**Canada - Nova Scotia**
**Offshore Petroleum Board**

# Technical Summaries

# of Scotian Shelf

# Significant and Commercial

# Discoveries

November 2000

*This is a publication of the Canada-Nova Scotia Offshore Petroleum Board, November 2000.*

# Abstract / Resumé

The Canada-Nova Scotia Offshore Petroleum Board (the Board) last reported estimates of discovered resources in a 1991 joint publication with the Canada Oil and Gas Lands Administration and the Nova Scotia Department of Mines and Energy. That publication reported an estimate of total discovered resources but did not provide detailed estimates for individual significant or commercial discoveries. As a more detailed update to the 1991 publication this document represents the Board's current independent assessment of the recoverable hydrocarbon resources discovered within the Scotian Basin. Not all discoveries have been assessed to the same level of detail and we anticipate that this document will be continuously updated as further information becomes available or additional studies are conducted.

Currently twenty-one (21) discoveries have been declared significant and five (5) have been declared commercial pursuant to the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Acts. Within this report, each discovery is documented to provide information about the wells drilled within the structure, significant flow tests, geological/geophysical attributes, structural cross-section and areal extent, petrophysical parameters, hydrocarbons in place, and anticipated hydrocarbon recoverable resource. The results of the Board's current assessment is presented in summary tables of Original Hydrocarbons in Place and Recoverable Resources.

La dernière fois que l'Office Canada - Nouvelle-Écosse des Hydrocarbures Extracôtiers (l'Office) a donné compte rendu des évaluations des ressources découvertes est en 1991 dans une publication écrite conjointement avec l'ancienne Administration du pétrole et du gaz des terres du Canada et le Ministère de l'Énergie et des Mines de la Nouvelle-Écosse. Cette publication n'inclu pas d'évaluations détaillées pour les grandes découvertes uniques commerciales. Ce document est une revision de la publication de 1991 et inclu des évaluations indépendantes par l'Office sur le pétrole extrait dans le Bassin Scotian. Pas toute les découvertes sont étudiées en détail et nous nous attendons à ce que dans l'avenir, ce document sera revisé continuellement avec de la nouvelle information et au fur et à mesure que d'autres études sont conclues.

En ce moment, vingt et un (21) découvertes ont été déclarées significantes et cinq (5) ont été déclarées commerciales sous la Loi de mise en oeuvre de l'Accord Canada-Nouvelle-Écosse. Dans ce document, chacune de ces découvertes sont documentées pour donner de l'information sur les puits forés dans les structures, les essais de production significantes, les charactéristiques géologiques et géophysiques, les sections structurelles et les domaines, les paramètres pétrophysiques, le pétrole en place, et les ressources pétrolières récupérables. Les résultats de l'Office sont présentés en tableaux sommaires avec le pétrole en place et les ressources récupérables.

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# Introduction

The purpose of this report is to document an independent assessment of the recoverable hydrocarbon resource currently held under Significant and Commercial Discovery status offshore Nova Scotia.

The Nova Scotia offshore area is comprised of approximately 400 000 $km^2$, extending from the low water mark on the coast of Nova Scotia to the outer limits of the continental margin. Since the first exploration in the 1950's, 359, 395 km of 2D seismic and 6076 $km^2$ of 3D seismic have been recorded and 168 wells have been drilled. This has resulted in the declaration of twenty-one (21) Significant Discoveries and five (5) Commercial Discoveries located in the Sable Island area approximately 150 km offshore (See map on page 15). These declarations are based on the following Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Acts definitions:

"Commercial Discovery means 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."

"Significant Discovery means 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."

This resource assessment report is based on industry seismic and drilling data that has been submitted to the Board and has passed its period of statutory confidentiality. Work completed by Canada Oil and Gas Lands Administration served as the foundation for much of the technical data used within the probabilistic determination of hydrocarbons in place. In some instances, additional data has been referenced from the Petroleum Development Agency, Department of Natural Resources, Nova Scotia, and the Geological Survey of Canada.

An independent assessment of the total resource potential for the sedimentary basins of the Scotian Shelf has not been undertaken by the Board, nor is it within the scope of this study. It continues to be the Board's opinion that, while dated, the most relevant and comprehensive assessment of the total resource potential for the Shelburne (portion), Abenaki, Mohican and Sable Subbasins of the Scotian Basin (excluding the Laurentian Subbasin), offshore Nova Scotia, was reported by Wade et al.[1]. This study, based on data available up to December 31, 1983 (62 wells drilled; 13 Significant Discoveries confirmed), indicated that the median expectation of discovered and undiscovered potential petroleum resources are 512 E9M3 (18.1 Tcf) of gas; with an associated 58.2 E6M3 (366.1 MMBbls) of condensate, and 112.5 E6M3 (707.6 MMBbls) of oil.

A preliminary resource assessment for the undrilled Laurentian Subbasin, the easternmost extension of the Scotian Basin, was published in 1992 by MacLean and Wade[2]. The authors interpret the basin to have an average (mean) expectation of containing 250 E9M3 (8-9 Tcf) of recoverable gas and 100 E6M3 (600-700 MMBbls) of recoverable oil. Low probability (speculative) resource estimates are suggested by the authors to be several times these levels.

A final resource assessment of the East Georges Bank Basin by the Canadian government has not been published. Assessments for the early Mesozoic Fundy Basin, and upper Paleozoic Maritimes and Sydney Basins have not yet been conducted.

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[1] Wade, J.A., Campbell, G.R., Proctor, R.M. and Taylor, G.C., 1989: *Petroleum Resources of the Scotian Shelf.* Geological Survey of Canada Paper 88-19, 26p.

[2] MacLean, B. C., and Wade, J. A., 1992: *Petroleum geology of the continental margin south of the islands of St. Pierre and Miquelon, Offshore Eastern Canada.* Bulletin of Canadian Petroleum Geology, vol.40, no.3, p.222-253.

# Summary of Original Hydrocarbons in Place[1]

# (Metric Units)

| | Gas In Place (E9M3) | | | | | Oil/Condensate in Place (E6M3) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | P90 | P50 | P10 | Mean | | P90 | P50 | P10 | Mean |
| **Alma** | 15.420 | 17.730 | 20.380 | 17.830 | | 1.064 | 1.223 | 1.406 | 1.230 |
| **Arcadia** | 4.905 | 6.660 | 9.038 | 6.853 | | 0.172 | 0.233 | 0.316 | 0.240 |
| **Banquereau** | 3.160 | 3.950 | 4.930 | 4.010 | | 0.088 | 0.111 | 0.138 | 0.112 |
| **Chebucto** | 13.916 | 16.642 | 19.898 | 16.805 | | 0.473 | 0.566 | 0.677 | 0.571 |
| **Citnalta** | 5.362 | 8.111 | 12.264 | 8.551 | | 2.236 | 3.382 | 5.114 | 3.566 |
| **Cohasset** | 0.202 | 0.202 | 0.202 | 0.202 | | 10.647 | 10.647 | 10.647 | 10.647 |
| **Glenelg** | 14.547 | 18.659 | 23.930 | 19.018 | | 0.786 | 1.008 | 1.292 | 1.027 |
| **Intrepid** | 2.524 | 3.161 | 3.957 | 3.210 | | 0.232 | 0.291 | 0.364 | 0.295 |
| **North Triumph** | 9.660 | 15.820 | 24.410 | 16.540 | | 0.290 | 0.475 | 0.732 | 0.496 |
| **Olympia** | 3.658 | 5.389 | 7.933 | 5.640 | | 0.530 | 0.781 | 1.150 | 0.818 |
| **Onondaga** | 6.067 | 6.790 | 7.596 | 6.816 | | 0.000 | 0.000 | 0.000 | 0.000 |
| **Panuke** | 0.113 | 0.113 | 0.113 | 0.113 | | 6.676 | 6.676 | 6.676 | 6.676 |
| **Primrose (Gas)** | 5.062 | 6.430 | 8.163 | 6.544 | | 0.172 | 0.219 | 0.278 | 0.222 |
| **Primrose (Oil)** | 0.833 | 0.856 | 0.880 | 0.856 | | 0.657 | 0.675 | 0.694 | 0.675 |
| **South Sable** | 0.197 | 0.202 | 0.208 | 0.202 | | 0.006 | 0.006 | 0.006 | 0.006 |
| **South Venture** | 12.867 | 17.785 | 24.572 | 18.361 | | 2.522 | 3.486 | 4.816 | 3.599 |
| **Thebaud** | 21.133 | 31.551 | 47.047 | 33.134 | | 3.170 | 4.733 | 7.057 | 4.970 |
| **Uniacke** | 4.188 | 5.545 | 7.338 | 5.680 | | 0.239 | 0.316 | 0.418 | 0.324 |
| **Venture** | 50.437 | 64.986 | 83.738 | 66.279 | | 5.044 | 6.499 | 8.374 | 6.628 |
| **West Olympia** | 0.686 | 0.925 | 1.196 | 0.936 | | 0.105 | 0.142 | 0.183 | 0.143 |
| **West Sable (Gas)** | 3.601 | 6.749 | 12.653 | 7.616 | | 1.008 | 1.890 | 3.543 | 2.132 |
| **West Sable (Oil)** | 0.690 | 1.195 | 2.070 | 1.311 | | 8.513 | 14.750 | 25.550 | 16.190 |
| **W. Venture C-62** | 1.632 | 2.048 | 2.701 | 2.116 | | 0.042 | 0.053 | 0.070 | 0.055 |
| **W. Venture N-91** | 3.585 | 4.495 | 5.635 | 4.566 | | 0.000 | 0.000 | 0.000 | 0.000 |
| | | | | | | | | | |
| **Grand Total** | **184.445** | **245.994** | **330.852** | **253.190** | | **44.672** | **58.160** | **79.502** | **60.624** |

[1] The P90, P50, P10 and Mean are extracted from probabilistic analysis definitions. Thus, the P90 value represents a value with a 90% chance of being equalled or exceeded, at P50 there is a 50% chance that the indicated value will be equalled or exceeded, and at P10 there exists a 10% chance that the indicated value will be equalled or exceeded. The Mean is the expected value for the parameter; the sum of all samples divided by the number of samples, and as such also represents our Best Current Estimate (BCE) of the parameter. The Grand Totals are summed arithmetically due to the fact that some entries in the table have been deterministically defined. The figures are reported here in Metric Units.

# Summary of Original Hydrocarbons in Place[2]

# (Imperial Units)

| | Gas In Place (BCF) | | | | | Oil/Condensate in Place (MMBbl) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | P90 | P50 | P10 | Mean | | P90 | P50 | P10 | Mean |
| **Alma** | 545 | 626 | 720 | 630 | | 6.69 | 7.69 | 8.84 | 7.74 |
| **Arcadia** | 173 | 235 | 319 | 242 | | 1.08 | 1.47 | 1.99 | 1.51 |
| **Banquereau** | 112 | 139 | 174 | 142 | | 0.56 | 0.70 | 0.87 | 0.71 |
| **Chebucto** | 491 | 588 | 703 | 593 | | 2.98 | 3.56 | 4.26 | 3.59 |
| **Citnalta** | 189 | 286 | 433 | 302 | | 14.06 | 21.27 | 32.17 | 22.43 |
| **Cohasset** | 7 | 7 | 7 | 7 | | 66.97 | 66.97 | 66.97 | 66.97 |
| **Glenelg** | 514 | 659 | 845 | 672 | | 4.94 | 6.34 | 8.13 | 6.46 |
| **Intrepid** | 89 | 112 | 140 | 113 | | 1.46 | 1.83 | 2.29 | 1.86 |
| **North Triumph** | 341 | 559 | 862 | 584 | | 1.82 | 2.99 | 4.61 | 3.12 |
| **Olympia** | 129 | 190 | 280 | 199 | | 3.34 | 4.91 | 7.24 | 5.14 |
| **Onondaga** | 214 | 240 | 268 | 241 | | 0.00 | 0.00 | 0.00 | 0.00 |
| **Panuke** | 4 | 4 | 4 | 4 | | 41.99 | 41.99 | 41.99 | 41.99 |
| **Primrose (Gas)** | 179 | 227 | 288 | 231 | | 1.08 | 1.38 | 1.75 | 1.40 |
| **Primrose (Oil)** | 29 | 30 | 31 | 30 | | 4.13 | 4.25 | 4.37 | 4.25 |
| **South Sable** | 7 | 7 | 7 | 7 | | 0.04 | 0.04 | 0.04 | 0.04 |
| **South Venture** | 454 | 628 | 868 | 648 | | 15.86 | 21.93 | 30.29 | 22.64 |
| **Thebaud** | 746 | 1114 | 1661 | 1170 | | 19.94 | 29.77 | 44.39 | 31.26 |
| **Uniacke** | 148 | 196 | 259 | 201 | | 1.50 | 1.99 | 2.63 | 2.04 |
| **Venture** | 1781 | 2295 | 2957 | 2341 | | 31.72 | 40.87 | 52.67 | 41.69 |
| **West Olympia** | 24 | 33 | 42 | 33 | | 0.66 | 0.89 | 1.15 | 0.90 |
| **West Sable (Gas)** | 127 | 238 | 447 | 269 | | 6.34 | 11.89 | 22.28 | 13.41 |
| **West Sable (Oil)** | 24 | 42 | 73 | 46 | | 53.55 | 92.77 | 160.70 | 101.83 |
| **W. Venture C-62** | 58 | 72 | 95 | 75 | | 0.27 | 0.33 | 0.44 | 0.35 |
| **W. Venture N-91** | 127 | 159 | 199 | 161 | | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | | | | | | | |
| **Grand Total** | **6514** | **8687** | **11684** | **8941** | | **280.98** | **365.82** | **500.05** | **381.31** |

[2] The P90, P50, P10 and Mean are extracted from probabilistic analysis definitions. Thus, the P90 value represents a value with a 90% chance of being equalled or exceeded, at P50 there is a 50% chance that the indicated value will be equalled or exceeded, and at P10 there exists a 10% chance that the indicated value will be equalled or exceeded. The Mean is the expected value for the parameter; the sum of all samples divided by the number of samples, and as such also represents our Best Current Estimate (BCE) of the parameter. The Grand Totals are summed arithmetically due to the fact that some entries in the table have been deterministically defined. The figures are reported here in Imperial Units.

# Summary of Recoverable Resource[3]

# (Metric Units)

| | Recoverable Gas (E9M3) | | | | | Recoverable Oil/Condensate (E6M3) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **P90 Low** | **P50 Med** | **P10 High** | **Mean BCE** | | **P90 Low** | **P50 Med** | **P10 High** | **Mean BCE** |
| **Alma** | 7.710 | 11.525 | 16.304 | 11.590 | | 0.532 | 0.795 | 1.125 | 0.800 |
| **Arcadia** | 2.453 | 4.329 | 7.230 | 4.454 | | 0.086 | 0.152 | 0.253 | 0.156 |
| **Banquereau** | 1.580 | 2.568 | 3.944 | 2.607 | | 0.044 | 0.072 | 0.110 | 0.073 |
| **Chebucto** | 6.958 | 10.817 | 15.918 | 10.923 | | 0.237 | 0.368 | 0.541 | 0.371 |
| **Citnalta** | 2.681 | 5.272 | 9.811 | 5.558 | | 1.118 | 2.198 | 4.091 | 2.318 |
| **Cohasset** | 0.089 | 0.089 | 0.089 | 0.089 | | 4.685 | 4.685 | 4.685 | 4.685 |
| **Glenelg** | 7.274 | 12.128 | 19.144 | 12.362 | | 0.393 | 0.655 | 1.034 | 0.668 |
| **Intrepid** | 1.262 | 2.055 | 3.166 | 2.087 | | 0.116 | 0.189 | 0.291 | 0.192 |
| **North Triumph** | 4.830 | 10.283 | 19.528 | 10.751 | | 0.145 | 0.308 | 0.586 | 0.323 |
| **Olympia** | 1.829 | 3.503 | 6.346 | 3.666 | | 0.265 | 0.508 | 0.920 | 0.532 |
| **Onondaga** | 3.034 | 4.414 | 6.077 | 4.430 | | 0.000 | 0.000 | 0.000 | 0.000 |
| **Panuke** | 0.050 | 0.050 | 0.050 | 0.050 | | 2.937 | 2.937 | 2.937 | 2.937 |
| **Primrose (Gas)** | 2.531 | 4.180 | 6.530 | 4.254 | | 0.086 | 0.142 | 0.222 | 0.145 |
| **Primrose (Oil)** | 0.167 | 0.257 | 0.352 | 0.257 | | 0.131 | 0.203 | 0.278 | 0.203 |
| **South Sable** | 0.099 | 0.131 | 0.166 | 0.131 | | 0.003 | 0.004 | 0.005 | 0.004 |
| **South Venture** | 6.434 | 11.560 | 19.658 | 11.935 | | 1.261 | 2.266 | 3.853 | 2.339 |
| **Thebaud** | 10.567 | 20.508 | 37.638 | 21.537 | | 1.585 | 3.076 | 5.646 | 3.231 |
| **Uniacke** | 2.094 | 3.604 | 5.870 | 3.692 | | 0.119 | 0.205 | 0.335 | 0.210 |
| **Venture** | 25.219 | 42.241 | 66.990 | 43.081 | | 2.522 | 4.224 | 6.699 | 4.308 |
| **West Olympia** | 0.343 | 0.601 | 0.957 | 0.608 | | 0.052 | 0.092 | 0.146 | 0.093 |
| **West Sable (Gas)** | 1.801 | 4.387 | 10.122 | 4.950 | | 0.504 | 1.228 | 2.834 | 1.386 |
| **West Sable (Oil)** | 0.138 | 0.358 | 0.828 | 0.393 | | 1.703 | 4.425 | 10.220 | 4.857 |
| **W. Venture C-62** | 0.816 | 1.331 | 2.161 | 1.375 | | 0.021 | 0.035 | 0.056 | 0.036 |
| **W. Venture N-91** | 1.793 | 2.922 | 4.508 | 2.968 | | 0.000 | 0.000 | 0.000 | 0.000 |
| | | | | | | | | | |
| **Grand Total** | **91.747** | **159.112** | **263.388** | **163.749** | | **18.546** | **28.768** | **46.868** | **29.865** |

