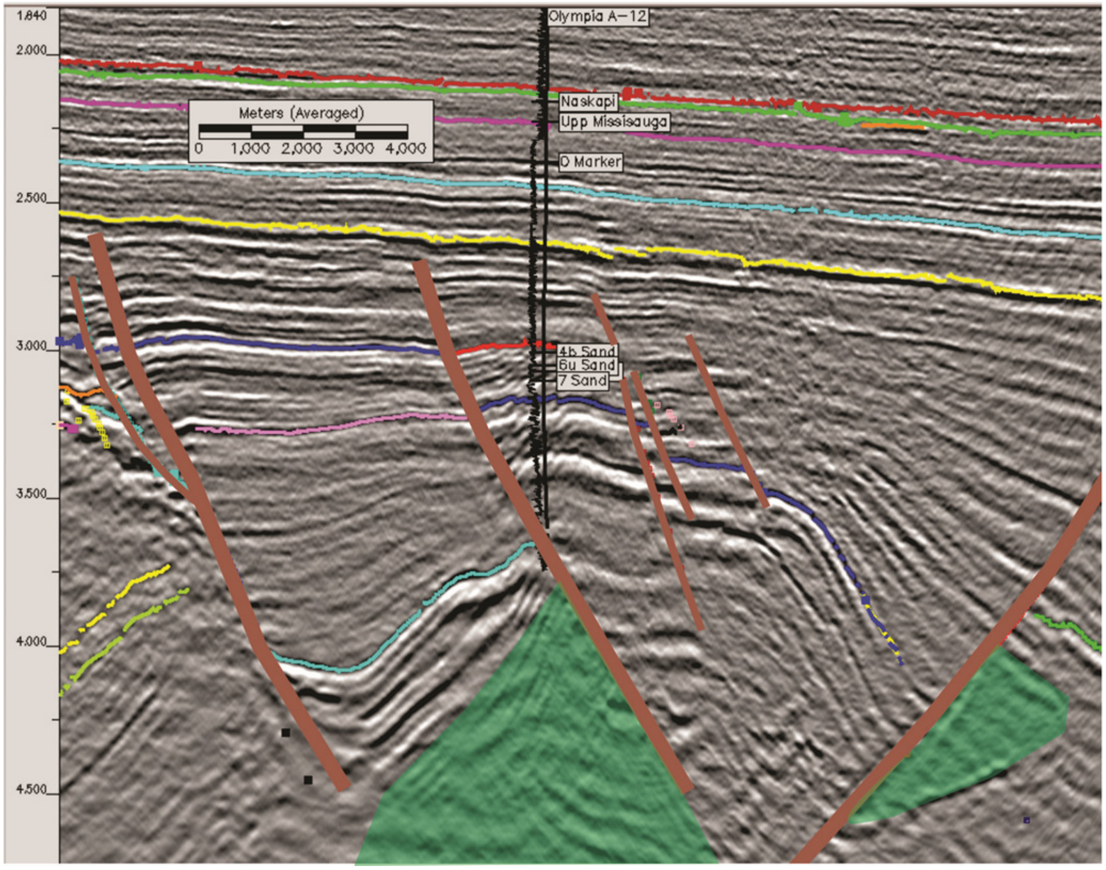

Figure 3.7.1 Olympia seismic time line showing gamma ray log.

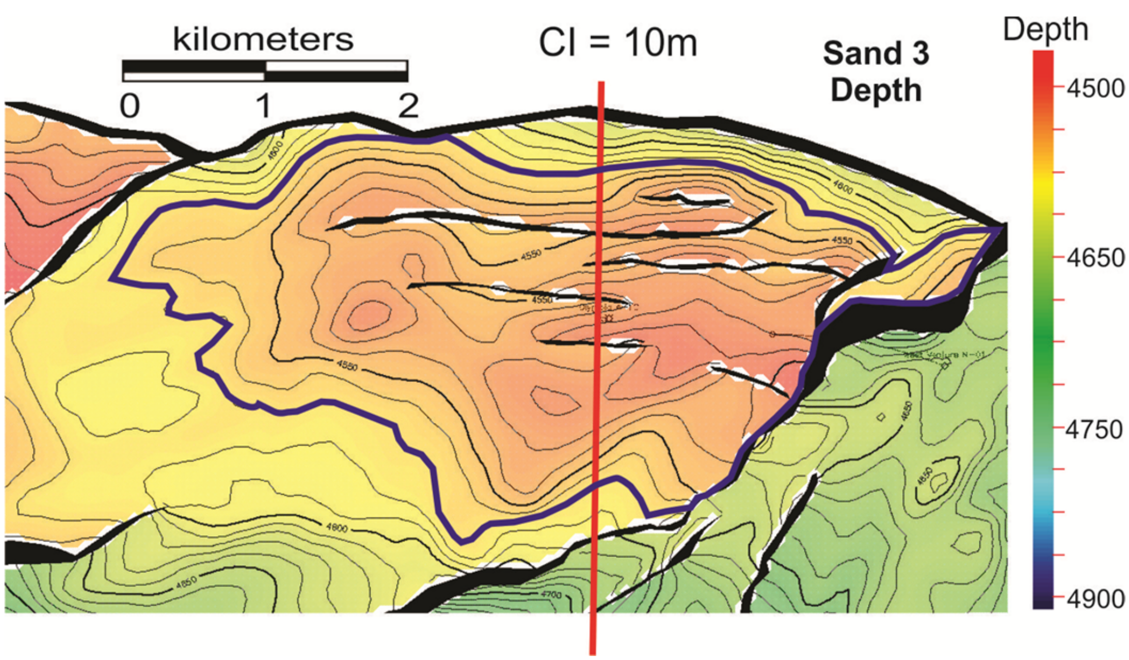

Figure 3.7.2 Olympia 3 Sand depth map used for 4b Sand.

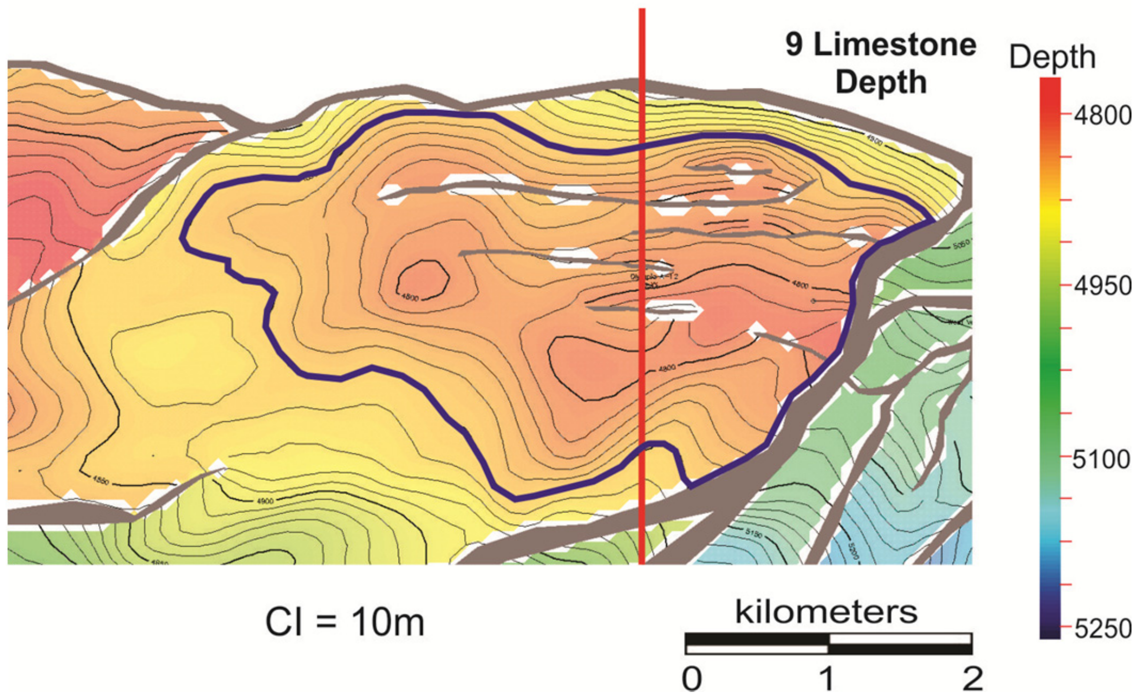

Figure 3.7.3 Olympia 9 Limestone depth map used for Sand 6u, 6m, and 7.

3.7.3. Reservoir Description

The reservoir sands at Olympia are located in the lower member of the Missisauga Formation (Kimmeridgian-Tithonian). Seismic mapping and well data indicate that the majority of the reservoir sands can be correlated with equivalent sands in West Olympia to the west and with the Venture and West Venture fields to the east. The well was drilled near the crest of the structure and encountered four significant gas-bearing sands.

All Olympia reservoir sands are found in stepped overpressure conditions, with the top of overpressure occurring approximately 100 m above the shallowest gas reservoir (Sand 4b). The Olympia sands are correlatable along strike with other gas fields indicating excellent east-west lateral continuity. It is expected that the sands thin and deteriorate toward the field's southern margin.

The reservoirs consist of stacked sequences of cyclic deltaic and strandplain sands interfingering with marine and prodelta shales, which provide effective top seals. Log profiles of the Lower Missisauga member reflect delta front and channel depositional environments with increasing current and tidal influences.

3.7.4. Formation Evaluation

Three of the four Olympia gas zones were tested with flow rates ranging from 7.4 to 17.5 MMscf/d (Table 3.7.1). The Olympia zones have fair to excellent reservoir quality with net pay porosities varying between 0.13–0.22, and DST results which indicate permeability is fair to excellent. Sand 4b was tested (DST# 8) and flowed gas, condensate and minor water. The water recovered by DST# 8 had a very high salinity indicating that the gas-water contact was at or near the base of the perforations. In addition, the lower portion of the 4b sand has elevated water saturation (transition zone) therefore the interpreted gas water-contact was placed at the base of perforations in DST# 8. Sands 6u and 6m have log and/or DST defined GWCs. Sand 7 is a GDT, however water saturation is increasing at the base of the sand. The results of the Olympia A-12 petrophysical assessment are shown below (Table 3.3.7.2; Figs. 3.7.4–3.7.6).

Table 3.7.1 Olympia A-12 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 2	5694-5704	tight	Mic Mac	No Rec.			No Rec.		
DST 3	5199-5210	tight	Mic Mac	No Rec.			No Rec.		
DST 4	5167-5182	tight	Mic Mac	No Rec.			No Rec.		
DST 5	4664-4678	Sand 6m	Missisauga	419	75		14.8	472	
DST 6	4640-4648	Sand 6u	Missisauga	413	6	67	14.6	38	421
DST 7	4622-4633	Sand 6u	Missisauga	496	17	13	17.5	107	82
DST 8	4525-4538	Sand 4b	Missisauga	210	17	1	7.4	107	6
DST 9	4450-4462	wet	Missisauga	0.5		140	0.02		881

Table 3.7.2 Olympia A-12 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Sand 4b	4526.3	4548.0	23.7	5.5	0.197	0.43
Sand 6u	4622.1	4647.2	25.1	12.0	0.218	0.47
Sand 6m	4664.0	4713.3	49.3	15.1	0.206	0.49
Sand 7	4724.8	4752.0	27.3	5.2	0.129	0.47
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60						

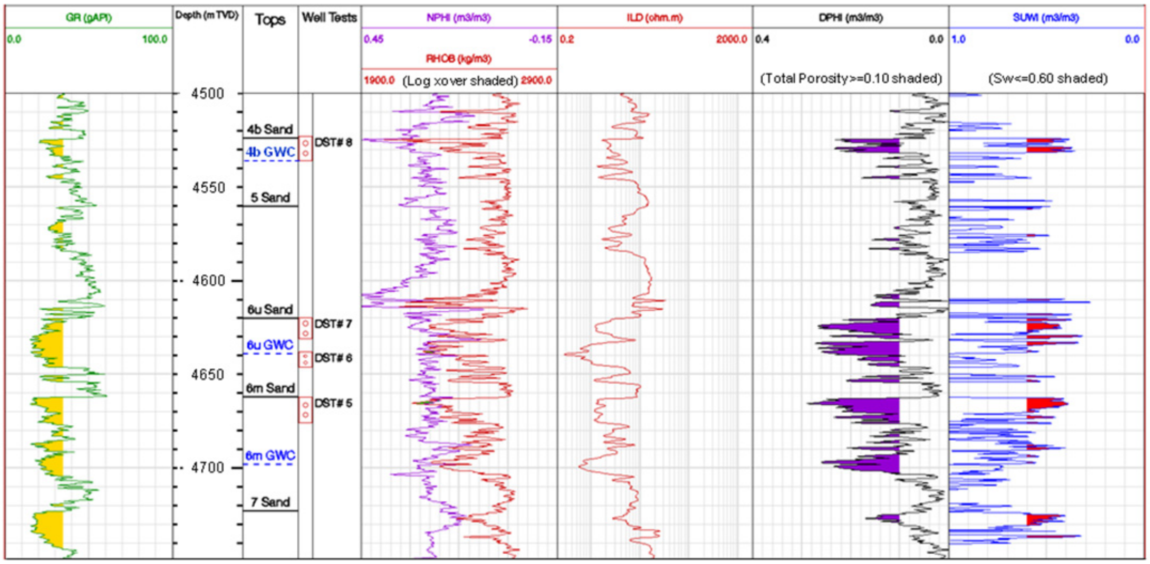

Figure 3.7.4 Olympia A-12 petrophysical results plot: all zones.

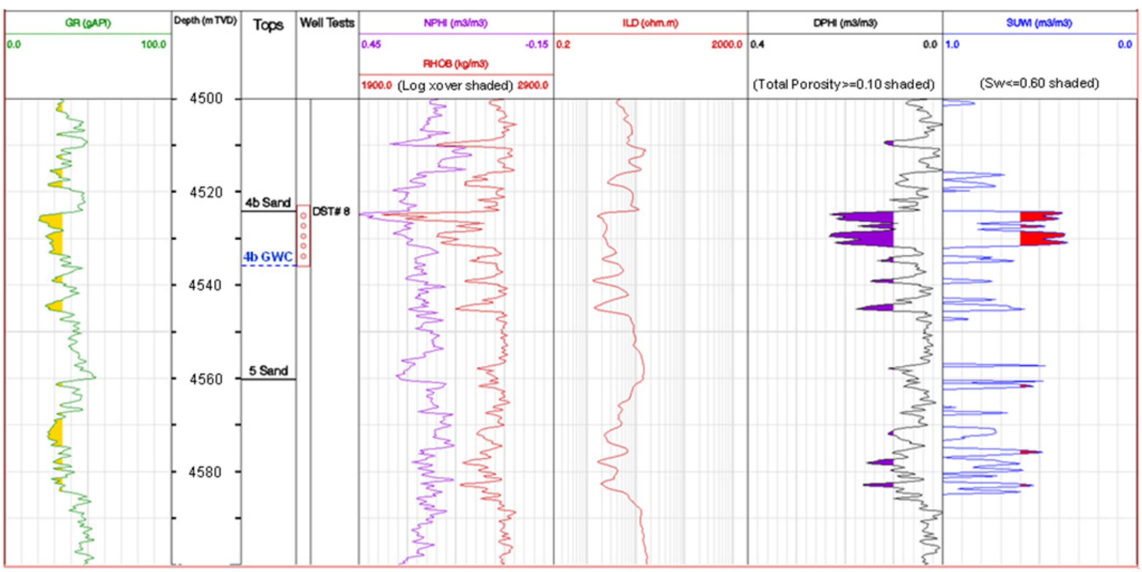

Figure 3.7.5 Olympia A-12 petrophysical results plot: 4b Sand.

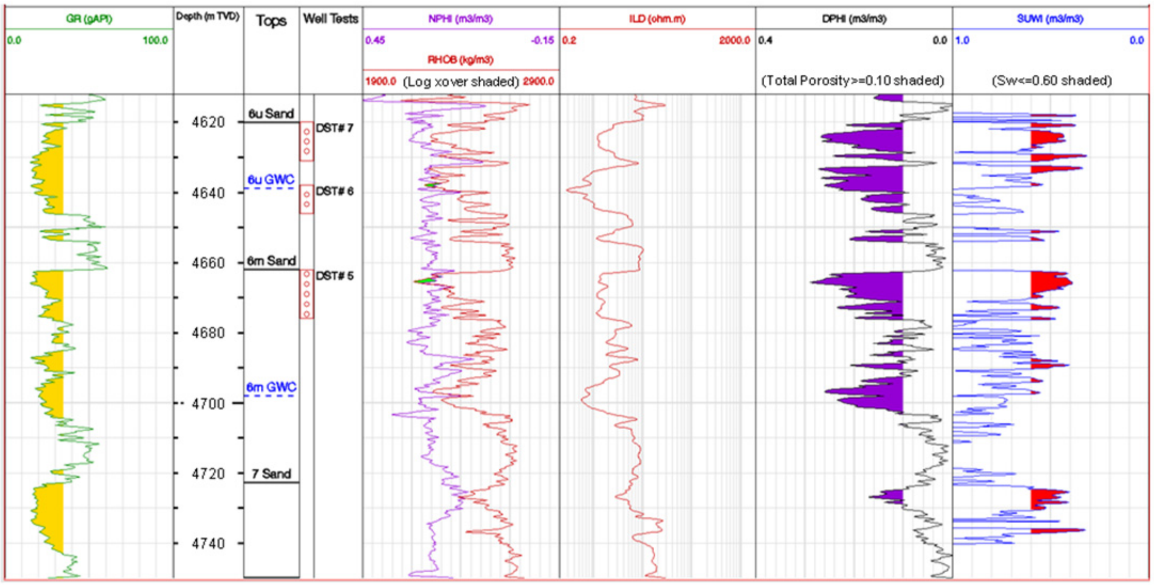

Figure 3.7.6 Olympia A-12 petrophysical results plot: Sands 6u–7.

3.7.5. Resource Assessment

The Olympia Sand 3 depth map (Fig. 3.7.2) was used to determine the area of the 4b Sand while the Olympia 9 Limestone depth map (Fig. 3.7.3) was used for Sands 6u, 6m, and 7. The P50 area for the 4b Sand was determined by projecting the interpreted GWC onto the Olympia Sand 3 depth map. The elevation of the 4b Sand GWC is consistent with the mapped spill point.

The P50 area for the 6u and 6m Sands was defined by projecting the GWC for these sands onto the 9 Limestone depth map. In order to determine the P50 area for the 7 Sand, the GWC was placed half-way between the gas down to and water up to which resulted in approximately +/-5 m uncertainly on the contact. For all sands the minimum and maximum areas were assigned by varying the P50 area +/-10%.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50.

Given the modest column heights and pool areas of the Olympia gas sands, the assigned P50 recovery factors ranged from 45 - 55%. A series of faults cross the field along strike and while the throws are limited, the faults are laterally continuous and would probably impact gas recovery. These factors resulted in the lower assigned recovery factors.

DST 9 recovered very minor gas and formation water from the 3b Sand, located approximately 70 m above the 4b Sand. This could indicate a minor 3b Sand gas accumulation updip of the well location at the crest of the structure, but this possible upside was not included in the assessment.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.7.3).

Table 3.7.3 Olympia probabilistic volume calculation variables.

4b Sand	P100	P50	P00	Mean
Area (km^2)	5.3	5.9	6.5	5.9
Net Pay (m)	4.0	6.0	8.0	6.0
Porosity (fraction)	0.18	0.20	0.22	0.20
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	305	314	232	314
CGR (BBL/MMCF)	10	15	20	15
Gas Recovery Factor	0.40	0.50	0.60	0.50

6u Sand	P100	P50	P00	Mean
Area (km^2)	5.8	6.4	7.0	6.4
Net Pay (m)	9.0	12	15	12
Porosity (fraction)	0.20	0.22	0.24	0.22
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	340	350	360	350
CGR (BBL/MMCF)	3	6	9	6
Gas Recovery Factor	0.45	0.55	0.65	0.55

6m Sand	P100	P50	P00	Mean
Area (km^2)	5.1	5.7	6.3	5.7
Net Pay (m)	7.0	10	13	10
Porosity (fraction)	0.20	0.22	0.24	0.22
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	342	352	362	352
CGR (BBL/MMCF)	22	32	42	32
Gas Recovery Factor	0.45	0.55	0.65	0.55

7 Sand	P100	P50	P00	Mean
Area (km^2)	4.8	5.3	5.8	5.3
Net Pay (m)	3.0	5.0	7.0	5.0
Porosity (fraction)	0.11	0.13	0.15	0.13
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	344	354	364	354
CGR (BBL/MMCF)	8.0	10.0	12.0	10.0
Gas Recovery Factor	0.30	0.50	0.60	0.4667

3.7.6. Results

The probabilistic assessment results for the Olympia field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.7.4 and 3.7.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.7.7 and 3.7.8) Recoverable liquids are also included (Fig 3.7.9).

Table 3.7.4 Olympia probabilistic OGIP.

Sum of all sands	P90	P50	P10	Mean
OGIP ($E9m^3$)	6.74	7.59	8.50	7.62
OGIP (Bcf)	238	268	300	269
4b Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.949	1.21	1.51	1.23
OGIP (Bcf)	33.5	42.8	53.5	43.3
6u Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	2.64	3.23	3.91	3.26
OGIP (Bcf)	93.4	114	138	115
6m Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	1.93	2.43	3.00	2.45
OGIP (Bcf)	68.3	85.9	106	86.6
7 Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.490	0.665	0.861	0.674
OGIP (Bcf)	17.3	23.5	30.4	23.8

Table 3.7.5 Olympia probabilistic recoverable resources.

Sum of all sands	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	3.57	4.05	4.62	4.08
Rec. Gas (Bcf)	126	143	163	144
Rec. Condensate ($E6m^3$)	0.321	0.388	0.472	0.393
Rec. Condensate (MMB)	2.02	2.44	2.97	2.47
4b Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.462	0.603	0.776	0.612
Rec. Gas (Bcf)	16.3	21.3	27.4	21.6
Rec. Condensate ($E6m^3$)	0.0366	0.0502	0.0685	0.0515
Rec. Condensate (MMB)	0.230	0.316	0.431	0.324
6u Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	1.42	1.77	2.19	1.79
Rec. Gas (Bcf)	50.1	62.4	77.5	63.3
Rec. Condensate ($E6m^3$)	0.0402	0.0588	0.0822	0.0604
Rec. Condensate (MMB)	0.253	0.370	0.517	0.380
6m Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	1.04	1.33	1.68	1.35
Rec. Gas (Bcf)	36.7	47.0	59.5	47.6
Rec. Condensate ($E6m^3$)	0.176	0.238	0.320	0.245
Rec. Condensate (MMB)	1.11	1.50	2.01	1.54
7 Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.229	0.320	0.428	0.326
Rec. Gas (Bcf)	8.09	11.3	15.1	11.5
Rec. Condensate ($E6m^3$)	0.0226	0.0351	0.0523	0.0366
Rec. Condensate (MMB)	0.142	0.221	0.329	0.230

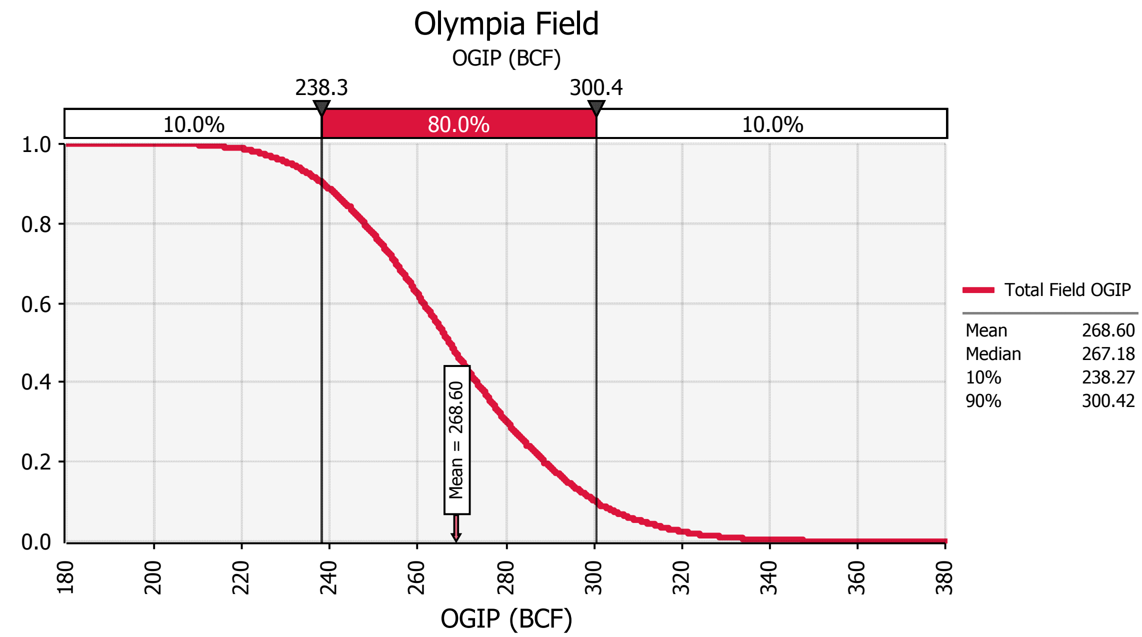

Figure 3.7.7 Olympia OGIP descending cumulative probability chart.

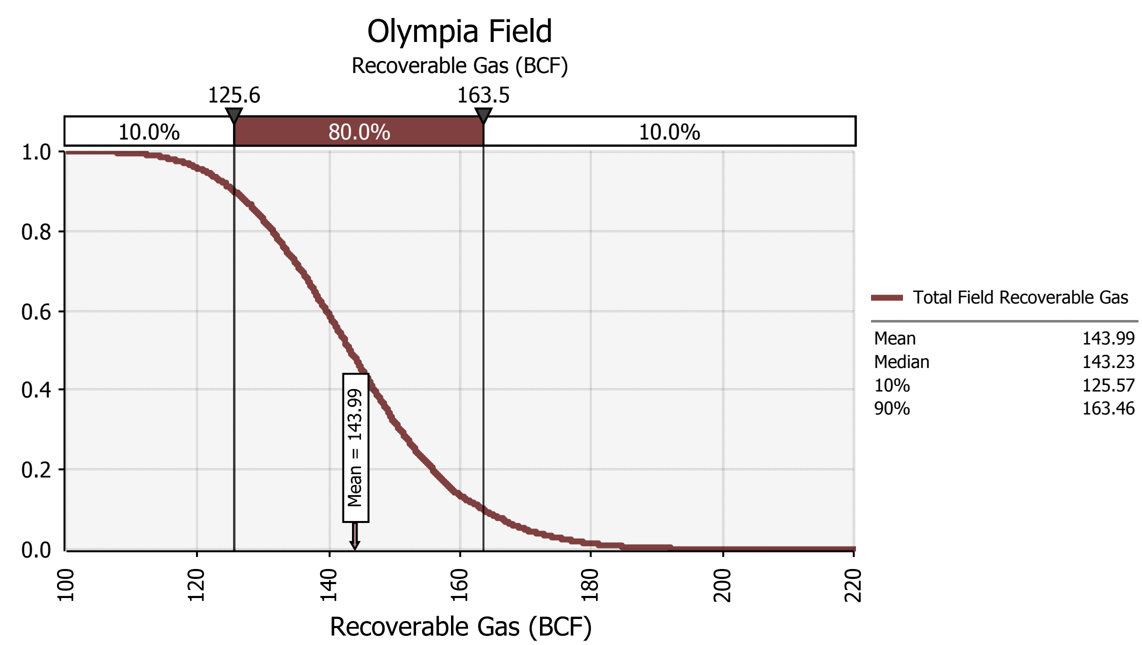

Figure 3.7.8 Olympia recoverable gas descending cumulative probability chart.

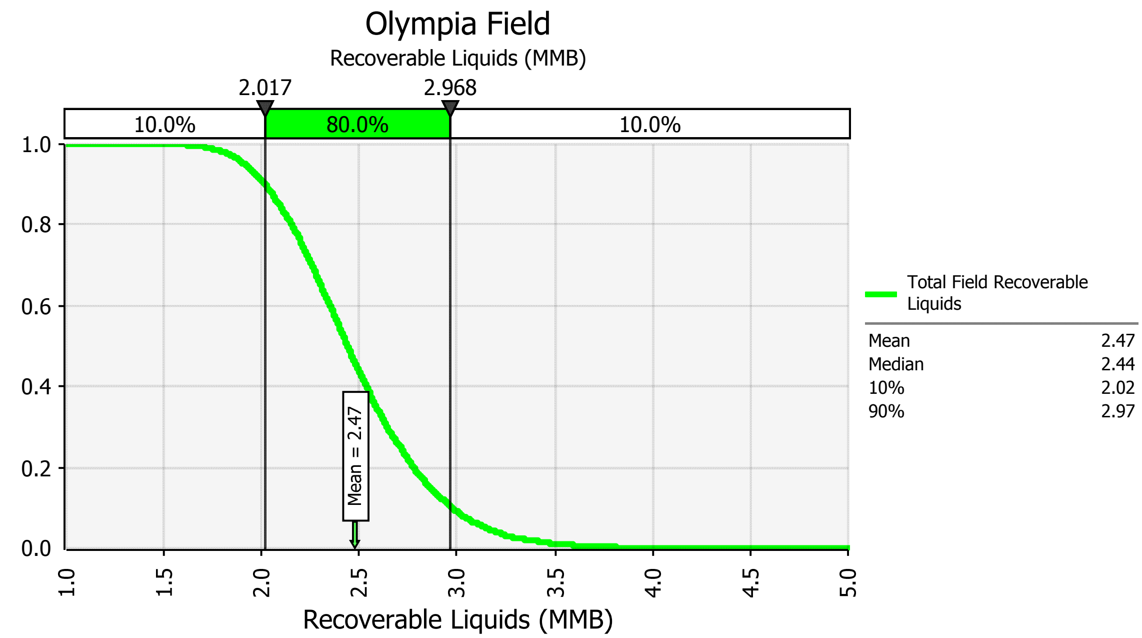

Figure 3.7.9 Olympia recoverable condensate liquids descending cumulative probability chart.

3.8 Onondaga - Significant Discovery

3.8.1. Overview

The Onondaga gas field is located approximately 35 km south-west of Sable Island (Fig. 1.1). The field was discovered in 1969 and has been delineated by four additional wells.

Discovery Well

Well:	Onondaga E-84
Company:	Shell
Spud:	01-Sept-69
Well Termination:	11-Nov-69
Total Depth:	3988.3 m
Water Depth:	57.9 m
Latitude:	43°43’16.13”N
Longitude:	60°13’17.18”W
Target:	Drilled to test for the presence of hydrocarbons in sands above a large salt diapir.

Additional Wells

The field was delineated by the following four wells:

- Shell Onondaga O-95
- Shell Onondaga F-75
- Shell Onondaga B-96
- Shell Onondaga B-84

3.8.2. Structure

The Onondaga structure is salt-cored with two major down-to-basin normal faults and associated minor faulting. The seismic line (Fig. 3.8.1) shows the Zone 1 gas reservoir horizon (red), at the Upper Missisauga level and the Zone 2 horizon (orange).

Faults divide the structure into three compartments as shown on the Zone 1 depth map (Fig. 3.8.2). Compartment 1 on the southern flank has 3 well penetrations and contains better quality gas sands than those encountered in Compartment 3. Compartment 2 in the central faulted zone at the crest of the structure has no well penetration at this level. Compartment 3 on the northern flank has two well penetrations which both encountered a thin gas-bearing sand

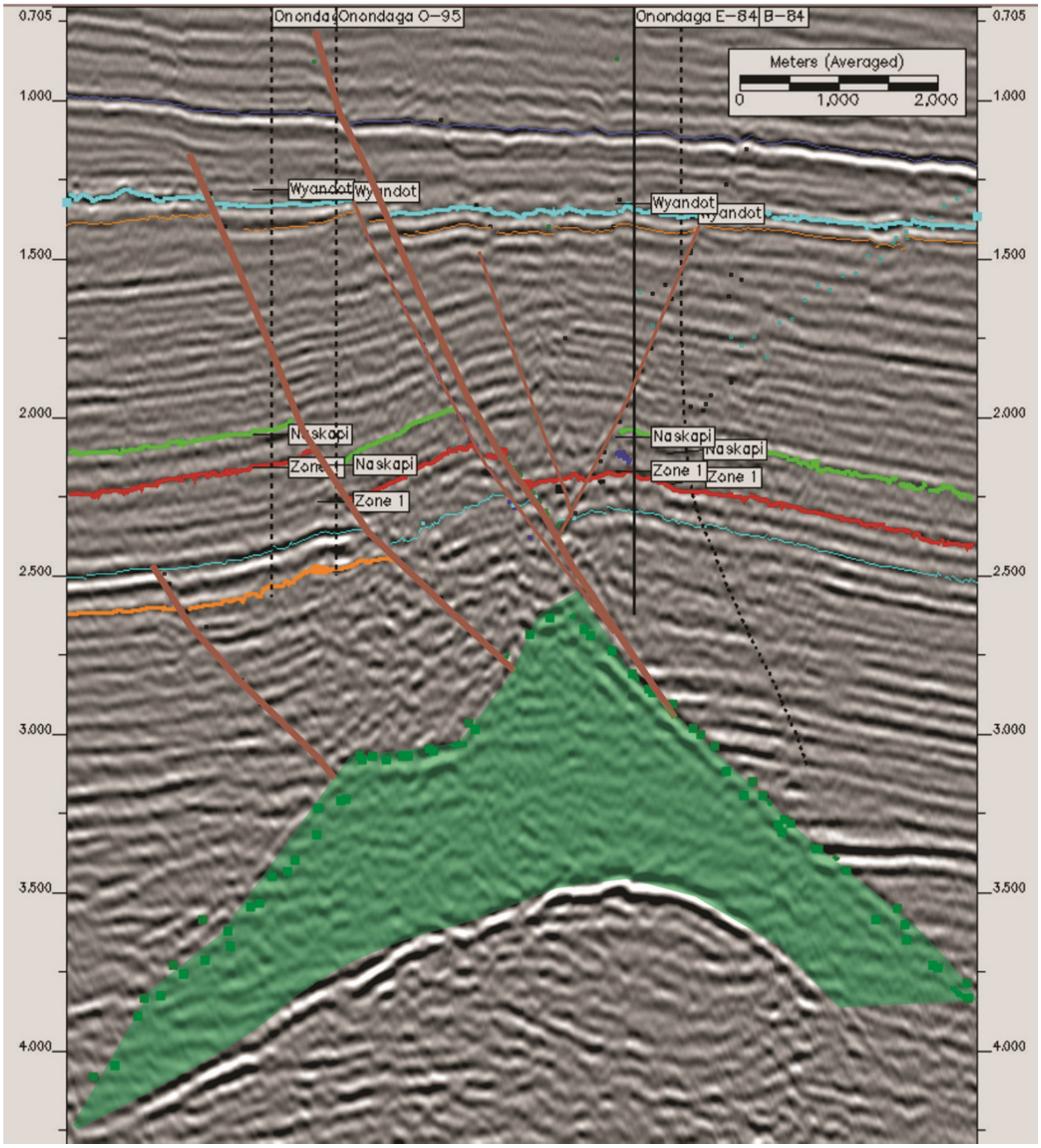

Figure 3.8.1 Onondaga seismic time line.