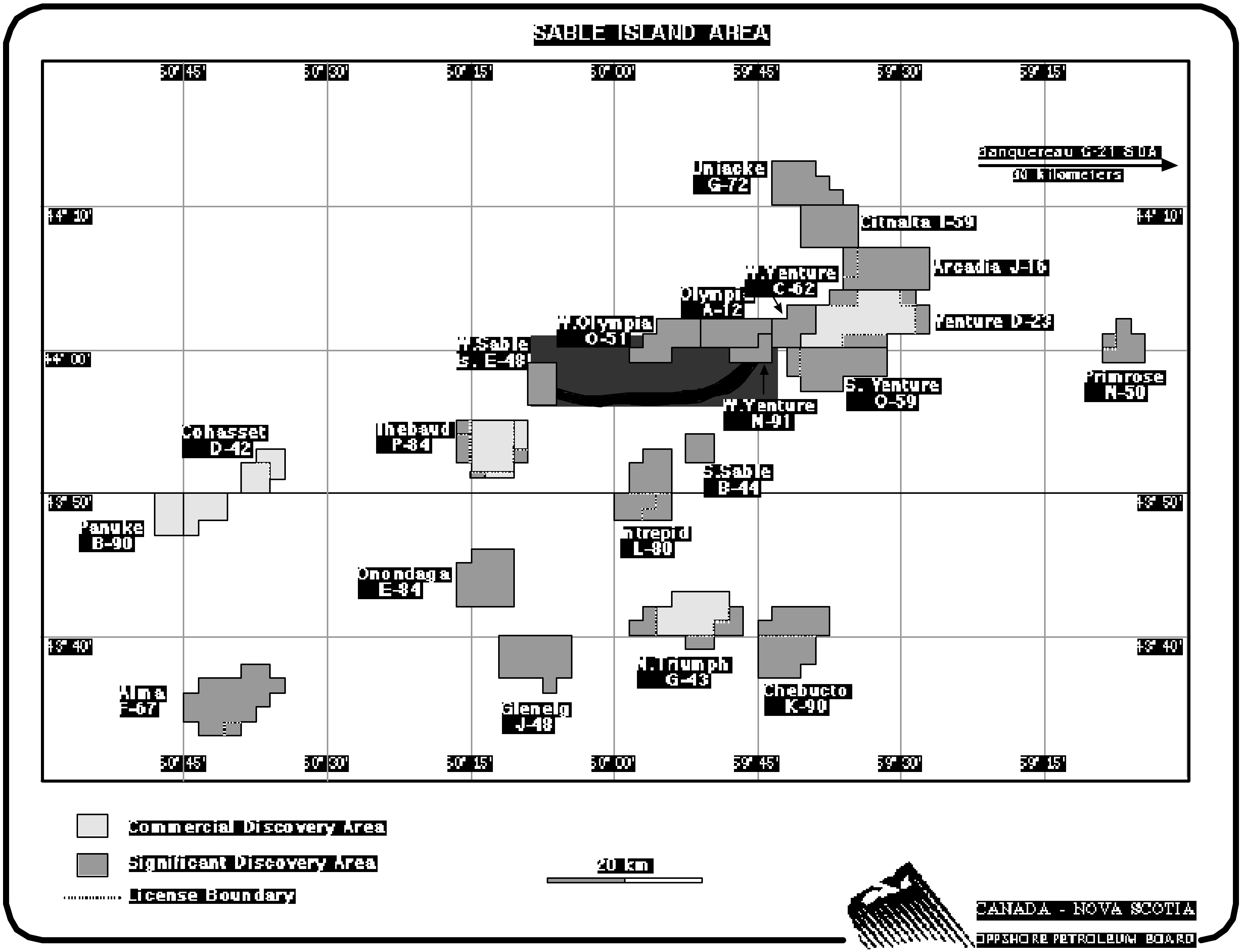
[3] Recoverable resource is calculated from the Original Hydrocarbons in Place via Low, Medium and High case recovery factors of 50%, 65% and 80% for the for gas resources and 20%, 30% and 40% for oil. These factors are applied to the P90, P50, and P10 cases of the Original Hydrocarbons in Place summary. The Best Current Estimate (BCE) values are based on the probabilistic mean value with a 65% recovery factor for gas and a 30% recovery factor for oil. The Grand Totals are summed arithmetically due to the fact that some entries in the table have been deterministically defined. The figures are reported here in Metric Units.

# Summary of Recoverable Resource[4]

# (Imperial Units)

| | Recoverable Gas (BCF) | | | | | Recoverable Oil/Condensate (MMBbl) | | | |
|---|---|---|---|---|---|---|---|---|---|
| | P90 High | P50 Med | P10 Low | Mean BCE | | P90 High | P50 Med | P10 Low | Mean BCE |
| **Alma** | 272 | 407 | 576 | 409 | | 3.35 | 5.00 | 7.08 | 5.03 |
| **Arcadia** | 87 | 153 | 255 | 157 | | 0.54 | 0.95 | 1.59 | 0.98 |
| **Banquereau** | 56 | 91 | 139 | 92 | | 0.28 | 0.45 | 0.69 | 0.46 |
| **Chebucto** | 246 | 382 | 562 | 386 | | 1.49 | 2.31 | 3.40 | 2.34 |
| **Citnalta** | 95 | 186 | 346 | 196 | | 7.03 | 13.83 | 25.73 | 14.58 |
| **Cohasset** | 3 | 3 | 3 | 3 | | 29.47 | 29.47 | 29.47 | 29.47 |
| **Glenelg** | 257 | 428 | 676 | 437 | | 2.47 | 4.12 | 6.50 | 4.20 |
| **Intrepid** | 45 | 73 | 112 | 74 | | 0.73 | 1.19 | 1.83 | 1.21 |
| **North Triumph** | 171 | 363 | 690 | 380 | | 0.91 | 1.94 | 3.68 | 2.03 |
| **Olympia** | 65 | 124 | 224 | 129 | | 1.67 | 3.19 | 5.79 | 3.34 |
| **Onondaga** | 107 | 156 | 215 | 156 | | 0.00 | 0.00 | 0.00 | 0.00 |
| **Panuke** | 2 | 2 | 2 | 2 | | 18.48 | 18.48 | 18.48 | 18.48 |
| **Primrose (Gas)** | 89 | 148 | 231 | 150 | | 0.54 | 0.89 | 1.40 | 0.91 |
| **Primrose (Oil)** | 6 | 9 | 12 | 9 | | 0.83 | 1.27 | 1.75 | 1.27 |
| **South Sable** | 3 | 5 | 6 | 5 | | 0.02 | 0.03 | 0.03 | 0.03 |
| **South Venture** | 227 | 408 | 694 | 421 | | 7.93 | 14.25 | 24.23 | 14.71 |
| **Thebaud** | 373 | 724 | 1329 | 761 | | 9.97 | 19.35 | 35.51 | 20.32 |
| **Uniacke** | 74 | 127 | 207 | 130 | | 0.75 | 1.29 | 2.10 | 1.32 |
| **Venture** | 891 | 1492 | 2366 | 1521 | | 15.86 | 26.57 | 42.14 | 27.10 |
| **West Olympia** | 12 | 21 | 34 | 21 | | 0.33 | 0.58 | 0.92 | 0.59 |
| **West Sable (Gas)** | 64 | 155 | 357 | 175 | | 3.17 | 7.73 | 17.83 | 8.72 |
| **West Sable (Oil)** | 5 | 13 | 29 | 14 | | 10.71 | 27.83 | 64.28 | 30.55 |
| **W. Venture C-62** | 29 | 47 | 76 | 49 | | 0.13 | 0.22 | 0.35 | 0.22 |
| **W. Venture N-91** | 63 | 103 | 159 | 105 | | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | | | | | | | |
| **Grand Total** | **3240** | **5619** | **9301** | **5783** | | **116.65** | **180.94** | **294.79** | **187.84** |

[4] Recoverable resource is calculated from the Original Hydrocarbons in Place via Low, Medium and High case recovery factors of 50%, 65% and 80% for the for gas resources and 20%, 30% and 40% for oil. These factors are applied to the P90, P50, and P10 cases of the Original Hydrocarbons in Place summary. The Best Current Estimate (BCE) values are based on the probabilistic mean value with a 65% recovery factor for gas and a 30% recovery factor for oil. The Grand Totals are summed arithmetically due to the fact that some entries in the table have been deterministically defined. The figures are reported here in Imperial Units.


SABLE ISLAND AREA
Banquereau G-21 SDA
40 kilometers
Uniacke G-72
Citnalta I-59
Arcadia J-16
W.Venture C-62
Olympia A-12
Venture D-23
W.Olympia O-51
W.Sable
S. E-48
S. Venture O-59
Primrose N-50
W.Venture N-91
Cohasset D-42
Thebaud P-84
S.Sable B-44
Panuke B-90
Intrepid L-80
Onondaga E-84
N.Triumph G-43
Chebucto K-90
Alma F-67
Glenelg J-48
Commercial Discovery Area
Significant Discovery Area
License Boundary
20 km
CANADA - NOVA SCOTIA
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# Sable Subbasin Overview

The geometry of the sedimentary fill in the Sable Subbasin was originally defined by the coalescing of early Mesozoic local depocentres and later dominated by the subsequent formation and propagation of a series of large down-to-basin listric faults. These faults were initiated by the high sedimentation rates associated with the progradation of the late Jurassic to early Cretaceous Sable Delta complex. Sediment loading also triggered the mobilization of deeply buried Late Triassic to Early Jurassic age salts which accentuated the growth of syndepositional faults and the formation of numerous localized sediment sinks from the Middle Jurassic to the Tertiary.

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Late Triassic to the Tertiary. In the Triassic, rift related, fine grain clastic sediments of the Eurydice formation were deposited and then overlain by thick marine salts of the Argo formation. In the Early Jurassic, shallow marine dolomites and fluvial sandstones and shales of the Iroquois and Mohican formations respectively were deposited.

Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the end of the Late Jurassic are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the Sable Island area and beyond. In this region, the resultant sedimentary section is thick and has a high sand/shale ratio. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed deltaic progradation followed and is represented by the strandplain succession of the Logan Canyon and Dawson Canyon formations. Cessation of deltaic sedimentation in the Late Cretaceous permitted the establishment of a regional carbonate facies of the Wyandot formation. Upon cessation of deltaic sedimentation, extensive carbonate deposition took place, which was eventually buried by Tertiary age coastal plain and marine shelf clastics.

The above paragraphs offer only a brief overview of the geology of the Sable Subbasin, as a detailed and comprehensive treatment of this subject is beyond the scope of this publication. However, to remedy this, readers are directed to consult the following references which provide the best foundation upon which one may gain a full and complete understanding of all aspects of the geology and hydrocarbon systems as they relate to the Sable Subbasin and other offshore sedimentary basins in the CNSOPB's area of jurisdiction. Additional industry generated data in the form of site specific and/or regional geophysical, geochemical and geological reports, seismic maps and profiles, well history reports, lithological, paleontological and fluid samples, and other related materials are archived by the Board and may be accessed at its Data Archive and Laboratory Facility.

## References of Publications (books, articles and reports) related to Geology, Source Rock and Hydrocarbon Characterization, Scotian Basin and Adjacent Areas, Eastern Canada

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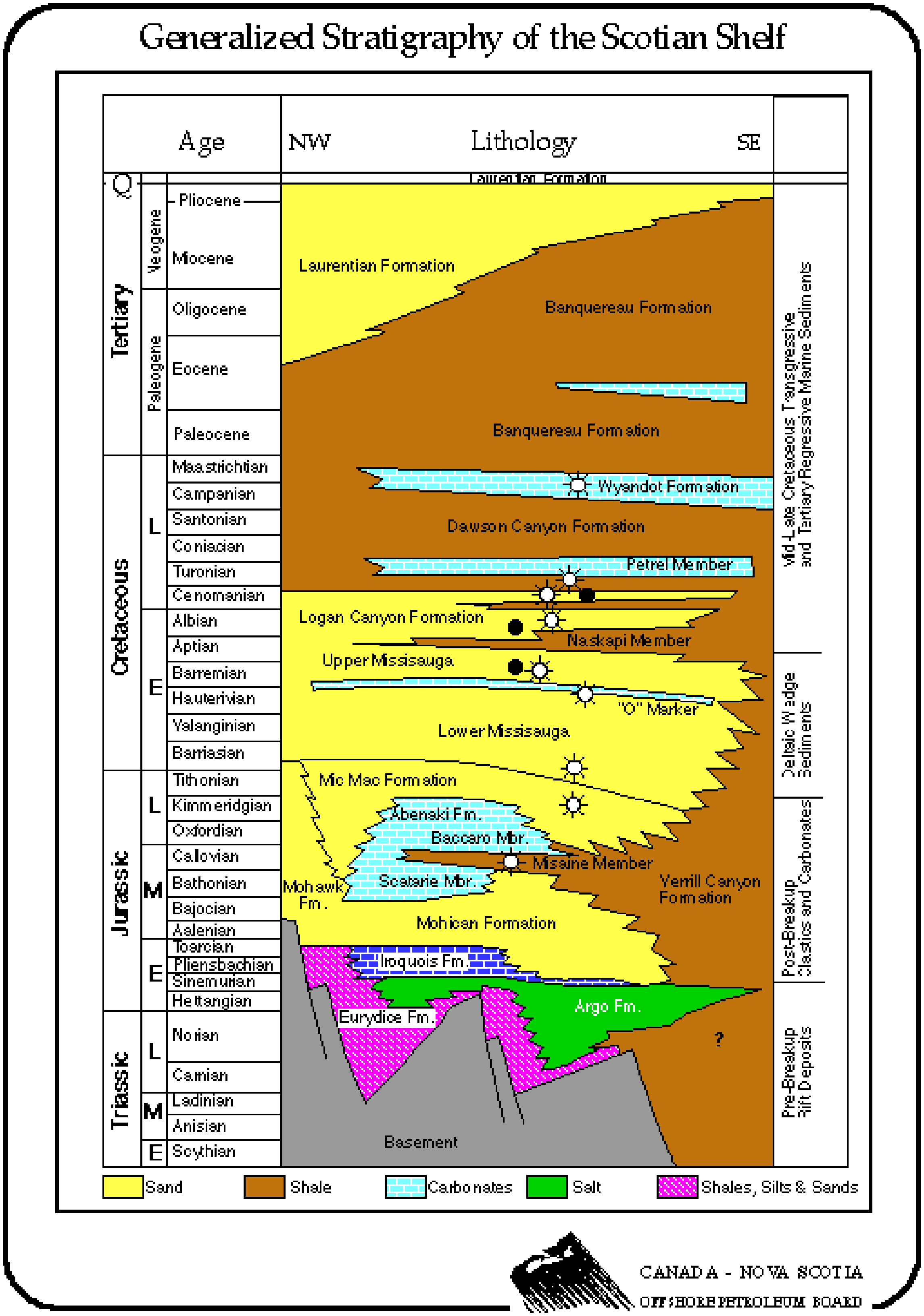
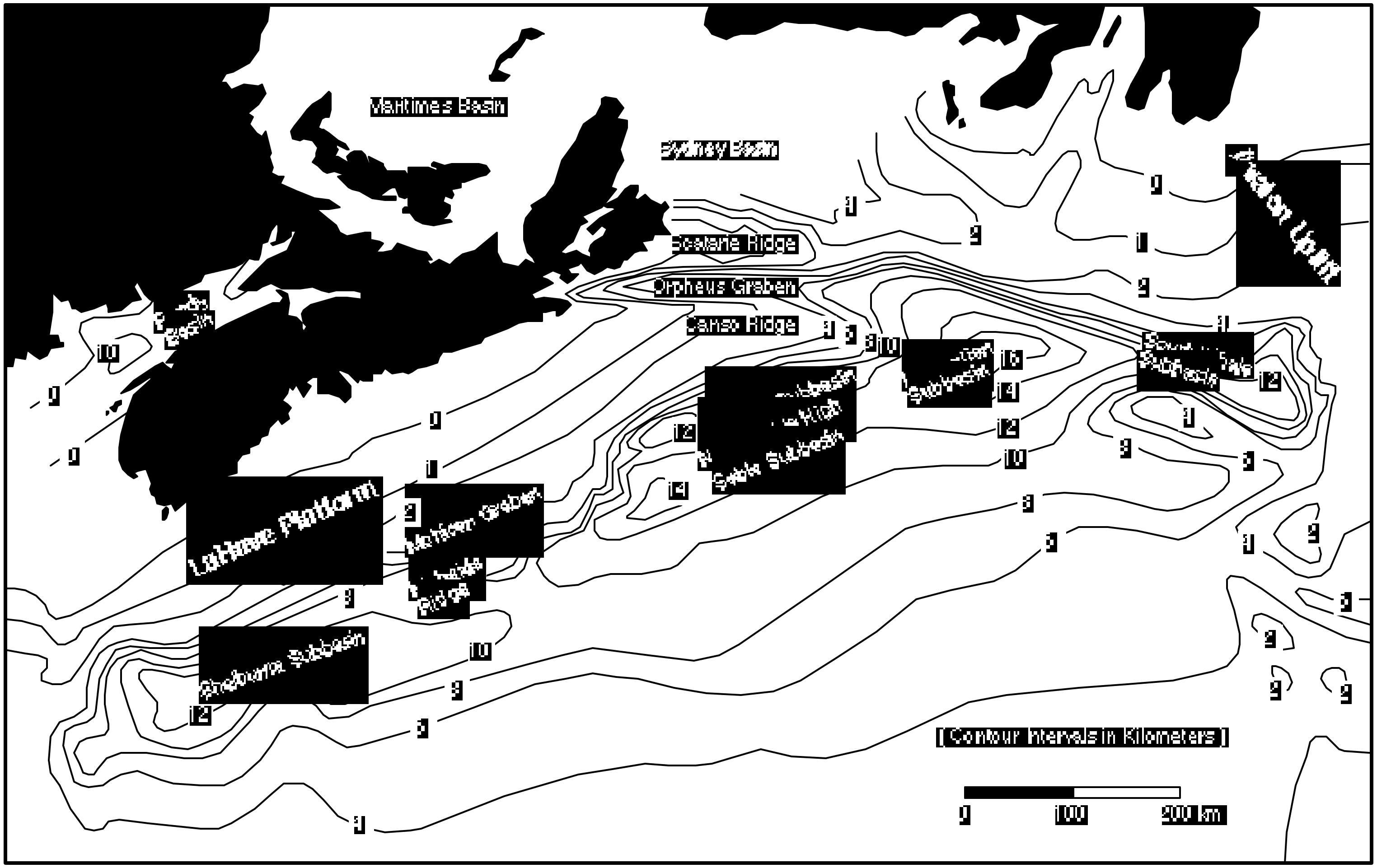

Generalized Stratigraphy of the Scotian Shelf
Age
NW
Lithology
SE
Q
Tertiary
Neogene
Paleogene
Pliocene
Miocene
Oligocene
Eocene
Paleocene
Cretaceous
L
Maastrichtian
Campanian
Santonian
Coniacian
Turonian
Cenomanian
E
Albian
Aptian
Barremian
Hauterivian
Valanginian
Barriasian
Jurassic
L
Tithonian
Kimmeridgian
Oxfordian
M
Callovian
Bathonian
Bajocian
Aalenian
E
Toarcian
Pliensbachian
Sinemurian
Hettangian
Triassic
L
Norian
Carnian
M
Ladinian
Anisian
E
Scythian
Laurentian Formation
Laurentian Formation
Banquereau Formation
Banquereau Formation
Wyandot Formation
Dawson Canyon Formation
Petrel Member
Logan Canyon Formation
Naskapi Member
Upper Missisauga
"O" Marker
Lower Missisauga
Mic Mac Formation
Abenaki Fm.
Baccaro Mbr.
Misaine Member
Scatarie Mbr.
Mohawk Fm.
Verrill Canyon Formation
Mohican Formation
Iroquois Fm.
Argo Fm.
Eurydice Fm.
?
Basement
Mid-Late Cretaceous Transgressive and Tertiary Regressive Marine Sediments
Deltaic Wedge Sediments
Post-Breakup Clastics and Carbonates
Pre-Breakup Rift Deposits
Sand
Shale
Carbonates
Salt
Shales, Silts & Sands
CANADA - NOVA SCOTIA
OFFSHORE PETROLEUM BOARD

# Total Sediment Thickness of the Scotian Basin and Adjacent Areas

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# Calculation Methodology

## *Determination of Original Hydrocarbons in Place and Recoverable Resource*

Calculations of original hydrocarbon in place were undertaken using the following standard volumetric equation, employed within a Monte Carlo style probabilistic simulation.

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

where;

$OHIP$ = Original Hydrocarbon (Gas/Oil) in Place ($m^3$)
$A$ = Areal extent of the accumulation (ha * 10000)
$h$ = Average Net Pay for the reservoir zone (m)
$f$ = Average Effective Porosity (Fraction)
$S_w$ = Average Water Saturation (Fraction)
$FVF$ = Formation Volume Factor for the hydrocarbon ($m^3/m^3$)

It is difficult to assign average properties to the above calculation with a high degree of confidence since the majority of hydrocarbon discoveries have been penetrated by only a single well. This drilling density was not sufficient to allow confidence in geological extrapolation across the structure. For this reason, the CNSOPB has conducted a probabilistic analysis of the volume in place. Due to limited input data, developing ranges for the input parameters proved difficult. The approach was based on the observation that one primary variable usually contains a magnitude of uncertainty that overshadows uncertainties within the other parameters. In these cases, the majority of input parameters were held constant at the well-observed values, while the probabilistic sampling was conducted on this single primary variable. Although this probabilistic analysis is not completely rigorous, it was deemed sufficient for this document to quantify a reasonable range of expectations for the output values. The analysis and mapping contained within this report will be updated as further information is obtained, or additional study is conducted on the various assets, and as warranted by development activity. The approach used to determine the input parameter ranges and associated confidence is explained in detail below.

The input variables have been defined as triangular distributions based on minimum, most likely and maximum justifiable values. Minimum values have been defined based on observed or inferred fluid contacts and via test observations. Maximum values are defined as maximum figures obtainable while still honoring the geological data. Most likely values are primarily those defined via the well penetrations, or via interpreting mapped surfaces.

In order to calculate the hydrocarbon recoverable resource in each pool, an analysis of the available data was undertaken in the following manner:

1) Identification of the significant pay zones from logs and drillstem tests (DSTs).

2) Plotting of core analysis and correlation of log depths to core analysis.

3) Development of core porosity versus log porosity relationships to determine porosity for entire zones to be analyzed. (The cores usually cover only parts of the pay zones).

4) Determining porosities on the basis of correlations developed above.

5) Determining net pay, and plotting porosity and water saturation profiles.

6) Quantitative evaluation of net pays and determination of thickness weighted porosity and porosity-thickness weighted water saturations for each zone, to determine the average net pay and average water saturation for each zone.

7) Determination of areal extent and estimation of the total pool volumes.

8) Determination of reservoir pressure based on DSTs, repeat formation tests (RFTs), and other tests.

9) Determination of reservoir temperature from DSTs, wireline logs, and temperature gradients.

10) Determination of Formation Volume Factors (FVFs) based on 8) and 9), and on densities of produced fluids, or on detailed analysis of captured fluids.

11) Calculation of Original Hydrocarbon in Place, including associated products of condensate and solution gas.

12) Conceptual depletion strategy and estimation of associated recovery factors.

13) Tabulation of recoverable resource.

Within the Original Hydrocarbon in Place and Recoverable Resource tables, four output figures are reported for all variables. They are labeled as P90/Low, P50/Med, P10/High, and Mean/BCE. The P90, P50, P10 and Mean are extracted from probabilistic analysis definitions. Thus, the P90 value represents a value with a 90% chance of being equalled or exceeded, at P50 there is a 50% chance that the indicated value will be equalled or exceeded, and at P10 there exists a 10% chance that the indicated value will be equalled or exceeded. The Mean is the expected value for the parameter; the sum of all samples divided by the number of samples, and as such also represents te Best Current Estimate (BCE) of the parameter.

The aspects of the volumetric equations which need to be determined for each zone are discussed below.

## Area Assignment

Where a discovery or delineation well has intersected, or where pressure data can reasonably infer a hydrocarbon/water contact, the most likely and maximum area assignments have both been assigned the same value. The minimum value may also reflect this value, if it cannot be contradicted by reservoir extent predicted from DST results. The area of the hydrocarbon accumulation is calculated by determining the area outlined by projecting the hydrocarbon/water contact onto the closest seismic structure map.

When a discovery or delineation well has not intersected a contact, and one cannot be reasonably inferred, maximum area extent is calculated by assuming the structure is filled to spill point. The most likely area is typically based on the structure being 1/2 full (vertically), and minimum area is obtained assuming the base of zone's porosity at the well location as a water contact.

## Top Reservoir

This parameter is defined by the projection of the known reservoir sand pool tops from the respective well to the structure's crest as delineated by seismic mapping. Given the available seismic dataset's vintage, quality, coverage, nature and number of reflectors, pool elevation/position relative to the mapped reflector and the like, the accuracy of each crestal top an estimate only and margins of error are themselves variable. More current geological and geophysical may exis t for various fields but in most cases remains under the applicable confidentiality periods and thus is not publicly available at this time. Well from which sand top data extracted and/or projected to field crest indicated in brackets.

## Average Net Pay

For fields where the reservoir is relatively thick compared to the vertical relief of the structure, a net pay map relating pay in the well to the anomaly structure is constructed, interpreted, and an average net pay is calculated. For discoveries that have fairly thin reservoirs, the pay calculated in the well is taken to be the average net pay for the zone. Net pays in the well are calculated using standard calculation techniques, and cutoffs for porosity, water saturation and shale content are tabulated within each section. Any pay interval less than 1m thick is discounted.

## Average Porosity

Effective porosities are calculated using the neutron-density crossplot technique. Generally, sonic porosity calculations are also undertaken. Where cores are available over the pay zone, a core porosity versus log porosity relationship is determined, and effective log porosity is adjusted where needed. Average porosity is determined by dividing the sum of the porosity-thickness by the thickness of net pay after cutoffs have been honored.

## Average Water Saturation

Where possible, water resistivities of the formation water are taken from an analysis of water recovered from DSTs or RFTs. Where this is not possible the resistivities are determined from the SP log in wet zones in the same formation, or by assuming a salinity for the water based on nearby analogous fields. Using effective porosities and calculated water resistivities, water saturations are calculated using a petrophysical system employing appropriate water saturation equations (typically Simandoux). Average water saturation is determined by dividing the sum of the saturated-porosity-thickness by the porosity-thickness after cutoffs have been honoured.

## Formation Pressure

Datum depths for each pool are derived by taking the structural top of the anomaly and the hydrocarbon-water contact and finding the mid-point (Formation Datum Depth). The formation pressure is calculated by taking the extrapolated shut-in pressure from tests and adjusting to the datum depth by correcting from the mid point of the test (or depth of the gauge) by using appropriate gas or oil gradients. Where a DST pressure is not available, RFT pressures are used.

## Formation Temperature

Formation temperatures are taken from DST results or from temperature gradient graphs that are available for many of the areas. In some cases, formation temperatures were calculated by extrapolating a temperature gradient from maximum bottom hole log temperatures.

## Formation Volume Factors/Shrinkage Factors

Formation Volume Factors (FVFs) are based on composition, reservoir pressure and temperature, standard pressure and temperature. For gas accumulations we have employed correlations based on specific gravity, reservoir pressure and reservoir temperature obtained from DST tests in the exploration wells. Due to uncertainties in composition and the other primary variables in this calculation, a range of +/-5% has been assigned to the calculated FVF variable to define the probabilistic range boundaries.

## Original Hydrocarbons in Place and Recoverable Reserves

As each zone's volume can be considered an independent entity, total volumes in place for the various fields are also summed probabilistically. This is performed by extracting from each zone simulation the mean and standard deviation of the hydrocarbons in place. These numbers are then included in the final probabilistic simulation with a log-normal distribution for each zone. The results of this simulation define the Original Hydrocarbons in Place for the field.

Condensate Gas Ratios and Gas Oil Ratios calculated from well testing observations are used to estimate the associated streams from gas and oil accumulations.

Recoverable hydrocarbon resources are calculated by applying a recovery factor to the above calculated figures. A number of simulation models, incorporating sensitivities in reservoir parameters and facilities, have demonstrated average recovery factors in the range from 50% to 80% for gas accumulations. Experience, simulation models and decline analysis of currently producing oil assets on the Scotian shelf predict average recovery factors from 20 to 40% for oil accumulations. Based on these observations, we have assigned factors of 50%, 65% and 80% for Low, Medium and High recovery factors for gas accumulations, and 20%, 30%, and 40% for oil accumulations. Best Current Estimate recovery factors are 65% and 30% for gas and oil accumulations, respectively.

A low recovery factor was assigned to the low accumulation case, and correspondingly higher factors to the higher accumulation cases. This has been done to limit the reporting requirements within this document, and is not meant to imply that the recovery factor is completely coupled to the resource size; a low volume accumulation will not necessarily ensure a low recovery factor, and vice versa. Recovery factors on a given hydrocarbon accumulation are a result of careful engineering and resource management, continuously re-evaluated in the light of additional information. The approach within this report has been taken to present the largest currently justifiable range of resources that could be recovered from these assets.

It should also be noted that these recovery factors provide an estimate of the recoverable resource and, particularly with respect to natural gas accumulations, may differ substantially from market based (Sales) reserves where volumes of non-hydrocarbon gases, LPG, plant fuel, etc. would be removed, and an assessment of economic limit would then be made.

# Alma - Significant Discovery

## *Overview*

The Alma gas field is located approximately 75 km south-west of Sable Island. The field was discovered in 1984 and has been delineated with one additional well. This accumulation is located within the Middle Cretaceous age Sable Delta complex in the Sable Subbasin.

At the time of writing (November 2000), Alma is planned to be the second field for development in the Sable Offshore Energy Project's Tier 2 phase. Like the currently producing fields at Venture and North Triumph, it will be linked via a subsea gathering pipeline to the project's central processing complex located at the Thebaud field, ~50 km to the northeast. SOEI's approved development plan indicates that following development of the South Venture field, gas from Alma will assist in sustaining plateau production for the Project, with staged development of the remaining Tier 2 field at Glenelg following later.

### Discovery Well:

Well: Shell PCI et al Alma F-67
Spud: 83-12-02
R.R.: 84-07-05
T.D.: 5054 m

The discovery well is located in 67.9 m of water at approximately 43°36'17.98"N latitude, 60°39'56.29"W longitude. It was drilled to test for the presence of hydrocarbons in lower Cretaceous and upper Jurassic age sands that were incorporated in a large rollover anticline associated with down-to-the-basin growth faults.

### Additional Wells:

The field was further delineated by an additional well 5 km to the south-west of the discovery well.

Well:

Shell PCI et al Alma K-85 (43°34'44.32"N, 60°43'01.69"W)

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| F-67 | DST#2 | 3026-3032 | Missisauga | 48 | | 91 |
| F-67 | DST#4 | 3016-3021 | Missisauga | No flow | | |
| F-67 | DST#5 | 2978-2984 | Missisauga | 522 | 29 | |
| F-67 | DST#6 | 2911-2916 | Missisauga | 319 | 24 | |
| F-67 | DST#7 | 2872-2890 | Missisauga | 846 | 59 | |
| K-85 | DST#1 | 3073-3083 | Missisauga | 371 | 2 | |

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| K-85 | DST#2 | 3020-3028 | Missisauga | 459 | 35 | |
| K-85 | DST#3 | 2950-2963 | Missisauga | 595 | 35 | |
| K-85 | DST#4 | 2931-2938 | Missisauga | 272 | | |
| K-85 | DST#5 | 2843-2857 | Missisauga | 855 | 59 | |

## *Geological/Geophysical Overview*

The Alma field is located in a distal seaward position southwest of the main Sable Delta in the Sable Subbasin. Its position therefore dictates that the reservoir section will be dominated by marine and current depositional facies that are thin and limited to the top of the Missisauga formation: the phase of maximum progradation of the Sable Delta that occurred during the Middle Cretaceous.

### Structure

The Alma Structure is a large fault-bounded roll-over anticline, formed as a result of basement block faulting, or, deep salt motion. The structure consists of two highs centered near the wells, bounded by east-northeast to west-southwest trending faults. These bounding faults converge on the west end of the structure and diverge towards the east. There is approximately 2300 ha. of areal closure at the Top Missisauga seismic marker and about 150 m of combined simple and fault closure.

The major listric faults appear to sole out into possible deep Argo salts of latest Triassic-earliest Jurassic age and extend up into the Tertiary aged Banquereau formation. There are two fault blocks south of this structure showing closure but remain undrilled. Definition of the structure and reservoir zone spatial dimensions is limited to the closest mappable seismic marker, known as the 'O-Marker Equivalent', which roughly corresponds to the boundary between Upper and Middle members of the Missisauga formation and is the top of the sand sequence at Alma.