(Zone 2), as shown on the Zone 2 depth map (Fig. 3.8.3). The antithetic fault observed on the seismic line (Fig. 3.8.1) has negligible throw at the mapped depths.

The P50 area closure (purple) on the Zone 1 map is defined by the GWC and is limited by either a leak point encountered along the crestal fault, or leakage at the point where the northern fault is encountered. The P50 area closure (purple) shown on the Zone 2 map is based on GDT and would be limited by an assumed leak point along the fault. This is explained in more detail below in Section 3.8.5.

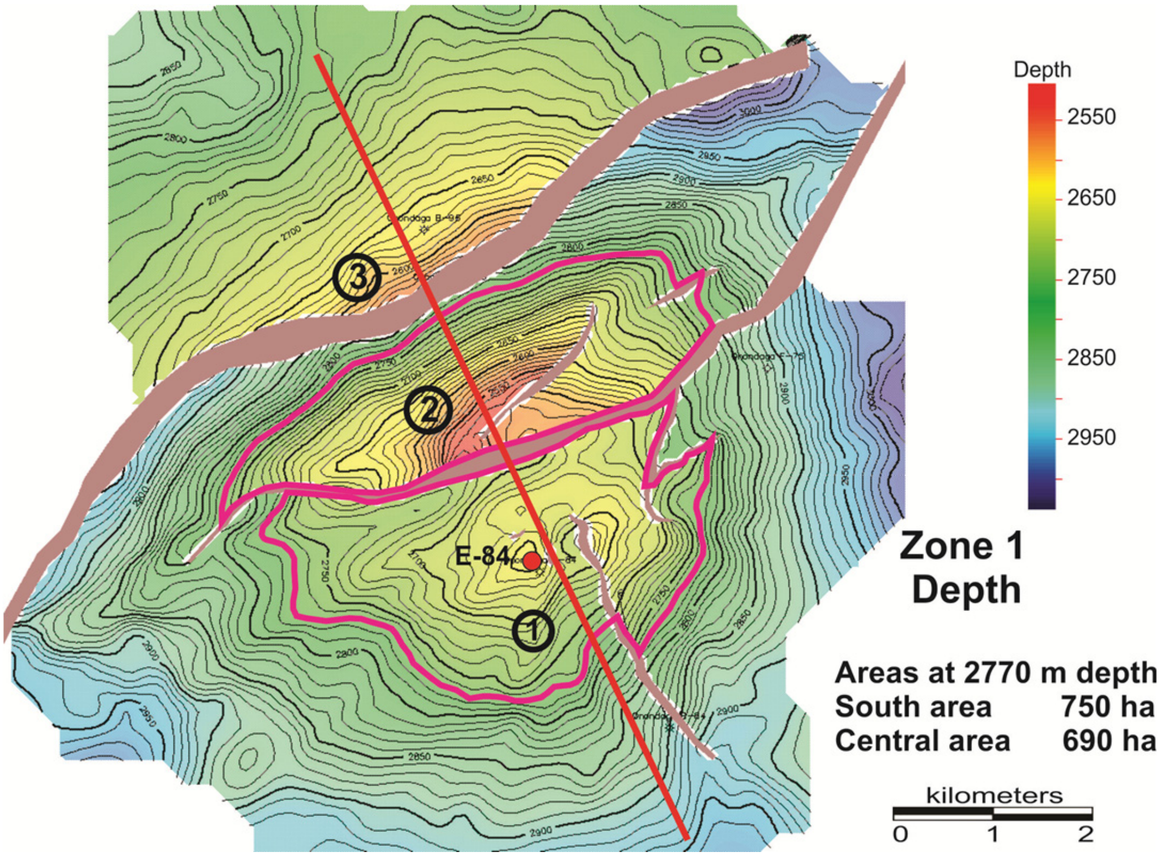

Figure 3.8.2 Onondaga Zone 1 depth map.

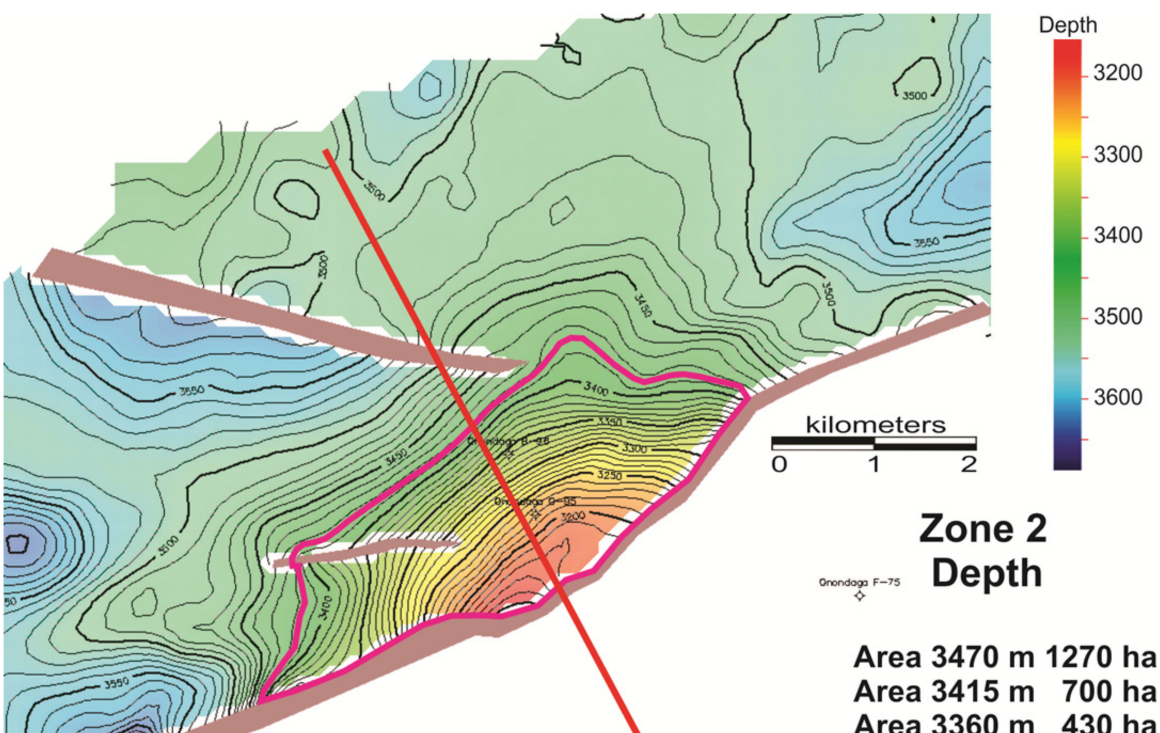

Figure 3.8.3 Onondaga Zone 2 depth map.

3.8.3. Reservoir Description

The Onondaga gas reservoirs are located within Early Cretaceous strata of the middle and upper members of the Missisauga Formation (Berriasian-Barremian). Five wells have been drilled encountering two normally-pressured gas reservoirs (Zones 1 & 2). Zone 1 is located at the top of the Upper Missisauga Formation directly below the Aptian age Naskapi shale and Zone 2 is in the Middle Missisauga Formation. There is considerable crestal faulting at Onondaga caused by movement of the underlying salt body. No wells have penetrated the Shell-designated “central fault block” at the Zone 1 depth, so the presence of gas in the central block, while considered likely, has not been confirmed. This central portion of the field is structurally higher and may have a common GWC with the southern portion of the field. The Zone 2 gas pool is limited to the north side of the main bounding fault as only the two northern wells (B-96 and O-95) encountered gas pay in this interval.

Reservoir sands in the field consist of stacked sequences of delta front, channel and strandplain-shoreface depositional facies in a dominantly marine setting. Well data shows that these coarsening-upward progradational sands are fine to coarse grained (occasionally pebbly), moderate to well sorted, siliceous and variably argillaceous, calcareous and dolomitic, with occasional coal stringers.

3.8.4. Formation Evaluation

Formation flow testing was not conducted in any of the Onondaga wells but considerable net gas pay is present in Zone 1 in both Onondaga E-84 and B-84. Zone 1 has very good to excellent reservoir properties with average net pay porosities of 0.20 and core permeabilities up to 1000 mD Zone 1 has a GWC defined by log data and wireline formation pressures (RFT & MDT data). Zone 2 has fair to good reservoir properties with net pay porosities ranging from 0.13 - 0.15 and is a GDT in both Onondaga B-96 and O-95. Results of the petrophysical assessment for Onondaga are shown below (Table 3.8.1; Figs. 3.8.4–3.8.5).

Table 3.8.1 Onondaga field petrophysical summary.

Well Name	Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Onondaga B-84	Zone 1	2770.6	2852.0	77.2	23.2	0.198	0.31
Onondaga E-84	Zone 1	2701.4	2825.0	123.6	32.3	0.202	0.29
Onondaga B-96	Zone 2	3383.0	3404.4	21.4	4.4	0.134	0.51
Onondaga O-95	Zone 2	3258.7	3284.0	25.3	10.4	0.145	0.27
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.65							

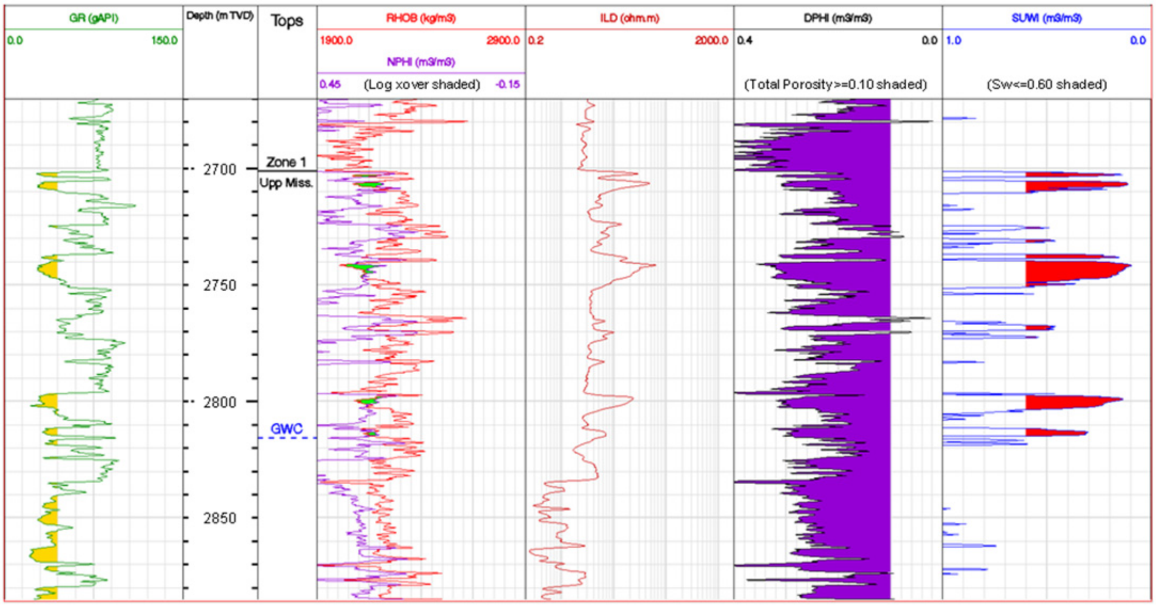

Figure 3.8.4 Onondaga E-84 petrophysical results plot: Zone 1.

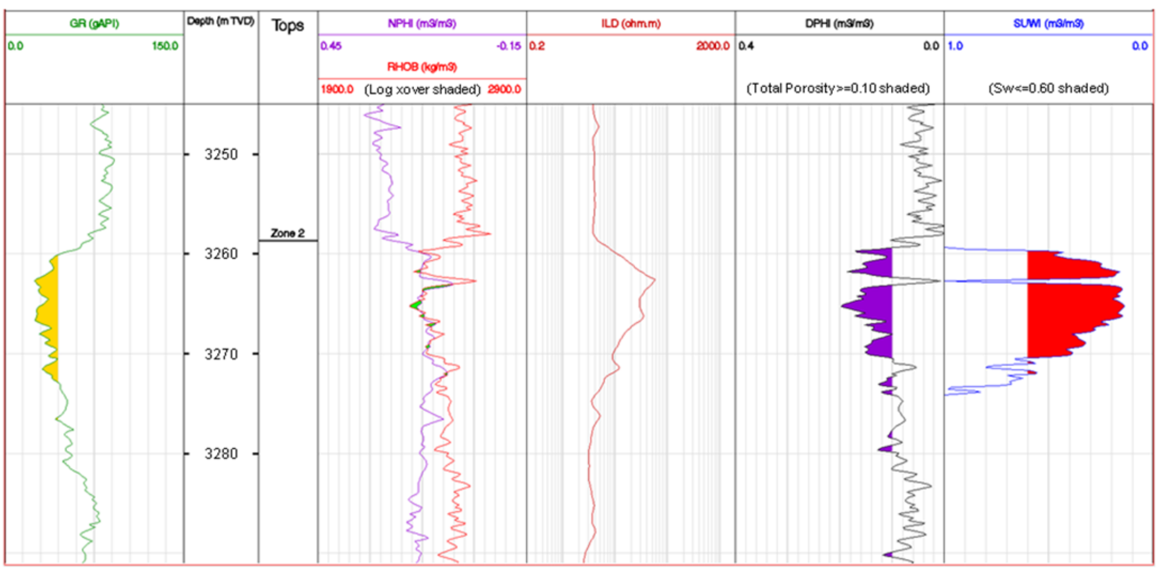

Figure 3.8.5 Onondaga O-95 petrophysical results plot: Zone 2.

3.8.5. Resource Assessment

Zone 1 has been subdivided into three regions (Fig. 3.8.2).

1. The southern region is penetrated by three wells, two of which are within closure and gas-bearing (E-84 & B-84) and one which is wet and on the flank of the structure (F-75).
2. The central region is located south of the north bounding fault in the structurally highest part of the field and has not been penetrated at this level.
3. The northern region located above the north-bounding fault, is penetrated by two wells (B-96 & O-95) both of which are wet in Zone 1.

For Zone 1, the P50 area for the southern region with confirmed gas pay was determined by projecting the log defined GWC onto the Zone 1 depth map. The height of the gas column in the southern area exceeds the throw along the edges of the fault that separates the southern and central regions. As a result, the central region was interpreted to have a 75% probability of being gas-charged. If charged, the central region probably shares a common GWC with the southern area. The P50 area for the central region was defined by projecting the "common" GWC on to the Zone 1 depth map. The minimum and maximum areas for both the southern and central regions were assigned by varying the P50 areas +/- 10%. The northern region of Zone 1 is wet.

For Zone 2, only Onondaga B-96 and O-95 encountered gas pay, limiting the gas accumulation to the northern portion of the field. Both B-96 and O-95 are GDT base porosity. This GDT was projected on to the Zone 2 depth map to define the minimum (P100) area. The maximum (P00) area was based on the mapped structural spill point. The Zone 2 P50 area was determined by using half the elevation (1/2 h) between the minimum and maximum areas (i.e. 3415 m contour).

The probabilistic input parameters for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. For Zone 1, the minimum and maximum inputs for these reservoir parameters were varied symmetrically around the P50. The reservoir quality and thickness of Zone 2 is poorer than that of Zone 1, therefore the inputs for porosity and hydrocarbon saturation were weighted toward the minimum values.

Zone 1 is a high quality reservoir interval and was assigned recovery factors ranging from 65 to 85%. Lower recovery factors, ranging from 55 to 75%, were assigned to Zone 2 as this interval has poorer quality reservoir than Zone 1.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.8.2).

Table 3.8.2 Onondaga probabilistic volume calculation variables.

Zone 1 South	P100	P50	P00	Mean
Area (km^2)	6.8	7.5	8.3	7.53
Net Pay (m)	15	25	35	25
Porosity (fraction)	0.18	0.20	0.22	0.20
Sh (1-Sw) (fraction)	0.65	0.70	0.75	0.70
Gas FVF	219	227	235	227
CGR (BBL/MMCF)	4.0	7.0	10	7.0
Gas Recovery Factor	0.65	0.75	0.85	0.75

Zone 1 Central	P100	P50	P00	Mean
Play adequacy	0.75	0.75	0.75	0.75
Area (km^2)	6.2	6.9	7.6	6.9
Net Pay (m)	15	25	35	25
Porosity (fraction)	0.18	0.20	0.22	0.20
Sh (1-Sw) (fraction)	0.65	0.70	0.75	0.70
Gas FVF	209	222	235	222
CGR (BBL/MMCF)	4.0	7.0	10	7.0
Gas Recovery Factor	0.65	0.75	0.85	0.75

Zone 2	P100	P50	P00	Mean
Area (km^2)	4.3	7.0	12.7	8.0
Net Pay (m)	2.0	6.0	10	6.0
Porosity (fraction)	0.10	0.14	0.16	0.133
Sh (1-Sw) (fraction)	0.40	0.60	0.65	0.55
Gas FVF	265	279	293	279
CGR (BBL/MMCF)	5.0	10	15	10
Gas Recovery Factor	0.55	0.65	0.75	0.55

3.8.6. Results

Probabilistic assessment results for the Onondaga field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.8.3 and 3.8.4). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.8.6 and 3.8.7).

Table 3.8.3 Onondaga probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP (E9m^3)	6.60	11.6	14.0	11.0
OGIP (Bcf)	233	411	496	389
Zone 1 South	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	4.56	5.96	7.42	5.99
OGIP (Bcf)	161	211	262	211
Zone 1 Central	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0	4.90	6.48	4.02
OGIP (Bcf)	0	173	229	142
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.521	0.937	1.53	0.988
OGIP (Bcf)	18.4	33.1	54.1	34.9

Table 3.8.4 Onondaga probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	4.87	8.61	10.4	8.16
Rec. Gas (Bcf)	172	304	369	288
Rec. Condensate (E6m^3)	0.196	0.340	0.442	0.331
Rec. Condensate (MMB)	1.23	2.14	2.78	2.08
Zone 1 South	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	3.40	4.47	5.61	4.50
Rec. Gas (Bcf)	120	158	198	159
Rec. Condensate (E6m^3)	0.120	0.172	0.237	0.176
Rec. Condensate (MMB)	0.756	1.08	1.49	1.11
Zone 1 Central	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0	3.65	4.90	3.03
Rec. Gas (Bcf)	0	129	173	107
Rec. Condensate (E6m^3)	0	0.137	0.204	0.119
Rec. Condensate (MMB)	0	0.862	1.28	0.746
Zone 2	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.337	0.606	1.00	0.643
Rec. Gas (Bcf)	11.9	21.4	35.3	22.7
Rec. Condensate (E6m^3)	0.0176	0.0331	0.0588	0.0361
Rec. Condensate (MMB)	0.111	0.208	0.370	0.227

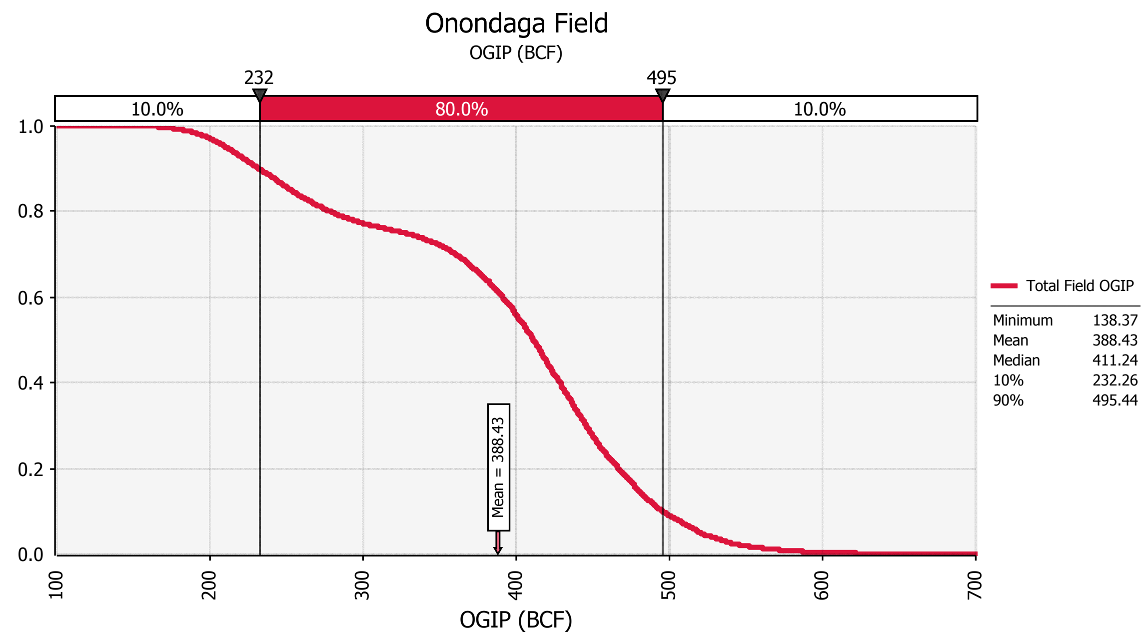

Figure 3.8.6 Onondaga OGIP descending cumulative probability chart.

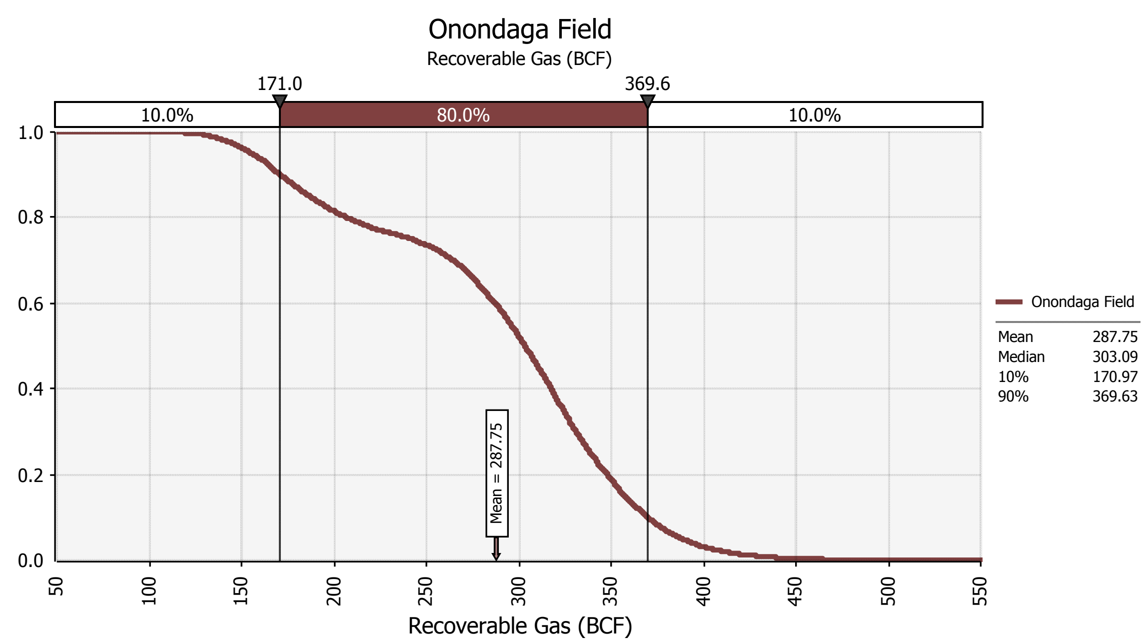

Figure 3.8.7 Onondaga recoverable gas descending cumulative probability chart.

3.9 Primrose - Significant Discovery

3.9.1. Overview

The Primrose gas and oil field is located approximately 64 km east of Sable Island (Fig. 1.1). The field was discovered in 1973 and delineated by two additional wells and one sidetrack.

Discovery Well

Well:	Primrose N-50
Company:	Shell
Spud:	14-Mar-72
Well Termination:	21-April-73
Total Depth:	1713.59 m
Water Depth:	90.8 m
Latitude:	43°59'48.43"N
Longitude:	59°06'51.63"W
Target:	Drilled to test for the presence of hydrocarbons in sands structurally trapped above a large salt diapir.

Additional Wells

The field was delineated by the following three wells:

- Shell Primrose A-41
- Shell Primrose 1aA-41 (sidetrack)
- Shell Primrose F-41

3.9.2. Structure

The Primrose structure is cored by a small salt diapir composed of latest Triassic to earliest Jurassic age evaporites of the Argo Formation. The poor quality 2D seismic line (Fig. 3.9.1) shows the salt (green) and the Wyandot horizon (blue). Above the salt is a thin caprock interval of Early Jurassic dolomites and shales that is draped by a thin veneer of Late Cretaceous. The top of the salt is quite shallow, at about 1300 m below seafloor.

At time of publication, the CNSOPB only had access to two 2D seismic lines over Primrose, which was insufficient for mapping the structure, therefore, the original map created by Shell was used for area calculations. The Wyandot map (Fig. 3.9.2) shows a circular structure that is faulted across the crest with a maximum closure height of approximately 225 m.

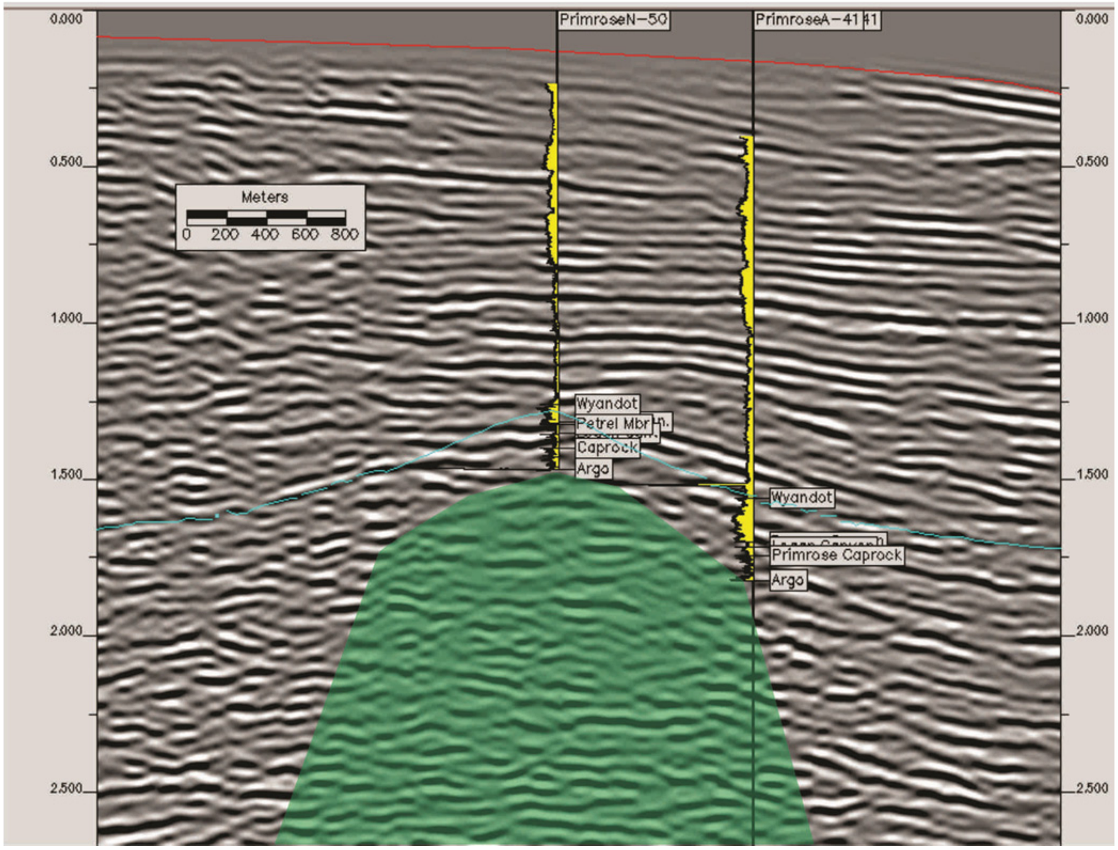

Figure 3.9.1 Primrose seismic time line showing gamma ray logs.

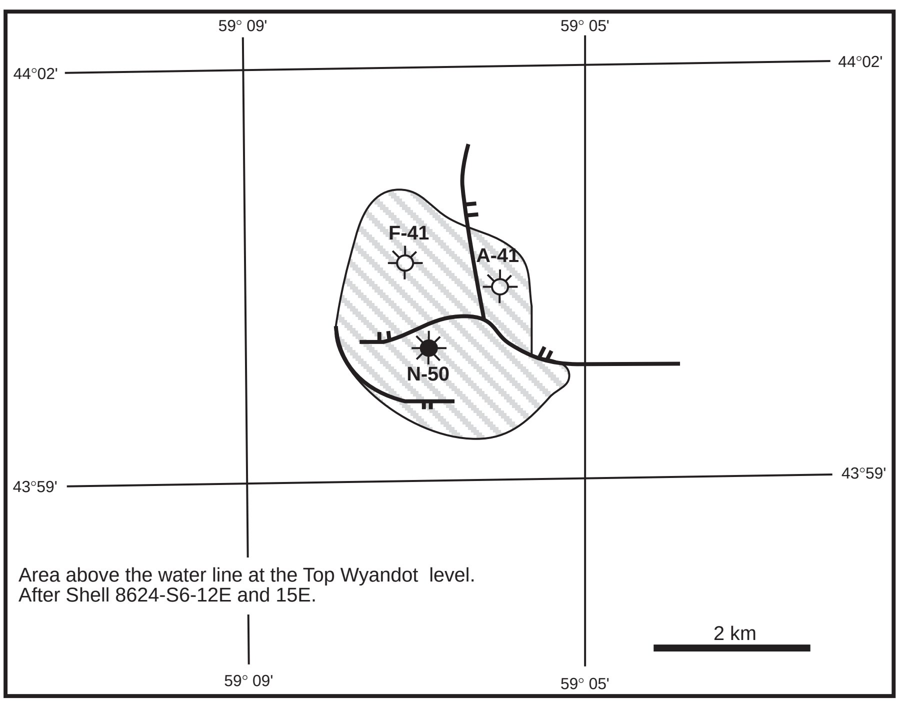

Figure 3.9.2 Primrose Top Wyandot Map (CNSOPB, 2000; after Shell)

3.9.3. Reservoir Description

The Primrose gas reservoirs are located within Late Cretaceous limestones of the Wyandot Formation and sandstones of the Logan Canyon Formation. The oil reservoirs are Early Jurassic (~Toarcian) shallow marine dolomites of the Iroquois Formation which form the caprock of the salt diapir. In total, three wells (of which Primrose 1aA-41 was sidetracked) have been drilled on the structural crest and flanks of the field. Overpressure conditions were not encountered in any of these wells.

The main Primrose gas reservoir is a thick, continuous package of limestones, marls and chalks representing deposition on a stable, shallow, open-marine continental shelf. Well data indicates that the carbonate sediments are generally lime mudstones that are soft, chalky, fossiliferous, pyritic argillaceous and interbedded with marls and calcareous gray shales and mudstones.

Additional gas pay is present in the marine shelfal sandstones of the Late Cretaceous (Cenomanian) Marmora member of the Logan Canyon Formation. These sands are very fine to fine grained, well sorted, calcareous, and variably argillaceous and pyritic. Thin gas and oil pay is also present in the Iroquois Formation dolomites that are microcrystalline, anhydritic, argillaceous, pyritic and interbedded with grey dolomitic shales.

3.9.4. Formation Evaluation

The Primrose field has three hydrocarbon bearing intervals, the Wyandot gas zone (Zone 1), Logan Canyon gas zone (Zone 2) and the Iroquois caprock gas and oil zones (Zone 3 gas & Zone 3 oil). Zone 1 has the largest reserves and tested gas at rates ranging from 3.3 to 17.4 MMscf/d (Table 3.9.1). It should be noted that these flow rates were only obtained after the zone was acidized and in most cases pressure depletion was noted during testing. Zone 1 has a field wide, log-defined, GWC. The reservoir characteristics of Zone 1 are fair to good with average porosities ranging from 0.23 to 0.26 and core permeabilities between 0.1 and 40 mD. Zone 1 core analysis data supported the use of a net gas pay porosity cutoff of 0.16 which is approximately equivalent to a permeability cutoff of 0.1 mD.

Zone 2 only has net gas pay in the Primrose N-50 and A-41 wells. The zone was tested in Primrose N-50 and flowed gas at rate of 16.8 MMscf/d. The zone is a GDT in both wells and has very good reservoir properties with average porosity range of 0.23–0.25.

Zone 3 is a dolomitic interval that includes an oil bearing interval (Zone 3 oil) with an overlying gas cap (Zone 3 gas). Primrose N-50 was the only well to encounter hydrocarbons in Zone 3. The zone tested gas at a rate of 2.4 MMscf/d and oil at 350 BBL/d. The base of Zone 3 has a transitional resistivity profile suggesting the OWC is near the base of the zone. The Zone 3 dolomites have fair to good reservoir properties with average porosity of 0.16. Flow testing indicates permeabilities are modest. Petrophysical assessment results for the Primrose field are shown below (Table 3.9.2) along with petrophysical results plots for Primrose N-50 (Figs. 3.9.3–3.9.5).

Table 3.9.1 Primrose field significant tests.

Well	Test#	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
N-50	PT 1*	1643-1650	Zone 3 oil	Iroquois (Caprock)	6.8	48 (oil)		0.24	300 (oil)	
N-50	PT 2*	1612-1650	Zone 3 gas / Zone 3 oil	Iroquois (Caprock)	71	56 (oil)		2.5	350 (oil)	
N-50	PT 3	1498-1532	Zone 2	Logan Canyon	476	9		16.8	56	
N-50	PT 4*	1391-1400	Zone 1	Wyandot	385	11		13.6	71	
N-50	PT 5*	1372-1379	Zone 1	Wyandot	493	17		17.4	110	
1aA-41	PT 3**	1551-1561	Zone 1	Wyandot	93		13	3.3		82
1aA-41	PT 2**	1512-1530	Zone 1	Wyandot	195		11	6.9		69
1aA-41	PT 1**	1422-1475	Zone 1	Wyandot	No Rec			No Rec		
F-41	PT 1**	1509-1530	Zone 1	Wyandot	122			4.3		

* Flow rates shown are after zone was acidized.
** Flow rates shown are after zone was acidized. Flow rates decreased during testing.

Table 3.9.2 Primrose field petrophysical summary.

Well	Zone	Top (m MD)	Base (m MD)	GR Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Primrose N-50	Zone 1[1]	1356.4	1446.0	89.6	42.9	0.229	0.35
Primrose N-50	Zone 2[2]	1497.9	1571.3	73.3	12.6	0.227	0.32
Primrose N-50	Zone 3 gas[2]	1608.5	1642.9	34.4	4.3	0.161	0.52
Primrose N-50	Zone 3 oil[2]	1642.9	1657.4	14.5	4.6	0.155	0.47
Primrose A-41	Zone 1[1]	1416.0	1565.9	149.9	66.6	0.262	0.44
Primrose A-41	Zone 2[2]	1647.1	1689.7	42.7	9.3	0.253	0.53
Primrose 1aA-41	Zone 1[1]	1417.7	1569.0	148.6	48.9	0.249	0.51
Primrose F-41	Zone 1[1]	1470.5	1566.1	95.5	37.5	0.263	0.50

[1] Zone 1 Cutoffs: PHI >= 0.16, Vsh <= 0.40, Sw <= 0.60 (PHI=0.16 equivalent to permeability of 0.1 mD)
[2] Zone 2 & 3 Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60

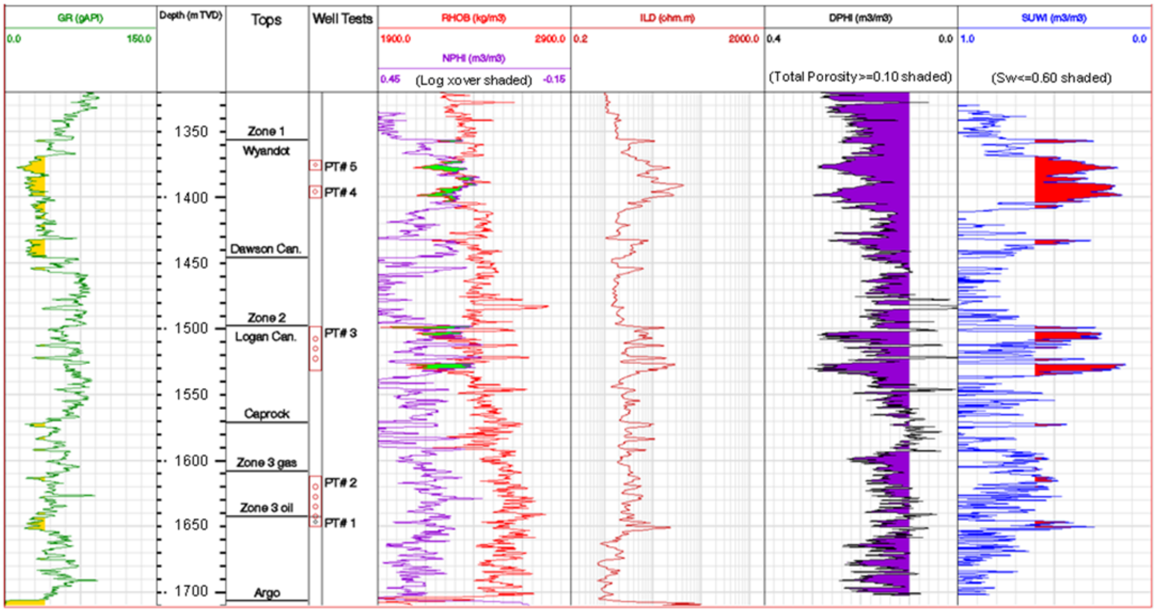

Figure 3.9.3 Primrose N-50 petrophysical results plot: all zones.

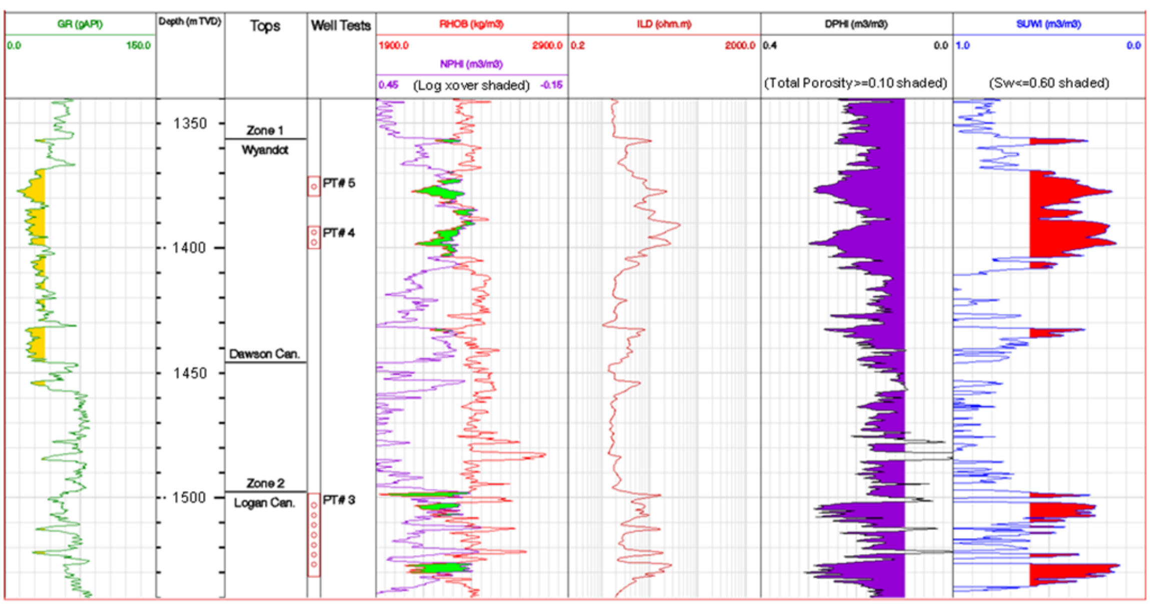

Figure 3.9.4 Primrose N-50 petrophysical results plot: Zones 1 & 2.

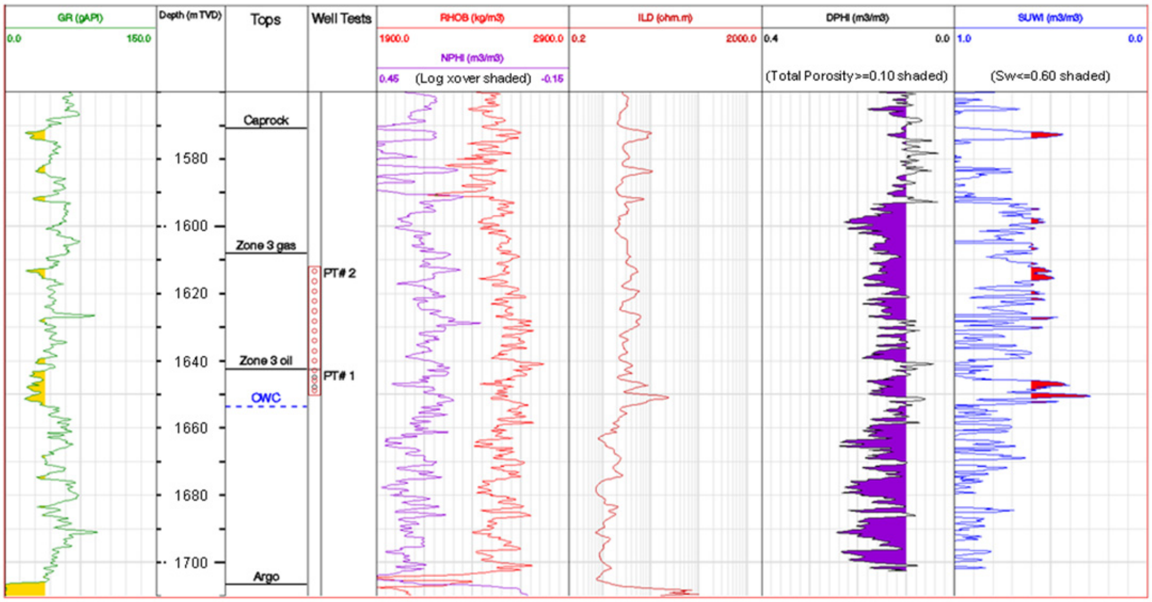

Figure 3.9.5 Primrose N-50 petrophysical results plot: Zone 3.

3.9.5. Resource Assessment

At the time of report the CNSOPB did not have access to digital seismic data (SEGY) for the Primrose field. The Top Wyandot structure map originally submitted by Shell was therefore used to define areal extents for each reservoir. The P50 area for Zone 1 was defined by projecting the field wide GWC onto this Top Wyandot structure map. The minimum and maximum areas for the zone were defined by decreasing and increasing the P50 value by 10% to allow for mapping uncertainty.

The P50 area for Zone 2 was based on the GDT in the Primrose A-41 well. The minimum area was assigned by reducing the P50 value by 10% to allow for mapping uncertainty. The maximum area was defined by assuming the structure was filled down to the top of Zone 2 in Primrose F-41 which is a water-up-to on logs.

The oil and gas accumulation in Zone 3 appears to be limited to the N-50 fault block as Primrose N-50 was the only well to encounter hydrocarbons in this interval. The P50 area for Zone 3 gas (gas cap) was limited to the N-50 fault block. The minimum area was assigned by reducing the P50 value by 10% to allow for mapping uncertainty. The maximum area was defined by assuming that crestal faults are not sealing and the log/DST-defined gas-oil contact is continuous across the field. The P50 area for Zone 3 oil (oil leg) was limited to the N-50 fault block. The minimum area was assigned by reducing the P50 value by 10%. The Zone 3 oil maximum area was determined by assuming that crestal faults are not sealing and the interpreted oil-water contact is continuous across the field.

The P50 input parameters for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50.

Given the low to modest permeability of the chalks in Zone 1 and the depletion noted during testing, the assigned recovery factors ranged from 25 to 55% with a P50 of 40%. The Zone 2 sandstones have very good to excellent reservoir quality resulting in recovery factors of between 65 and 85% being used. The Zone 3 (gas & oil zone) dolomites have fair to good reservoir quality, therefore recovery factors between 50 and 70% were assigned to the gas cap and 20 to 40% to the oil leg.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.9.3).

Table 3.9.3 Primrose probabilistic volume calculation variables.

Zone 1	P100	P50	P00	Mean
Area (km^2)	6.6	7.3	8.0	7.3
Net Pay (m)	40	50	60	50
Porosity (fraction)	0.22	0.25	0.28	0.25
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	155	159	163	159
CGR (BBL/MMCF)	3.0	6.0	9.0	6.0
Gas Recovery Factor	0.25	0.40	0.55	0.40

Zone 2	P100	P50	P00	Mean
Area (km^2)	1.8	2.0	2.8	2.2
Net Pay (m)	8.0	11	14	11
Porosity (fraction)	0.21	0.24	0.27	0.24
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	156	160	164	160
CGR (BBL/MMCF)	2.0	3.0	4.0	3.0
Gas Recovery Factor	0.65	0.75	0.85	0.75

Zone 3 – gas	P100	P50	P00	Mean
Area (km^2)	1.0	1.1	2.0	1.37
Net Pay (m)	2.0	4.0	6.0	4.0
Porosity (fraction)	0.14	0.16	0.18	0.16
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	158	162	166	162
CGR (BBL/MMCF)	0	0	0	0
Gas Recovery Factor	0.50	0.60	0.70	0.60

Zone 3 – oil	P100	P50	P00	Mean
Area (km^2)	1.2	1.3	2.5	1.67
Net Pay (m)	3.0	5.0	7.0	5.0
Porosity (fraction)	0.14	0.16	0.18	0.16
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Oil FVF	1.31	1.31	1.31	1.31
GOR (m^3/m^3)	95.6	96.2	96.7	96.2
Oil Recovery Factor	0.20	0.30	0.40	0.30

3.9.6. Results

Probabilistic assessment results for the Primrose field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (3.9.4 and 3.9.5). Descending cumulative probability charts show field totals for OGIP (Fig. 3.9.6), recoverable gas (Fig. 3.9.7), original oil in place (OOIP) (Fig. 3.9.8), and recoverable oil (Fig. 3.9.9).

Table 3.9.4 Primrose probabilistic OGIP and original oil in place (OOIP).

Sum of all zones	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	7.16	8.55	10.2	8.64
OGIP (Bcf)	253	302	361	305
OOIP (E6m^3)	0.382	0.542	0.769	0.561
OOIP (MMB)	2.40	3.41	4.84	3.53
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	6.51	7.96	9.57	8.01
OGIP (Bcf)	230	281	338	283
Zone 2	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.430	0.549	0.697	0.558
OGIP (Bcf)	15.2	19.4	24.6	19.7
Zone 3 - gas	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.0464	0.0688	0.100	0.0714
OGIP (Bcf)	1.64	2.43	3.52	2.52
Zone 3 - oil	**P90**	**P50**	**P10**	**Mean**
OOIP (E6m^3)	0.382	0.542	0.769	0.561
OOIP (MMB)	2.40	3.41	4.84	3.53

Table 3.9.5 Primrose probabilistic recoverable resources

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	2.83	3.60	4.59	3.65
Rec. Gas (Bcf)	100	127	162	129
Rec. Condensate (E6m^3)	0.0779	0.110	0.157	0.115
Rec. Condensate (MMB)	0.490	0.695	0.990	0.723
Rec. Oil (E6m^3)	0.109	0.162	0.238	0.169
Rec. Oil (MMB)	0.688	1.02	1.50	1.06
Rec. Solution Gas (E9m^3)	0.0105	0.0155	0.0228	0.0162
Rec. Solution Gas (Bcf)	0.371	0.548	0.806	0.572

Zone 1	P90	P50	P10	Mean
Rec. Gas (E9m^3)	2.34	3.14	4.11	3.20
Rec. Gas (Bcf)	82.7	111	145	113
Rec. Condensate (E6m^3)	0.0688	0.105	0.151	0.108
Rec. Condensate (MMB)	0.433	0.662	0.949	0.679

Zone 2	P90	P50	P10	Mean
Rec. Gas (E9m^3)	0.320	0.411	0.527	0.419
Rec. Gas (Bcf)	11.3	14.5	18.6	14.8
Rec. Condensate (E6m^3)	0.00506	0.00688	0.00928	0.00706
Rec. Condensate (MMB)	0.0318	0.0433	0.0584	0.0444
Zone 3 - gas	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.0275	0.0411	0.0606	0.0428
Rec. Gas (Bcf)	0.970	1.45	2.14	1.51
Rec. Condensate (E6m^3)	0	0	0	0
Rec. Condensate (MMB)	0	0	0	0
Zone 3 - oil	**P90**	**P50**	**P10**	**Mean**
Rec. Oil (E6m^3)	0.109	0.162	0.238	0.169
Rec. Oil (MMB)	0.688	1.02	1.50	1.06
Rec. Solution Gas (E9m^3)	0.0105	0.0155	0.0228	0.0162
Rec. Solution Gas (Bcf)	0.371	0.548	0.806	0.572

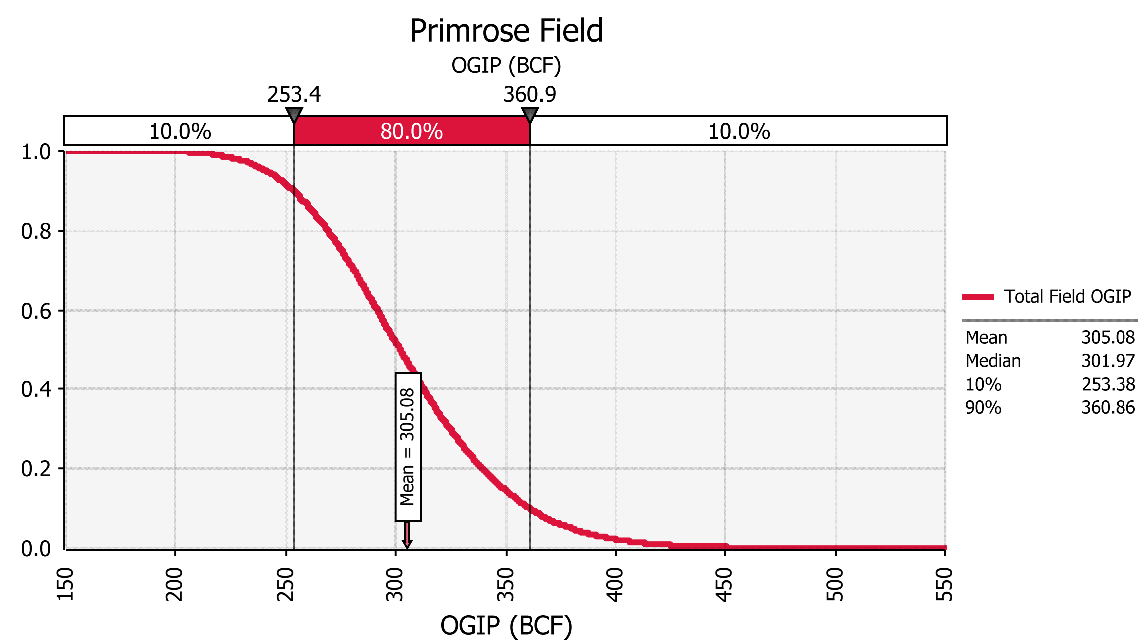

Figure 3.9.6 Primrose OGIP descending cumulative probability chart.

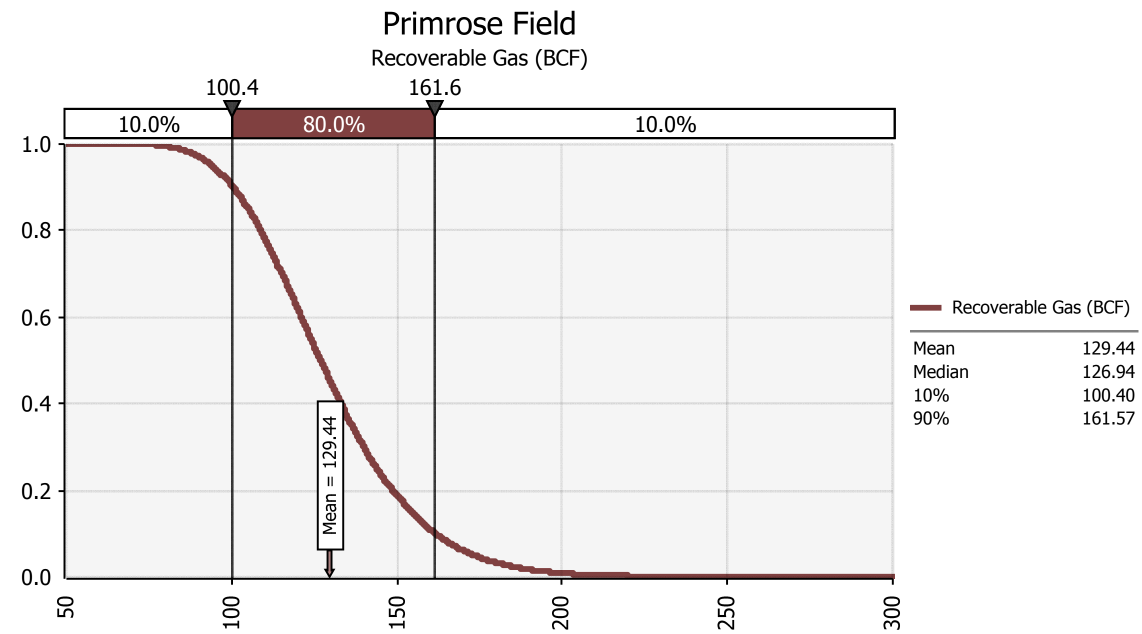

Figure 3.9.7 Primrose recoverable gas descending cumulative probability chart.

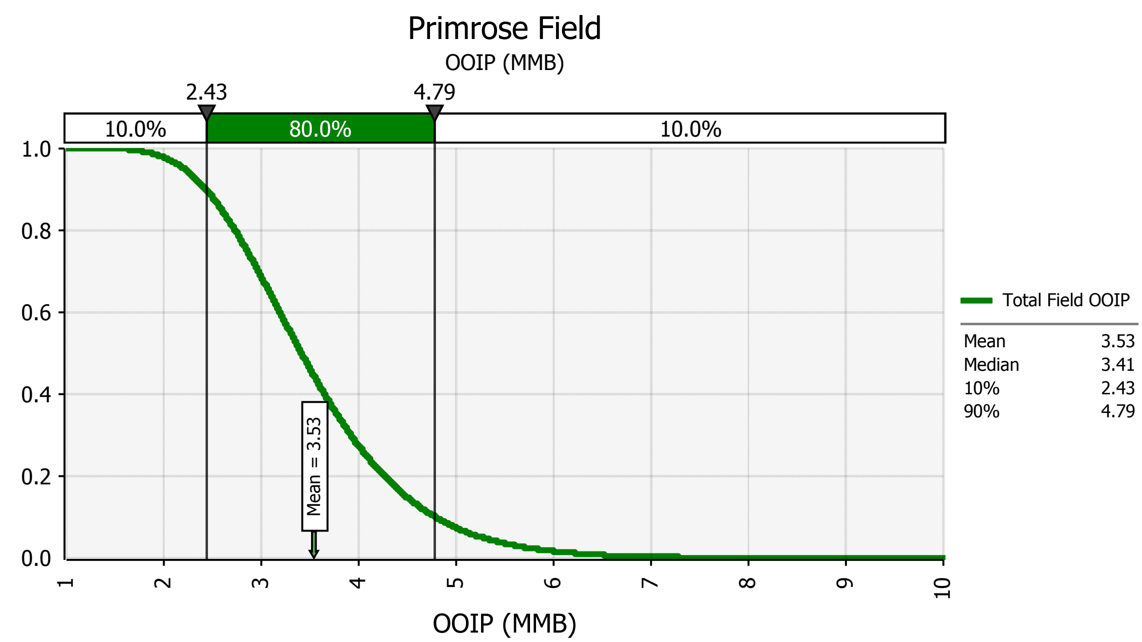

Figure 3.9.8 Primrose OOIP descending cumulative probability chart (oil is restricted to Zone 3).

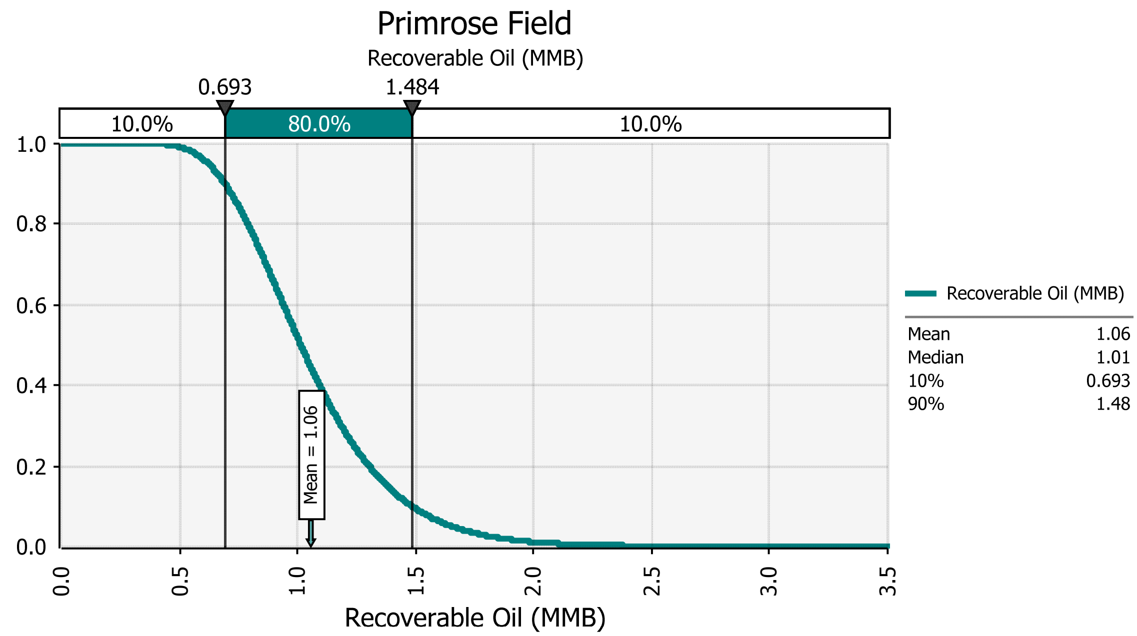

Figure 3.9.9 Primrose recoverable oil descending cumulative probability chart (oil is restricted to Zone 3).

3.10 South Sable - Significant Discovery

3.10.1. Overview

The South Sable gas field is located 6 km due south of Sable Island (Fig. 1.1). The field was discovered in 1988 and was assessed based on the discovery well.

Discovery Well

Well:	South Sable B-44
Company:	Mobil et al.
Spud:	27-Mar-88
Well Termination:	13-Jul-88
Total Depth:	5207.57 m
Water Depth:	35.05 m
Latitude:	43°53'06.56"N
Longitude:	59°51'42.09"W
Target:	Drilled to test for the presence of hydrocarbon bearing sands trapped against a down-to-basin growth fault.

Additional Wells

No delineation drilling was conducted.

3.10.2. Structure

The South Sable structure is a rollover anticline associated with a growth fault reacting to underlying salt movement as shown on the seismic line (Fig. 3.10.1). The Zone 1 horizon (red) has a small structural closure against the high side of a secondary fault, as shown on the Zone 1 depth map (Fig. 3.10.2). The P50 area contour (purple) spills to the west and relies on fault seal along two minor crestal faults.

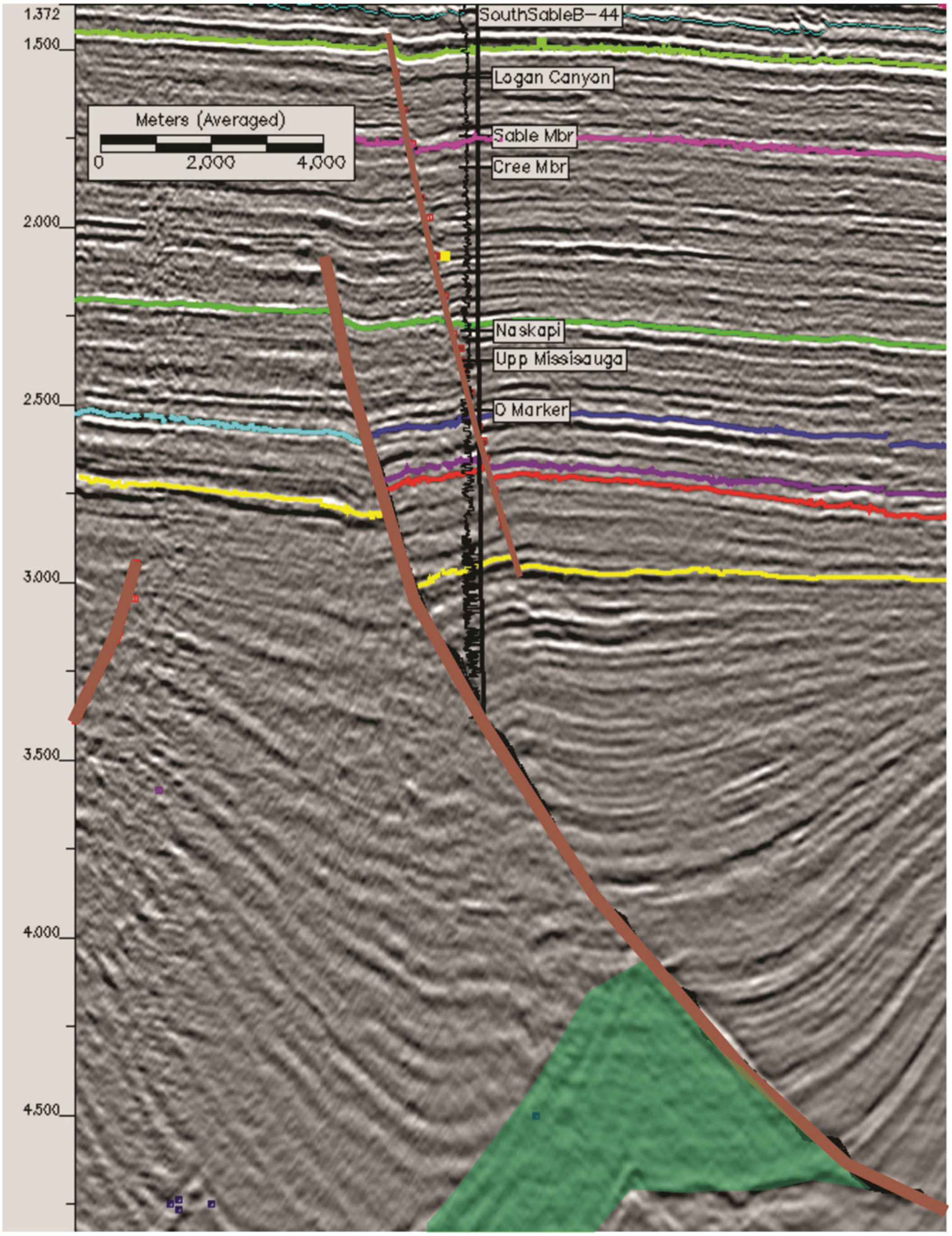

Figure 3.10.1 South Sable seismic time line showing gamma ray log.

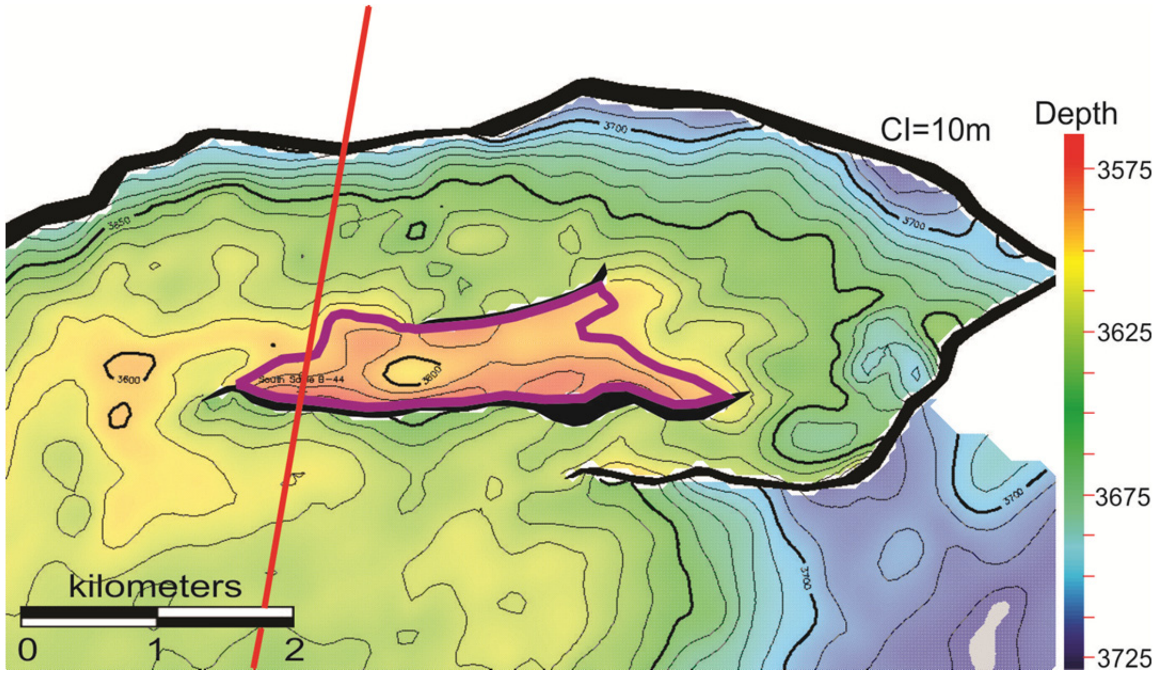

Figure 3.10.2 South Sable Zone 1 depth map.

3.10.3. Reservoir Description

The South Sable gas reservoirs are located in the lower member (Kimmeridgian-Tithonian) of the Early Cretaceous Missisauga Formation. The well was drilled near the structural crest of the field encountering only one significant gas-bearing sand (Zone 1). Seismic mapping suggests that the reservoir sands thicken slightly towards the north-bounding growth fault and have good continuity across the field.

Well data indicates that Zone 1 is a progradational, coarsening upward, shoreface sand that is medium to coarse grained, moderate to well sorted, and siliceous.

3.10.4. Formation Evaluation

The Zone 1 gas reservoir encountered in South Sable B-44 was tested and flowed at a rate of 21.4 MMscf/d (Table 3.10.1). The zone has good reservoir quality with net pay porosity of 0.16 and permeabilities of 0.01–20 mD, based on log, core and DST data. Zone 1 has a log and RFT-defined GWC near the base of the sand. South Sable B-44 petrophysical assessment results are shown below (Table 3.10.2) (Fig. 3.10.3.)

Table 3.10.1 South Sable B-44 significant tests.

Test#	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	3641-3648	1	Missisauga	606	19	7	21.4	119	44

Table 3.10.2 South Sable B-44 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	3640.5	3656.0	15.5	10.2	0.158	0.46
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60						

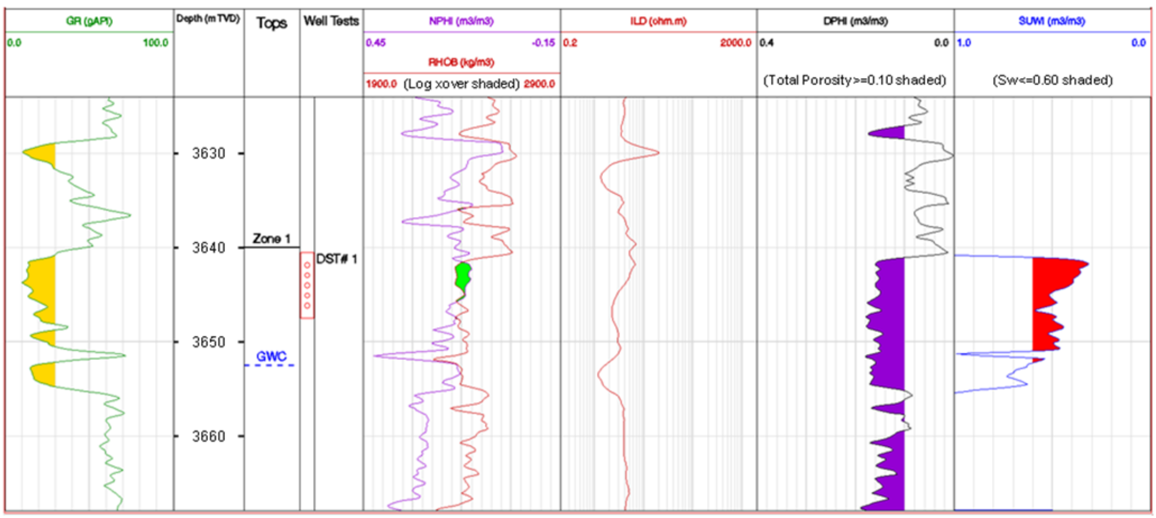

Figure 3.10.3 South Sable B-44 petrophysical results plot: Zone 1.