The sedimentary section adjacent to the bounding faults at Alma shows little in the way of thickening into the fault planes. This observation however, appears valid for strata only as old as the Upper Cretaceous (Naskapi member, Logan Canyon formation). The quality of the seismic data below the Naskapi, and the lack of good mappable, deep horizons may mask evidence of growth. In profile, the faults can clearly be seen extending upwards into the Tertiary age Banquereau formation and at this stratigraphic level show some evidence of minor growth. This suggests that there were two phases of motion on the major faults; an earlier subsidence-driven phase of growth faulting (Middle to Late Jurassic (Mic Mac formation) to Middle Cretaceous (Missisauga formation)), and a later phase related to deep basement block faulting or salt motion. Several smaller faults with similar directional trends are also found within the closure areas.

### Stratigraphy

Like other fields on the outer portion of the Sable Delta complex (e.g. North Triumph), the sedimentary section penetrated at Alma reveals that the generally progradational fluvial sands at the top of the Missisauga were subjected to significant marine influences. However, unlike North Triumph, the Missisauga formation at Alma is extremely thin and appears to occupy the most southwesterly and distal portion of the Sable Delta.

The distal seaward position of the Alma Structure from the main sediment source (Sable Delta), resultant poorly developed and/or lack of Missisauga age seismic reflections, and thinness of the reservoir package all infer that little or no sand progressed beyond the Alma complex. The results of Merigomish C-52 wells, drilled immediately south of Alma confirm this interpretation. Indeed, the full reservoir interval representing the entire Missisauga formation, is no more that 270 m thick.

Log and core data reveal that the Missisauga sands can be subdivided into four major coarsening upward sequences which contain a high percentage of silts and sands. Within the sequences are several subsets of fining-upwards cycles, with thicknesses increasing up-section. Each of these cycles represent individual strand-plain depositional events, although in this distal deltaic position they are incomplete, being mostly lower to upper shoreface sand facies.

## Reservoir Description

The productive reservoirs in the Alma field are the Cretaceous age sands of the Upper member of the Missisauga formation. Well data indicates that the formation gently thins to the southwest, from 268 m at F-67 to 261 m at K-85; a distance of 5.1 km. The section appears to lose sand and shale-out from both the top and bottom of the formation. There are four major sands (with subdivisions) that can be correlated between the two wells. Numbered from the base of the reservoir section they include Sands 1, 1a, 1b, 1c ('D' Pool), Sand 2 ('C' Pool), Sand 3 ('C' Pool), and Sands 4a and 4b ('A' Pool). The reservoir quality of these sands in the two adjacent as yet undrilled structures is expected to be poor. Thickness and sand continuity will probably change only slightly.

Well logs, cores and cuttings from the two wells suggest the Missisauga sands represent deposition in a marine-dominated delta-fringe / strandplain sedimentary environment, and thus the sands likely have sheet-like geometries. The sand sequences are generally coarsening-upward cycles, with sands that are well sorted, subangular in shape and range from very fine to fine grain in size. The cement is mostly siliceous, with some calcareous and minor sideritic intervals. Glauconite grains and coal fragments are common in well developed sands at the top of the sequence. Fossil fragments and bioturbation are also present.

Higher porosity and permeability values track grain size increases, with the best reservoirs developed in the coarser grained intervals at the tops of each sand body. Reservoirs containing sediments with grain sizes larger than fine sand are rare, and although dominantly fine grained, the actions of currents and wave have resulted in well sorted sands with good preserved porosity. The slightly argillaceous nature of the sands results in moderate to fair porosity values, ranging from about 23% (clean sands) to 15% or less (shaley and bioturbated). Core analysis reveals that the average porosities for the F-67 and K-85 wells are rather low at 13.7% and 11.4% respectively. Core analysis for the reservoir sands in both wells also shows low average permeability values.

## *Petrophysical Overview*

Petrophysical evaluation of the two wells in the Alma field utilized log, core and pressure data[1]. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Alma field using the cutoffs tabled below. Effective porosities were calculated using the standard neutron - density crossplotting technique. The neutron - density curves were edited in 'washed out' intervals to correct for bad log readings. A 10% porosity cutoff, which corresponds to a permeability cutoff of 0.5 mD, was used to define net pay at Alma. Water saturations were determined from log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 60 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 50 |
| **Permeability Horizontal** | (mD) | 15-20 |

[1] Petrophysical evaluation provided by the Petroleum Development Agency, Department of Natural Resources, Nova Scotia.

## *Original Hydrocarbons in Place*

Area calculations for these reservoirs were based on inferred gas/water contacts, anticipated areal extent of the reservoir sands, and, for the 'D' pool, possible extension of the reservoir into an adjacent fault block. The variations in net pay and porosity that were observed between the discovery and delineation wells has also served as the basis for their selection as primary variables within the probabilistic analysis. Justifiable ranges on these parameters were based on mapped variations of properties, averaged over the reservoir extent. Water saturation was held constant at the well observed values within the probabilistic calculations. Formation pressures were obtained from DST and RFT pressure measurements. Pressure/Depth analysis was conducted to assist in defining the fluid contacts for the field. Formation temperatures were obtained by establishing a temperature gradient from maximum bottom hole log temperatures.

| **Pool A - Sand 4a/b** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 2480 | 2480 | 2480 | 2480 |
| **Top Reservoir** | (mSS) | | | | 2805 (F-67) |
| **Net Pay** | (m) | 13.5 | 16.6 | 18.7 | 16.3 |
| **Porosity** | (%) | 12 | 13 | 14 | 13 |
| **Sw** | (%) | 26 | 26 | 26 | 26 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^oC$) | 108 | 108 | 108 | 108 |
| **Gas FVF** | | 217 | 223 | 229 | 223 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 7.150 | 8.840 | 10.000 | 8.690 |
| **OOIP** | (E6M3) | | | | |

| **Pool B - Sand 3** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 4224 | 4224 | 4224 | 4224 |
| **Top Reservoir** | (mSS) | | | | 2920 (F-67) |
| **Net Pay** | (m) | 7.4 | 8.0 | 8.6 | 8.0 |
| **Porosity** | (%) | 13.2 | 13.5 | 13.8 | 13.5 |
| **Sw** | (%) | 40 | 40 | 40 | 40 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^oC$) | 109 | 109 | 109 | 109 |
| **Gas FVF** | | 217 | 223 | 229 | 223 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 5.640 | 6.090 | 6.570 | 6.100 |
| **OOIP** | (E6M3) | | | | |

| Pool C - Sand 2 | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 4512 | 4512 | 4512 | 4512 |
| **Top Reservoir** | (mSS) | | | | 2945 (F-67) |
| **Net Pay** | (m) | 1.7 | 2.0 | 2.3 | 2.0 |
| **Porosity** | (%) | 12 | 12 | 12 | 12 |
| **Sw** | (%) | 54.0 | 51.0 | 47.0 | 51.0 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^oC$) | 111 | 111 | 111 | 111 |
| **Gas FVF** | | 218 | 224 | 230 | 224 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.020 | 1.190 | 1.380 | 1.200 |
| **OOIP** | (E6M3) | | | | |

| Pool D - Sand 1c | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 917 | 1091 | 1372 | 1120 |
| **Top Reservoir** | (mSS) | | | | 3005 (F-67) |
| **Net Pay** | (m) | 3.1 | 3.4 | 4.0 | 3.5 |
| **Porosity** | (%) | 14 | 14 | 14 | 14 |
| **Sw** | (%) | 25 | 25 | 25 | 25 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^oC$) | 112 | 112 | 112 | 112 |
| **Gas FVF** | | 218 | 224 | 230 | 224 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.718 | 0.895 | 1.148 | 0.922 |
| **OOIP** | (E6M3) | | | | |

| Pool D - Sand 1b | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1444 | 2160 | 3106 | 2224 |
| **Top Reservoir** | (mSS) | | | | 3040 (F-67) |
| **Net Pay** | (m) | 1.2 | 1.4 | 1.7 | 1.5 |
| **Porosity** | (%) | 14 | 14 | 14 | 14 |
| **Sw** | (%) | 57 | 57 | 57 | 57 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^oC$) | 112 | 112 | 112 | 112 |
| **Gas FVF** | | 218 | 224 | 230 | 224 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.276 | 0.421 | 0.630 | 0.440 |
| **OOIP** | (E6M3) | | | | |

| Pool D - Sand 1a | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 957 | 1172 | 1519 | 1208 |
| **Top Reservoir** | (mSS) | | | | 3055 (F-67) |
| **Net Pay** | (m) | 2 | 2 | 2 | 2 |
| **Porosity** | (%) | 14 | 14 | 14 | 14 |

| | | | | | |
|---|---|---|---|---|---|
| **Sw** | (%) | 37 | 37 | 37 | 37 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^{o}$C) | 112 | 112 | 112 | 112 |
| **Gas FVF** | | 218 | 224 | 230 | 224 |
| **Oil Bo** | | | | | |
| | | | | | |
| **OGIP** | (E9M3) | 0.380 | 0.460 | 0.600 | 0.480 |
| **OOIP** | (E6M3) | | | | |

## *Depletion Scenario and Recoverable Resource*

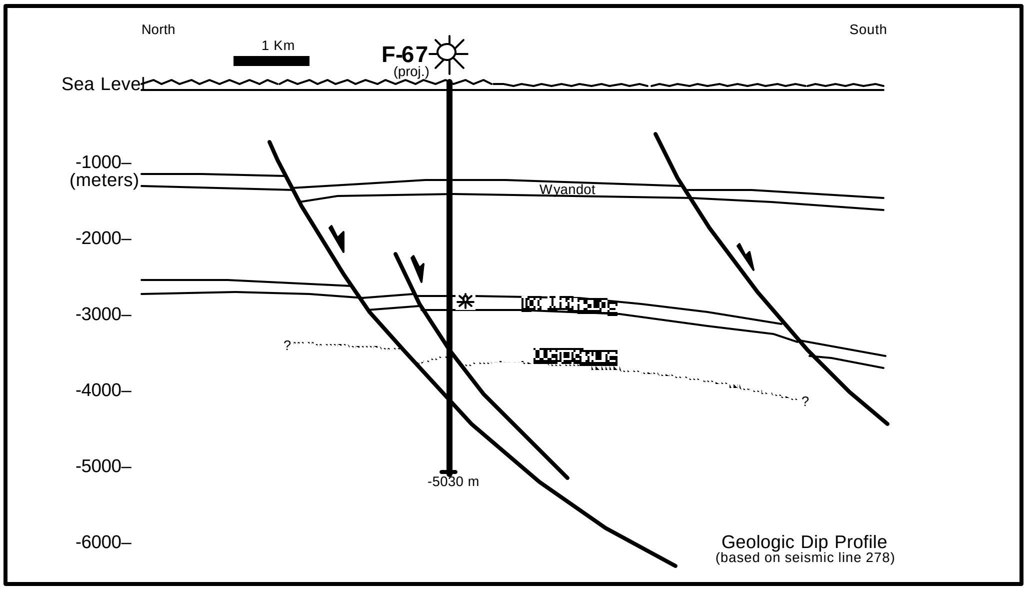
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 69 M3/E6M3 of recoverable gas, based on average DST results.

At the time of writing (November 2000), Alma is planned to be the second field for development in the Sable Offshore Energy Project's Tier 2 phase. Like the currently producing fields at Venture and North Triumph, it will be linked via a subsea gathering pipeline to the project's central processing complex located at the Thebaud field, ~50 km to the northeast. SOEI's approved development plan indicates that following development of the South Venture field, gas from Alma will assist in sustaining plateau production for the Project, with staged development of the remaining Tier 2 field at Glenelg following later. Proposed within this plan is the drilling of 5 development wells within the structure. The field will be placed under compression during its late life from a central compression facility located approximately 35 km away at the Thebaud location.

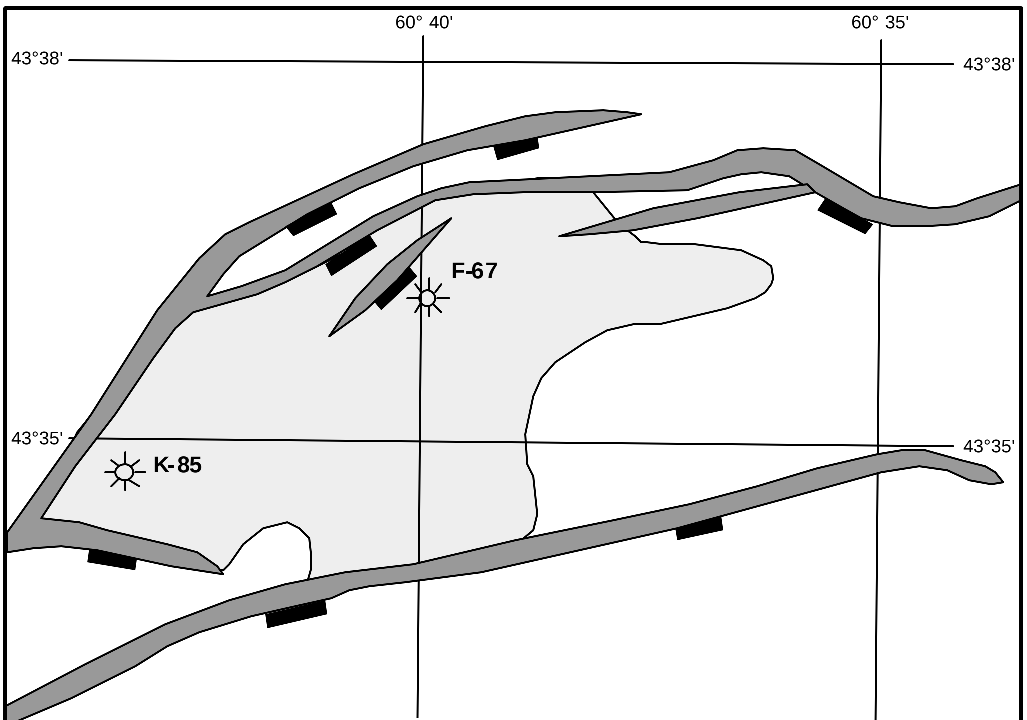
| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 15.42 (545) | 17.73 (626) | 20.38 (720) | 17.83 (630) |
| **Condensate** | (E6M3) | 1.064 (6.69) | 1.223 (7.69) | 1.406 (8.84) | 1.231 (7.74) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 7.710 (272) | 11.52 (407) | 16.30 (576) | 11.59 (409) |
| **Condensate** | (E6M3) | 0.532 (3.35) | 0.795 (5.00) | 1.125 (7.08) | 0.800 (5.03) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Alma




Geologic Dip Profile
(based on seismic line 278)




Area above the water line at the Top Missisauga level.
After SOEPDPA.

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# Arcadia - Significant Discovery

## *Overview*

The Arcadia field is located approximately 30 km north-east of Sable Island. The field was discovered in 1983 and its current assessment is based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil et al Arcadia J-16 |
| Spud: | 83-01-27 |
| R.R.: | 83-07-19 |
| T.D.: | 6005 m |

The discovery well is located in 5.5 m of water at approximately 44°05'43.58"N latitude, 59°31'58.19"W longitude. It was 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 fault.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| J-16 | DST#1 | 5606-5620 | Mic Mac | No Rec | | |
| J-16 | DST#2 | 5227-5235 | Mic Mac | No Rec | | |
| J-16 | DST#5 | 5165-5175 | Mic Mac | 399 | 14 | 12 |
| J-16 | DST#6 | 5031-5041 | Mic Mac | | | 1824 |
| J-16 | DST#8 | 4892-4901 | Mic Mac | 161 | | 7 |
| J-16 | DST#9 | 4857-4864 | Mic Mac | 147 | 1 | 5 |
| J-16 | DST#10 | 4640-4645 | Missisauga | | | 175 |

## Geological/Geophysical Overview

The Arcadia gas field is located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. With its proximity to sediment source, basin hinge-line position and resultant rapid subsidence, the progradational strata deposited at Arcadia consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. All the reservoir sands are located in the Late Jurassic Mic Mac formation.

### Structure

The Arcadia structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic to Early Jurassic age salts of the Argo formation. Such a combination resulted in the formation of significant overpressure conditions which are encountered in the reservoir sands.

Arcadia is a large, somewhat triangular-shaped, westerly tapering rollover anticline bound on the north by a major down-to-the-basin listric growth fault. The structure occurs within a narrow (6-8 km) transition zone of faults which define the basin hinge line, separating the more stable platformal region to the north from the basin depocentre to the south. The structural crest of the field is adjacent to the northeast-southwest trending bounding fault, though at depth migrates towards the center of the structure which in turn becomes more elongate. At this lower elevation, a small fault synthetic with and parallel to the main north bounding fault forms the field's southern boundary. Maximum structural closure at the Jurassic 'A' seismic marker is about 55 m.

In seismic profiles the structure is interpreted to have a large area of closure with modest relief. Although several regional seismic markers are prominent in the area, internal field reflections define its structural configuration. These limestone reflections, also mapped in other gas fields of the Venture-Olympia trend, include the #3-Equivalent Limestone ("Top Jurassic Marker"), #9 Limestone ("Jurassic 'A' Marker") and Abenaki formation.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. This deltaic pulse overwhelmed and buried a pre-existing reefal and platformal carbonate facies of the Abenaki formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

The reservoir sands discovered at Arcadia are stratigraphically located within the Late Jurassic Mic Mac formation. Mapping and well data suggest that the Arcadia reservoir strata and that of the Venture field immediately to the south are equivalent, although direct sand-to-sand correlations are uncertain. Only one exploratory well has been drilled at Arcadia at the top of structural closure and 3 major reservoirs were encountered over a 175 meter thick section and were logged, cored and tested (e.g. Sands/Zones 3, 5 & 5a).

All Arcadia gas reservoirs are deep and exist under high overpressure conditions. The preservation/enhancement of porosity and permeability at depth in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size. 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.

Arcadia reservoirs consist of stacked sequences of cyclic deltaic and strandplain sands interfingering with marine and prodelta shales. These capping shales and occasional tight oolitic limestones provide effective top seals within the succession. Log profiles and cores of the Mic Mac reservoir strata reflect delta front and channel depositional conditions with strandplain nearshore and tidal facies also present. The well data show that the reservoir characteristics of these very fine to medium grained, well sorted, siliceous and calcareous coarsening upward sands have fair effective porosities and permeabilities ranging from 9-12% and 0.6-80 mD respectively.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the Arcadia J-16 well was completed. The results of this evaluation, for each reservoir in the field, are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Arcadia field using the cutoffs tabled below. Effective porosities were calculated using, the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log. No discernible gas/water contacts were detected on the logs in any of the Arcadia reservoirs.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | ~0.6 - 80 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

The areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The proven area was assigned based upon the single well test, most likely based on the structure being half full, and possible area extending to structural spill point. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained from DST temperature measurements or from available temperature gradient graphs.

| **Zone 1a - Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1127 | 1550 | 2157 | 1600 |
| **Top Reservoir** | (mSS) | | | | 5110 (J-16) |
| **Net Pay** | (m) | 3 | 3 | 3 | 3 |
| **Porosity** | (%) | 10.8 | 10.8 | 10.8 | 10.8 |
| **Sw** | (%) | 47.9 | 47.9 | 47.9 | 47.9 |
| **Pressure** | (kPa) | 101000 | 101000 | 101000 | 101000 |
| **Temp** | ($^{o}$C) | 147 | 147 | 147 | 147 |
| **Gas FVF** | | 388 | 399 | 410 | 399 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.754 | 1.046 | 1.450 | 1.078 |
| **OOIP** | (E6M3) | | | | |

| **Zone 1b - Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1127 | 1550 | 2157 | 1600 |
| **Top Reservoir** | (mSS) | | | | 5110 (J-16) |
| **Net Pay** | (m) | 8 | 8 | 8 | 8 |
| **Porosity** | (%) | 11.0 | 11.0 | 11.0 | 11.0 |
| **Sw** | (%) | 42.3 | 42.3 | 42.3 | 42.3 |
| **Pressure** | (kPa) | 101000 | 101000 | 101000 | 101000 |
| **Temp** | (oC) | 147 | 147 | 147 | 147 |
| **Gas FVF** | | 388 | 399 | 410 | 399 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.277 | 3.135 | 4.391 | 3.242 |
| **OOIP** | (E6M3) | | | | |

| Zone 1c - Mic Mac | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1127 | 1550 | 2157 | 1600 |
| **Top Reservoir** | (mSS) | | | | 4850 (J-16) |
| **Net Pay** | (m) | 2.5 | 2.5 | 2.5 | 2.5 |
| **Porosity** | (%) | 10.3 | 10.3 | 10.3 | 10.3 |
| **Sw** | (%) | 44.7 | 44.7 | 44.7 | 44.7 |
| **Pressure** | (kPa) | 101000 | 101000 | 101000 | 101000 |
| **Temp** | (oC) | 147 | 147 | 147 | 147 |
| **Gas FVF** | | 388 | 399 | 410 | 399 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.643 | 0.880 | 1.229 | 0.909 |
| **OOIP** | (E6M3) | | | | |

| Zone 2 - Mic Mac | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1127 | 1550 | 2157 | 1600 |
| **Top Reservoir** | (mSS) | | | | 4820 (J-16) |
| **Net Pay** | (m) | 3.8 | 3.8 | 3.8 | 3.8 |
| **Porosity** | (%) | 8.0 | 8.0 | 8.0 | 8.0 |
| **Sw** | (%) | 36.7 | 36.7 | 36.7 | 36.7 |
| **Pressure** | (kPa) | 90000 | 90000 | 90000 | 90000 |
| **Temp** | ($^{o}$C) | 132 | 132 | 132 | 132 |
| **Gas FVF** | | 385 | 396 | 407 | 396 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.856 | 1.180 | 1.650 | 1.219 |
| **OOIP** | (E6M3) | | | | |

| Zone 3 - Mic Mac | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1127 | 1550 | 2157 | 1600 |
| **Top Reservoir** | (mSS) | | | | 4730 (J-16) |
| **Net Pay** | (m) | 2.8 | 2.8 | 2.8 | 2.8 |
| **Porosity** | (%) | 4.8 | 4.8 | 4.8 | 4.8 |
| **Sw** | (%) | 52.0 | 52.0 | 52.0 | 52.0 |
| **Pressure** | (kPa) | 90000 | 90000 | 90000 | 90000 |
| **Temp** | ($^{o}$C) | 132 | 132 | 132 | 132 |
| **Gas FVF** | | 381 | 392 | 403 | 392 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.285 | 0.393 | 0.544 | 0.405 |
| **OOIP** | (E6M3) | | | | |

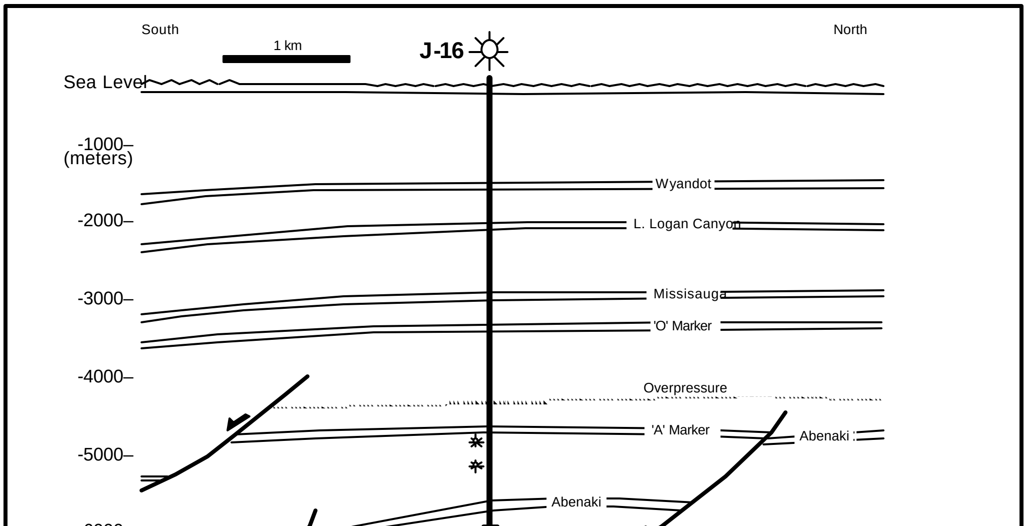
## Depletion Scenario and Recoverable Resource

Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 35 M3/E6M3 of recoverable gas and is based on DST observations.

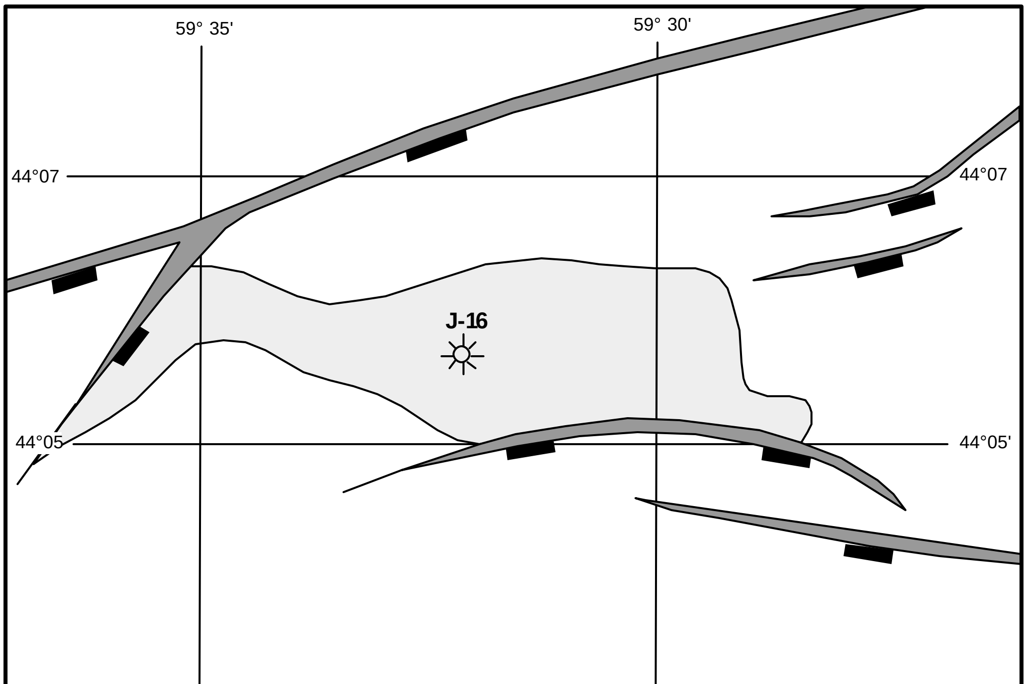
| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 4.905 (173) | 6.660 (235) | 9.038 (319) | 6.853 (242) |
| **Condensate** | (E6M3) | 0.172 (1.08) | 0.233 (1.47) | 0.316 (1.99) | 0.240 (1.51) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 2.453 (87) | 4.329 (153) | 7.230 (255) | 4.454 (157) |
| **Condensate** | (E6M3) | 0.086 (0.54) | 0.152 (0.95) | 0.254 (1.60) | 0.156 (0.98) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Arcadia




Geologic Dip Profile
(based on 3D seismic line 324)




Area above the water line at the Jurassic "A" level.
After COGLA.

CANADA - NOVA SCOTIA
OFFSHORE PETROLEUM BOARD

# Banquereau - Significant Discovery

## *Overview*

The Banquereau field is located approximately 110 km east of Sable Island. The field was discovered in 1982 and its current assessment is based on the discovery well. This accumulation is located within in the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | PEX et al Banquereau C-21 |
| Spud: | 81-12-02 |
| R.R.: | 82-08-01 |
| T.D.: | 4991 m |

The discovery well is located in 83 m of water at approximately 44°10’07.52”N latitude, 58°34’00.24”W longitude. It was drilled to test for the presence of hydrocarbons in a rollover anticline associated with down-to-the-basin faults.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| C-21 | DST#1 | 4035-4046.5 | Missisauga | TSTM | | |
| C-21 | DST#2 | 3585-3596 | Missisauga | 566 | 15 | 6 |
| C-21 | DST#3 | 3360-3372.5 | Logan Canyon | 22 | | 93 |
| C-21 | DST#4 | 4949-4991 | Missisauga | No Flow to Surface | | |

## *Geological/Geophysical Overview*

The Banquereau gas field is located in the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at Banquereau consist of a shale dominated, thin sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The Banquereau field is located in the Early Cretaceous Logan Canyon and Missisauga formations.

### Structure

The Banquereau structure was formed via sediment loading on an unstable thick marine shale substrate and low-rate syndepositional movement along a major growth fault. The faulting penetrates upwards into Tertiary age strata and soles into the deep Jurassic age marine shales of the Verrill Canyon formation. Banquereau is a low relief, narrow, elongate anticlinal feature bounded to the north by a major, southeast-dipping, down-to-the-basin fault, and exhibits both fault and rollover related closure. The structural crest of the field is near its center and has a maximum vertical closure of approximately 70 m.

Several regional seismic reflectors define the Banquereau structure. These seismic markers include, respectively, the Late Cretaceous Wyandot Limestone, the Missisauga 'O' Marker, and several others (e.g., "Top Jurassic" (Mic Mac), "Top Baccaro" (Abenaki) and the "Ochre Marker". These latter reflectors are operator defined though subsequent research shows that they are limestones and are incorrectly named, all being located within the late Early Cretaceous Missisauga formation.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the Banquereau area occupied a position that was distal to deltaic sedimentation and thus sands of the Mic Mac and Lower Missisauga formations were not deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest and beyond. The Banquereau area was located on the eastern flank of the delta and as such is shale dominated and received little sand. However, this absence of clastics enhanced the conditions allowing for deposition of oolitic limestones within the Middle and Upper Missisauga members. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. Renewed delta progradation followed, though persisting in its southwesterly orientation and resulted in only thin sands being deposited in the Banquereau area.

### Reservoir Description

The Banquereau gas reservoirs are found within strata of the Early Cretaceous Naskapi member, Logan Canyon formation, and at the top of the Missisauga formation. Only one exploratory well has been drilled on the structural crest at Banquereau and two reservoir quality sands were encountered containing significant gas pays. Both reservoirs are under hydropressure conditions and were drillstem tested. It is believed that the reservoir sands thicken slightly towards the north bounding growth fault and have good lateral continuity throughout the field area. Overpressured conditions are present in the deeper Verrill Canyon formation shales.

Reservoir sands in the Banquereau field consist of isolated sequences of delta front, channel and strandplain-shoreface depositional facies in a shale dominated marine setting. Well data shows that these coarsening upward progradational sands are very fine to medium grained, well sorted, siliceous and variably argillaceous. The reservoir characteristics of the gas sands are fair with effective average porosities ranging from 9-14% and permeabilities 0.1-20 mD based on well logs and drillstem test results.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the Banquereau C-21 well was completed. The results of this evaluation, for each reservoir in the field, are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Banquereau field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | 0.1 - 20 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

Log defined gas/water contacts were used to determine the areal extent of the reservoirs. Average net pay was determined to be the primary uncertain variable. Porosity and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **Zone I - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1300 | 1300 | 1300 | 1300 |
| **Top Reservoir** | (mSS) | | | | 3315 (C-21) |
| **Net Pay** | (m) | 8.4 | 11.3 | 13.1 | 11.0 |
| **Porosity** | (%) | 13.6 | 13.6 | 13.6 | 13.6 |
| **Sw** | (%) | 33.4 | 33.4 | 33.4 | 33.4 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^{o}$C) | 383 | 383 | 383 | 383 |
| **Gas FVF** | | 262 | 269 | 276 | 269 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.640 | 3.580 | 4.150 | 3.480 |
| **OOIP** | (E6M3) | | | | |

| **Zone II - Logan Can.** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1300 | 1300 | 1300 | 1300 |
| **Top Reservoir** | (mSS) | | | | 3550 (C-21) |
| **Net Pay** | (m) | 1.8 | 2.7 | 3.5 | 2.7 |
| **Porosity** | (%) | 12.7 | 12.7 | 12.7 | 12.7 |
| **Sw** | (%) | 54.9 | 54.9 | 54.9 | 54.9 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^{o}$C) | 383 | 383 | 383 | 383 |
| **Gas FVF** | | 261 | 268 | 275 | 268 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.350 | 0.540 | 0.690 | 0.530 |
| **OOIP** | (E6M3) | | | | |

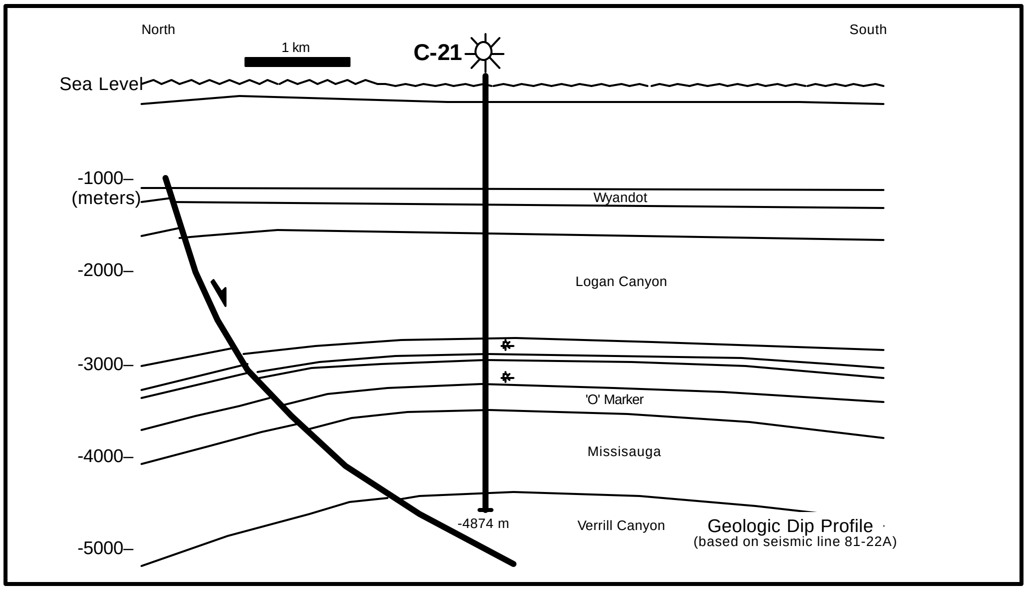
## Depletion Scenario and Recoverable Resource