3.10.5. Resource Assessment

The P50 area for Zone 1 was defined by projecting the interpreted GWC onto the Zone 1 depth map. The minimum and maximum areas were assigned by varying the P50 area +/- 10% to allow for mapping uncertainty.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50. Given the limited column height and area of the Zone 1 gas pool, the assigned recovery factor range was 55–75%.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.10.3).

Table 3.10.3 South Sable probabilistic volume calculation variables.

Zone 1	P100	P50	P00	Mean
Area (km^2)	1.4	1.6	1.8	1.6
Net Pay (m)	7.0	10	13	10
Porosity (fraction)	0.14	0.16	0.18	0.16
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	257	264	271	264
CGR (BBL/MMCF)	3.0	6.0	9.0	6.0
Gas Recovery Factor	0.55	0.65	0.75	0.65

3.10.6. Results

Probabilistic assessment results for the South Sable field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.10.4 and 3.10.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.10.4 and 3.10.5).

Table 3.10.4 South Sable probabilistic OGIP.

Zone 1	P90	P50	P10	Mean
OGIP (E9m^3)	0.289	0.368	0.462	0.374
OGIP (Bcf)	10.2	13.0	16.3	13.2

Table 3.10.5 South Sable probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	0.186	0.238	0.303	0.242
Rec. Gas (Bcf)	6.57	8.42	10.7	8.55
Rec. Condensate (E6m^3)	0.00537	0.00797	0.0112	0.00816
Rec. Condensate (MMB)	0.0338	0.0501	0.0702	0.0513

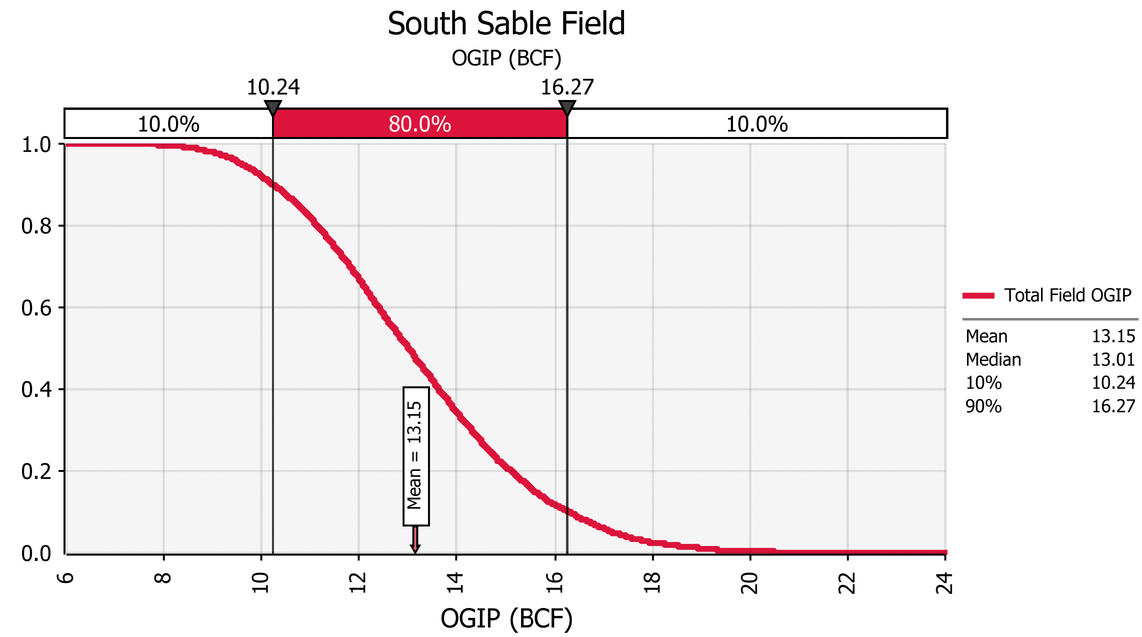

Figure 3.10.4 South Sable OGIP descending cumulative probability chart.

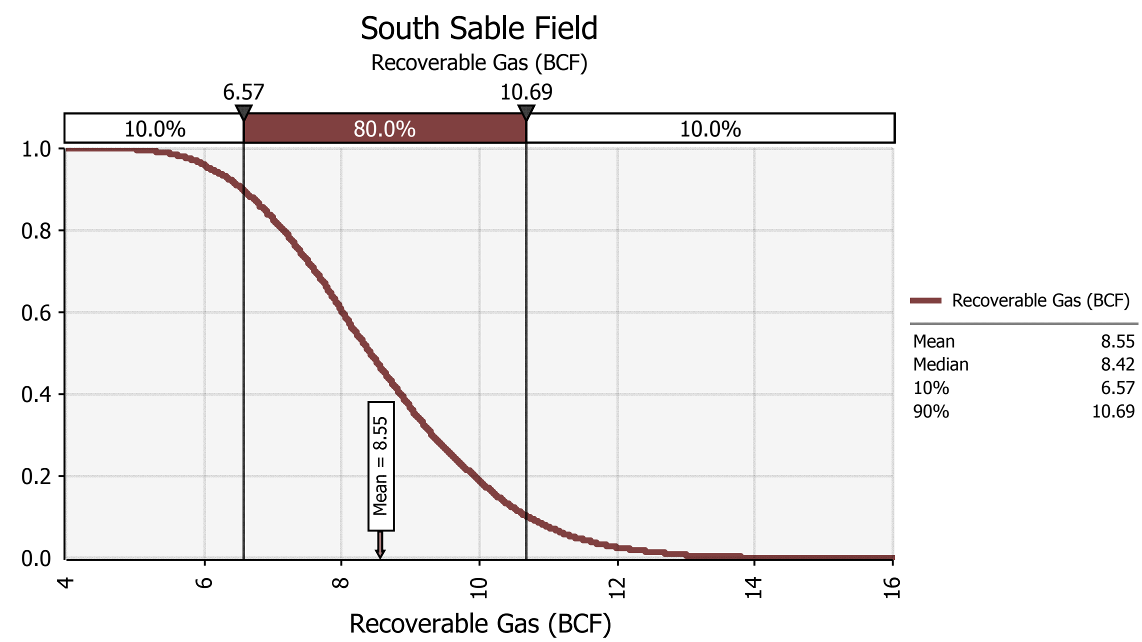

Figure 3.10.5 South Sable recoverable gas descending cumulative probability chart.

3.11 Uniacke - Significant Discovery

3.11.1. Overview

The Uniacke gas field is located approximately 35 km north of Sable Island's eastern tip (Fig. 1.1). The field was discovered in 1984 and this assessment is based on the discovery well.

Discovery Well

Well:	Uniacke G-72
Company:	Shell Petro-Canada et al.
Spud:	09-May-83
Well Termination:	04-Apr-84
Total Depth:	5735 m
Water Depth:	152.9 m
Latitude:	44°11'29.17"N
Longitude:	59°41'09.75"W
Target:	Drilled to test for the presence of hydrocarbons in the sands trapped against a large down-to-basin growth fault.

Additional Wells

No delineation drilling was conducted.

3.11.2. Structure

The Uniacke structure is associated with rollover on the down-thrown side of a rotated growth fault as shown on the seismic line. (Fig. 3.11.1). The Zone 1 Upper seismic horizon (red) is slightly above the two pay zones and is used to map the structural configuration of both zones. The top Mic Mac horizon is shown in yellow.

Simple anticlinal closure on the Zone 1 Upper depth map (Fig.11.2) is limited to 15 m at the well location and any additional closure would be dependent on fault seal. The P50 area contour (purple) shows the limit of faulted closure before spill to the southeast. Having continuous fault seal along the north, east and south bounding faults could allow the north and south structures to form a single pool, but no estimates were made of possible gas volumes in the undrilled, southeast portion of the structure. The red map indicates the location of the seismic line.

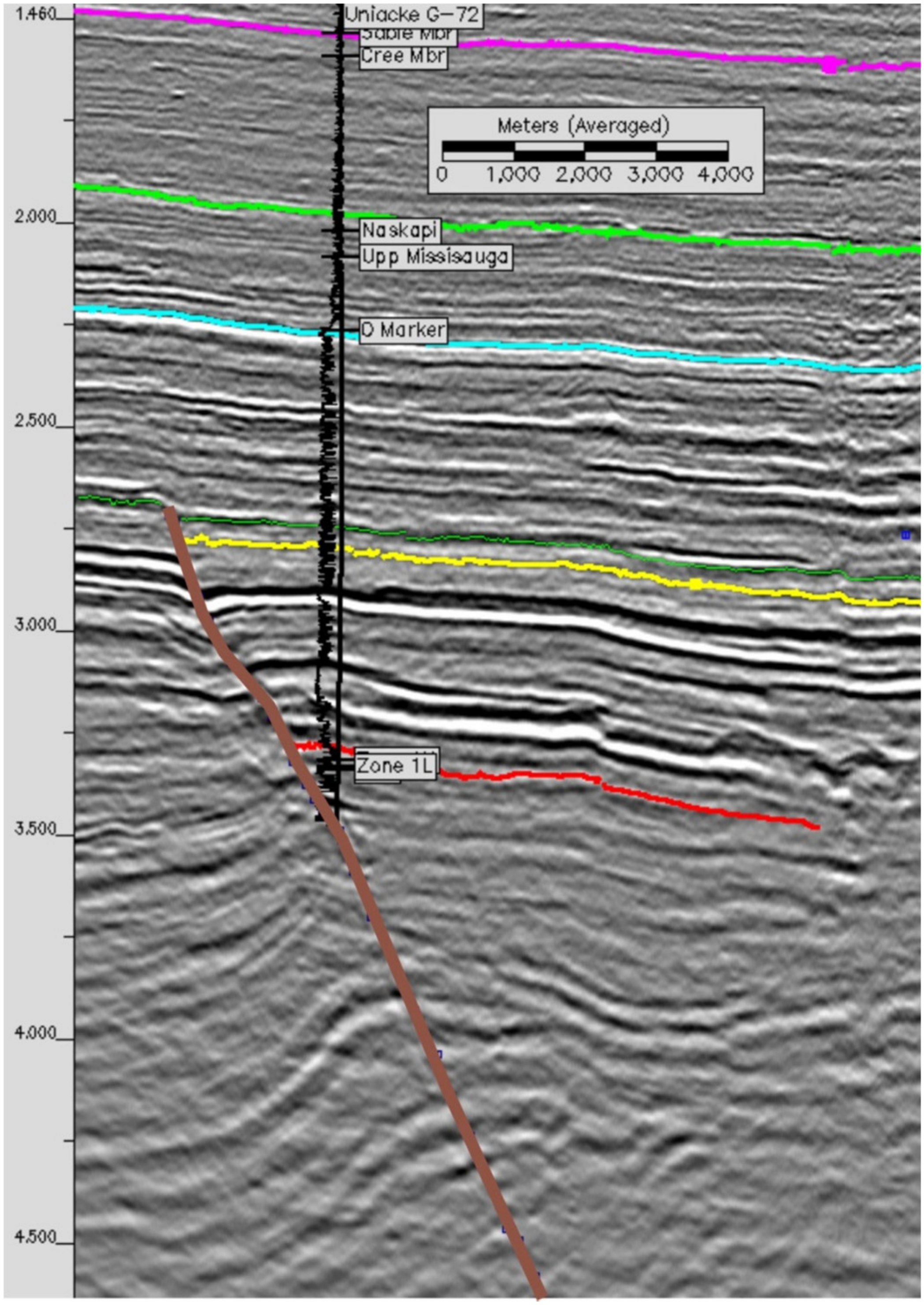

Figure 3.11.1 Uniacke seismic time line showing gamma ray log.

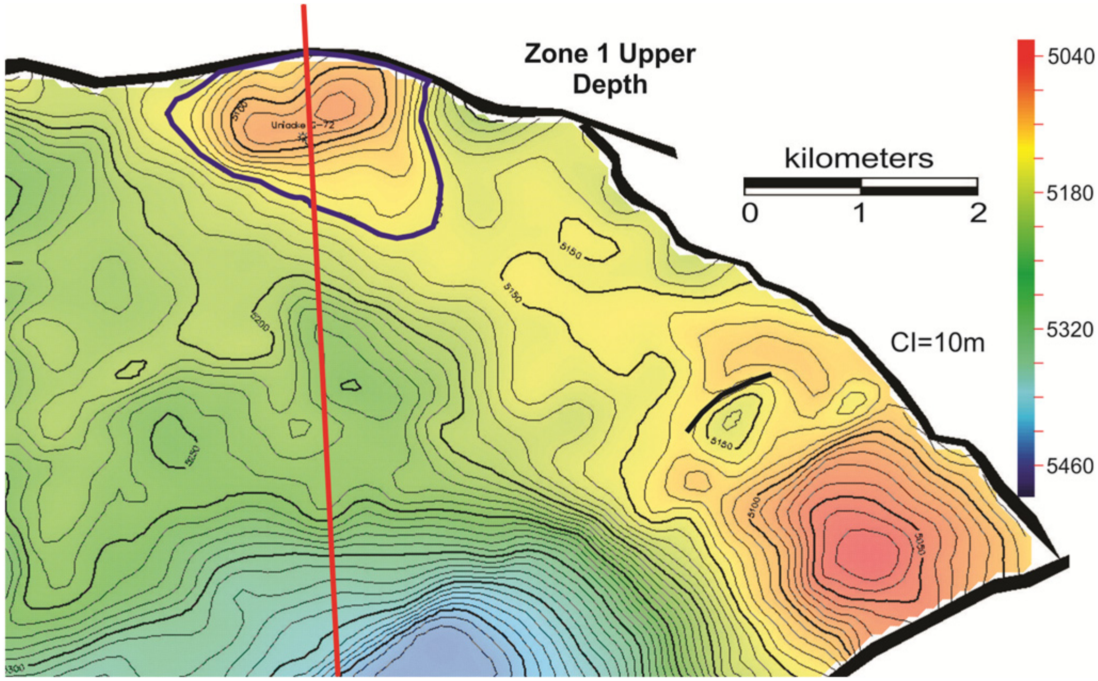

Figure 3.11.2 Uniacke Zone 1 Upper depth map used for Zones 1 Upper and Lower.

3.11.3. Reservoir Description

The Uniacke reservoir sands are located within the Late Jurassic (Callovian-Tithonian) Mic Mac Formation. The exploration well encountered gas pay in a 70 m gross interval that was subdivided into upper (Zone 1U) and lower (Zone 1L) reservoir units.

The reservoir interval is highly overpressured and consists of a sequence of deltaic, strandplain and shoreface facies interfingering with thin marine and prodelta shales. Well logs and cores reveal a sand sequence that initially coarsens upward (progradational: inner shelf to shoreface) and then reverses and fines upwards. The sands are very fine to fine grained, well sorted, dolomitic and calcareous, and variably argillaceous.

3.11.4. Formation Evaluation

Both Uniacke reservoirs (Zones 1U & 1L) were flow tested with gas rates varying from 12.5 to 20.6 MMscf/d (Table 3.11.1). The zones have good reservoir quality with a net pay porosity range from 0.17 to 0.18 and a permeability range from 0.1 to 200 mD. Zone 1U is a gas-down-to, however Zone 1L has a log and DST defined GWC. Well log data combined with DST results indicate that Zones 1U and 1L are probably a single gas pool with a common GWC. Uniacke G-72 petrophysical assessment results are shown below (Table 3.11.2; Fig. 3.11.3).

Table 3.11.1 Uniacke G-72 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	5110-5237	Zone 1U & 1L	Mic Mac	583			20.6		
DST 2	5290-5320	wet	Mic Mac			25			156
DST 3	5242-5260	wet	Mic Mac	1.4		358	0.05		2252
DST 4	5215-5226	Zone 1L Misrun*	Mic Mac	169-227*			6-8*		
DST 5	5215-5226	Zone 1L	Mic Mac	354	20	19	12.5	126	117
DST 6	5191-5199	Zone 1U	Mic Mac	399	23	9	14.1	147	56
DST 7	4364-4371	wet	Mic Mac			5			32
DST 8	4077-4082	tight	Mic Mac	No Rec.			No Rec.		

* Flow rate estimated - misrun

Table 3.11.2 Uniacke G-72 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1U	5190.6	5215.4	24.8	5.1	0.174	0.42
Zone 1L	5215.4	5260.0	44.5	10.0	0.176	0.53
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.65						

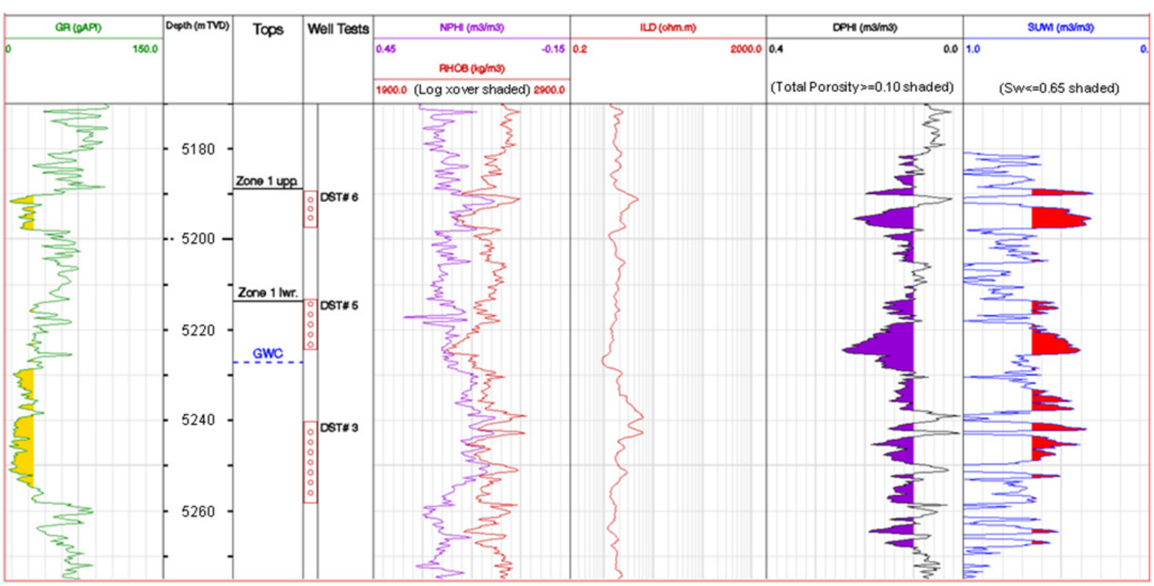

Figure 3.11.3 Uniacke G-72 petrophysical results plot: Zone 1U & 1L.

3.11.5. Resource Assessment

Although well and DST data suggest that Zones 1U and 1L are a single gas pool, some uncertainty remains given that the zones are separated by an interval of predominantly siltstone with questionable permeability. Therefore, the two zones were evaluated separately.

The P50 area for Zone 1U, which is a log GDT, was defined by the deepest closing contour on the Zone 1 depth map, prior to spill to the southeast. Zone 1L has a log-defined GWC supported by DST data. This GWC was projected on to the Zone 1 depth map to define the P50 area. For both zones the minimum and maximum values were assigned by varying the P50 area +/-10% to allow for mapping uncertainty.

The Uniacke structure is interpreted to spill toward the southeast. There is a structural high with fault-dependent closure in the most southeasterly portion of the Uniacke fault block. This structural high may be charged with gas that has migrated through the saddle from the northwestern part of the field. The presence of gas in this southeastern high is speculative and not included.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50. Zones 1U and 1L are both good quality reservoirs, but the presence of a GWC in Zone 1L and the resulting elevated water saturations will have a negative impact on gas recovery. As a result, the assigned recovery factor ranges for Zone 1L (50–70%) were slightly lower than those used for Zone 1U (55–75%).

All key input parameters used for probabilistic volume calculations are listed below (Table 3.11.3).

Table 3.11.3 Uniacke probabilistic volume calculation variables.

Zone 1 Upper	P100	P50	P00	Mean
Area (km^2)	1.8	2.0	2.2	2.0
Net Pay (m)	3.0	5.0	7.0	5.0
Porosity (fraction)	0.15	0.17	0.19	0.17
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	392	403	414	403
CGR (BBL/MMCF)	55	57	59	57
Gas Recovery Factor	0.55	0.65	0.75	0.65

Zone 2	P100	P50	P00	Mean
Area (km^2)	1.4	1.6	1.8	1.6
Net Pay (m)	8.0	10	12	10
Porosity (fraction)	0.16	0.18	0.20	0.18
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	393	404	415	404
CGR (BBL/MMCF)	55	57	59	57
Gas Recovery Factor	0.50	0.60	0.70	0.60

3.11.6. Results

Probabilistic assessment results for the Uniacke field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (3.11.4 and 3.11.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.11.4 and 3.11.5).

Table 3.11.4 Uniacke probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP (E9m^3)	0.793	0.929	1.09	0.937
OGIP (Bcf)	28.0	32.8	38.6	33.1
Zone 1 Upper	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.309	0.408	0.521	0.411
OGIP (Bcf)	10.9	14.4	18.4	14.5
Zone 1 Lower	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.419	0.521	0.637	0.527
OGIP (Bcf)	14.8	18.4	22.5	18.6

Table 3.11.5 Uniacke probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	0.484	0.578	0.685	0.583
Rec. Gas (Bcf)	17.1	20.4	24.2	20.6
Rec. Condensate (E6m^3)	0.155	0.184	0.219	0.186
Rec. Condensate (MMB)	0.977	1.16	1.38	1.17
Zone 1 Upper	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.197	0.264	0.343	0.268
Rec. Gas (Bcf)	6.97	9.31	12.1	9.46
Rec. Condensate (E6m^3)	0.0631	0.0844	0.110	0.0857
Rec. Condensate (MMB)	0.397	0.531	0.689	0.539
Zone 1 Lower	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.247	0.311	0.388	0.314
Rec. Gas (Bcf)	8.73	11.0	13.7	11.1
Rec. Condensate (E6m^3)	0.0790	0.0994	0.125	0.101
Rec. Condensate (MMB)	0.497	0.625	0.784	0.635

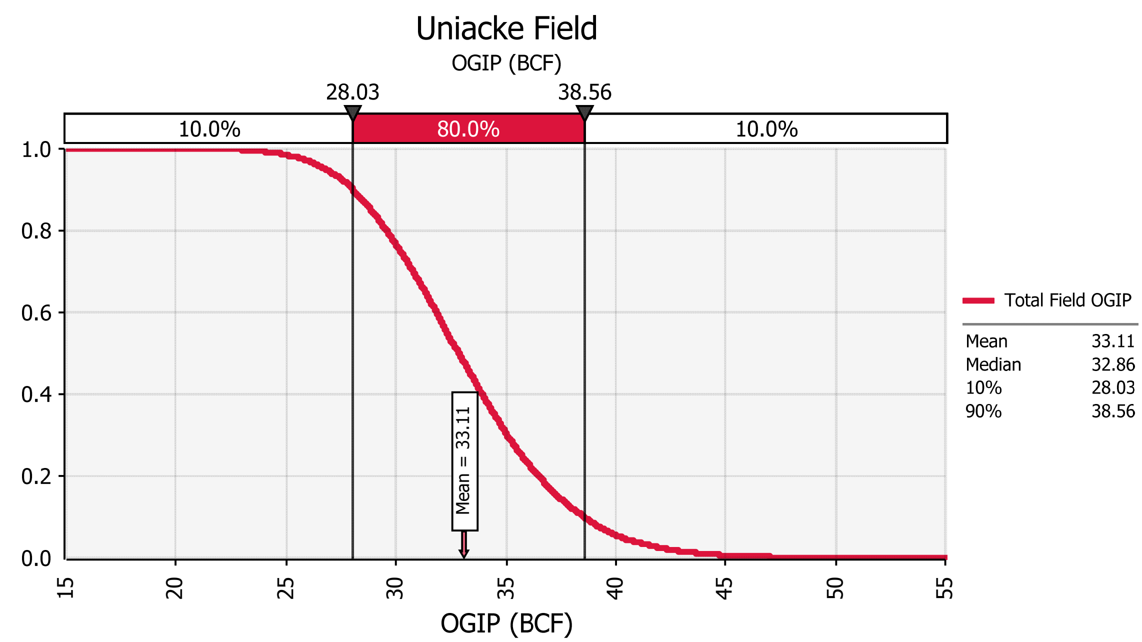

Figure 3.11.4 Uniacke OGIP descending cumulative probability chart.

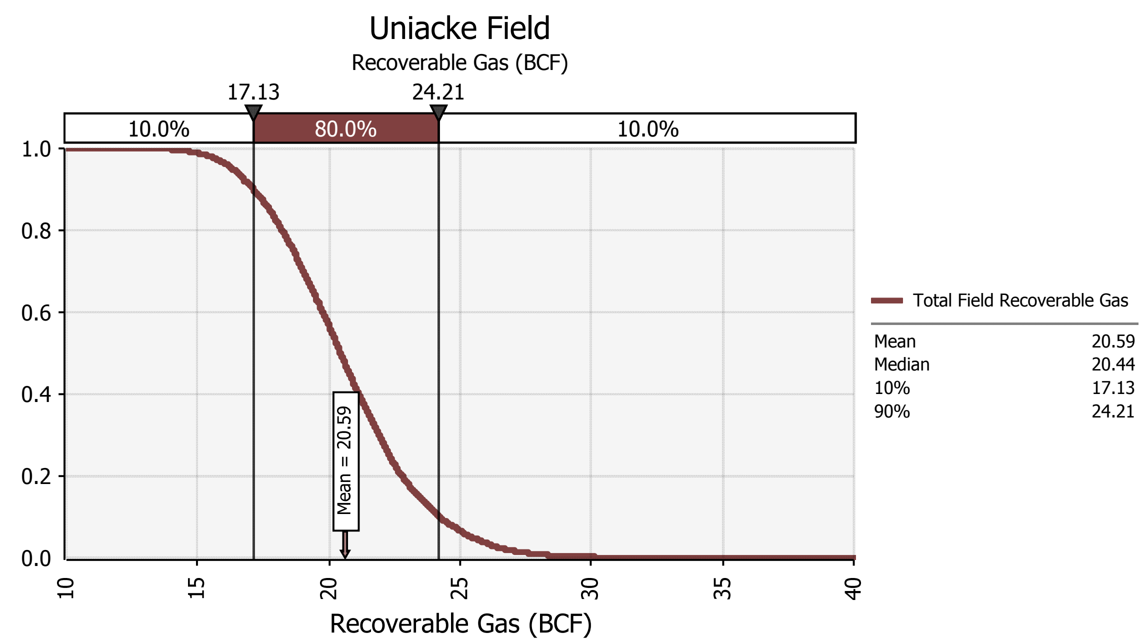

Figure 3.11.5 Uniacke recoverable gas descending cumulative probability chart.

3.12 West Olympia - Significant Discovery

3.12.1. Overview

The West Olympia gas field is located approximately 10 km due north of Sable Island (Fig. 1.1). The field was discovered in 1985 and this assessment is based on the discovery well.

Discovery Well

Well:	West Olympia O-51
Company:	Mobil et al.
Spud:	23-Jun-85
Well Termination:	12-Nov-85
Total Depth:	4816 m
Water Depth:	38 m
Latitude:	44°00’47.802”N
Longitude:	59°53’03.639”W
Target:	Drilled to test for the presence of hydrocarbons in the sands trapped against a down-to-the-basin fault.

Additional Wells

No delineation drilling was conducted.

3.12.2. Structure

The West Olympia structure is a low relief rollover anticline bounded by two down-to-basin normal faults as shown on the seismic line (Fig. 3.12.1). The field is the westernmost member of a series of fields along this fault trend, with Olympia, West Venture and Venture. The 3 Sand is shown as the red horizon with the top Mic Mac as yellow.

The discovery well on the 3 Sand depth map (Fig. 3.12.2) is positioned on the eastern flank of the structure, requiring reservoir seal along portions of the north and south faults to extend closure to the well location. The two bounding faults converge six kilometers to the south west and the inferred leak point for the P50 area contour (purple) could exist on either fault.

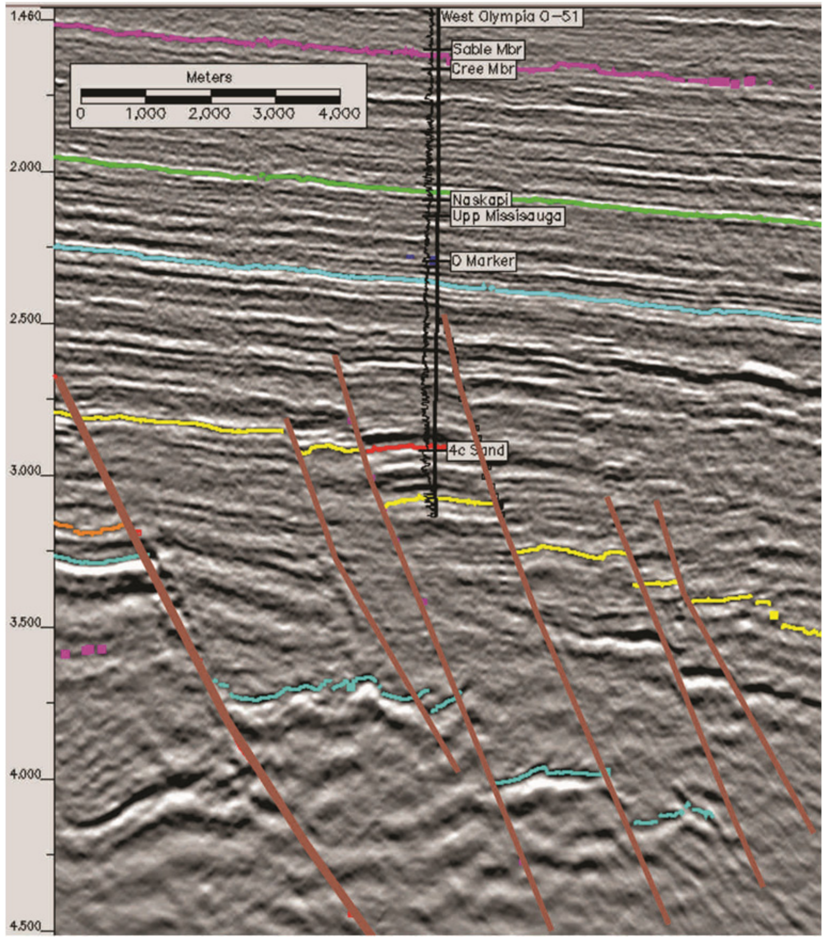

Figure 3.12.1 West Olympia seismic time line showing gamma ray log.

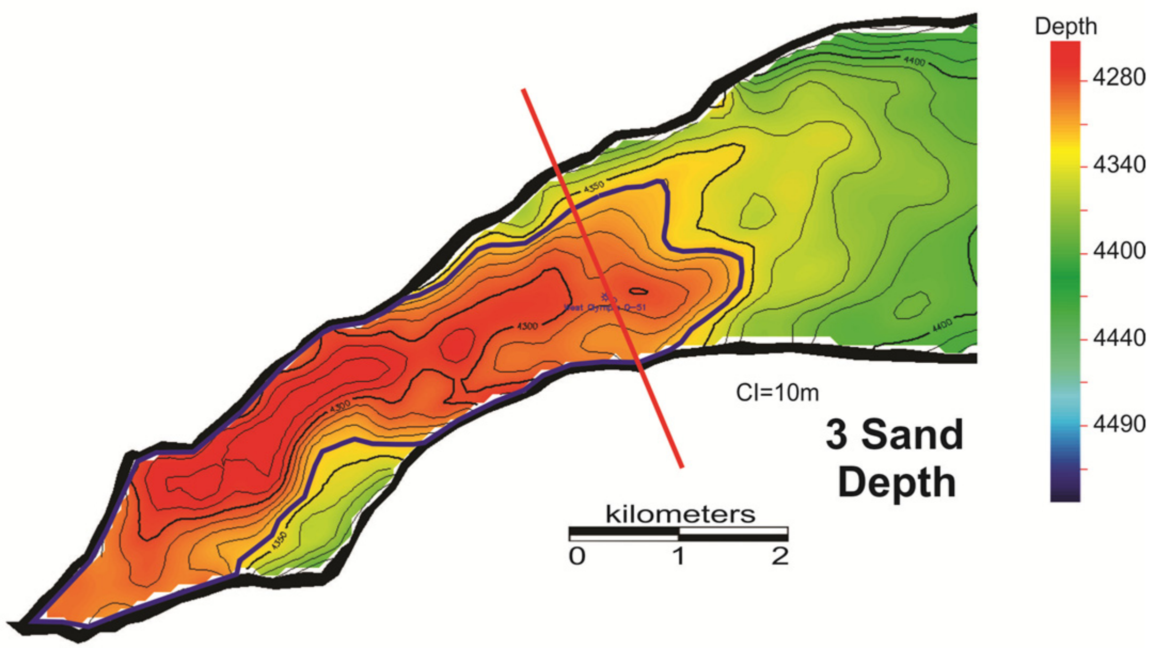

Figure 3.12.2 West Olympia 3 Sand depth map used for 4c Sand.

3.12.3. Reservoir Description

The West Olympia reservoir zone is stratigraphically located within the lower member (Kimmeridgian-Tithonian) of the Missisauga Formation. Seismic mapping and well data indicate that the majority of the Missisauga Formation reservoir sands can be correlated with equivalent sands of the Venture, West Venture and Olympia fields. The well encountered only one major gas-bearing reservoir (4c Sand).

The West Olympia reservoir is overpressured with the top of overpressure occurring about 100 m above the 4c Sand. Along-strike correlations to adjacent fields demonstrate the excellent east-west lateral continuity of these zones. The two DSTs conducted in the 4c Sand showed evidence of pressure depletion which suggests the field area may be stratigraphically limited.

The reservoir sands are similar to those encountered in the related on-strike fields and consist of stacked sequences of cyclic deltaic and strandplain sands interfingering with marine and prodelta shales. The 4c Sand has a coarsening upward profile suggesting a shoreface depositional setting. The sand is fine to coarse grained, siliceous, occasionally calcareous and variably argillaceous.

3.12.4. Formation Evaluation

The two formation tests of the 4c Sand demonstrated flow rates ranging from 17.7 to 18.8 MMscf/d (Table 3.12.1). The zone has good reservoir quality with net pay porosity of 0.17 and DST results which indicate permeability is fair to good. The sand is a gas down to base porosity. The lower portion of the 4c Sand has elevated water saturations suggesting that the GWC is probably within 5 – 10 m of the base of porosity in the sand. West Olympia O-51 petrophysical assessment results are shown below (Table 3.12.2) (Fig. 3.12.3).