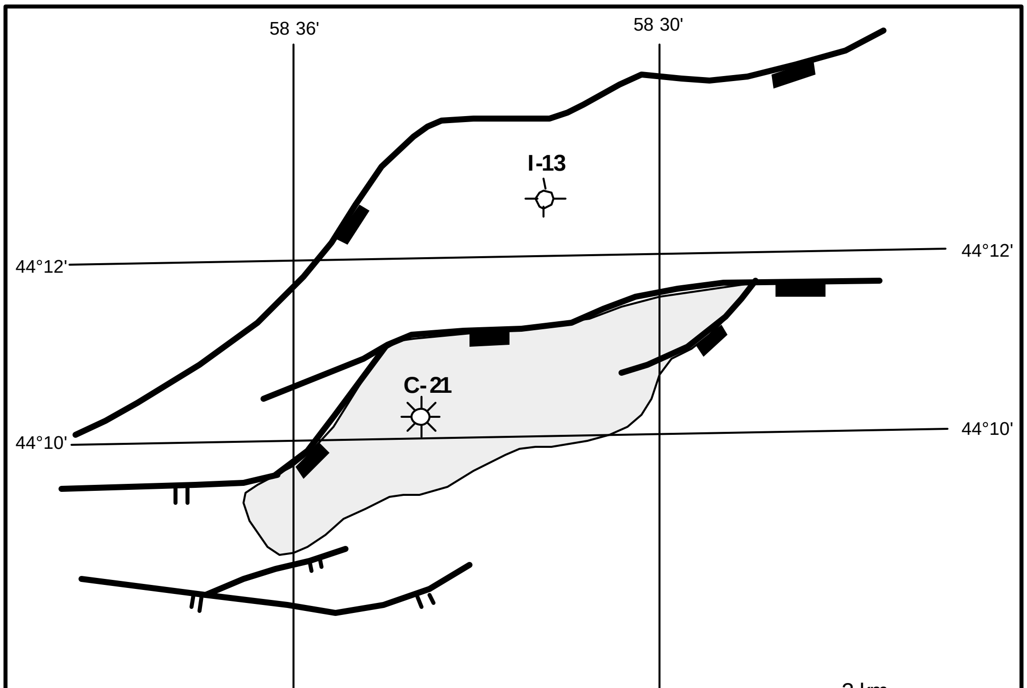
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 28 M3/E6M3 of recoverable gas, and is based upon average DST results.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 3.160 (112) | 3.950 (139) | 4.930 (174) | 4.010 (142) |
| **Condensate** | (E6M3) | 0.088(0.56) | 0.111 (0.70) | 0.138 (0.88) | 0.112 (0.71) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 1.580 (56) | 2.568 (91) | 3.944 (139) | 2.607 (92) |
| **Condensate** | (E6M3) | 0.044 (0.28) | 0.072 (0.45) | 0.110 (0.69) | 0.073 (0.46) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Banquereau




Area above the water line at the Cretaceous "O" Marker level.
After Petro Canada 8624-P28-28E.

CANADA - NOVA SCOTIA
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# Chebucto - Significant Discovery

## *Overview*

The Chebucto gas field is located approximately 40 km south-east of Sable Island. The field was discovered in 1984 and its current assessment is based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin on the southeastern edge of the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Husky-Bow Valley et al Chebucto K-90 |
| Spud: | 84-01-06 |
| R.R.: | 84-08-02 |
| T.D.: | 5235 m |

The discovery well is located in 86.2 m of water at approximately 43°39'44.74"N latitude, 59°42'52.05"W longitude. It was 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 conducted.

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| K-90 | DST#1 | 4609-4621 | Missisauga | No Flow to Surface | | |
| K-90 | DST#2 | 4287-4299 | Missisauga | No Flow to Surface | | |
| K-90 | DST#3 | 4262-4276 | Missisauga | 0.4 | | 275 |
| K-90 | DST#4 | 4227-4238 | Missisauga | 416 | 14 | 227 |
| K-90 | DST#5 | 4166-4177 | Logan Canyon | No Flow to Surface | | |
| K-90 | DST#6 | 3866-3877 | Logan Canyon | TSTM | | 40 |
| K-90 | DST#7 | 3798-3815 | Logan Canyon | 586 | 25 | 80 |
| K-90 | DST#8 | 3352-3357 | Logan Canyon | No Flow to | Surface | |
| K-90 | DST#8A | 3352-3357 | Logan Canyon | 218 | 9 | 6 |

## Geological/Geophysical Overview

The Chebucto gas field is located in the Mesozoic age Sable Subbasin on the southeastern edge of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at Chebucto consist of a shale dominated, thin sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Early Cretaceous Logan Canyon and Missisauga formations.

### Structure

The Chebucto structure was formed via sediment loading on an unstable thick marine shale substrate and low rate syndepositional movement along a major growth fault. The fault penetrates upwards into Tertiary age strata and soles into the deep Jurassic age marine shales of the Verrill Canyon formation. Chebucto is a large oval to guitar-shaped anticline located between two major down-to-the-basin faults, and exhibits both fault and rollover related closure. Both faults have a northeast-southwest trend and are connected by a near north-south crosscutting fault splay that dips to the east. The structural crest of the field is near its center and has a maximum vertical closure of approximately 275 m.

One regional and several internal field seismic reflectors exclusive to Chebucto, delineate the structure. These seismic markers include, respectively, the Late Cretaceous Wyandot Limestone, the "Naskapi Shale" and the "Upper Missisauga". The latter two, 'A' and 'B' Markers, are both located within the bottom half of the Middle Missisauga member. These two reflectors are operator defined though subsequent research shows that they are incorrectly named, as they are located in the overlying Cree member, Logan Canyon formation and above the known overpressure section.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the Chebucto-North Triumph area occupied a position that was distal to deltaic sedimentation and thus no Mic Mac formation sands were deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest. The Chebucto area was located on the southeastern flank of the delta and as such is shale dominated and received little sand. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed delta progradation followed, though persisting in its southwesterly orientation and resulted in only thin sands being deposited in the Chebucto area.

### Reservoir Description

The Chebucto gas reservoirs are found within strata of the Early Cretaceous Cree and Naskapi members, Logan Canyon formation, and at the top of the Missisauga formation. Only one exploratory well has been drilled near the structural crest at Chebucto and a number of reservoir quality sands were encountered with at least four containing significant gas pays. The uppermost three sands are under hydropressure conditions while the lowest gas sand is slightly overpressured, and all except for the shallowest were drillstem tested. It is believed that the reservoir sands thicken slightly towards the north bounding growth fault and have good continuity throughout the field area. The deepest, overpressured sand equates with the main reservoir at the North Triumph field 12 kilometers to the northwest.

Reservoir sands in the Chebucto field consist of isolated sequences of delta front, channel and strandplain-shoreface depositional facies in a shale dominated marine setting. Well data shows that these coarsening upward progradational sands are very fine to fine grained, well sorted, siliceous, calcareous and variably argillaceous and dolomitic. The reservoir characteristics of the gas sands are fair to good with effective average porosities ranging from 15-18% and permeabilities 5-20 mD based on well logs and drillstem test results.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the Chebucto K-90 well was completed. The results of this evaluation, for each reservoir in the field, are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Chebucto field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | 5 - 20 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

The Chebucto reservoir is separated into three main units; Zone 1 in the Missisauga formation and Zones 2 and 3 in the Logan Canyon formation. For Zones 1 and 3, log defined gas/water contacts were used to determine an area for gas in place. Zone 2 in the K-90 well, tested considerable water along with significant gas rates. Some uncertainty remains as to whether this water is an indication of a nearby gas/water contact or simply mud filtrate as this section of the hole was left open to overbalanced mud for several weeks. This is sufficient time for mud filtrate to deeply invade the surrounding formation. Therefore, there is a distinct possibility that the water produced on the DST is mud filtrate and not 'true' formation water. Thus the probabilistic area distribution for Zone 2 has been assigned with the base of porosity within the well as the proven and most likely value, with the possible area extending to structural spill point. For Zone 1 and 3, net pay was selected as the primary variable within the probabilistic calculations. Due to the relatively large areal extent and the limited well control, these variables were assigned +/- 25% variations from the discovery well's observed values. The porosity and water saturation for all zones, and net pay for Zone 2, were held constant at the well observed values within the calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained from DST temperature measurements or from available temperature gradient graphs.

| Zone 3 - Logan Can. | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 3825 | 3825 | 3825 | 3825 |
| **Top Reservoir** | (mSS) | | | | 3285 (K-90) |
| **Net Pay** | (m) | 3.4 | 4.0 | 4.6 | 4.0 |
| **Porosity** | (%) | 17 | 17 | 17 | 17 |
| **Sw** | (%) | 40 | 40 | 40 | 40 |
| **Pressure** | (kPa) | 34000 | 34000 | 34000 | 34000 |
| **Temp** | ($^o$C) | 100 | 100 | 100 | 100 |
| **Gas FVF** | | 252 | 2591266 | 259 | |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 3.465 | 4.044 | 4.604 | 4.042 |
| **OOIP** | (E6M3) | | | | |

| Zone 2 - Logan Can. | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 2141 | 2570 | 3263 | 2642 |
| **Top Reservoir** | (mSS) | | | | 3750 (K-90) |
| **Net Pay** | (m) | 16 | 16 | 16 | 16 |
| **Porosity** | (%) | 15.7 | 15.7 | 15.7 | 15.7 |
| **Sw** | (%) | 39.2 | 39.2 | 39.2 | 39.2 |
| **Pressure** | (kPa) | 39000 | 39000 | 39000 | 39000 |
| **Temp** | ($^o$C) | 116 | 116 | 116 | 116 |
| **Gas FVF** | | 263 | 270 | 277 | 270 |

| | | | | | |
|---|---|---|---|---|---|
| **Oil Bo** | | | | | |
| | | | | | |
| **OGIP** | (E9M3) | 8.827 | 10.585 | 13.481 | 10.894 |
| **OOIP** | (E6M3) | | | | |

| **Zone 1 - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 2050 | 2050 | 2050 | 2050 |
| **Top Reservoir** | (mSS) | | | | 3975 (K-90) |
| **Net Pay** | (m) | 3.4 | 4.0 | 4.6 | 4.0 |
| **Porosity** | (%) | 13.2 | 13.2 | 13.2 | 13.2 |
| **Sw** | (%) | 45 | 45 | 45 | 45 |
| **Pressure** | (kPa) | 52000 | 52000 | 52000 | 52000 |
| **Temp** | ($^o$C) | 118 | 118 | 118 | 118 |
| **Gas FVF** | | | | | |
| **Oil Bo** | | | | | |
| | | | | | |
| **OGIP** | (E9M3) | 1.609 | 1.869 | 2.126 | 1.869 |
| **OOIP** | (E6M3) | | | | |

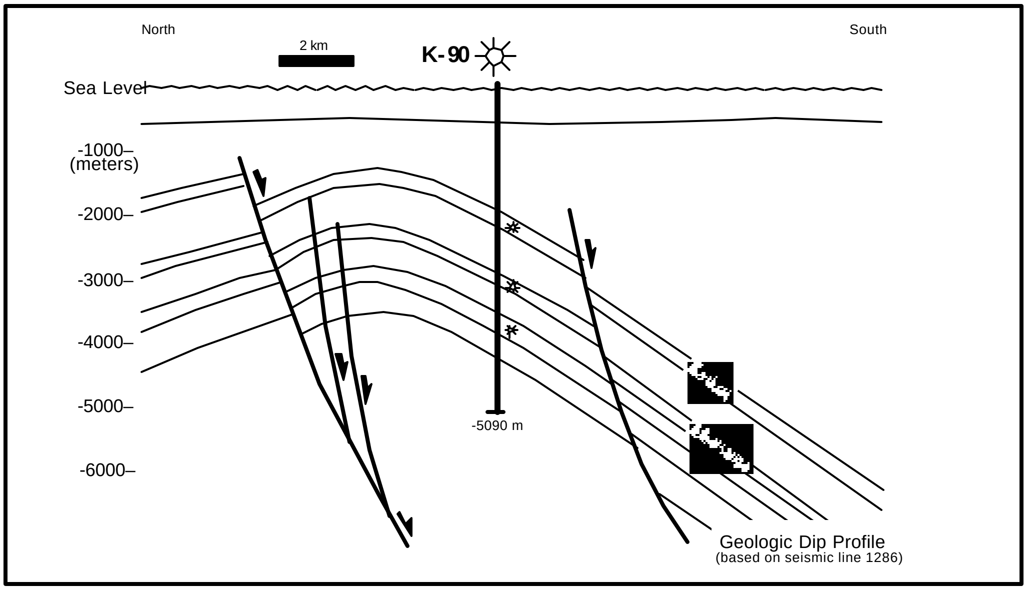
## *Depletion Scenario and Recoverable Resource*

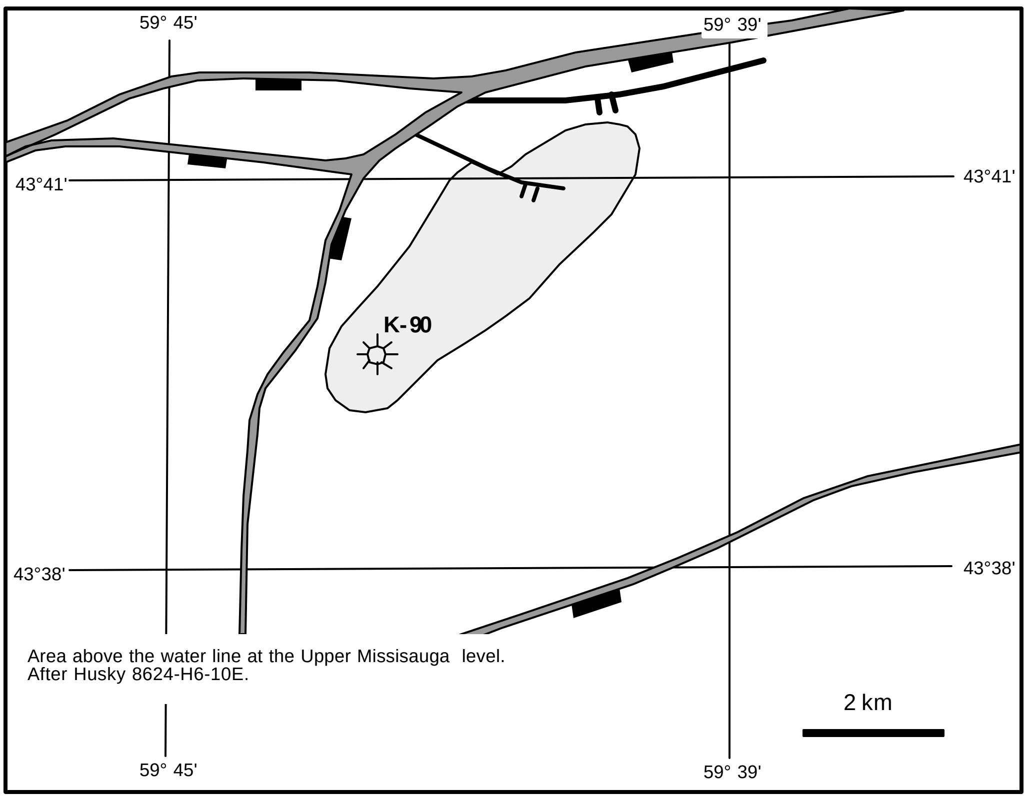
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 34 M3/E6M3 of recoverable gas, and is based on DST observations.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 13.92 (491) | 16.64 (588) | 19.90 (703) | 16.81 (593) |
| **Condensate** | (E6M3) | 0.473 (2.98) | 0.566 (3.56) | 0.677 (4.26) | 0.571 (3.59) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 6.958 (246) | 10.82 (382) | 15.92 (562) | 10.92 (386) |
| **Condensate** | (E6M3) | 0.237 (1.49) | 0.368 (2.31) | 0.541 (3.40) | 0.371 (2.34) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Chebucto




Area above the water line at the Upper Missisauga level.
After Husky 8624-H6-10E.