Table 3.12.1 West Olympia O-51 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	4356-4386	4c Sand	Missisauga	501	65		17.7	409	
DST 2	4356-4386	4c Sand	Missisauga	532	73		18.8	459	
DST 3	4257-4262	tight	Missisauga	No Flow to Surface			No Flow to Surface		

Table 3.12.2 West Olympia O-51 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
4c Sand	4356.0	4401.2	45.2	10.4	0.172	0.50
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60						

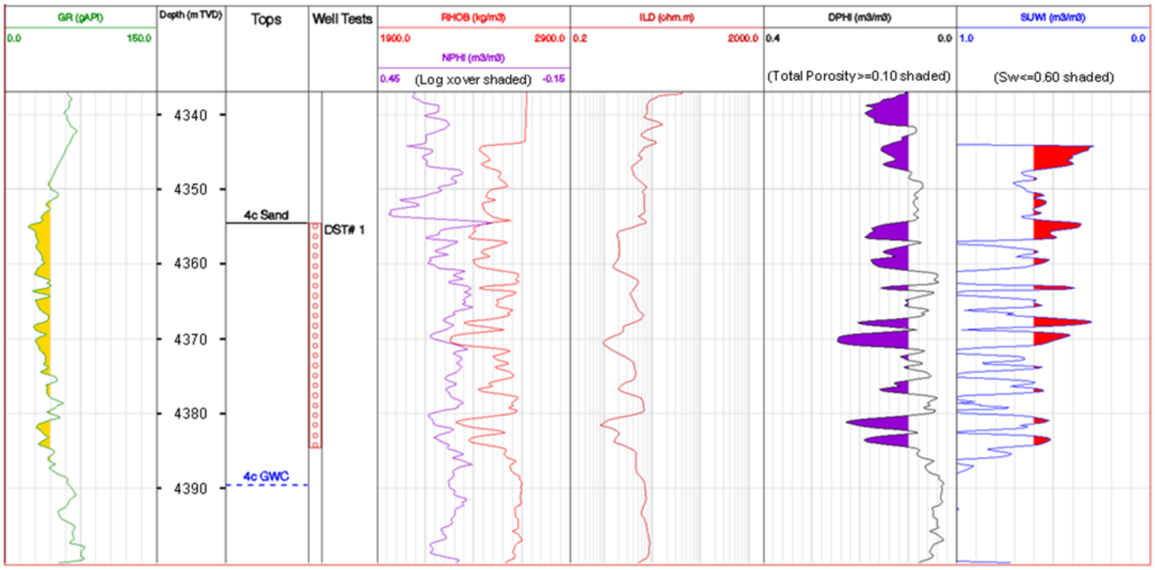

Figure 3.12.3 West Olympia O-51 petrophysical results plot: 4c Sand.

3.12.5. Resource Assessment

The 4c Sand is a GDT base porosity; however, the lower portion of the zone has elevated water saturations that indicate the GWC is likely within 5–10 m from the base of the sand. The most likely GWC was interpreted to be 5 m below the base of porosity. This interpreted GWC was projected on to the 3 Sand depth map to determine the P50 area for the zone. The minimum and maximum values were obtained by varying the P50 area +/- 10% to allow for mapping uncertainty.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50.

The pressure depletion noted during testing suggests that the reservoir may be stratigraphically limited to a smaller area than that suggested by the structure map. Therefore, the range of assigned recovery factors is 30–50%.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.12.3).

Table 3.12.3 West Olympia probabilistic volume calculation variables.

4c Sand	P100	P50	P00	Mean
Area (km^2)	6.9	7.7	8.5	7.7
Net Pay (m)	5.0	10	15	10
Porosity (fraction)	0.14	0.17	0.20	0.17
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	320	329	338	329
CGR (BBL/MMCF)	17	27	37	27
Gas Recovery Factor	0.30	0.40	0.50	0.40

3.12.6. Results

Probabilistic assessment results for the West Olympia field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.12.4 and 3.12.5). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.12.4 and 3.12.5).

Table 3.12.4 West Olympia probabilistic OGIP.

Sand-4c	P90	P50	P10	Mean
OGIP ($E9m^3$)	1.48	2.12	2.92	2.16
OGIP (Bcf)	52.1	75.0	103	76.4

Table 3.12.5 West Olympia probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	0.572	0.841	1.19	0.864
Rec. Gas (Bcf)	20.2	29.7	41.9	30.5
Rec. Condensate ($E6m^3$)	0.0817	0.127	0.188	0.131
Rec. Condensate (MMB)	0.514	0.796	1.18	0.825

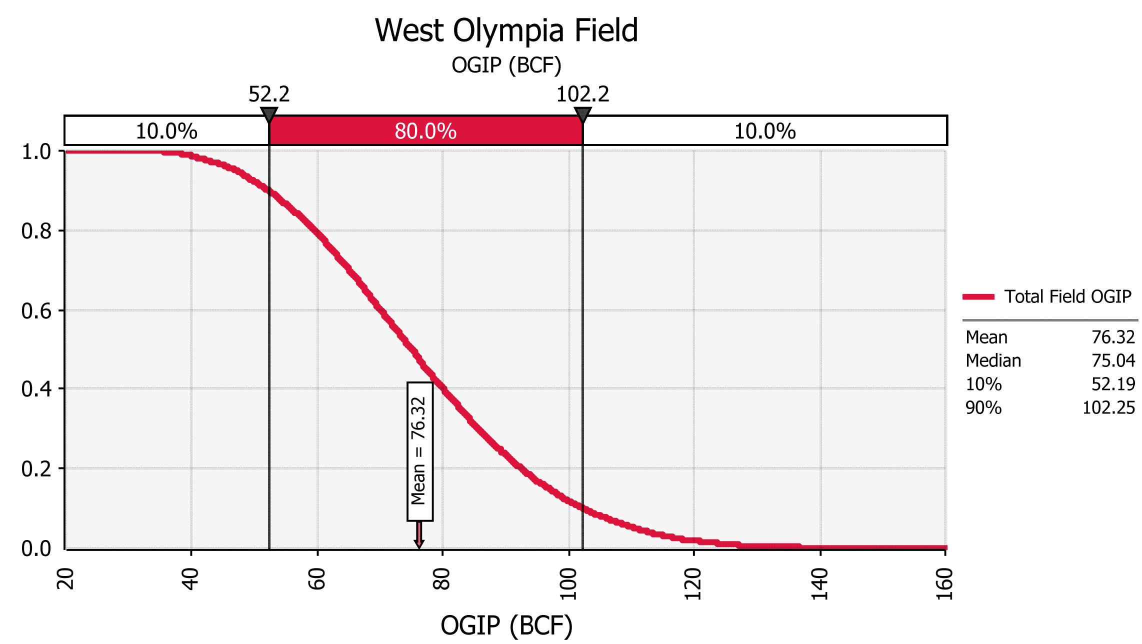

Figure 3.12.4 West Olympia OGIP descending cumulative probability chart.

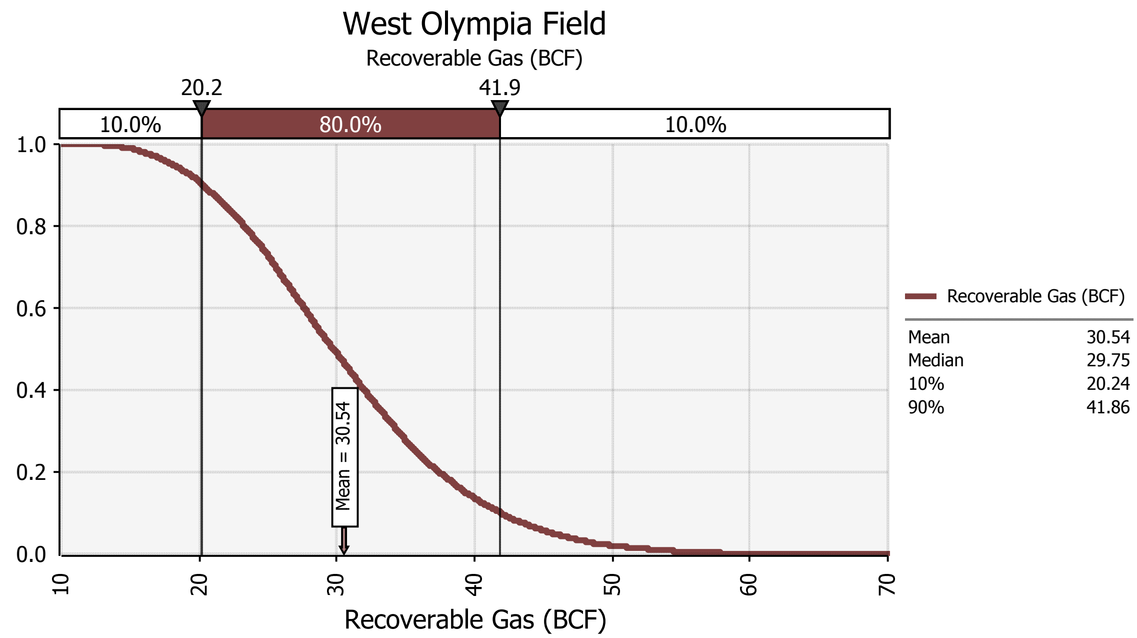

Figure 3.12.5 West Olympia recoverable gas descending cumulative probability chart.

3.13 West Sable - Significant Discovery

3.13.1. Overview

The West Sable gas and oil field is located beneath the western tip of Sable Island (Fig. 1.1). The field was discovered in 1971 and was delineated by eight additional wells, including a sidetrack. Seven of these wells, including the sidetrack, were drilled from the same surface location.

Discovery Well

Well:	Sable Island E-48
Company:	Mobil Tetco
Spud:	28-May-71
Well Termination:	15-Oct-71
Total Depth:	3602.74 m
Water Depth:	0 m
Latitude:	43°57’20.35”N
Longitude:	60°07’24.44”W
Target:	Drilled to test for the presence of hydrocarbons in Cretaceous sands trapped in a heavily faulted anticline above a large salt dome.

Additional Wells

The following eight delineation wells were drilled to access the various fault blocks associated with the structure. Sable Island O-47 was drilled on the flank of the structure and the seven “H” wells, including one sidetrack, were drilled from a common surface location. Sable Island 1H-58 was drilled as a sidetrack which kicked off from H-58 at a depth of 1128 m and reached a total depth of 1615 m.

- Mobil - Tetco Sable Island O-47
- Mobil - Tetco Sable Island H-58
- Mobil - Tetco Sable Island 1H-58 (sidetracked from H-58)
- Mobil - Tetco Sable Island 2H-58
- Mobil - Tetco Sable Island 3H-58
- Mobil - Tetco Sable Island 4H-58
- Mobil - Tetco Sable Island 5H-58
- Mobil - Tetco Sable Island 6H-58

3.13.2. Structure

The West Sable structure is a heavily faulted, salt-cored anticline as shown on the seismic line (Fig. 3.13.1). The two mapping horizons are the Logan Canyon

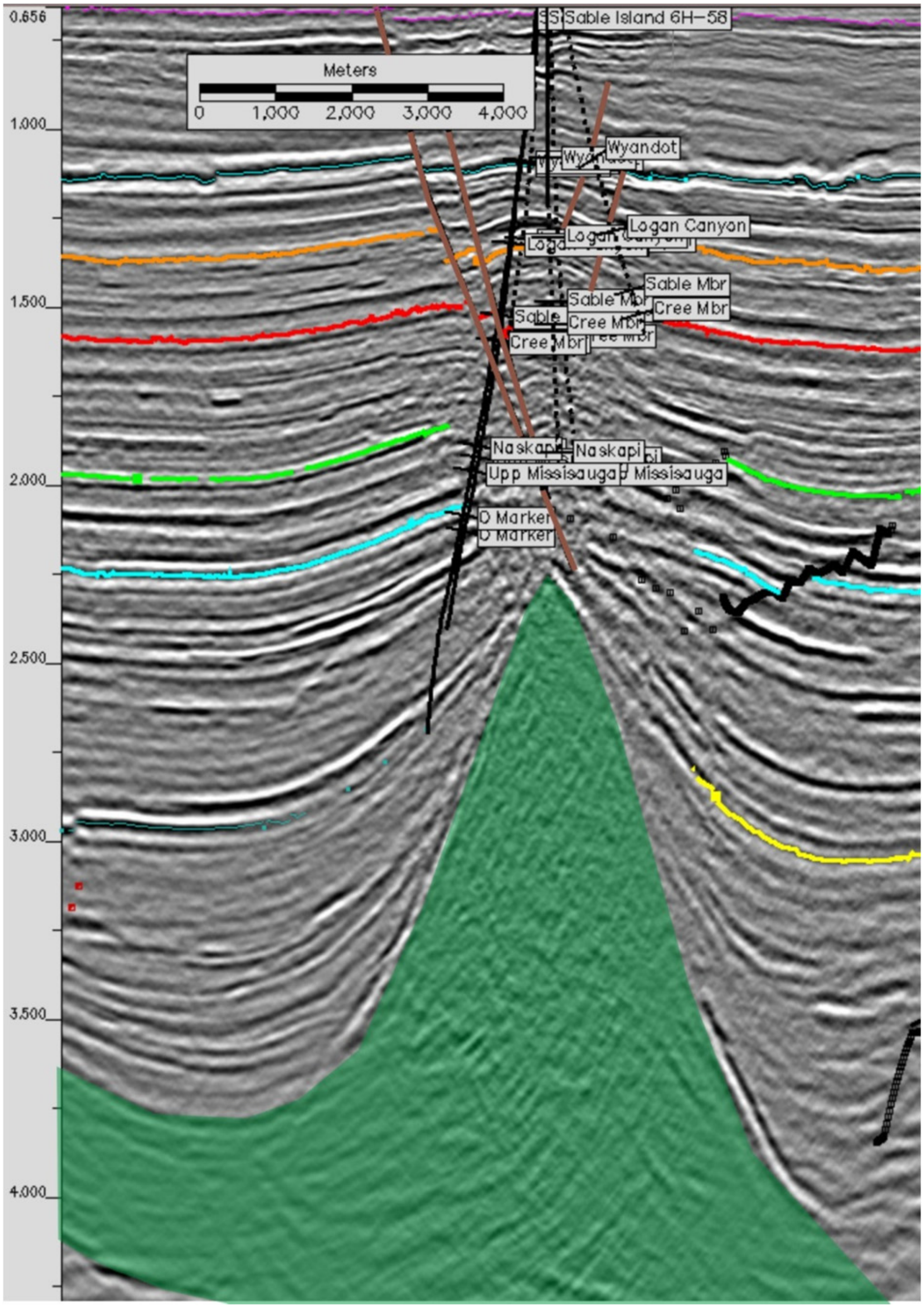

Figure 3.13.1 West Sable seismic time line.

(orange) and the Cree (red). There are 16 gas zones separated into many separate fault blocks. The Logan Canyon depth map (Fig 13.2) is the structure map used for Zones 1, 2, and 3.while the Cree depth map (Fig. 3.13.3) is used for Zones 4 to 16. The P50 area contour (purple) on each map indicates that spill occurs at leak points along faults.

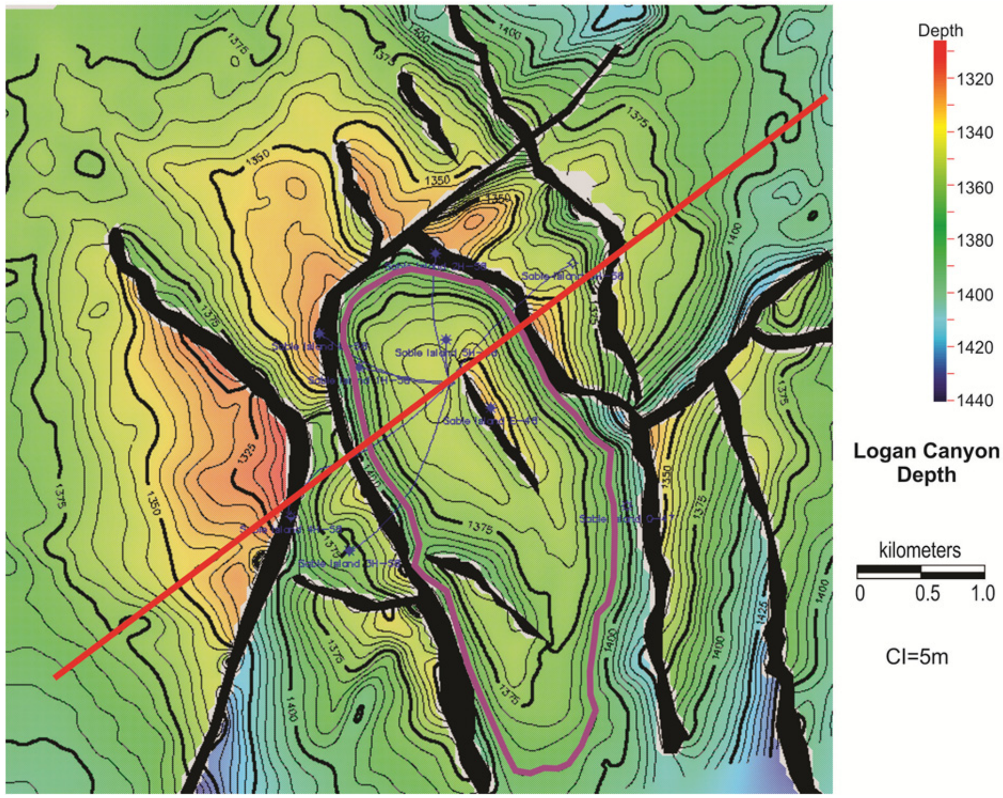

Figure 3.13.2 West Sable Logan Canyon depth map used for Zones 1–3.

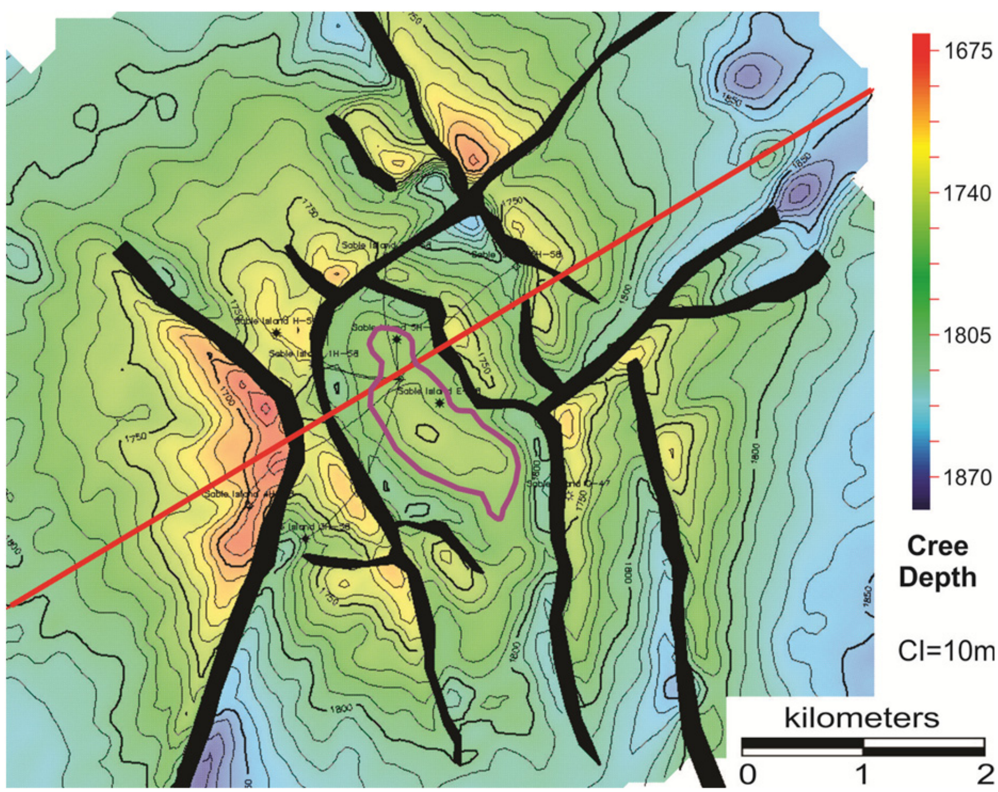

Figure 3.13.3 West Sable Cree depth map used for Zones 4–16.

3.13.3. Reservoir Description

The West Sable reservoirs are located within sandstones of the Turonian-Santonian age Dawson Canyon (gas zone), and Aptian-Cenomanian age Logan Canyon (gas and oil zones) formations.

The Dawson Canyon reservoirs are thick coarsening-upward fluvial and shoreface sands that are very fine to medium grained, moderate to well sorted, calcareous, argillaceous, and variably fossiliferous, pyritic and sideritic. The deeper Logan Canyon sands range from thin to thickly bedded and represent strandplain deposition, though fluvial strata appear to dominate lower in the section. The sands are fine to coarse grained and contain the same constituents as the Dawson Canyon sediments, though also including noticeable quantities of carbonaceous material and kaolinite.

Sable Island O-47 encountered minor gas pay in the slightly overpressured Lower member of the Early Cretaceous Missisauga Formation. These sands are coarsening-upward fluvial deposits and are medium to coarse grained, moderate to poorly sorted, siliceous, calcareous, and variably argillaceous, carbonaceous and sideritic.

3.13.4. Formation Evaluation

The West Sable field has many separate oil and gas pools (>25). Most of these pools have separate log and/or DST defined fluid contacts. The largest hydrocarbon accumulations are in the Dawson Canyon and Upper Logan Canyon formations (Zone 1, Zone 2 gas and Zone 2 oil). These zones are the most areally extensive and contain the majority of the field's hydrocarbon reserves. The deeper zones, Zone 3 oil to Zone 16, have thin hydrocarbon columns and limited areal extents.

Most of the oil and gas zones in the West Sable field were flow-tested. Gas and oil flow rates varied widely ranging from <1 to 15 MMscf/d for the gas zones and 75 to 2880 Bbls/d for the oil zones (Table 3.13.1). Reservoir characteristics of the West Sable sandstones are very good to excellent with an average porosity range of 0.21–0.33 and core permeabilities up to 2800 mD, with most values between 1–1000 mD.

Minor gas pay is present in the Lower Missisauga Formation. However, only two DSTs in Sable Island O-47 were able to flow gas at significant rates from these sands and considerable depletion was noted during testing. The sands appear to be trapped in a separate fault block to the east of the main West Sable reservoirs. Seismic mapping combined with the noted pressure depletion suggests that these zones are likely very limited in areal extent and do not contain significant reserves. As a result, these Lower Missisauga sands were excluded from the West Sable resource assessment.

The results of the petrophysical assessment for Sable Island E-48 are shown below (Table 3.13.1). In Table 3.13.2, the hydrocarbon reservoirs are gas, unless labelled otherwise. Petrophysical results plots for Sable Island E-48 are also displayed below (Figs. 3.13.4–3.13.9).

Table 3.13.1 West Sable field significant tests.
(Tests listed by well from shallowest to deepest)

Well	Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
E-48	DST 1	1134-1173	-	Wyandot	Rec. mud (tight)			Rec. mud (tight)		
E-48	PT 20	1144-1148	-	Wyandot	Gas TSTM (tight)			Gas TSTM (tight)		
E-48	PT 19	1366-1369	Zone 1	Dawson Canyon	69.4			2.45		
E-48	PT 18	1397-1398	Zone 2 gas	Logan Canyon	157.2			5.55		
E-48	PT 21	1431-1433	Zone 2 gas	Logan Canyon	113.8			4.02		
E-48	PT 16	1460-1462	Zone 2 oil	Logan Canyon	5.7	62 (oil)		0.20	390 (oil)	
E-48	Comp. Test	1460-1462	Zone 2 oil	Logan Canyon	36.8	458 (oil)		1.30	2880 (oil)	
E-48	PT 17	1534-1535	Zone 3 oil	Logan Canyon	4.2	70 (oil)		0.15	440 (oil)	
E-48	PT 15	1586-1588	Zone 3 oil	Logan Canyon	5.7	59 (oil)		0.20	370 (oil)	
E-48	PT 14	1631-1632	Zone 3 oil	Logan Canyon	8.5	82 (oil)		0.30	515 (oil)	
E-48	DST 3	1716-1768	Zone 4	Logan Canyon	85.0			3.00		
E-48	DST 4	1806-1824	Zone 5	Logan Canyon	368.1			13.00		
E-48	PT 13	1810-1812	Zone 5	Logan Canyon	124.6	117	2	4.40	733	16
E-48	PT 12	1909-1910	Zone 5	Logan Canyon	80.7	20	5	2.85	127	30
E-48	PT 11	1973-1974	Zone 5	Logan Canyon	39.6	21	61	1.40	132	382
E-48	PT 6	2002-2003	Zone 5A oil	Logan Canyon	28.3	126		1.00	790 (oil)	
E-48	PT 10	2032-2036	Zone 6	Logan Canyon	143.6	43		5.07	270	
E-48	PT 9	2059-2060	Zone 7	Logan Canyon	70.5	65	88	2.49	410	555
E-48	PT 8	2133.6-2134	Zone 8 oil	Logan Canyon	22.1	87		0.78	550 (oil)	
E-48	PT 7	2147-2148	Zone 8 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
E-48	PT 5	2173-2177	Zone 9	Logan Canyon	19.8	66	165	0.70	414	1036
E-48	PT 4A	2195-2196	Zone 10	Logan Canyon	105.1	114		3.71	715	
E-48	PT 3	2206-2211	Zone 11	Logan Canyon	198.8	264		7.02	1660	
E-48	DST 5	2227-2243	Zone 13	Logan Canyon	424.8			15.00		
E-48	PT 2	2236-2240	Zone 13	Logan Canyon	286.0	132		10.10	830	
E-48	PT 1	2285-2287	Zone 15	Logan Canyon	300.2	101		10.60	634	
E-48	DST 7	2974-2983	-	Argo Caprock	Gas TSTM (tight)			Gas TSTM (tight)		
O-47	DST 3	1908-1943	Zone 5	Logan Canyon	Rec. wtr (wet)			Rec. wtr (wet)		
O-47	PT 2	3382-3391	-	Lower Missisauga	0.2			0.01		
O-47	PT 4	3510-3513	-	Lower Missisauga	0.4			0.01		
O-47	DST 4	3530-3636	-	Lower Missisauga	Gas TSTM (tight)			Gas TSTM (tight)		

Well	Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
O-47	PT 1	3570-3571	-	Lower Missisauga	7.1			0.25		
O-47	DST 5	3713-3727	-	Lower Missisauga	18.7		155	0.66		974
O-47	DST 6	3731-3737	-	Lower Missisauga	Rec. mud (tight)			Rec. mud (tight)		
O-47	DST 7	3770-3801	-	Lower Missisauga	19.8			0.70		
O-47	DST 8	3770-3894	-	Lower Missisauga	354.0			12.50		
O-47	PT 5	3803-3809	-	Lower Missisauga	260.5	0.1		9.20	1	
H-58	DST 1	1503-1518	Zone 2 gas	Logan Canyon	150.1			5.30		
H-58	DST 4	1700-1719	Zone 3 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
H-58	DST 6	1734-1750	Zone 3 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
H-58	DST 7	2050-2070	Zone 5	Logan Canyon	Rec. wtr & mud (wet)			Rec. wtr & mud (wet)		
1H-58	PT 3	1539-1541	Zone 2 gas/ Zone 2 oil	Logan Canyon	206.7	36 (oil)	3	7.30	228 (oil)	16
2H-58	PT 10	1471-1472	Zone 1	Dawson Canyon	82.1			2.90		
2H-58	PT 9	1559-1567	Zone 2 gas/ Zone 2 oil	Logan Canyon	60.9	19 (oil)		2.15	120 (oil)	
2H-58	PT 8	1692-1693	Zone 3 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
2H-58	PT 6	1745-1747	Zone 3 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
2H-58	PT 7	1745-1747	Zone 3 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
2H-58	PT 4	1910-1914	Zone 4	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
2H-58	PT 5	1910-1914	Zone 4	Logan Canyon	36.8	95	95	1.30	600	600
2H-58	PT 3	2010-2014	Zone 5	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
2H-58	PT 2	2028-2031	Zone 5	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
2H-58	PT 1	2046-2049	Zone 5	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
3H-58	PT 6	1611-1612	Zone 2 gas	Logan Canyon	87.8			3.10		
3H-58	PT 5	1629-1630	Zone 2 gas/ Zone 2 oil	Logan Canyon	73.6	12 (oil)		2.60	75 (oil)	
3H-58	PT 4	1632-1633	Zone 2 gas/ Zone 2 oil	Logan Canyon	53.2	22 (oil)		1.88	136 (oil)	
3H-58	PT 3	1637-1639	Zone 2 oil	Logan Canyon	47.6	58 (oil)		1.68	365 (oil)	
3H-58	PT 2	1648-1649	Zone 2 oil	Logan Canyon	12.2	162 (oil)		0.43	1021 (oil)	
3H-58	PT 1	1662-1663	Zone 2 oil	Logan Canyon	Minor gas & wtr (wet)			Minor gas & wtr (wet)		
3H-58	DST 1	1956-2004	Zone 4	Logan Canyon	Rec. mud & wtr (wet)			Rec. mud & wtr (wet)		
5H-58	PT 5	1492-1496	Zone 2 oil	Logan Canyon	Rec. water (wet)			Rec. water (wet)		
5H-58	PT 4	1640-1642	Zone 3 oil	Logan Canyon	20.0	245 (oil)		0.71	1540 (oil)	
5H-58	PT 3	1758-1760	Zone 4	Logan Canyon	42.5	216		1.50	1356	
5H-58	PT 2	1904-1906	Zone 5	Logan Canyon	260.5	80		9.20	506	
5H-58	PT 1	1914-1919	Zone 5	Logan Canyon	87.8	30		3.10	186	

Table 3.13.2 Sable Island E-48 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
Zone 1	1363.5	1396.3	32.8	4.7	0.274	0.59
Zone 2 gas	1396.3	1449.3	53.1	7.5	0.243	0.55
Zone 2 oil	1449.3	1468.3	19.0	6.7	0.317	0.46
Zone 3 oil	1492.7	1640.3	147.6	22.4	0.224	0.67
Zone 4	1673.0	1767.9	94.9	19.8	0.235	0.59
Zone 5	1767.9	1948.1	180.3	14.2	0.261	0.44
Zone 5A oil	1991.2	2016.7	25.5	1.2	0.280	0.33
Zone 6	2031.4	2045.2	13.8	5.9	0.266	0.49
Zone 7	2052.0	2059.0	7.0	4.6	0.259	0.46
Zone 8 oil	2127.2	2143.5	16.3	4.0	0.221	0.66
Zone 9	2173.4	2176.6	3.2	1.4	0.232	0.69
Zone 10	2192.8	2197.2	4.4	2.7	0.262	0.42
Zone 11	2202.1	2216.8	14.7	7.0	0.232	0.29
Zone 12	2216.8	2228.0	11.2	1.1	0.243	0.48
Zone 13	2228.0	2243.3	15.4	6.2	0.219	0.45
Zone 14	2268.5	2271.5	3.0	2.9	0.250	0.45
Zone 15	2285.1	2288.3	3.2	3.0	0.259	0.47
Zone 16	2298.0	2302.0	4.0	1.7	0.211	0.47
Gas Zone Cutoffs: Vsh <= 0.40, Phi >= 0.10, Sw <= 0.70						
Oil Zone Cutoffs: Vsh <= 0.40, Phi >= 0.15, Sw <= 0.70						

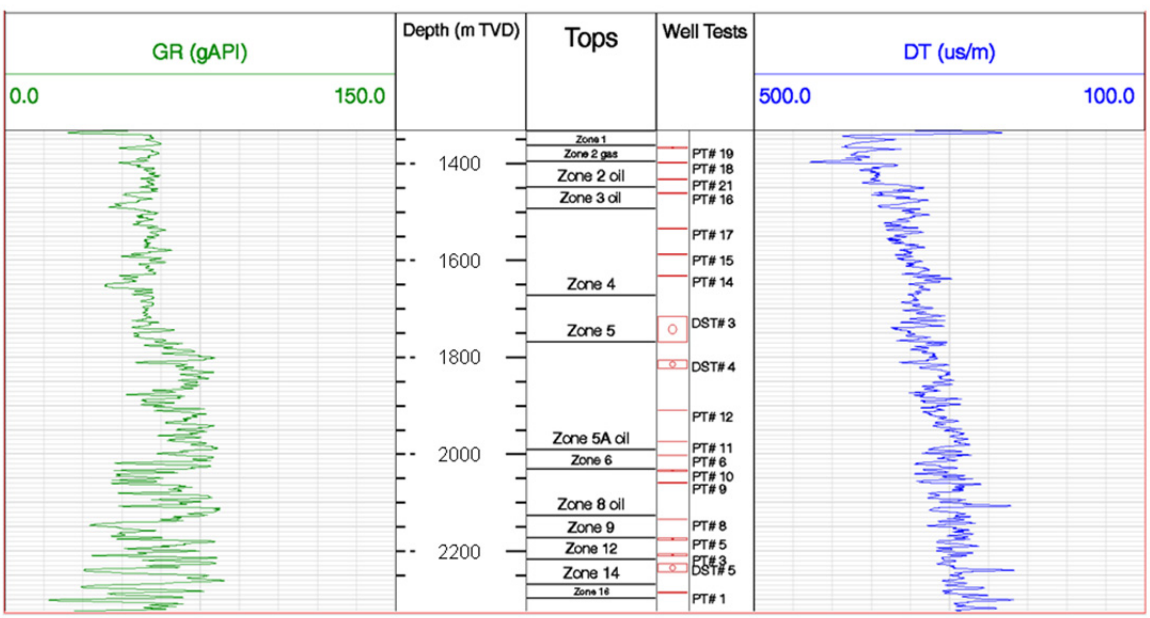

Figure 3.13.4 Sable Island E-48 petrophysical results plot: all zones. (Due to their proximities not all zone tops are displayed)

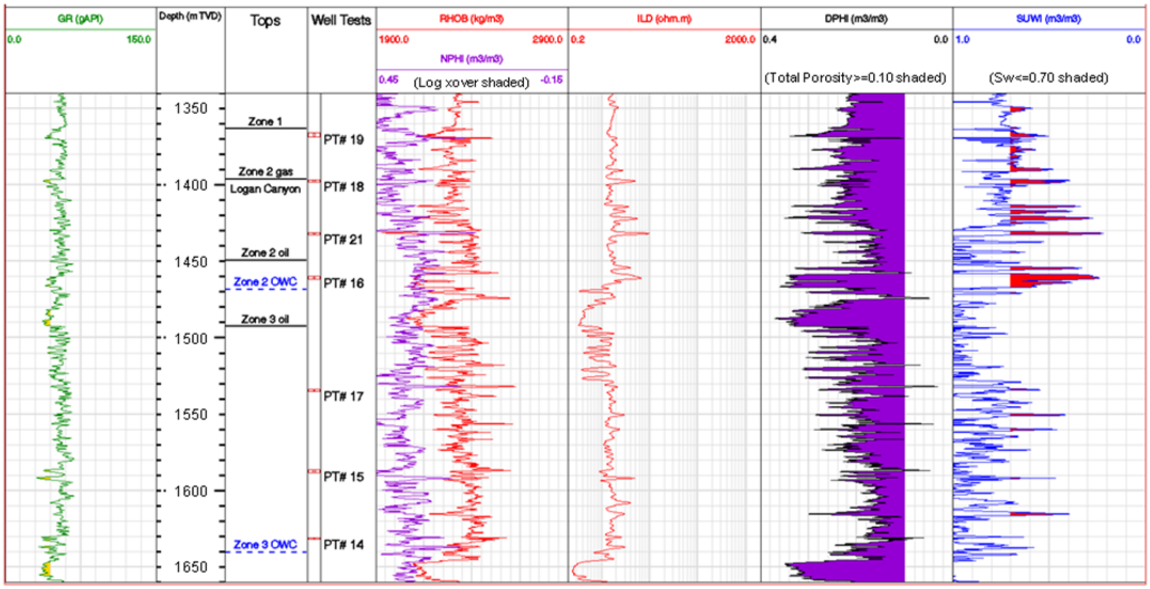

Figure 3.13.5 Sable Island E-48 petrophysical results plot: Zones 1 – 3 oil.