CANADA - NOVA SCOTIA
OFFSHORE PETROLEUM BOARD

# Citnalta - Significant Discovery

## *Overview*

The Citnalta gas field is located approximately 43.45 km north-east of Sable Island. The field was discovered in 1974 and its current assessment is based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin in a north-central position of the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil-Tetco-Texaco Citnalta I-59 |
| Spud: | 74-02-04 |
| R.R.: | 74-04-29 |
| T.D.: | 4575 m |

The discovery well is located in 94.48 m of water depth at approximately 44°08’42.58”N latitude, 59°37’32.”W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a large rollover anticline associated with a north bounding down-to-the-basin listric fault.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| I-59 | PD#1 | 4054-4059 | Mic Mac | 77 | 10 | |
| I-59 | PD#2 | 3951-3958 | Missisauga | 168 | 70 | |
| I-59 | PD#3 | 3777-3782 | Missisauga | 312 | 131 | 4 |

## *Geological/Geophysical Overview*

The Citnalta gas field is located in the Mesozoic age Sable Subbasin in a north-central position of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. With its proximity to sediment source, basin hinge-line position and resultant rapid subsidence, the progradational strata deposited at Arcadia consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions, with the reservoir sands located in the Late Jurassic Mic Mac formation and Lower Member of the Missisauga formation.

### Structure

The Citnalta structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic-Early Jurassic age salts of the Argo formation. The possibility exists that the structure may also have been affected by the motion of an underlying salt piercement feature.

Citnalta is a large, circular-shaped simple rollover anticline bound on the north by a major down-to-the-basin listric growth fault. The structure occurs on the edge of a platformal region which bounds the zone of major down-to-the-basin hinge-line faults to the south. The structural crest of the field is in a central position offset slightly upwards the bounding fault.

In seismic profiles the structure is interpreted to have a large area of closure with about 180 m of relief. Several regional seismic markers are prominent in the area but the Citnalta field is mapped on the basin of an internal field reflector (#9 Limestone / “Jurassic ‘A’ Marker”), and a deeper Abenaki formation reflector. These limestone reflections are generally common to other gas fields of the Venture-Olympia-Arcadia trend.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. In the Citnalta-Arcadia area this deltaic pulse overwhelmed and buried the pre-existing reefal and platformal carbonate facies of the Abenaki formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by the deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a later Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. The position of Citnalta on the north-central part of the delta (sediment by-pass) and the relative stability of the buried carbonate platform (reduced subsidence) resulted in the deposition of abbreviated Mic Mac and Missisauga sections as compared to the thick strata in adjacent fields on and south of the basin hinge-line faults such as Arcadia and Venture respectively.

### Reservoir Description

The Citnalta reservoir sands are located within the Late Jurassic Mic Mac formation. Mapping and well data suggest that the reservoir strata and that of the Arcadia and Venture fields to the immediate south are equivalent, although direct sand-to-sand correlations remain uncertain. A single exploratory well has been drilled at Citnalta and 3 major reservoirs were encountered over a 300 meter thick section that were logged, cored and tested (e.g., Sands/Zones 3, 5 & 5a). Good to excellent sand continuity is expected across the entire structure.

All Arcadia gas reservoirs are found in normal hydropressure conditions. They consist of stacked sequences of cyclic deltaic and strandplain sands interfingering with thin marine and prodelta shales. These capping shales and occasional tight oolitic limestones provide effective top seals within the succession. Log profiles and cores of the Mic Mac reservoir strata reflect delta front and channel depositional conditions with strandplain nearshore and tidal facies also present. The well data show that the reservoir characteristics of these very fine to medium grained, well sorted, siliceous and calcareous coarsening and fining upward sands have fair to good effective porosities ranging from 12-18% and permeabilities averaging 15 mD.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the Citnalta I-59 well was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Citnalta field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| | | |
| **Permeability Horizontal** | (mD) | ~15 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

Under DST gas and condensate was tested from three distinct zones; two in the Mic Mac, and one in the Missisauga. A small amount of water was tested from the Missisauga zone, but no water line is observed. In these zones, the area uncertainty was determined to be the primary variable within the probabilistic calculations. Structural spill point was used to determine the possible areal extent of each of these reservoir; for the most-likely value a 1/2 full structure was arbitrarily assigned; with the minimum area assigned based on DST observations. Porosity, net pay, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained from DST temperature measurements or from available temperature gradient graphs.

| **Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 819 | 1326 | 2044 | 1383 |
| **Top Reservoir** | (mSS) | | | | 3775 (I-59) |
| **Net Pay** | (m) | 5.5 | 5.5 | 5.5 | 5.5 |
| **Porosity** | (%) | 12.6 | 12.6 | 12.6 | 12.6 |
| **Sw** | (%) | 46.2 | 46.2 | 46.2 | 46.2 |
| **Pressure** | (kPa) | 38000 | 38000 | 38000 | 38000 |
| **Temp** | ($^{o}$C) | 108 | 108 | 108 | 108 |
| **Gas FVF** | | 266 | 274 | 282 | 274 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.833 | 1.355 | 2.090 | 1.413 |
| **OOIP** | (E6M3) | | | | |

| **Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 819 | 1326 | 2044 | 1383 |
| **Top Reservoir** | (mSS) | | | | 3945 (I-59) |
| **Net Pay** | (m) | 13.4 | 13.4 | 13.4 | 13.4 |
| **Porosity** | (%) | 16.7 | 16.7 | 16.7 | 16.7 |
| **Sw** | (%) | 43..4 | 43..4 | 43..4 | 43..4 |
| **Pressure** | (kPa) | 40000 | 40000 | 40000 | 40000 |
| **Temp** | ($^{o}$C) | 113 | 113 | 113 | 113 |
| **Gas FVF** | | 269 | 277 | 285 | 277 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.874 | 4.653 | 7.154 | 4.853 |
| **OOIP** | (E6M3) | | | | |

| **Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 819 | 1326 | 2044 | 1383 |
| **Top Reservoir** | (mSS) | | | | 4015 (I-59) |
| **Net Pay** | (m) | 8.5 | 8.5 | 8.5 | 8.5 |
| **Porosity** | (%) | 12.7 | 12.7 | 12.7 | 12.7 |
| **Sw** | (%) | 46.2 | 46.2 | 46.2 | 46.2 |
| **Pressure** | (kPa) | 42000 | 42000 | 42000 | 42000 |
| **Temp** | ($^{o}$C) | 116 | 116 | 116 | 116 |
| **Gas FVF** | | 276 | 284 | 292 | 284 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.355 | 2.179 | 3.382 | 2.282 |
| **OOIP** | (E6M3) | | | | |

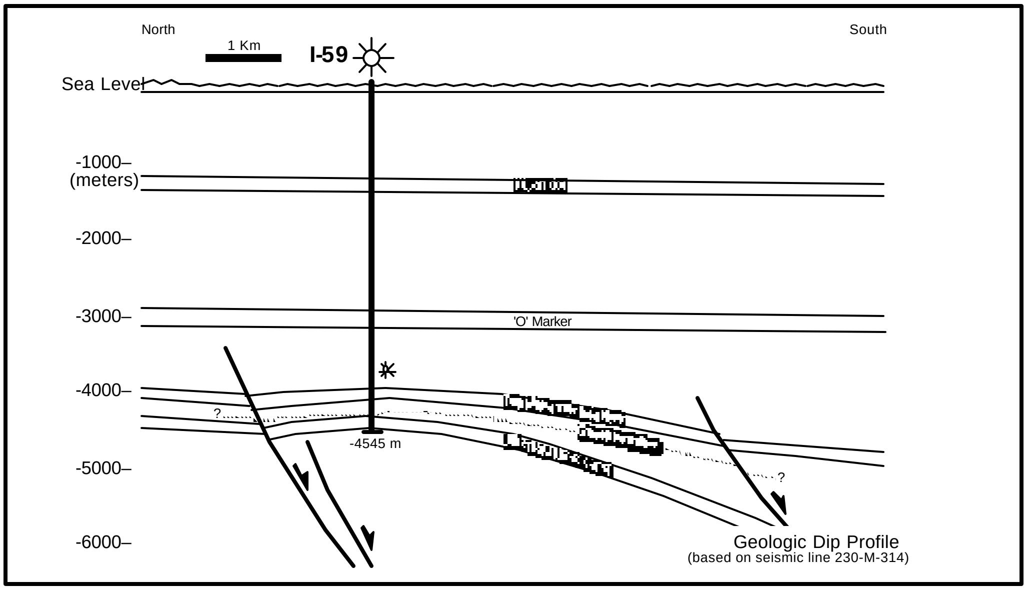
## *Depletion Scenario and Recoverable Resource*

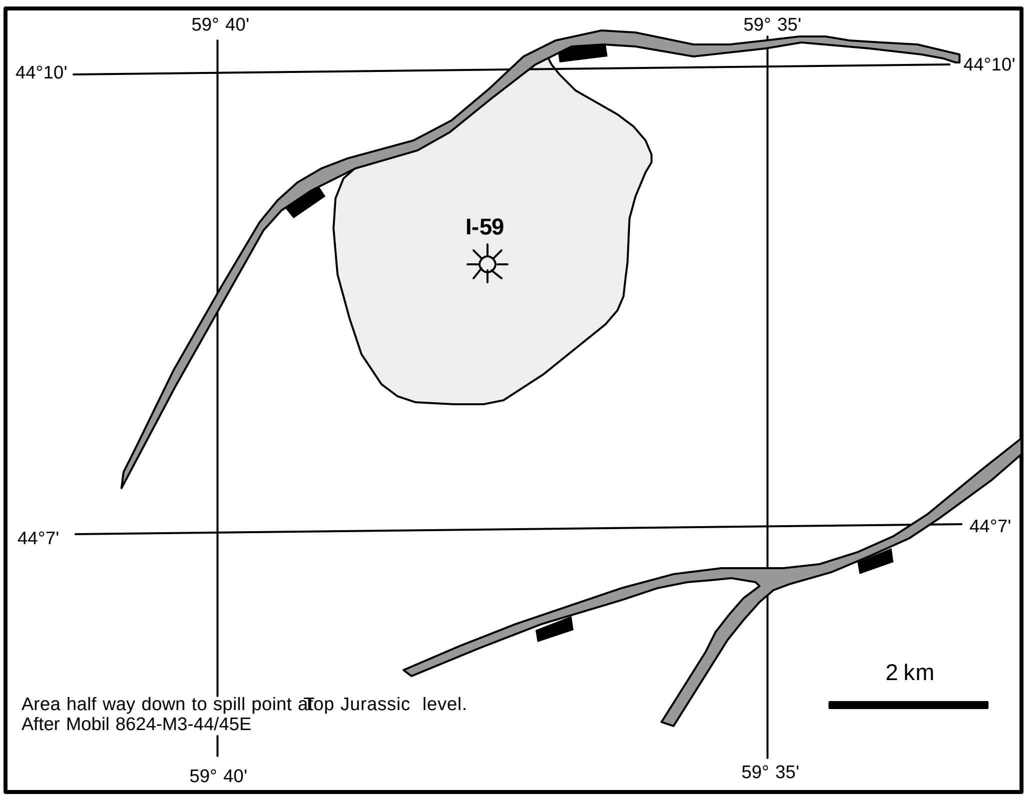
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 417 M3/E6M3 of recoverable gas.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 5.362 (189) | 8.111 (12) | 12.264 (433) | 8.551 (302) |
| **Condensate** | (E6M3) | 2.234 (14.1) | 3.380 (21.3) | 5.110 (32.1) | 3.563 (22.4) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 2.681 (95) | 5.272 (186) | 9.811 (346) | 5.558 (196) |
| **Condensate** | (E6M3) | 1.118 (7.03) | 2.198 (13.8) | 4.088 (25.7) | 2.318 (14.6) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Citnalta

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# Cohasset - Commercial Discovery

## *Overview*

The Cohasset oil field is located approximately 55 km south-west of Sable Island. The field was discovered in 1973 and delineated via two additional wells. This accumulation is located within the lower Cree member of the late Early Cretaceous Logan Canyon formation, on the western edge of the Sable Delta complex.

The Cohasset field, operated by PanCanadian Petroleum Limited, was produced under an approved development plan along with the Panuke field. Production began in 1993, and terminated in December 1999.

**Discovery Well:**

| | |
|---|---|
| Well: | Mobil Tetco Cohasset D-42 |
| Spud: | 73-04-27 |
| R.R.: | 73-07-16 |
| T.D.: | 4427.2 m |

The discovery well is located in 41.1 m of water at approximately 43°51’06.52”N latitude, 60°37’13.89”W longitude. It was drilled to test for the presence of hydrocarbons in a low relief positive feature along the Abenaki carbonate front. The carbonate was not of reservoir quality, but oil was tested from the sandstones within the overlying Missisauga and Logan Canyon.

### Additional Wells:

The field was delineated with three additional wells located 1 to 2 km from the discovery location. The P-42 well intersected correlatable sands but they were structurally lower and all wet.

| | |
|---|---|
| Well: | Mobil-Tetco-PEX Cohasset P-42 (43°51’50.32”N, 60°36’18.23”W) |
| | PCI et al Cohasset A-52 (43°51’08.11”N, 60°37’43.46”W) |

## Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| D-42 | PT#1 | 3480-3512 | Abenaki | Rec Water Cut Mud | | |
| D-42 | PT#3 | 2248-2255 | Missisauga | 0.99 | 43 | |
| D-42 | PT#4 | 1969-1973 | Logan Canyon | Not Measured | | |
| D-42 | PT#5 | 1968-1973 | Logan Canyon | 2.1 | 167 | |
| D-42 | PT#6 | 2510-2516 | Missisauga | TSTM | | |
| D-42 | PT#7 | 1861-1866 | Logan Canyon | 0.8 | 39 | |
| A-52 | DST#1 | 2385-2389 | Logan Canyon | 2.4 | 1230 | |
| A-52 | DST#2 | 2337-2341 | Logan Canyon | 5.8 | 890 | |
| A-52 | DST#3 | 2254-2270 | Logan Canyon | 7.5 | 780 | |
| A-52 | DST#4 | 2215-2226 | Logan Canyon | 3.5 | 353 | 37 |
| A-52 | DST#5 | 2149-2153 | Logan Canyon | 1.8 | 210 | 59 |
| A-52 | DST#6 | 2123-2127 | Logan Canyon | 7.2 | 812 | 71 |

# Geological/Geophysical Overview

The Cohasset oil field is located on the edge of a marine embayment on the western edge of the Sable Delta complex. The field's distal position on the delta and its high stratigraphic position resulted in the deposition of a thick interlayered sand/shale sequence. The sandstones have fluvial affinities but were significantly reworked by marine and tidal currents and generally fine upward in the section. The reservoir sequence occupies most of the lower Cree member of the late Early Cretaceous Logan Canyon formation.

## Structure

The Cohasset structure exists as an elongate, simple drape structure with low relief, four-way closure. It was formed through differential compaction of marine and deltaic clastic sediments over the edge of the buried Jurassic age carbonate fringing reef complex of the Abenaki formation. The Cohasset structure's eastern margin is slightly faulted though this is considered a much younger feature.

In seismic profiles the Cohasset structure exhibits very subtle closure, with the maximum relief of the structure estimated as being only 12-15 m high. This uncertainty is based on the fact that only a single seismic reflector is present within the reservoir sequence and the elevation differences are very close to the resolution of the 3D seismic dataset and well survey data. All reservoir sands are mapped based on projecting up or down from the Cohasset 7 Sand ("C7") datum, located near the center of the reservoir sequence.

## Stratigraphy

Up to earliest Cretaceous time the southwesterly progradation of the Sable Delta complex in the Cohasset area was limited to and influenced by the presence of the Jurassic Abenaki reef complex, as well as the distance from the locus of sedimentation in the Sable Subbasin. However, by the Early Cretaceous, clastic sedimentation overwhelmed and buried the Abenaki facies. These clastic sediments of the Middle and Upper members of the Missisauga formation represent fluvial and shoreface deposition in a marine dominated setting, such that most sand bodies are interbedded with inner shelf shales, though the lower sands tend to represent channel facies. Following a major regional marine transgression in the Sable Subbasin (Naskapi member, Logan Canyon formation), deltaic sedimentation was resumed but at a more subdued rate (Cree member).

## Reservoir Description

The reservoir sands at Cohasset occupy most of the 400 m thick Cree member of the Logan Canyon formation. Other sands are found as isolated bodies within the underlying marine shales of the Naskapi member, and, at the very top of the fluvial Missisauga formation. Prior to and during development of the field, the 27 reservoir sands have been penetrated, logged and cored by over 14 wells. All reservoir sands show remarkable lateral and vertical continuity across the field.

Within the Cree member, the reservoir sands consist of stacked coarsening upward cycles ranging from 15 to 25 m thick in the lower portion of the member and thinning to between 2-10 m at the top. The progradational strandplain sand cycles are stacked and interlayered with inner shelf marine shales and record lower to upper shoreface depositional environments, with the thicker lower sands being capped with lagoonal shales, tidal sands and transgressive lag deposits. These strandplain sand cycles have excellent reservoir characteristics, with porosities and permeabilities generally ranging from 22-32% and 200-300 mD respectively. A number of the sands have permeabilities exceeding 2 Darcies.

Reservoir sands in the Naskapi member are restricted to lower shoreface depositional environments, and thus are thin and have significantly reduced porosities and permeabilities. The uppermost sand located at the top of the Missisauga formation records a depositional environment and reservoir character similar to those sands in the Cree member, Logan Canyon formation.