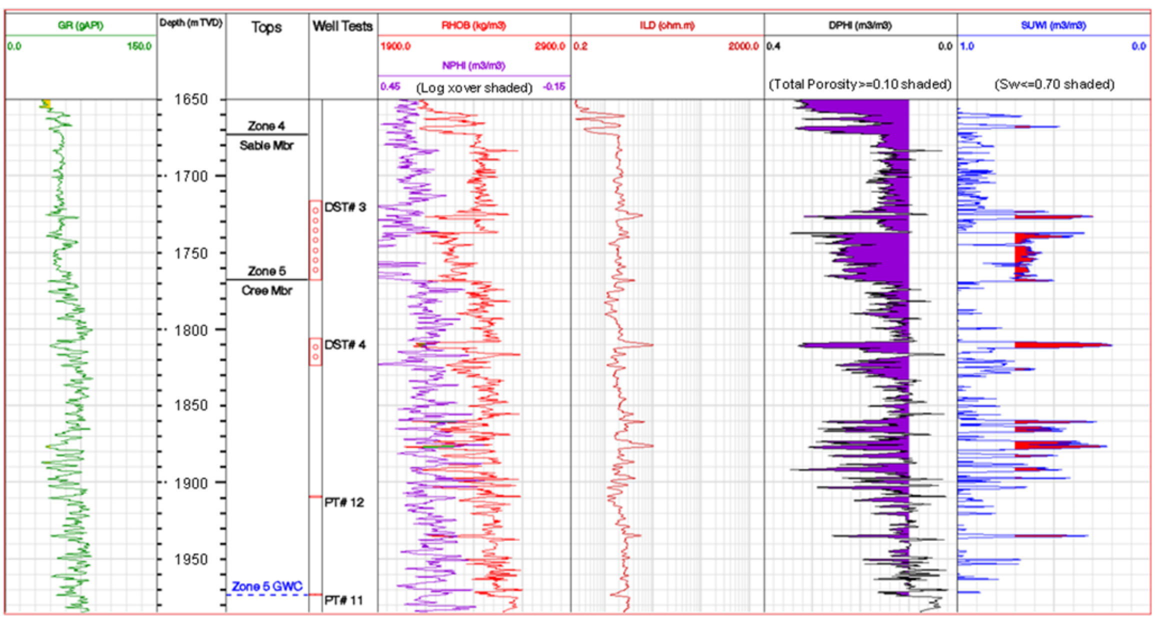

Figure 3.13.6 Sable Island E-48 petrophysical results plot: Zones 4 & 5.

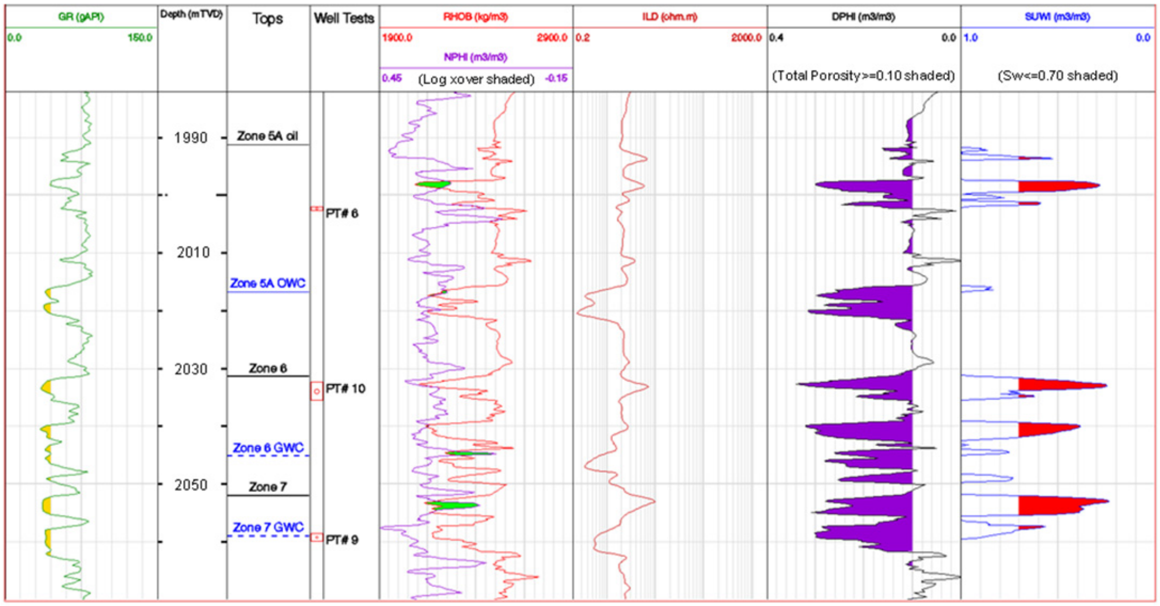

Figure 3.13.7 Sable Island E-48 petrophysical results plot: Zones 5A oil - 7

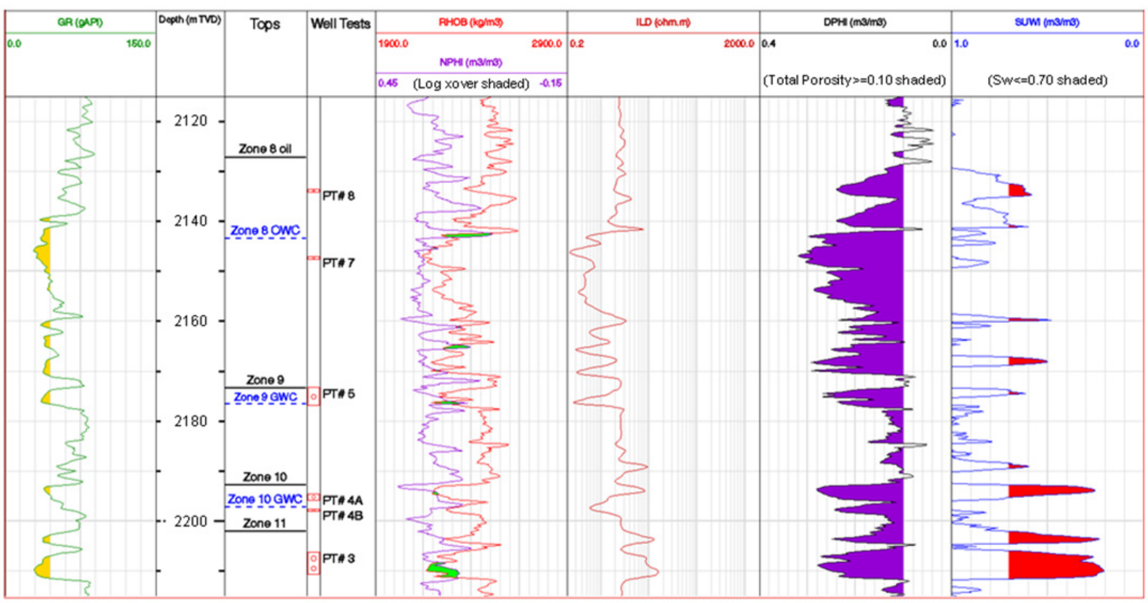

Figure 3.13.8 Sable Island E-48 petrophysical results plot: Zones 8 oil – 11.

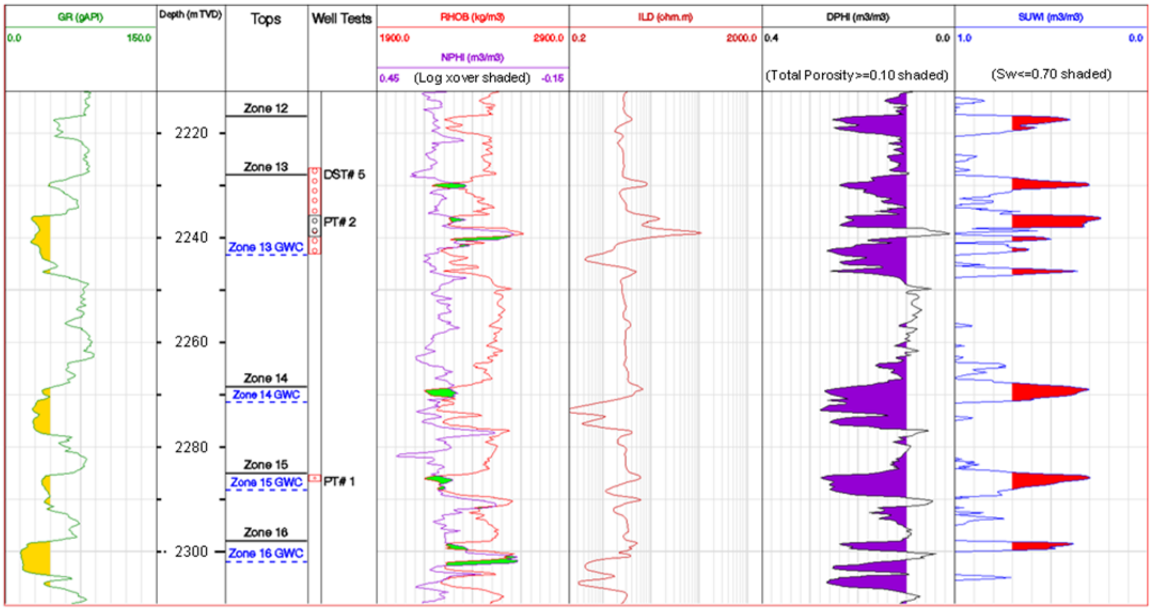

Figure 3.13.9 Sable Island E-48 petrophysical results plot: Zones 12 – 16.

3.13.5. Resource Assessment

Resource assessments were conducted on the four largest West Sable hydrocarbon zones (Zone 1, Zone 2 gas, Zone 2 oil, and Zone 3 oil). The deeper hydrocarbon zones (Zones 4–16) have very limited areas (P50 areas <1 km^2) and were combined into the following three groups:

1. Zones 4 and 5
2. Zones 5A oil and 8 oil
3. Zones 6 – 16.

Zone 1 is a GDT in all wells except Sable Island O-47 and 6H-58 which are wet. Uncertainty in the Zone 1 gas-water-contact was defined by bracketing the shallowest water up to (O-47) with the deepest gas down to (4H-58). The GWC was set half way between this 5 m difference. The interpreted Zone 1 contact was projected on to the Zone 2 depth map to define the P50 area for Zone 1. The Zone 1 gas pool may extend into the southwestern fault block but since this has not been confirmed by drilling, its area was limited to the central fault block.

Zone 2 has both an oil leg (Zone 2 oil) and an overlying gas cap (Zone 2 gas). The gas oil contact and OWCs were defined by log and DST data. These contacts were projected on to the Zone 2 depth map to define the P50 areas for Zone 2 gas and Zone 2 oil. These zones may extend into the southwestern fault block but since this has not been confirmed by drilling, the Zone 2 gas and oil pool areas were limited to the central fault block.

Only two West Sable wells have oil pay in Zone 3 oil (Sable Island E-48 & 5H-58) and all other wells are wet. The elevation of the OWC was determined by bracketing the deepest oil down to and the shallowest water up to in the wells. This contact was projected on to the Zone 2 depth map to define the P50 area. The Zone 3 oil accumulation is a relatively small (1.6–2.0 km^2) 4-way dip closure limited to the central fault block.

Zones 4 and 5 were assessed as a group. Well results indicate that the gas accumulation in these zones is limited to simple closure at the crest of the field. The deepest closing contour on the Zone 5 depth map was used to define the P50 area.

Zones 5A oil and Zone 8 oil were also assessed as a group. Sable Island E-48 is located at the crest of the structure and was the only well to encounter oil pay in these zones. The oil-water contact was defined by bracketing the oil down to in E-48 with the shallowest WUT. This contact was projected on to the Zone 5 depth map to define the P50 area which was limited to simple closure.

Zones 6–16 were assessed as a group and Sable Island E-48 is the only well with gas pay in these zones. This gas pay is also limited to simple closure at the crest of the field. The Zones 5A and Zone 8 oil P50 areas were used for Zones 6–16. For all West Sable zones, the minimum and maximum areas were determined by varying the P50 value +/-10% to allow for mapping uncertainty.

The P50 probabilistic input parameters for net pay, porosity and hydrocarbon saturation were based on the petrophysically-calculated well values. The minimum and maximum inputs for these parameters were varied symmetrically around the P50 value.

The reservoir characteristics of the West Sable sandstones are very good to excellent. Therefore, the assigned recovery factors for Zones 1–5 (gas zones) ranged from 65 to 85% and the oil zones varied from 25 to 45%. Many of the deeper gas zones (Zones 6–16) have thin gas pay over water which would negatively impact recovery. These deeper zones also have very small areas (~ 0.5 km^2) which limit the horizontal standoff to water. The assigned recovery factors were therefore reduced with a range of 50–70%.

All key input parameters used for probabilistic volume calculations are listed below for gas (Table 3.13.3) and oil (Table 3.13.4) zones.

Table 3.13.3 West Sable probabilistic volume calculation variables.

Zone 1	P100	P50	P00	Mean
Area (km^2)	4.3	4.8	5.3	4.8
Net Pay (m)	8.0	12	16	12
Porosity (fraction)	0.26	0.28	0.30	0.28
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	142	146	150	146
CGR (BBL/MMCF)	2.0	6.0	10	6.0
Gas Recovery Factor	0.65	0.75	0.85	0.75

Zone 2 gas	P100	P50	P00	Mean
Area (km^2)	4.3	4.8	5.3	4.8
Net Pay (m)	6.0	10	14	10
Porosity (fraction)	0.23	0.26	0.29	0.26
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	147	151	155	151
CGR (BBL/MMCF)	2.0	6.0	10	6.0
Gas Recovery Factor	0.65	0.75	0.85	0.75

Zones 4 & 5	P100	P50	P00	Mean
Area (km^2)	0.80	0.90	1.0	0.90
Net Pay (m)	25	35	45	35
Porosity (fraction)	0.23	0.26	0.29	0.26
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	173	185	197	185
CGR (BBL/MMCF)	30	60	90	60
Gas Recovery Factor	0.65	0.75	0.85	0.75

Zones 6 - 16	P100	P50	P00	Mean
Area (km^2)	0.45	0.50	0.55	0.50
Net Pay (m)	35	45	55	45
Porosity (fraction)	0.21	0.24	0.27	0.24
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	188	193	198	193
CGR (BBL/MMCF)	60	120	180	120
Gas Recovery Factor	0.50	0.60	0.70	0.60

Table 3.13.4 West Sable probabilistic volume calculation variables– oil zones.

Zone 2 oil	P100	P50	P00	Mean
Area (km^2)	5.9	6.5	7.2	6.5
Net Pay (m)	3.0	5.0	7.0	5.0
Porosity (fraction)	0.24	0.27	0.30	0.27
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Oil FVF	1.26	1.27	1.28	1.27
GOR (m^3/m^3)	83.2	84.4	85.6	84.4
Oil Recovery Factor	0.25	0.35	0.45	0.35

Zone 3 oil	P100	P50	P00	Mean
Area (km2)	1.6	1.8	2.0	1.8
Net Pay (m)	13	18	23	28
Porosity (fraction)	0.22	0.25	0.28	0.25
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Oil FVF	1.28	1.29	1.30	1.29
GOR (m3/m3)	86.7	91.0	95.4	91.0
Oil Recovery Factor	0.25	0.35	0.45	0.35

Zones 5A & 8	P100	P50	P00	Mean
Area (km2)	0.45	0.50	0.55	0.50
Net Pay (m)	3.0	6.0	9.0	6.0
Porosity (fraction)	0.22	0.25	0.28	0.25
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Oil FVF	1.37	1.39	1.40	1.39
GOR (m3/m3)	115	120	125	120
Oil Recovery Factor	0.25	0.35	0.45	0.35

3.13.6. Results

Probabilistic assessment results for the South Sable field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (3.13.5 and 3.13.6). Descending cumulative probability charts show field totals for OGIP (Fig. 3.13.10), OOIP (Fig. 3.13.11), recoverable gas (Fig. 3.13.12), recoverable oil (Fig. 3.13.13), and recoverable liquids (Fig. 3.13.14).

Table 3.13.5 West Sable probabilistic OGIP and original oil in place (OOIP).

Sum of all zones	P90	P50	P10	Mean
OGIP (E9m^3)	3.20	3.62	4.08	3.62
OGIP (Bcf)	113	128	144	128
OOIP (E6m^3)	5.79	6.82	8.06	6.90
OOIP (MMB)	36.4	42.9	50.7	43.4
Zone 1	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.915	1.17	1.46	1.18
OGIP (Bcf)	32.3	41.2	51.5	41.6
Zone 2 - gas	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.767	1.03	1.33	1.04
OGIP (Bcf)	27.1	36.3	46.9	36.7
Zones 4 & 5	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.657	0.827	1.03	0.835
OGIP (Bcf)	23.2	29.2	36.2	29.5
Zones 6 - 16	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m^3)	0.464	0.569	0.697	0.575
OGIP (Bcf)	16.4	20.1	24.6	20.3
Zone 2 - oil	**P90**	**P50**	**P10**	**Mean**
OOIP (E6m^3)	2.58	3.43	4.44	3.48
OOIP (MMB)	16.2	21.6	27.9	21.9
Zone 3	**P90**	**P50**	**P10**	**Mean**
OOIP (E6m^3)	2.46	3.12	3.86	3.15
OOIP (MMB)	15.5	19.6	24.3	19.8
Zones 5a & 8	**P90**	**P50**	**P10**	**Mean**
OOIP (E6m^3)	0.189	0.267	0.359	0.272
OOIP (MMB)	1.19	1.68	2.26	1.71

Table 3.13.6 West Sable probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	2.31	2.62	2.97	2.64
Rec. Gas (Bcf)	81.4	92.5	105	93.1
Rec. Condensate (E6m^3)	0.397	0.493	0.612	0.499
Rec. Condensate (MMB)	2.50	3.10	3.85	3.14
Rec. Oil (E6m^3)	0.979	2.38	2.91	2.42
Rec. Oil (MMB)	6.16	15.0	18.3	15.2
Rec. Solution Gas (E9m^3)	0.174	0.212	0.257	0.214
Rec. Solution Gas (Bcf)	6.16	7.47	9.08	7.56
Zone 1	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.680	0.872	1.11	0.884
Rec. Gas (Bcf)	24.0	30.8	39.1	31.2
Rec. Condensate (E6m^3)	0.0176	0.0302	0.0431	0.0297
Rec. Condensate (MMB)	0.111	0.190	0.271	0.187
Zone 2 gas	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.572	0.767	1.01	0.779
Rec. Gas (Bcf)	20.2	27.1	35.5	27.5
Rec. Condensate (E6m^3)	0.0150	0.0253	0.0386	0.0262
Rec. Condensate (MMB)	0.0944	0.159	0.243	0.165
Zones 4 and 5	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.487	0.620	0.776	0.629
Rec. Gas (Bcf)	17.2	21.9	27.4	22.2
Rec. Condensate (E6m^3)	0.140	0.207	0.289	0.211
Rec. Condensate (MMB)	0.881	1.30	1.82	1.33
Zones 6–16	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.273	0.343	0.422	0.345
Rec. Gas (Bcf)	9.63	12.1	14.9	12.2
Rec. Condensate (E6m^3)	0.156	0.227	0.315	0.232
Rec. Condensate (MMB)	0.982	1.43	1.98	1.46
Zone 2 oil	**P90**	**P50**	**P10**	**Mean**
Rec. Oil (E6m^3)	0.862	1.19	1.61	1.22
Rec. Oil (MMB)	5.42	7.51	10.1	7.66
Rec. Solution Gas (E9m^3)	0.0725	0.101	0.135	0.103
Rec. Solution Gas (Bcf)	2.56	3.55	4.77	3.63
Zone 3	**P90**	**P50**	**P10**	**Mean**
Rec. Oil (E6m^3)	0.819	1.08	1.41	1.10
Rec. Oil (MMB)	5.15	6.81	8.84	6.92
Rec. Solution Gas (E9m^3)	0.0745	0.0985	0.128	0.100
Rec. Solution Gas (Bcf)	2.63	3.48	4.51	3.53
Zones 5A and 8	**P90**	**P50**	**P10**	**Mean**
Rec. Oil (E6m^3)	0.0634	0.0927	0.130	0.0949
Rec. Oil (MMB)	0.399	0.583	0.816	0.597
Rec. Solution Gas (E9m^3)	0.00762	0.0111	0.0156	0.0114
Rec. Solution Gas (Bcf)	0.269	0.393	0.551	0.403

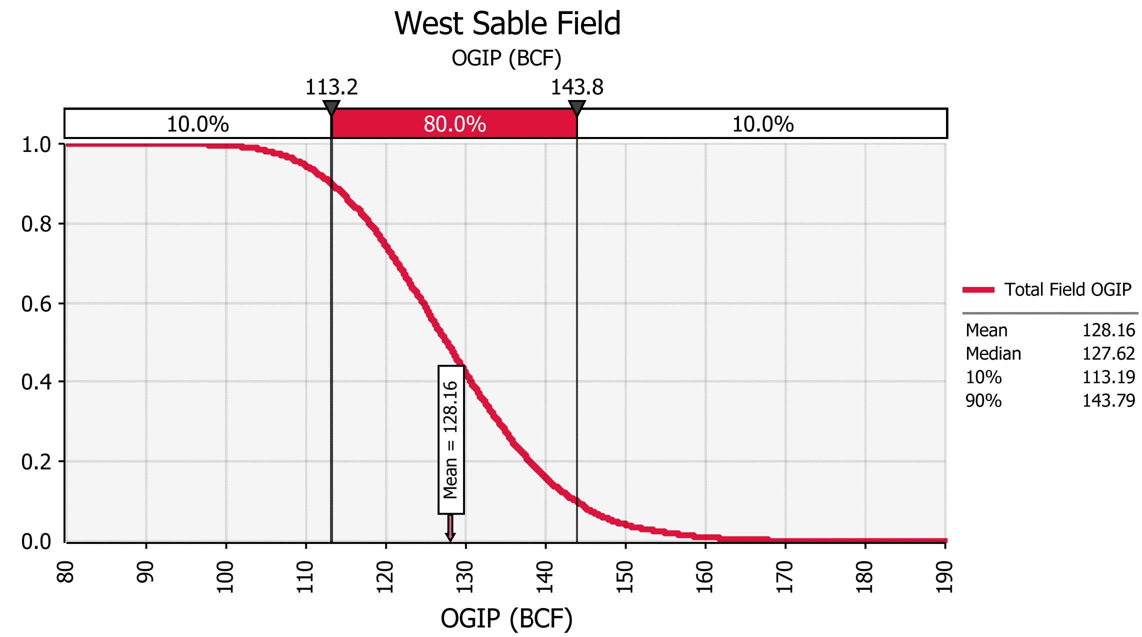

Figure 3.13.10 West Sable OGIP descending cumulative probability chart.

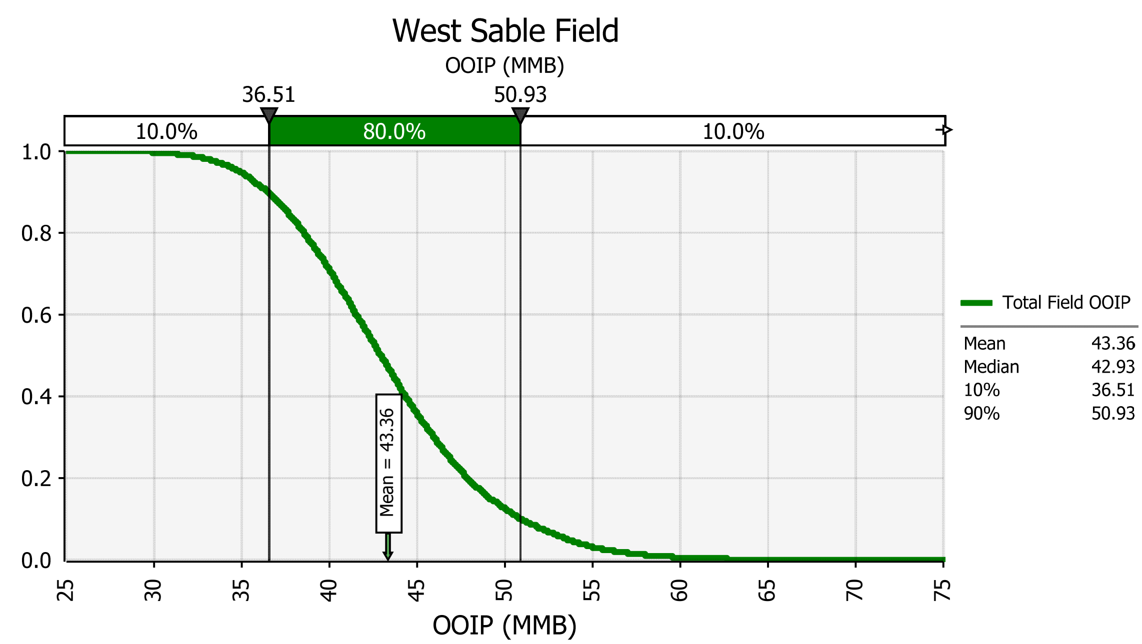

Figure 3.13.11 West Sable OOIP descending cumulative probability chart.

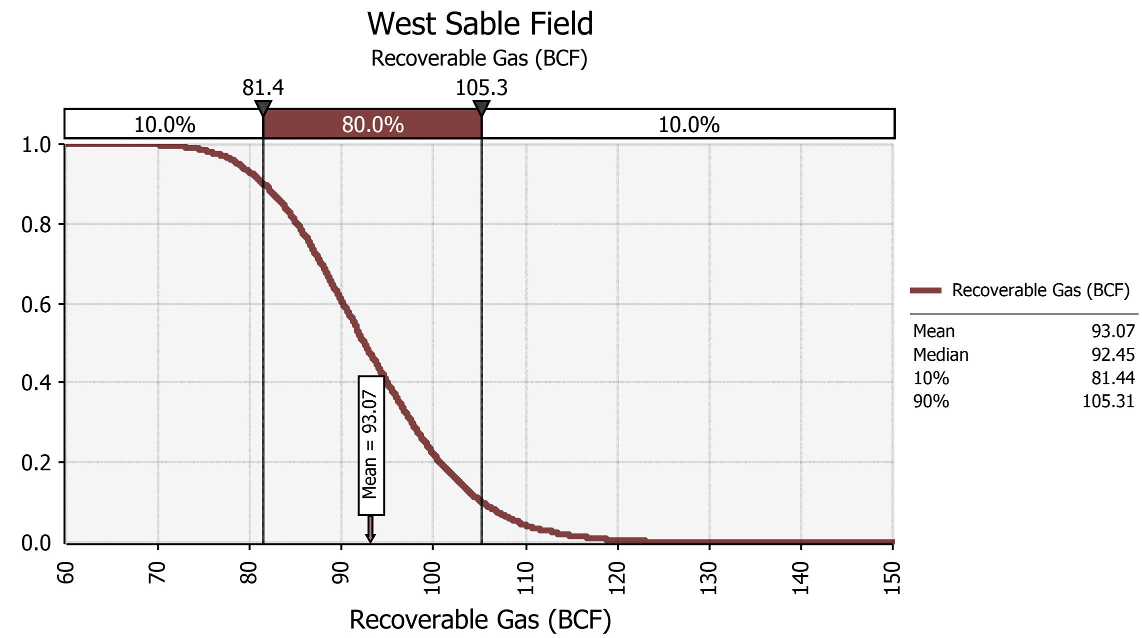

Figure 3.13.12 West Sable recoverable gas descending cumulative probability chart.

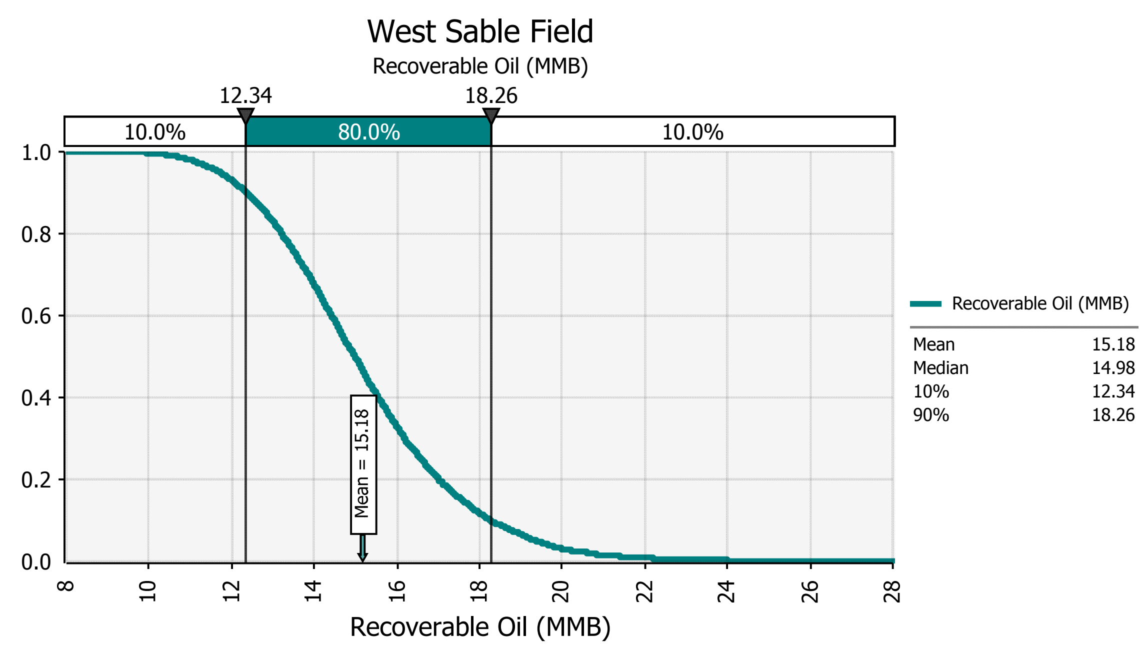

Figure 3.13.13 West Sable recoverable oil descending cumulative probability chart.

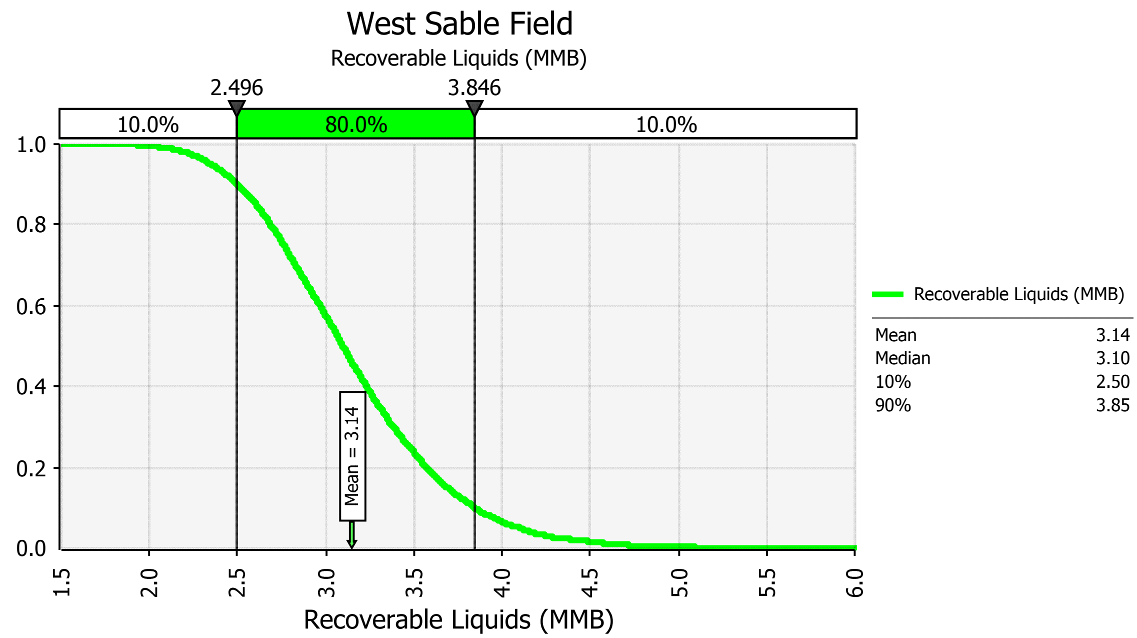

Figure 3.13.14 West Sable recoverable condensate liquids descending cumulative probability chart.

3.14 West Venture C-62 - Significant Discovery

3.14.1. Overview

The West Venture C-62 gas field is located 2.5 km east of Sable Island (Fig. 1.1). The field was discovered in 1985 and this assessment is based on the discovery well.

Discovery Well

Well:	West Venture C-62
Company:	Mobil et al.
Spud:	19-May-84
Well Termination:	23-Mar-85
Total Depth:	5522 m
Water Depth:	16 m
Latitude:	44°01’02.78”N
Longitude:	59°40’00.93”W
Target:	Drilled to test for the presence of trapped hydrocarbons in sands just west of the Venture field. The structure is bounded on the north by an extension of the same down-to-basin fault that bounds the northern limits of Venture.

Additional Wells

No delineation drilling was conducted.

3.14.2. Structure

The West Venture C-62 structure is a rollover anticline associated with a series of down-to-basin growth faults as shown on the seismic line (Fig. 3.14.1). The highly deviated well (dashed blue line) encountered numerous gas sands on the flank of the structure. The 4 Sand horizon (red) is used to represent the structural configuration for Sands C, 4A, 4B, 7Lr and 8.

As shown on the 4 Sand depth map (Fig. 3.14.2), there is limited simple anticlinal closure before encountering faults along the eastern and southern extents of the structure. The P50 area contour (purple) is based on GWCs and requires that the faults seal along this perimeter and the structure spills to the north.

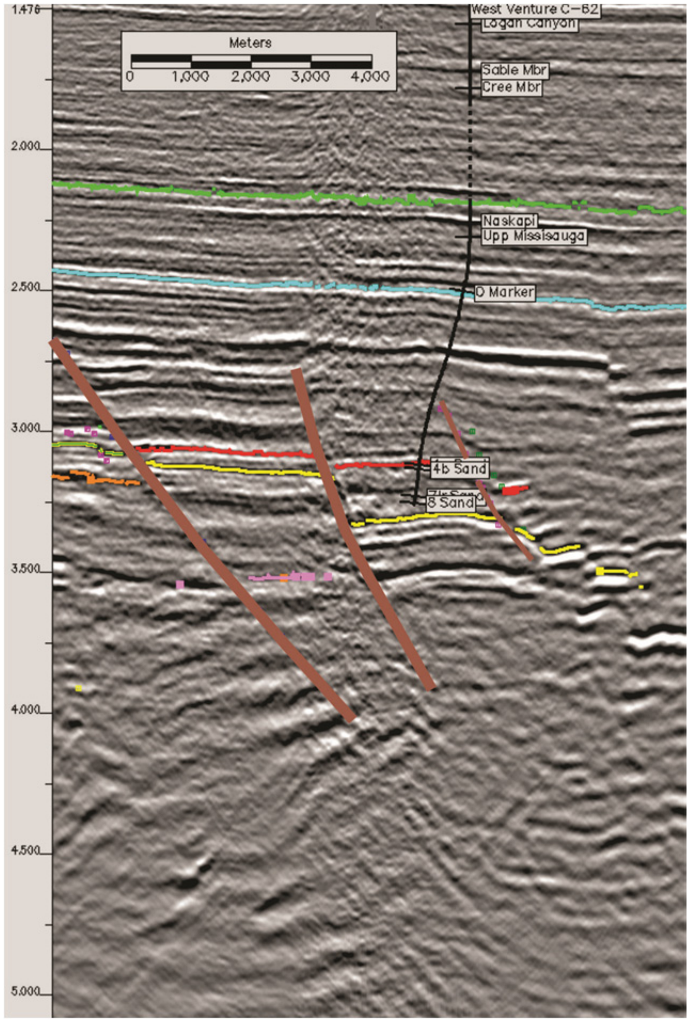

Figure 3.14.1 West Venture C-62 seismic time line.

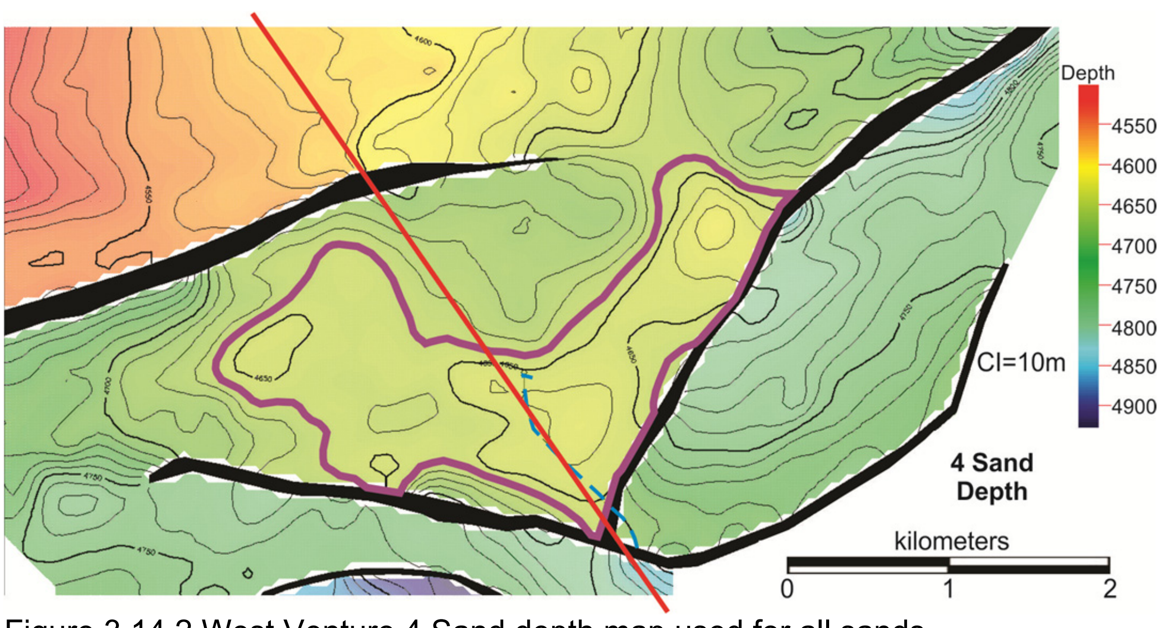

Figure 3.14.2 West Venture 4 Sand depth map used for all sands.

3.14.3. Reservoir Description

The West Venture C-62 reservoir sands are lateral equivalents to those recognized at the larger Venture gas field to the east, and the West Venture (N-91), Olympia and West Olympia fields to the west. The reservoir interval is located in the Kimmeridgian-Tithonian Lower Missisauga Formation. However, unlike Venture, only a few of the sands have gas pay.

All West Venture C-62 reservoir sands are in stepped overpressure conditions. The correlation of the reservoir sands with those at Venture to the east demonstrates that there is excellent lateral continuity along strike, though here they tend to thin and have poorer reservoir characteristics toward the field's southern margin.

The West Venture C-62 reservoirs consist of cyclic deltaic and strandplain sands capped with marine and prodelta shales which provide effective top seals within the succession. They tend to be fine to medium grained, moderately to well sorted, siliceous, dolomitic and variably argillaceous. Log profiles and cores of the deeper Mic Mac strata reflect delta front and channel depositional conditions.

3.14.4. Formation Evaluation

Two of the five West Venture C-62 gas zones were tested with flow rates ranging from 0.6 to 33.5 MMscf/d (Table 3.14.1). The West Venture C-62 zones have good to very good reservoir quality with net pay porosities varying from 0.16–0.23, and DST results indicating that permeability is fair to excellent. All sands have log- and/or DST-defined GWCs. The GWC in 8 Sand is somewhat interpretive and given the saturation profile at the base of the zone, the contact could be up to 10 m deeper. This deeper contact would not significantly increase net pay in the 8 Sand due to poor reservoir quality. West Venture C-62 petrophysical assessment results are shown below (Table 3.14.2) (Figs. 3.14.3–3.14.5).

Table 3.14.1 West Venture C-62 significant tests.

Test #	Depth (m)	CNSOPB Zone	Formation	Gas (E3M3/D)	Oil/Cond (M3/D)	Water (M3/D)	Gas (MMSCF/D)	Oil/Cond (BPD)	Water (BPD)
DST 1	5016-5027	wet	Missisauga	0.6		76	0.02		478
DST 2	4923-4930	4a Sand	Missisauga	16		105	0.6		660
DST 3	4741-4743	C Sand	Missisauga	949	25	6	33.5	157	38
DST 4	4591-4601	tight	Missisauga	Rec Water Cushion			Rec Water Cushion		

Table 3.14.2 West Venture C-62 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
C Sand	4731.8	4751.5	18.1	2.6	0.231	0.43
4a Sand	4916.3	4944.9	27.2	1.6	0.196	0.56
4b Sand	4952.8	4974.8	21.0	1.6	0.159	0.48
7Lr Sand	5156.9	5212.3	53.0	4.1	0.206	0.51
8 Sand	5215.6	5227.8	11.8	3.7	0.196	0.36
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60						

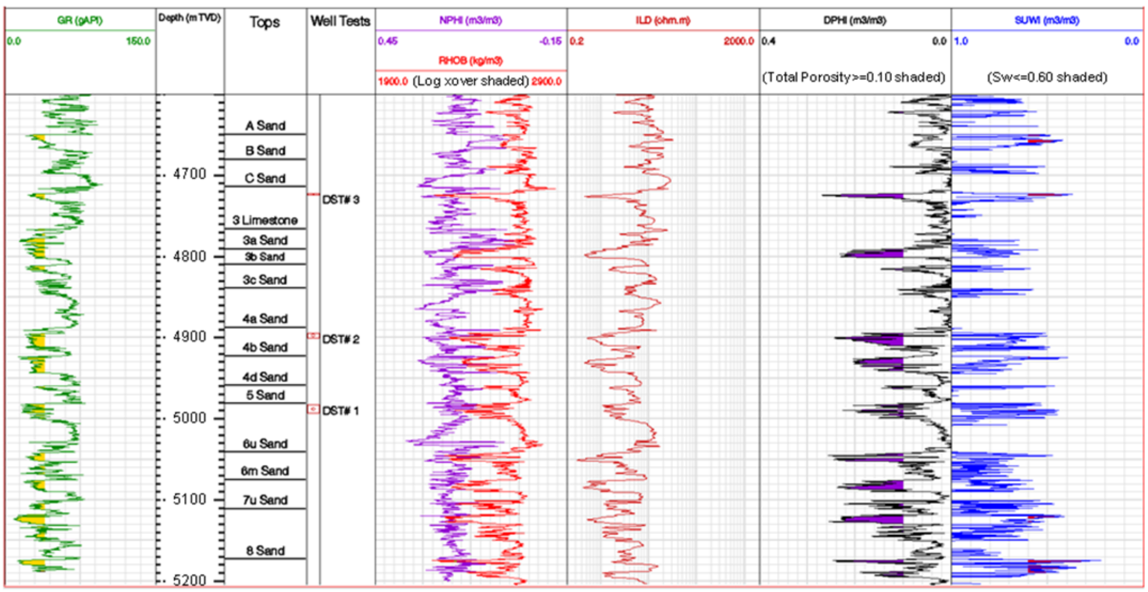

Figure 3.14.3 West Venture C-62 petrophysical results plot: all zones.

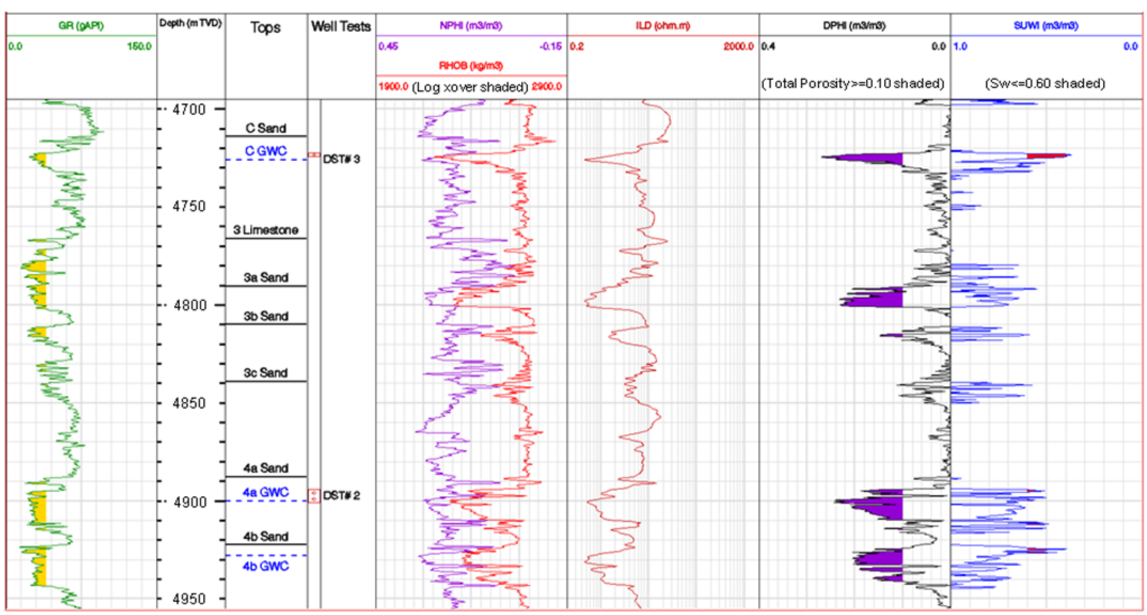

Figure 3.14.4 West Venture C-62 petrophysical results plot: C–4b Sands.

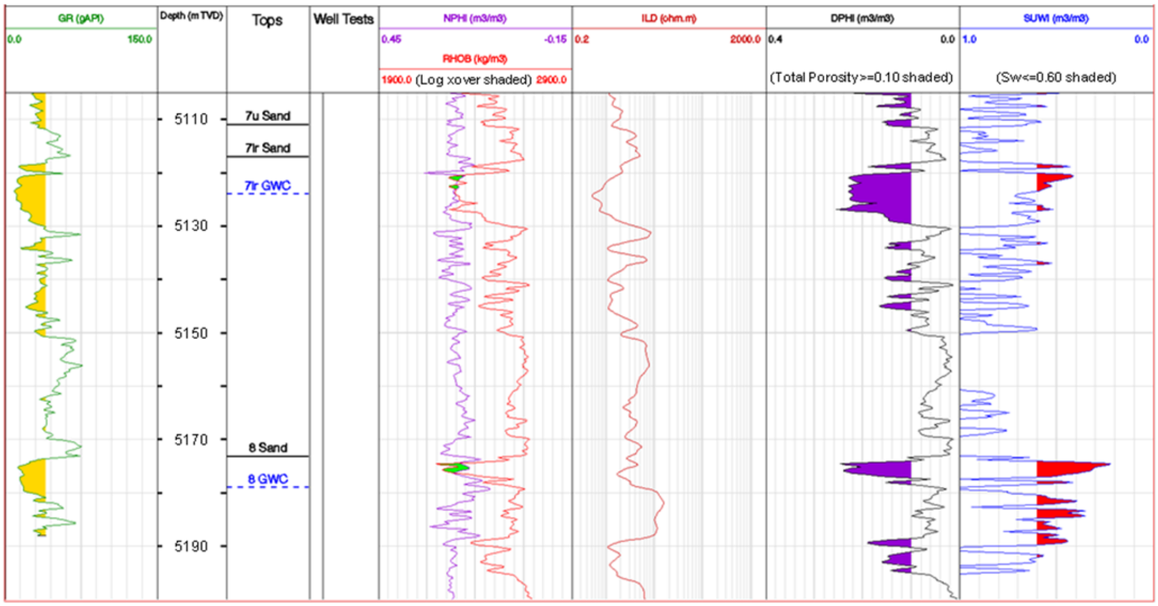

Figure 3.14.5 West Venture C-62 petrophysical results plot: 7Lr–8 Sands.

3.14.5. Resource Assessment

All West Venture C-62 gas zones have log- and/or DST-defined GWCs. The interpreted GWC was projected on to the 4 Sand depth map to define the P50 area for all zones. The minimum and maximum areas were assigned by varying the P50 value +/- 10% to allow for mapping uncertainty.

The P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the calculated well values. The West Venture C-62 zones all have thin gas pay over water which will negatively impact gas recovery. The C- and 4a Sands have thicker gas columns than the deeper Sands (4b–8). As a result, a P50 recovery factor of 60% was assigned to the C- and 4a Sands, while 55% was used for the 4b–8 Sands. The minimum and maximum inputs were varied symmetrically around the P50 value.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.14.3).

Table 3.14.3 West Venture C-62 probabilistic volume calculation variables.

C Sand	P100	P50	P00	Mean
Area (km^2)	3.0	3.3	3.6	3.3
Net Pay (m)	2.0	3.0	4.0	3.0
Porosity (fraction)	0.21	0.23	0.25	0.23
Sh (1-Sw) (fraction)	0.45	0.55	0.65	0.55
Gas FVF	350	360	370	360
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor	0.50	0.60	0.70	0.60

4a Sand	P100	P50	P00	Mean
Area (km^2)	3.0	3.3	3.6	3.3
Net Pay (m)	1.0	2.0	5.0	2.67
Porosity (fraction)	0.17	0.20	0.23	0.20
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	360	370	380	370
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor	0.50	0.60	0.70	0.60

4b Sand	P100	P50	P00	Mean
Area (km^2)	1.6	1.8	2.0	1.8
Net Pay (m)	1.0	2.0	5.0	2.67
Porosity (fraction)	0.17	0.20	0.23	0.20
Sh (1-Sw) (fraction)	0.35	0.45	0.55	0.45
Gas FVF	362	372	382	372
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor	0.45	0.55	0.65	0.55

7Lr Sand	P100	P50	P00	Mean
Area (km^2)	1.6	1.8	2.0	1.8
Net Pay (m)	2.0	4.0	6.0	4.0
Porosity (fraction)	0.18	0.21	0.24	0.21
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	370	380	390	380
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor	0.45	0.55	0.65	0.55

8 Sand	P100	P50	P00	Mean
Area (km^2)	1.6	1.8	2.0	1.8
Net Pay (m)	2.0	4.0	6.0	4.0
Porosity (fraction)	0.17	0.20	0.23	0.20
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	375	385	395	385
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor	0.45	0.55	0.65	0.55

3.14.6. Results

Probabilistic assessment results for the West Venture C-62 field are reported in table and chart form The tables include individual zone and field totals for in-place and recoverable hydrocarbons (3.14.4 and 3.14.5 Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.14.6 and 3.14.7).

Table 3.14.4 West Venture C-62 probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP ($E9m^3$)	1.31	1.52	1.76	1.53
OGIP (Bcf)	46.3	53.6	62.2	54.0
C Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.351	0.447	0.558	0.450
OGIP (Bcf)	12.4	15.8	19.7	15.9
4a Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.173	0.278	0.439	0.295
OGIP (Bcf)	6.10	9.82	15.5	10.4
4b Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.0937	0.152	0.242	0.161
OGIP (Bcf)	3.31	5.38	8.56	5.70
7Lr Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.198	0.283	0.385	0.289
OGIP (Bcf)	6.99	10.0	13.6	10.2
8 Sand	**P90**	**P50**	**P10**	**Mean**
OGIP (E9m3)	0.229	0.328	0.445	0.334
OGIP (Bcf)	8.09	11.6	15.7	11.8

Table 3.14.5 West Venture C-62 probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas ($E9m^3$)	0.748	0.872	1.02	0.878
Rec. Gas (Bcf)	26.4	30.8	36.0	31.0
Rec. Condensate ($E6m^3$)	0.0196	0.0243	0.0302	0.0246
Rec. Condensate (MMB)	0.123	0.153	0.190	0.155
C Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.206	0.268	0.340	0.271
Rec. Gas (Bcf)	7.29	9.45	12.0	9.57
Rec. Condensate ($E6m^3$)	0.00467	0.00739	0.0108	0.00762
Rec. Condensate (MMB)	0.0294	0.0465	0.0677	0.0479
4a Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.103	0.167	0.264	0.176
Rec. Gas (Bcf)	3.62	5.88	9.34	6.23
Rec. Condensate ($E6m^3$)	0.00251	0.00453	0.00798	0.00494
Rec. Condensate (MMB)	0.0158	0.0285	0.0502	0.0311
4b Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.0513	0.0838	0.134	0.0886
Rec. Gas (Bcf)	1.81	2.96	4.73	3.13
Rec. Condensate ($E6m^3$)	0.00123	0.00231	0.00402	0.00250
Rec. Condensate (MMB)	0.00774	0.0145	0.0253	0.0157
7Lr Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas ($E9m^3$)	0.107	0.155	0.213	0.159
Rec. Gas (Bcf)	3.79	5.49	7.53	5.60
Rec. Condensate ($E6m^3$)	0.00251	0.00424	0.00663	0.00445
Rec. Condensate (MMB)	0.0158	0.0267	0.0417	0.0280

8 Sand	P90	P50	P10	Mean
Rec. Gas (E9m^3)	0.125	0.180	0.247	0.183
Rec. Gas (Bcf)	4.40	6.37	8.71	6.48
Rec. Condensate (E6m^3)	0.00291	0.00494	0.00766	0.00515
Rec. Condensate (MMB)	0.0183	0.0311	0.0482	0.0324

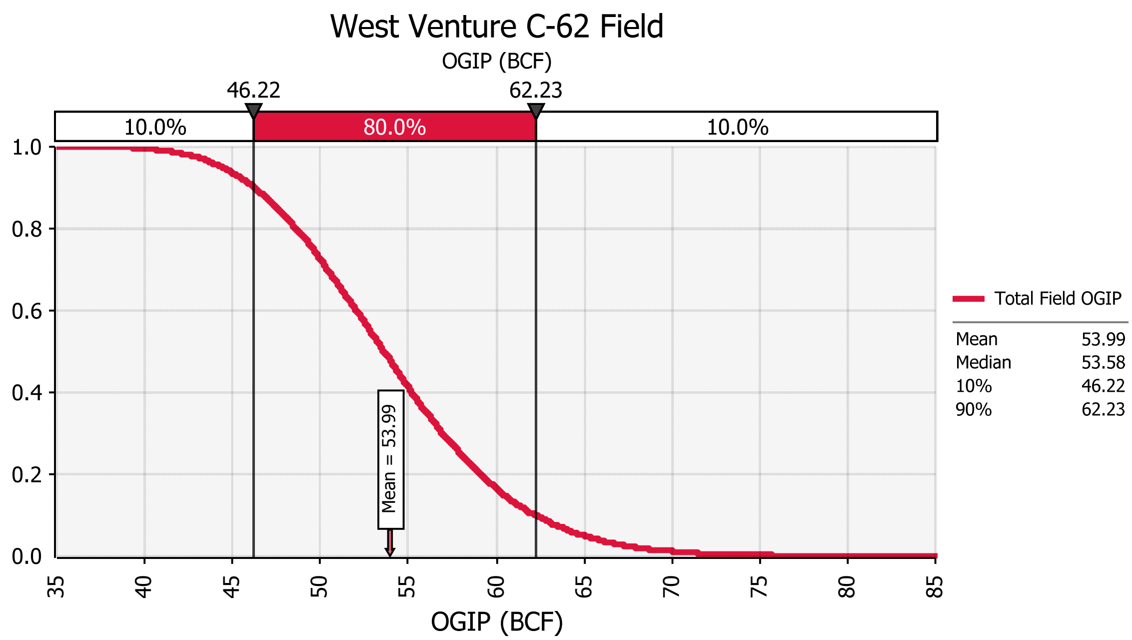

Figure 3.14.6 West Venture C-62 OGIP descending cumulative probability chart.

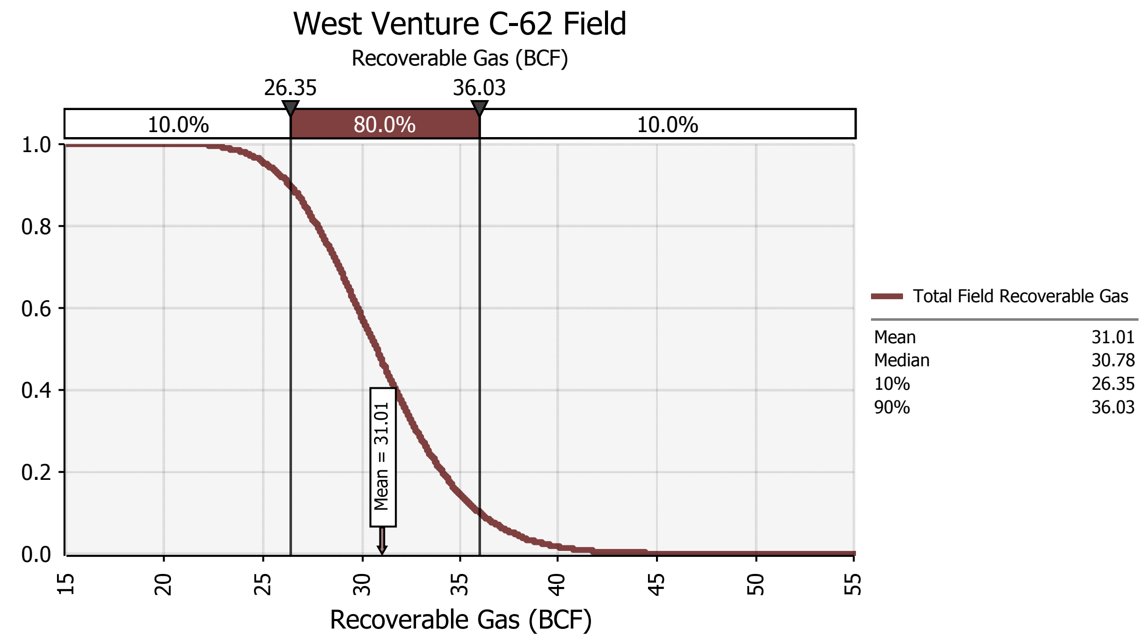

Figure 3.14.7 West Venture C-62 recoverable gas descending cumulative probability chart.

3.15 West Venture N-91 - Significant Discovery

3.15.1. Overview

The West Venture N-91 gas field is located 2.5 km due west of the eastern end of Sable Island (Fig. 1.1). The exploration well experienced an underground blowout while drilling and the B-92 service relief well has to be abandoned due to escaping gas at N-91 migrating toward the B-92 location via shallow Tertiary age sands. The second relief well (N-01) was also abandoned due to the successful completion of a "top kill" on the N-91 well. The field was discovered in 1985 and this assessment is based on the discovery well.

Discovery Well

Well:	West Venture N-91
Company:	Mobil et al.
Spud:	19-Apr-84
Well Termination:	07-Jul-85
Total Depth:	5547 m
Water Depth:	38 m
Latitude:	44°00'45.82"N
Longitude:	59°44'27.36"W
Target:	Drilled to test for hydrocarbons in Late Jurassic to Early Cretaceous sands incorporated in a large rollover anticline associated with a down-to-basin fault.

Additional Wells

No delineation drilling was conducted. Two relief wells, listed below, were abandoned prior to intersecting their targets.

- Mobil et al. West Venture B-92
- Mobil et al. West Venture N-01

3.15.2. Structure

The West Venture N-91 structure is associated with rollover on the down thrown side of a rotated growth fault as shown on the seismic line (Fig. 3.15.1). Two gas zones were encountered in the well. The depth map (Fig. 3.15.2) from the 6 Sand Upper horizon (red) is used for the 4b Sand volumetrics. The 13 Sand depth map (Fig. 3.15.2) was created from the orange seismic horizon. The Mic Mac horizon is shown in yellow.

The P50 area closing contour (purple) is shown on both maps and an upside closure on the 13 Sand depth map (Fig. 3.15.3) is highlighted in blue. The P50

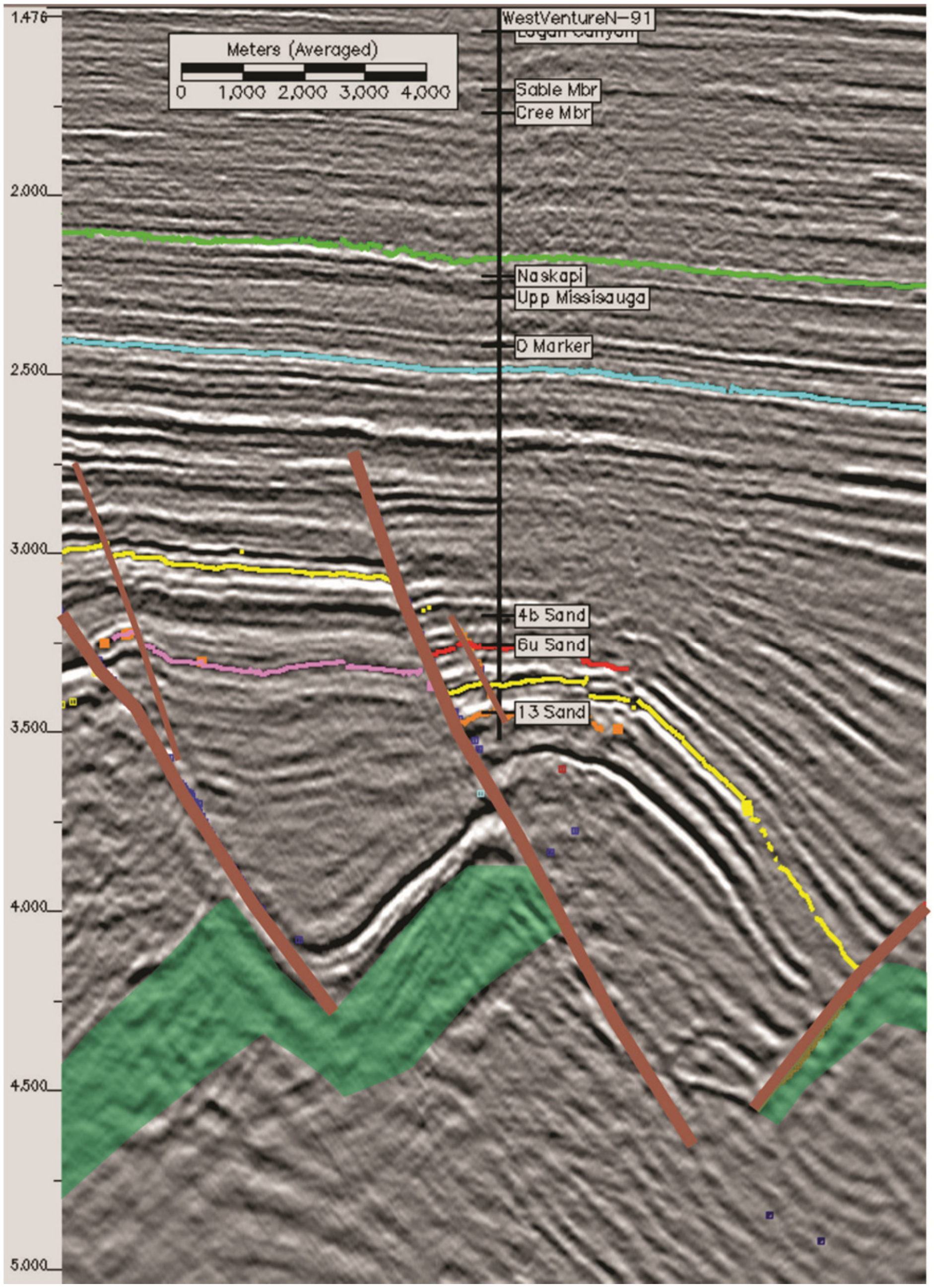

Figure 3.15.1 West Venture N-91 seismic time line.

area closures both require fault seal that has been shown to exist based on results of the petrophysical analysis and structure mapping. On the 6u Sand map, the structure spills to the east while the 13 Sand depth map has an inferred leak point at a fault.

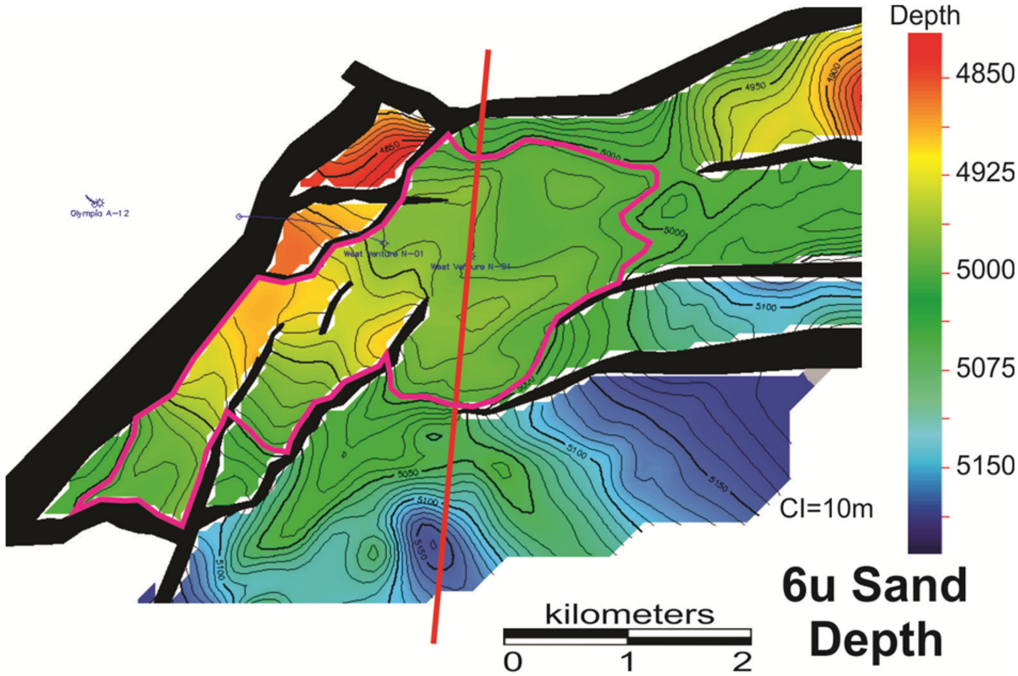

Figure 3.15.2 West Venture N-91 6 Upper Sand depth map used for 4b Sand.

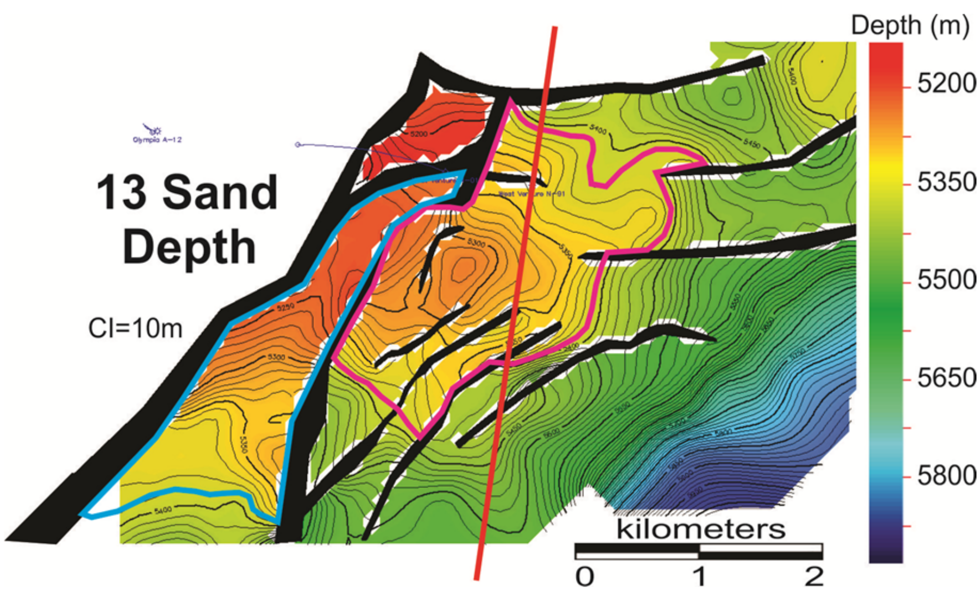

Figure 3.15.3 West Venture N-91 13 Sand depth map.

3.15.3. Reservoir Description

The West Venture N-91 reservoir sands are lateral equivalents to those recognized in the larger Venture gas field to the east and intervening West Venture C-62 field. These sands are located stratigraphically at the top of the

Late Jurassic Mic Mac Formation, and the Lower member of the Early Cretaceous to Late Jurassic Missisauga Formation.

All West Venture reservoir sands are in stepped overpressure conditions. Correlation of these reservoir sands with those at Venture and West Venture C-62 to the east, , and Olympia and West Olympia to the west, confirms their excellent lateral continuity along strike, though like the other fields tend to thin and have poorer reservoir characteristics toward the field's southern margin.

Reservoirs discovered at West Venture N-91 consist of cyclic deltaic and strandplain sands capped with marine and prodelta shales which provide effective top seals. They tend to be fine to medium grained, moderately to well sorted, siliceous, dolomitic and variably argillaceous. Log profiles and cores of the deeper Mic Mac strata reflect delta front and channel depositional conditions.

The overlying Missisauga section generally reflects continuing progradation of fluvial sand bodies though showing increasing influences of current and tidal energies. The resultant strandplain nearshore and tidal facies dominate these reservoirs and the sands are fine to medium grained, well sorted and have fair to good reservoir characteristics.

3.15.4. Formation Evaluation

The West Venture N-91 exploration well experienced an underground blowout from the 13 Sand and as a result no DSTs were conducted. It is roughly estimated that during the blowout a total of 10 Bcf of gas, from the 13 Sand, and 4.2 MMBbls of water, from the 3–8 Sands, migrated up the hole into highly porous and unconsolidated Tertiary sands.

The 4b and 13 Sands are the only two significant gas bearing zones encountered in the N-91 well. These sands have good reservoir quality with net pay porosities varying from 0.15 to 0.20. The 4b Sand is a gas-down-to while the 13 Sand has a log-defined GWC. The wells petrophysical assessment results are shown below (Table 3.15.1; Figs. 3.15.4–3.15.6).

Table 3.15.1 West Venture N-91 petrophysical summary.

Zone	Top (m MD)	Base (m MD)	GR. Thk (m TVD)	Net Pay (m TVD)	Net Pay Porosity	Average Sw
4b Sand	4821.3	4831.5	10.2	4.3	0.195	0.52
13 Sand	5384.0	5444.0	60.0	25.0	0.153	0.39
Cutoffs: PHI >= 0.10, Vsh <= 0.40, Sw <= 0.60						

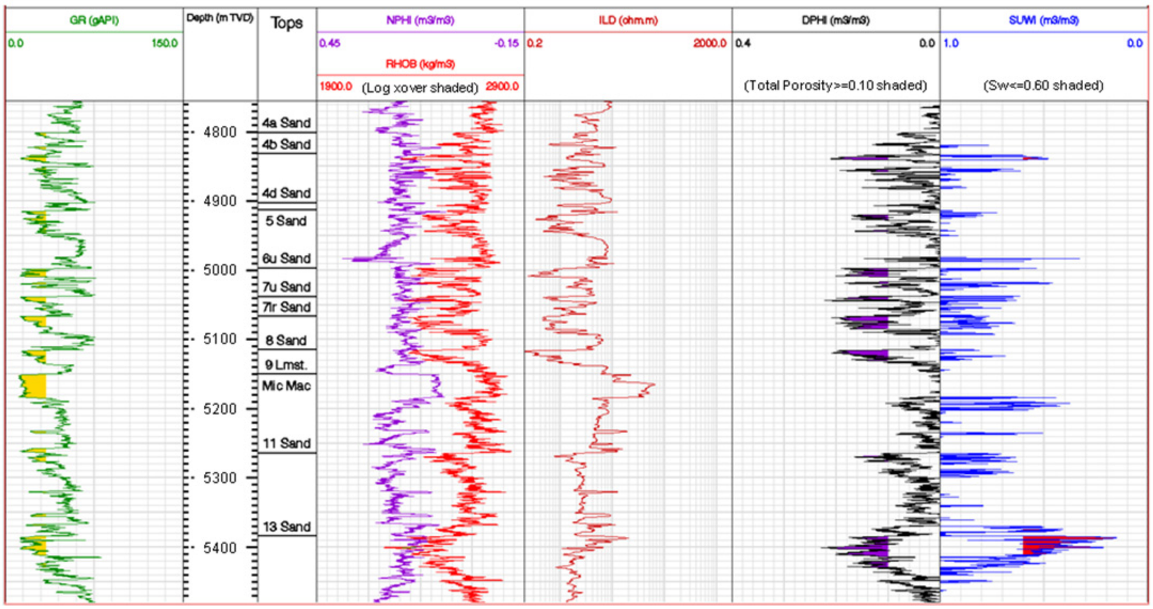

Figure 3.15.4 West Venture N-91 petrophysical results plot: all zones.

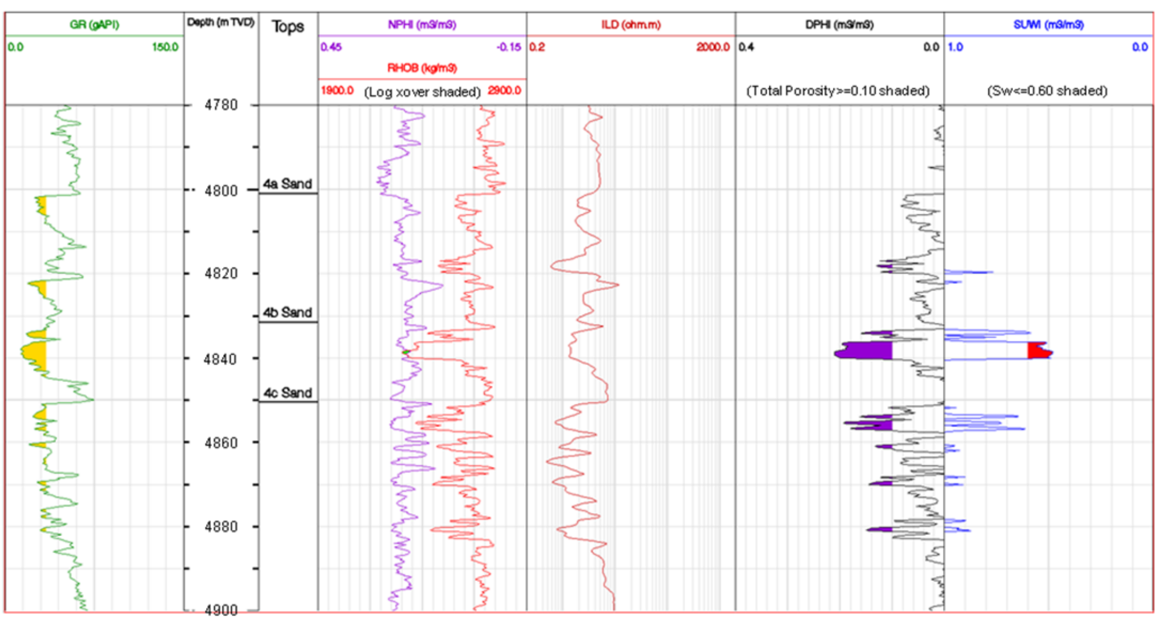

Figure 3.15.5 West Venture N-91 petrophysical results plot: 4b Sand.

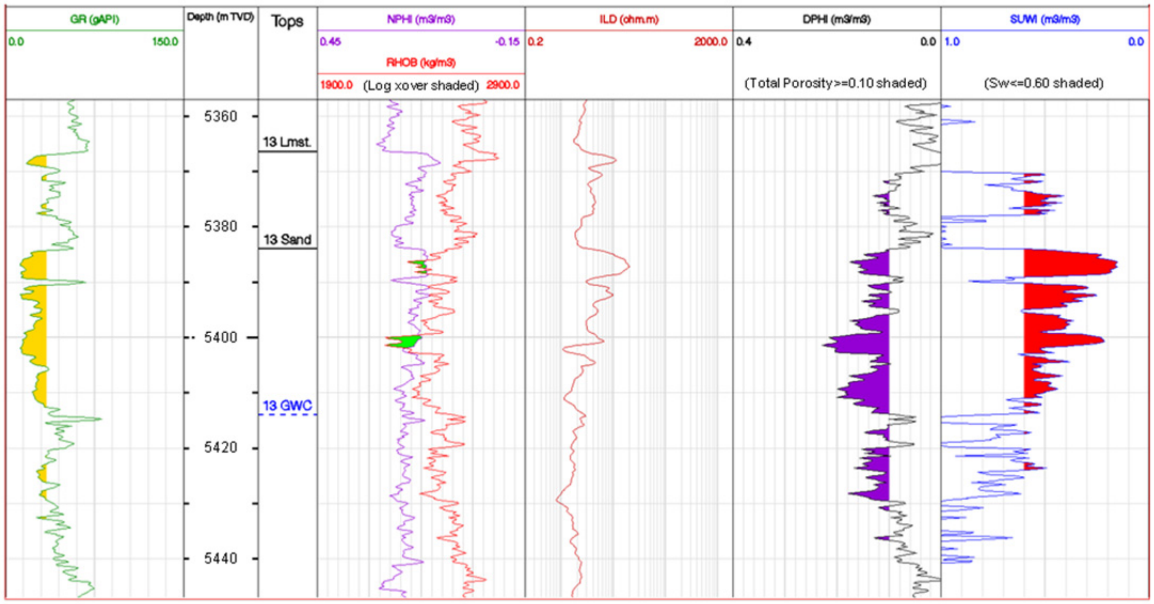

Figure 3.15.6 West Venture N-91 petrophysical results plot: 13 Sand.

3.15.5. Resource Assessment

The 4b Sand is a GDT on logs. The gas column height at the well was projected on to the 6u Sand depth map. This resulted in a closure area that was consistent with the mapped spill point, and therefore used to define the P50 area for the 4b Sand. The 13 Sand has a log-defined GWC which was projected on to the 13 Sand depth map to define the P50 area. For all zones the minimum and maximum areas were assigned by varying the P50 value +/- 10% to allow for mapping uncertainty.

P50 probabilistic inputs for net pay, porosity and hydrocarbon saturation were based on the calculated well values. Minimum and maximum inputs for these parameters were varied symmetrically around the P50. The 4b Sand has good reservoir quality but the sand is thin. The assigned recovery factors were therefore varied from 50 to 70%. The 13 Sand has a thick gas column and considerable net pay, however the sand was partially depleted during the blowout reducing its pressure, as a result the assigned recovery factors ranged from 50 to 70%. The total recoverable gas for the 13 Sand had 10 Bcf subtracted from the probabilistic total due to loss during the blowout.

All key input parameters used for probabilistic volume calculations are listed below (Table 3.15.2).

Table 3.15.2 West Venture N-91 probabilistic volume calculation variables.

4b=Sand	P100	P50	P00	Mean
Area (km^2)	5.2	5.8	6.4	5.8
Net Pay (m)	2.0	4.0	6.0	4.0
Porosity (fraction)	0.17	0.20	0.23	0.20
Sh (1-Sw) (fraction)	0.40	0.50	0.60	0.50
Gas FVF	362	372	382	372
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor	0.50	0.60	0.70	0.60

13=Sand	P100	P50	P00	Mean
Area (km^2)	3.1	3.4	5.5	4.0
Net Pay (m)	15	20	25	20
Porosity (fraction)	0.12	0.15	0.18	0.15
Sh (1-Sw) (fraction)	0.50	0.60	0.70	0.60
Gas FVF	390	400	410	400
CGR (BBL/MMCF)	2.0	5.0	8.0	5.0
Gas Recovery Factor* (* -10 Bcf applied to result)	0.50	0.60	0.70	0.60

3.15.6. Results

Probabilistic assessment results for the West Venture N-91 field are reported in table and chart form. The tables include individual zone and field totals for in-place and recoverable hydrocarbons (Tables 3.15.3 and 3.15.4). Descending cumulative probability charts also display in-place and recoverable gas (Figs. 3.15.7 and 3.15.8).

Table 3.15.3 West Venture N-91 probabilistic OGIP.

Sum of all zones	P90	P50	P10	Mean
OGIP ($E9m^3$)	2.97	3.68	4.64	3.77
OGIP (Bcf)	105	130	164	133
4b Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	0.595	0.855	1.15	0.867
OGIP (Bcf)	21.0	30.2	40.7	30.6
13 Sand	**P90**	**P50**	**P10**	**Mean**
OGIP ($E9m^3$)	2.13	2.82	3.74	2.89
OGIP (Bcf)	75.2	99.6	132	102

Table 3.15.4 West Venture N-91 probabilistic recoverable resources.

Sum of all zones	P90	P50	P10	Mean
Rec. Gas (E9m^3)	1.47	1.93	2.52	1.97
Rec. Gas (Bcf)	52.0	68.0	89.0	69.6
Rec. Condensate (E6m^3)	0.0437	0.0607	0.0857	0.0633
Rec. Condensate (MMB)	0.275	0.382	0.539	0.398
4b Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.351	0.510	0.697	0.518
Rec. Gas (Bcf)	12.4	18.0	24.6	18.3
Rec. Condensate (E6m^3)	0.00836	0.0140	0.0218	0.0146
Rec. Condensate (MMB)	0.0526	0.0881	0.137	0.0918
13 Sand	**P90**	**P50**	**P10**	**Mean**
Rec. Gas (E9m^3)	0.980	1.40	1.98	1.45
Rec. Gas (Bcf)	34.6	49.5	70.0	51.2
Rec. Condensate (E6m^3)	0.0291	0.0467	0.0706	0.0487
Rec. Condensate (MMB)	0.183	0.294	0.444	0.306

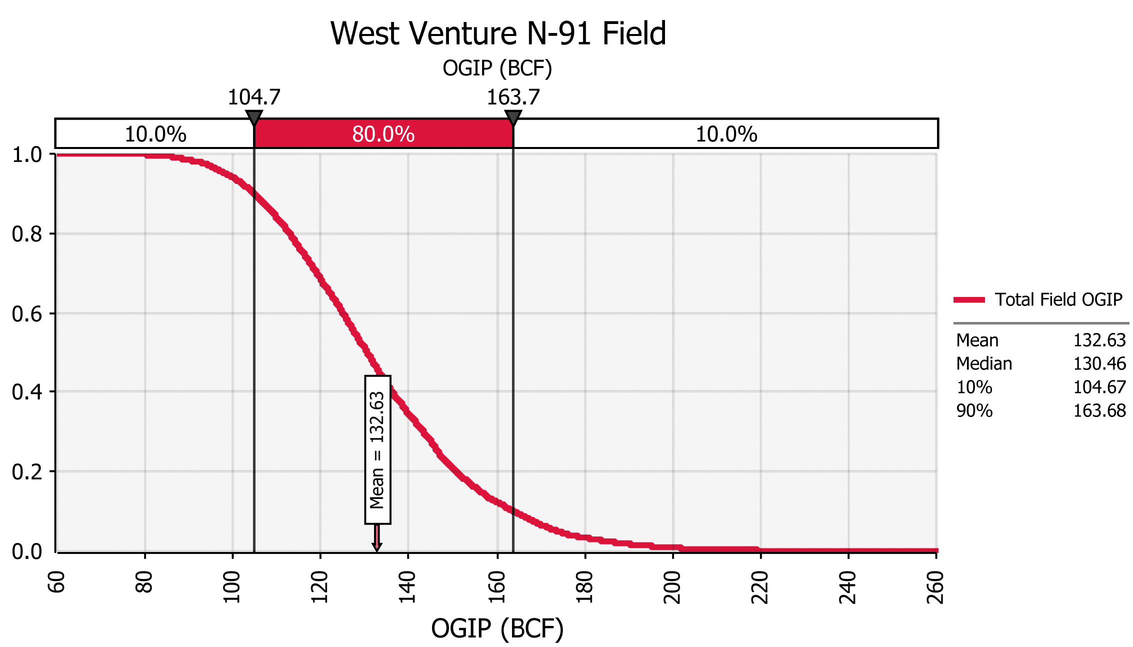

Figure 3.15.7 West Venture N-91 OGIP descending cumulative probability chart.

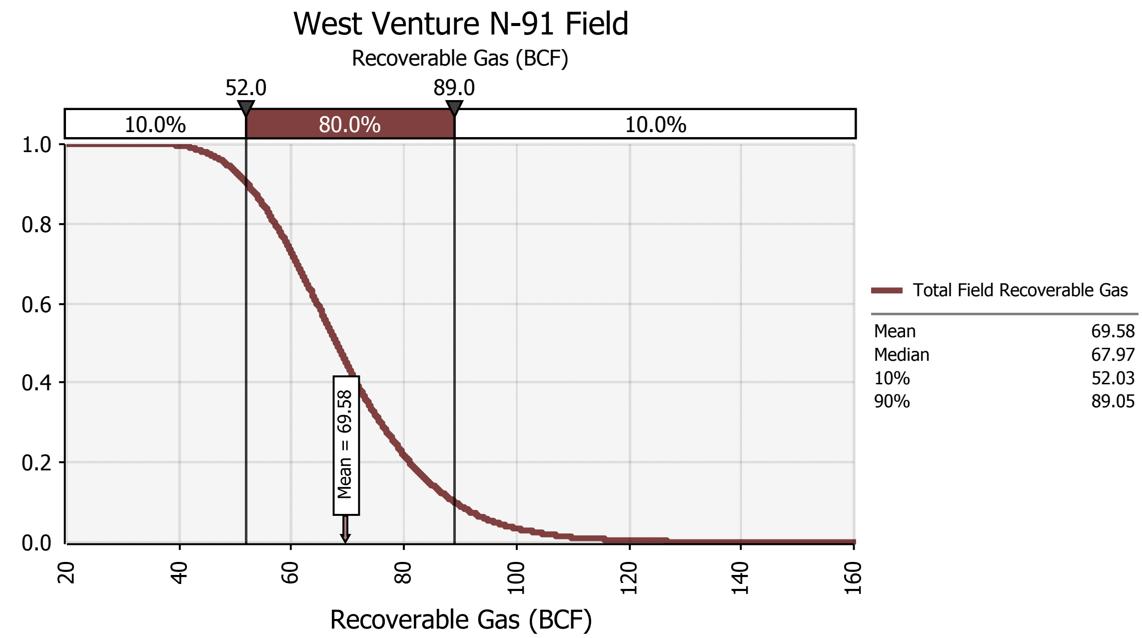

Figure 3.15.8 West Venture N-91 recoverable gas descending cumulative probability chart.

4 Results

The detailed assessment results for individual SDs are reported in Section 3 and not repeated here. A summary of field totals for in-place and recoverable hydrocarbons are presented in imperial units (Figs. 4.1 and 4.2) and metric units (Figs. 4.3 and 4.4). The 2014 mean OGIP estimates of 3,204 Bcf for all 15 SDs decreased by 277 Bcf (8%) from the 2000 results. A graph comparing these two assessment results (Fig 4.1) shows that significant variations occurred within some fields.

The 2014 total mean recoverable gas of 1,949 Bcf decreased by 313 Bcf (14%) from the 2000 results. A graph comparing these two assessment results (Fig 4.2) also shows significant changes within some fields. The largest reduction occurred at Chebucto which resulted from a smaller areal extent based on the petrophysical evaluation and seismic mapping. Another large reduction was observed at Uniacke where pool areas in the 2000 report included a separated closure to the south. This large area of closure requires unproven fault seal and was therefore excluded from the 2014 analysis.

The largest increase in estimated hydrocarbon volume occurred at Onondaga and resulted from the addition of the central fault block area. The increase at Glenelg resulted from the inclusion of additional gas zones. Overall, seven fields showed increased volumes while eight decreased.

A graph of SDs sorted by recoverable mean gas volume (Fig. 4.3), shows Glenelg to be significantly larger than Onondaga which is the second largest field. The remaining field sizes are distributed more evenly. While Glenelg has 509 Bcf of technically recoverable gas, the field is geologically complex and heavily faulted. Many individual sandstone reservoirs within these fault compartments are thin and have considerable risk of early water breakthrough. As a result, only one or two Glenelg fault compartments may have development potential.

Table 4.1 Summary of OHIP (Imperial units)

Field	Original Gas in Place (BCF)				Original Oil in Place (MMB)			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Arcadia	265	316	**319**	378				
Banquereau	229	268	**270**	314				
Chebucto	80	98	**100**	122				
Citnalta	244	277	**279**	316				
Glenelg	693	740	**742**	795				
Intrepid	83	94	**94**	105				
Olympia	238	268	**269**	300				
Onondaga	233	411	**389**	496				
Primrose	253	302	**305**	361	2.4	3.4	**3.5**	4.8
South Sable	10	13	**13**	16				
Uniacke	28	33	**33**	39				
West Olympia	52	75	**76**	103				
West Sable	113	128	**128**	144	36.4	42.9	**43.4**	50.7
West Venture C-62	46	54	**54**	62				
West Venture N-91	105	130	**133**	164				
Total	3020	3210	**3204**	3375	39.9	46.5	**46.9**	54.4

Table 4.2 Summary of Recoverable Hydrocarbons (Imperial units)

Field	Recoverable Gas (BCF)				Recoverable Oil (MMB)				Recoverable Condensate (MMB)			
	P90	P50	Mean	P10	P90	P50	Mean	P10	P90	P50	Mean	P10
Arcadia	130	158	**160**	193					1.3	1.6	**1.6**	2.0
Banquereau	143	170	**172**	202					0.7	0.8	**0.9**	1.1
Chebucto	53	66	**67**	82					0.4	0.5	**0.5**	0.6
Citnalta	149	172	**173**	198					8.3	9.8	**9.9**	11.6
Glenelg	473	508	**509**	546					3.3	3.6	**3.6**	4.0
Intrepid	48	54	**54**	61					0.4	0.5	**0.5**	0.6
Olympia	126	143	**144**	163					2.0	2.4	**2.5**	3.0
Onondaga	172	304	**288**	369					1.2	2.1	**2.1**	2.8
Primrose	100	127	**129**	162	0.7	1.0	**1.1**	1.5	0.5	0.7	**0.7**	1.0
South Sable	7	8	**9**	11					0.2	0.3	**0.3**	0.3
Uniacke	17	20	**21**	24					1.0	1.2	**1.2**	1.4
West Olympia	20	30	**31**	42					0.5	0.8	**0.8**	1.2
West Sable	81	93	**93**	105	12.3	15.0	**15.2**	18.3	2.5	3.1	**3.1**	3.9
West Venture C-62	26	31	**31**	36					0.1	0.2	**0.2**	0.2
West Venture N-91	52	68	**70**	89					0.3	0.4	**0.4**	0.5
Total	1819	1955	**1949**	2068	13.4	16.1	**16.3**	19.3	25.9	28.0	**28.2**	30.2

Table 4.3 Summary of OHIP (Metric units)

Field	Original Gas in Place (E9m3)				Original Oil in Place (E6m3)			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Arcadia	7.5	8.9	**9.0**	10.7				
Banquereau	6.5	7.6	**7.7**	8.9				
Chebucto	2.3	2.8	**2.8**	3.5				
Citnalta	6.9	7.9	**7.9**	8.9				
Glenelg	19.6	21.0	**21.0**	22.5				
Intrepid	2.4	2.7	**2.7**	3.0				
Olympia	6.7	7.6	**7.6**	8.5				
Onondaga	6.6	11.6	**11.0**	14.0				
Primrose	7.2	8.6	**8.6**	10.2	0.4	0.5	**0.6**	0.8
South Sable	0.3	0.4	**0.4**	0.5				
Uniacke	0.8	0.9	**0.9**	1.1				
West Olympia	1.5	2.1	**2.2**	2.9				
West Sable	3.2	3.6	**3.6**	4.1	5.8	6.8	**6.9**	8.1
West Venture C-62	1.3	1.5	**1.5**	1.8				
West Venture N-91	3.0	3.7	**3.8**	4.6				
Total	85.5	90.9	**90.7**	95.6	6.3	7.4	**7.5**	8.6

Table 4.4 Summary of Recoverable Hydrocarbons (Metric units)

Field	Recoverable Gas (E9M3)				Recoverable Oil (E6M3)				Recoverable Condensate (E6M3)			
	P90	P50	Mean	P10	P90	P50	Mean	P10	P90	P50	Mean	P10
Arcadia	3.7	4.5	**4.5**	5.5					0.2	0.3	**0.3**	0.3
Banquereau	4.1	4.8	**4.9**	5.7					0.1	0.1	**0.1**	0.2
Chebucto	1.5	1.9	**1.9**	2.3					0.1	0.1	**0.1**	0.1
Citnalta	4.2	4.9	**4.9**	5.6					1.3	1.6	**1.6**	1.8
Glenelg	13.4	14.4	**14.4**	15.5					0.5	0.6	**0.6**	0.6
Intrepid	1.4	1.5	**1.5**	1.7					0.1	0.1	**0.1**	0.1
Olympia	3.6	4.1	**4.1**	4.6					0.3	0.4	**0.4**	0.5
Onondaga	4.9	8.6	**8.2**	10.1					0.2	0.3	**0.3**	0.4
Primrose	2.8	3.6	**3.7**	4.6	0.1	0.2	**0.2**	0.2	0.1	0.1	**0.1**	0.2
South Sable	0.2	0.2	**0.2**	0.3					0.0	0.0	**0.0**	0.1
Uniacke	0.5	0.6	**0.6**	0.7					0.2	0.2	**0.2**	0.2
West Olympia	0.6	0.8	**0.9**	1.2					0.1	0.1	**0.1**	0.2
West Sable	2.3	2.6	**2.6**	3.0	2.0	2.4	**2.4**	2.9	0.4	0.5	**0.5**	0.6
West Venture C-62	0.7	0.9	**0.9**	1.0					0.0	0.0	**0.0**	0.0
West Venture N-91	1.5	1.9	**2.0**	2.5					0.0	0.1	**0.1**	0.1
Total	51.5	55.4	**55.2**	58.6	2.1	2.6	**2.6**	3.1	4.1	4.5	**4.5**	4.8

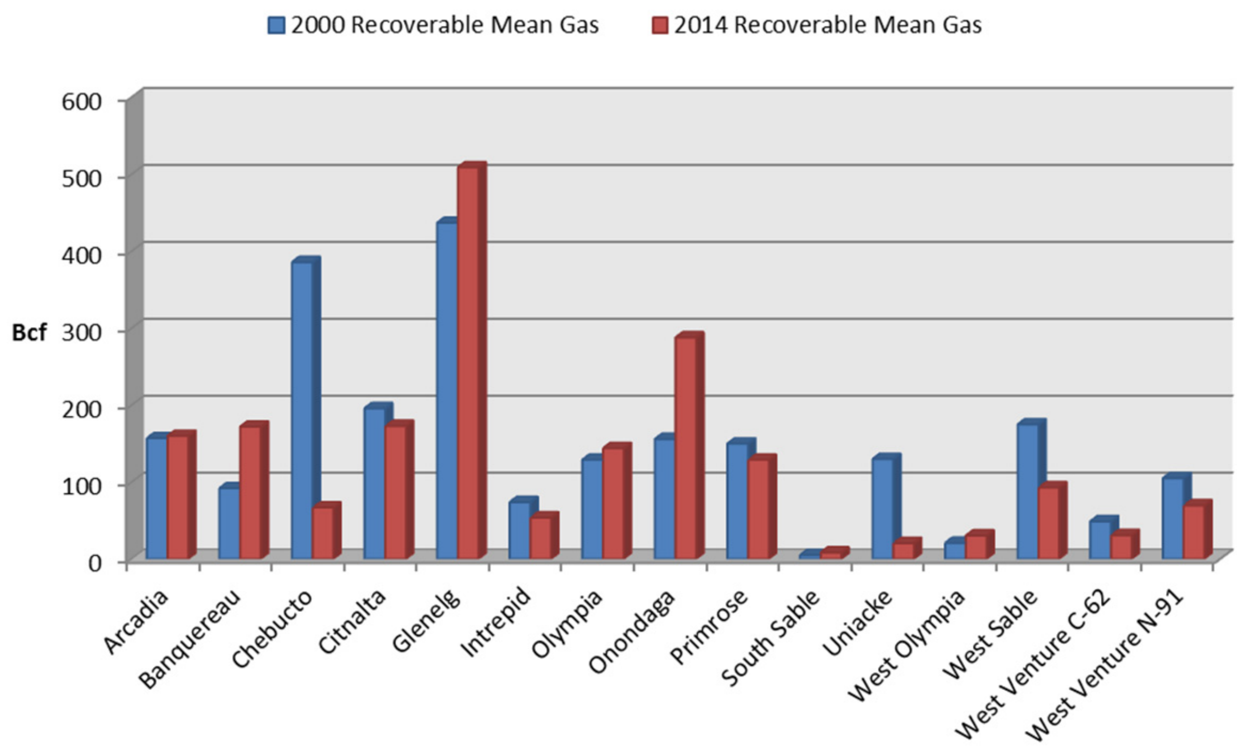

Figure 4.1 Comparison of 2000 and 2014 results for recoverable mean gas.

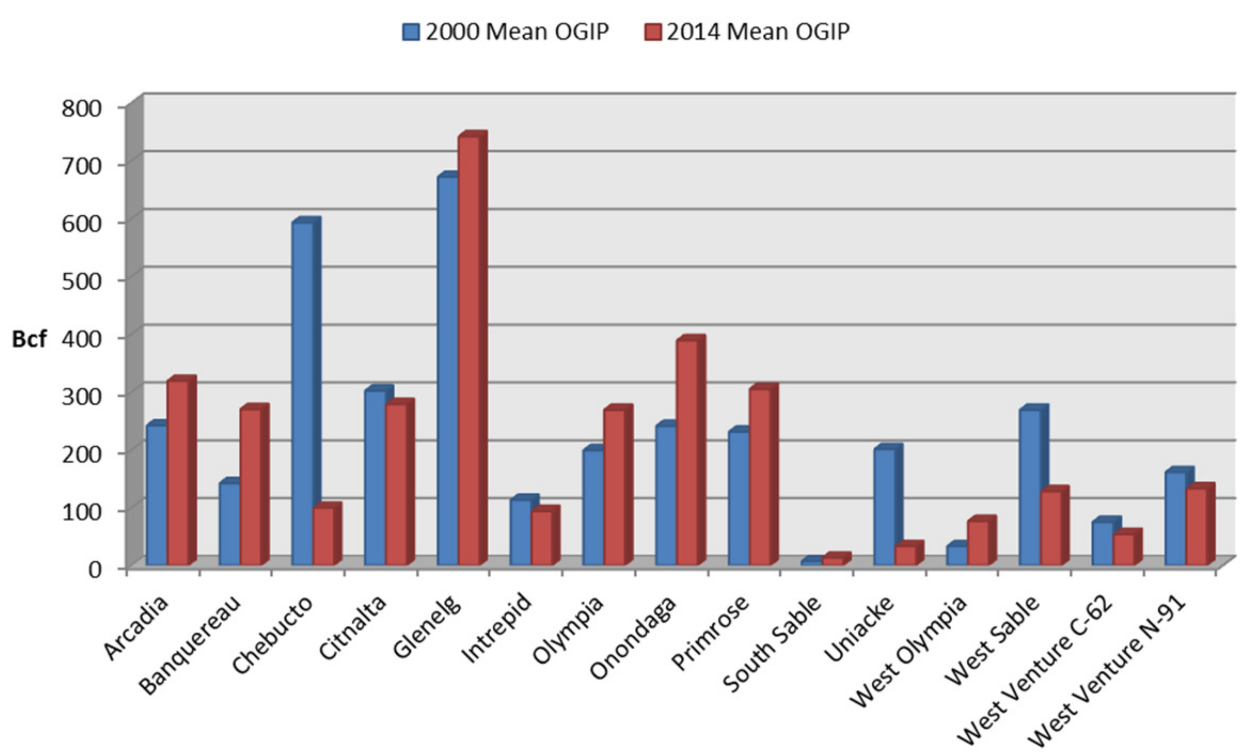

Figure 4.2 Comparison of 2000 and 2014 results for OGIP.

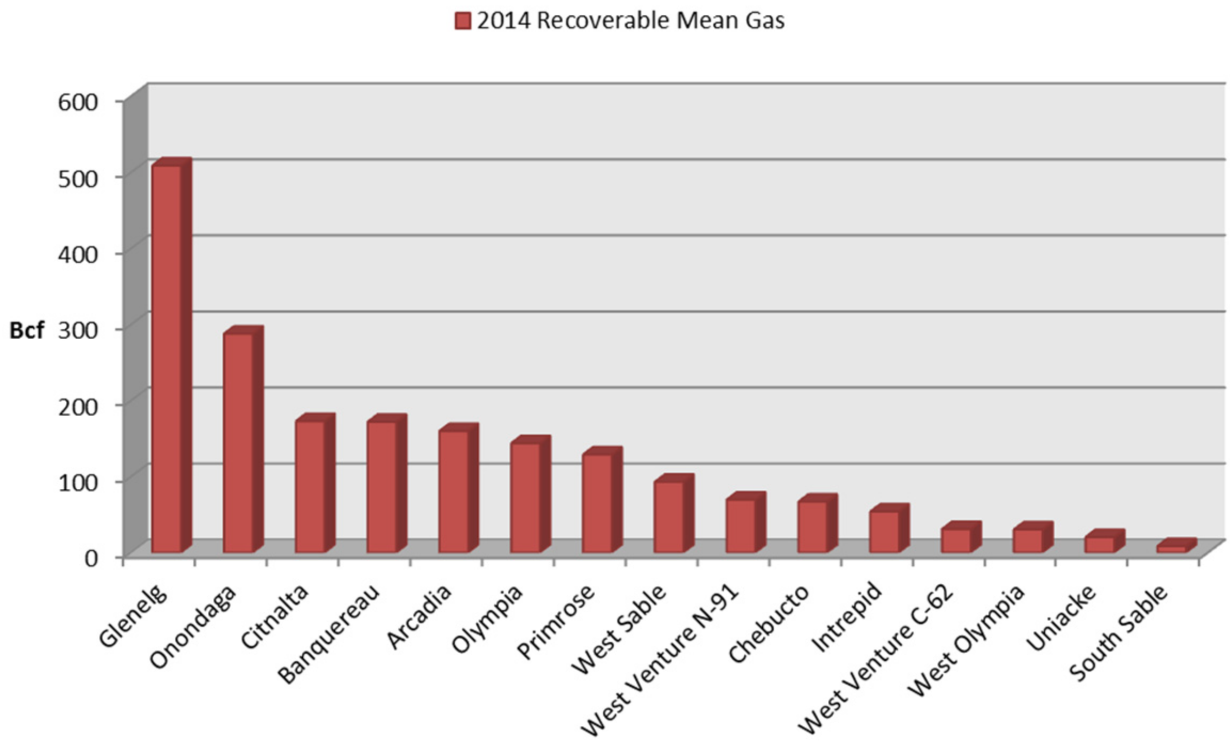

Figure 4.3 Recoverable mean gas ranked by field size.

5 Conclusions

All relevant data available to the CNSOPB was interpreted and analyzed in order to determine hydrocarbon volumes in the 15 undeveloped SDs. The availability of 3D seismic data allowed for a significant improvement in the accuracy of most SD structure maps. Detailed seismic mapping using 3D seismic data, combined with comprehensive petrophysical analysis and better constrained recovery factors, has resulted in a significantly improved understanding of the hydrocarbon volumes in these 15 SDs.

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