## *Petrophysical Overview*

A petrophysical evaluation of the Cohasset wells was completed. This data was used to calculate a deterministic assessment of oil in place.

Net pay was defined for the Cohasset field using the cutoffs tabled below. Effective porosities were calculated from the density log. Water saturations were determined from the log data using the Archie water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 60 |
| **Porosity Cutoff** | (%) | 16 |
| **Volume of Shale Cutoff** | (%) | 40 |
| **Permeability Horizontal** | (mD) | 200 - 300 |

## *Original Hydrocarbons in Place*

Hydrocarbons are located in a series of vertically stacked sands containing 27 different recognized pools. Original oil in place has been determined deterministically, and rationalized against production history to arrive at a Best Current Estimate value. Due to the late production stage of this asset, no probabilistic calculations have been undertaken.

Oil/water contacts are visible in many of the Cohasset reservoirs and are used to define the areal extent of each pool. Deterministic calculations define the oil in place at 10.647 E6M3. The Gas-Oil Ratio is 19 M3/M3 based on production history.

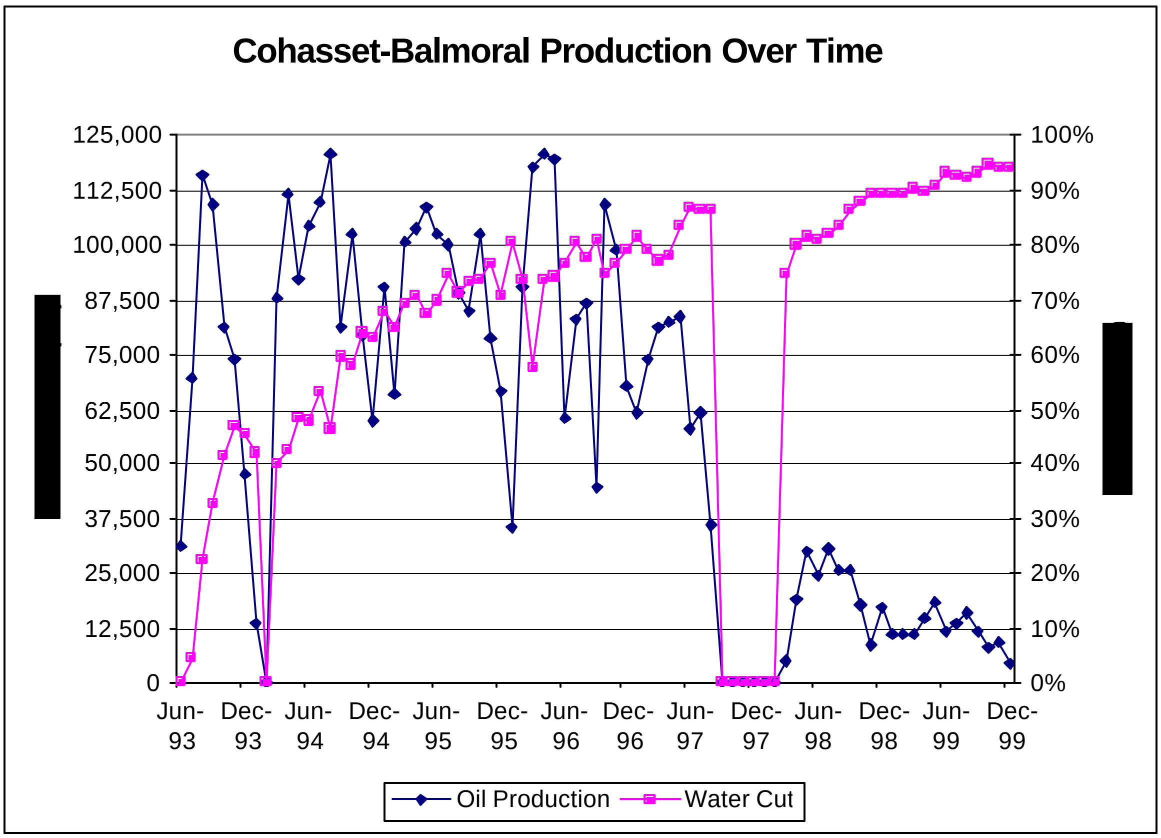
The Cohasset field is currently in production and is nearing the end of it's economic life. Detailed decline curve analysis conducted on the Cohasset reservoirs has provided a reasonable confirmation of the deterministically calculated oil in place as well as provided a reliable forecast of recoverable oil reserves.

## *Depletion Scenario and Recoverable Resource*

The Cohasset field was produced under an approved development plan along with the Panuke field. Production began in 1993, and terminated in December 1999, having produced 4.4983879 E6M3 (28.294009 MMbls) or an estimated 42.2% of the OOIP.

The field has been subject to zonal abandonment and the wellbores are suspended. Pending additional exploration in the area, the jacket will remain on location for an additional time period as an unmanned facility.

A Plot of monthly production for the field is included below. The field was developed with a total of 17 wells, many subject to several workovers and re-drilling throughout the project life.



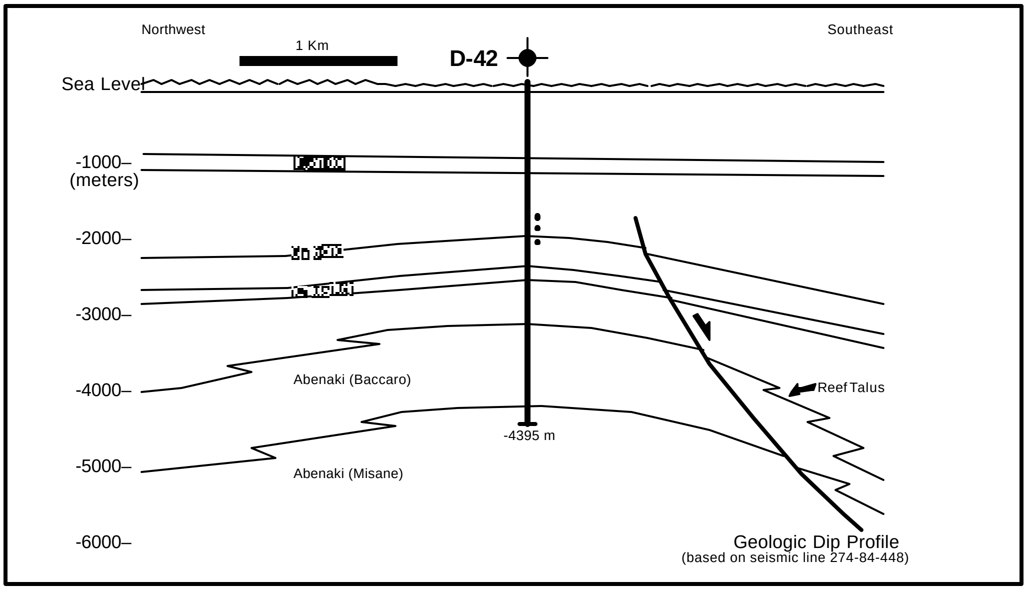

Most wells produced from several different zones commingled in the wellbore. In general, reservoir pressure support from the aquifer was excellent, and water injection for pressure maintenance was not required. All wells were ultimately produced to high water-cuts with electric submersible pumps.

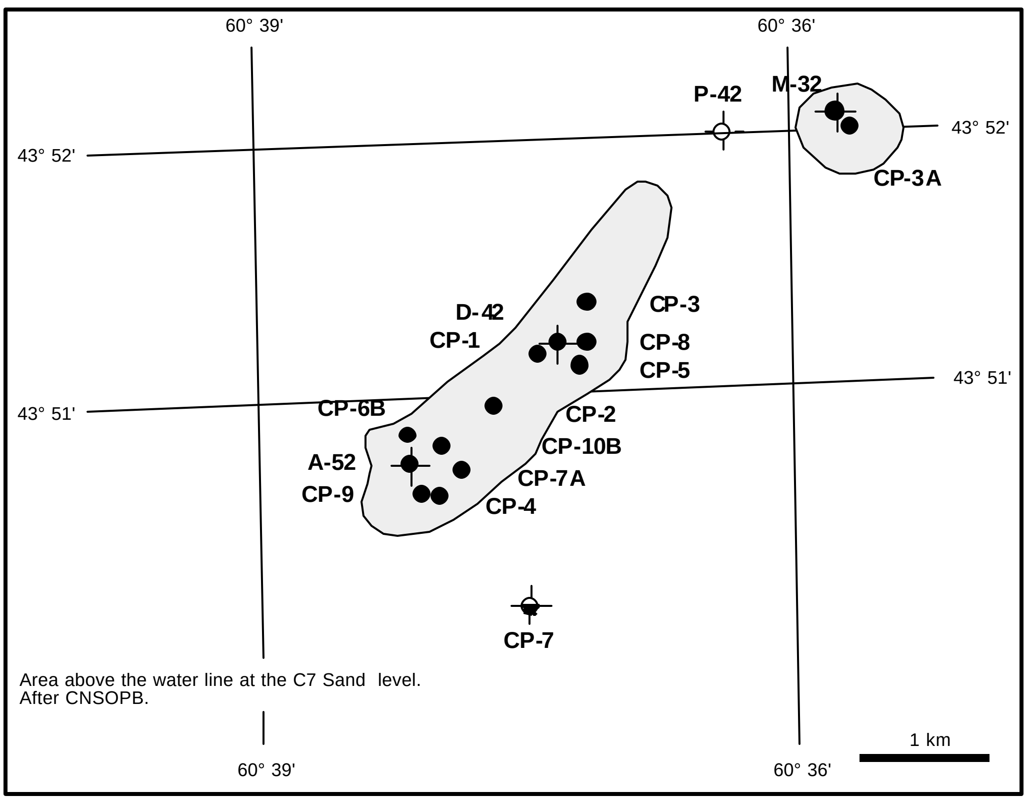
| **Total Stock Tank Hydrocarbons *** | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|
| **In Place** | | | | |
| **Gas** (E9M3) | | | | |

| | | |
|---|---|---|
| **Condensate** | (E6M3) | |
| **Oil** | (E6M3) | 10.65 (67.0) |
| **Assoc. Gas** | (E9M3) | 0.202 (7) |
| | | |
| **R.F. Gas** | | 0.509 |
| **R.F. Oil** | | 0.424 |
| | | |
| **Recoverable Resource** | | |
| | | |
| **Gas** | (E9M3) | |
| **Condensate** | (E6M3) | |
| **Oil** | (E6M3) | 4.498 (28.3) |
| **Assoc. Gas** | (E9M3) | 0.103 (3.63) |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Cohasset

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# Glenelg - Significant Discovery

## *Overview*

The Glenelg gas field is located approximately 40 km south of Sable Island. The field was discovered in 1983 and has been delineated via three additional wells. This accumulation is located within the Middle Cretaceous age sediments and at the nose of one of the Sable Delta's western lobes.

At the time of writing (November 2000), Glenelg is planned to be the third and last field for development in the Sable Offshore Energy Project's Tier 2 phase. Like the currently producing fields at Venture and North Triumph, and planned fields at South Venture and Alma, it will be linked via a subsea gathering pipeline to the project's central processing complex located at the Thebaud field, ~30 km to the north. SOEI's approved development plan indicates that following development of the South Venture and Alma fields, gas from Glenelg will assist in sustaining plateau production for the Project.

### Discovery Well:

| | |
|---|---|
| Well: | Shell Petro-Can Glenelg J-48 |
| Spud: | 83-02-22 |
| R.R.: | 83-11-08 |
| T.D.: | 5250 m |

The discovery well is located in 83.7 m of water at approximately 43°37'38.57"N latitude, 60°06'24.84"W longitude. It was drilled to test for the presence of hydrocarbons in the domal closure within a complex of east-west trending down-to-the-basin faults.

### Additional Wells:

Field was further delineated by three additional wells (plus one sidetrack) located within 2.5 to 3.5 km from the discovery location.

Well: Shell Petro-Can et al Glenelg E-58 & E-58A (43°37'17.512"N, 60°08'51.625"W)
Shell PCI et al Glenelg N-49 (43°38'59.43"N, 60°07'02.10"W)
Shell Petro-Can et al Glenelg H-38 (43°37'19.327"N, 60°08'48.614"W)

## Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| J-48 | DST#1 | 5075-5107 | Verrill Can. | Rec Form Fluid | | 11 |
| J-48 | DST#2 | 3950-3955 | Missisauga | 127 | | trace |
| J-48 | DST#3 | 3806-3815 | Missisauga | Rec Form Fluid | | |
| J-48 | DST#4 | 3767-3773 | Missisauga | 125 | | 88 |
| J-48 | DST#5 | 3746-3758 | Missisauga | 801 | 18 | |
| J-48 | DST#7 | 3608-3615 | Missisauga | 99 | | |
| J-48 | DST#8 | 3491-3496 | Missisauga | 595 | | |
| | | | | 467 | 19 | trace |
| J-48 | DST#9 | 3062-3065 | Missisauga | 849 | 65 | 8 |
| E-58 | DST#1 | 3702-3713 | Missisauga | 663 | 62 | |
| E-58 | DST#2 | 3567-3578 | Missisauga | 312 | | |
| N-49 | DST#1 | 3598-3603 | Missisauga | 596 | 20 | |
| N-49 | DST#2 | 3476-3485 | Missisauga | 884 | 24 | |
| N-49 | DST#3 | 3391-3402 | Missisauga | 483 | 12 | |

## Geological/Geophysical Overview

The Glenelg gas field is positioned seaward of the southwest to northeast trending Jurassic hinge zone along the paleoshelf edge and at the nose of one of the Sable Delta's western lobes. Given this distal position, the main reservoir zone, the Missisauga formation, is thinner than the much thicker section developed at Venture located near the subbasin and delta.

### Structure

The Glenelg complex is a series of roll-over anticlinal structures associated with a deep east-west trending listric fault, which probably soles into Triassic age Argo formation salts. The faulting associated with this feature, and those nearby, penetrates upwards through most of the overlying strata, in some cases almost to the present day seafloor. This faulting was both episodic, due to the expulsion of over-pressured gas from deeper sources into shallower reservoirs (see below), and syndepositional from the effects of sediment loading and subsidence. It is believed that the faults are sealing, and that the reservoir sands of the Missisauga and Logan Canyon formations are offset against thick marine shales of the Verrill Canyon formation.

As defined by 2-D and 3-D seismic, the complex is an irregular dumbbell-shaped east-west trending feature covering an estimated area of about 5200 hectares (12,900 acres). The north-bounding fault, and a secondary large en echelon fault, form the northern and southern boundaries of the complex respectively. Displacement of the Top Missisauga seismic datum along the northern fault ranges between 40-150 m (west-east) and an estimated 700-1000 m of offset along the southern fault.

Two structural highs are present, one at each end of the complex and separated by a lower relief saddle. The eastern feature is dissected by several fault splays roughly paralleling the bounding faults. Four of these smaller internal closures have been drilled, with the various combinations of fault closures, dip closures and stratigraphic trapping serving to define and delineate the 10 individual gas pools recognized throughout the deltaic sediments of the Glenelg field. The western feature is slightly larger than the eastern Glenelg field and does not appear to have been subdivided by faulting into several smaller sub-structures. Several other smaller closures abut or are adjacent to the Glenelg and like the western structure remain undrilled.

### Stratigraphy

The Glenelg field occupies a distal position on the southwestern flank of the Sable Delta complex. In this region, the various phases of Early Cretaceous age advances of the delta complex are manifested as numerous stacked cycles of fine to coarse grain sand. These sand sequences are interlayed with significant volumes of marine shales such that the overall sand-shale ratio of the Missisauga formation, the main reservoir interval, is lower than the equivalent section at the Venture field, which tends to be sand dominated.

Two phases of deltaic advancement are recognized in the Middle and Upper members of the Missisauga formation sediments at Glenelg. The Lower member of the formation was not deposited in this area and is represented by coeval marine shales of the Verrill Canyon formation. Only a few minor sands were deposited, these being precursors of the coming first phase of the delta's advance. Deposition of the Middle Missisauga member is seen in the development of thick a sequence of interlayered distributary channel sandstone complexes and marine and interbay shales. As the volume of sediment influx rapidly increased, the depositional facies reflected this change. Sediments of the Upper Missisauga member record the deposition of successive delta lobes advancing and coalescing across the Glenelg area. Delta-front to shallow marine shoreface facies dominate this sequence and the interbedded shales are thin. Following a major marine transgression as represented by the shales of the Naskapi member, Logan Canyon formation, fluvial and shallow marine depositional facies were re-established and again prograded across the area (Cree member).

## Reservoir Description

Pay zones and defined pools of hydro-pressured gas in the Glenelg structure are confined to the fluvial-deltaic and shallow marine sandstones of the Missisauga and Logan Canyon formations. Good between well correlation of the sheet-like sands exists for strata of the Logan Canyon and Upper Missisauga formations, with the sands believed to be thicker adjacent to the major bounding growth faults. The geometry of the narrow channel sands of the Middle and Lower Missisauga formation precludes the ability to correlate these sands between wells and across fault planes. However, clean high gamma shales that define sequence boundaries can be correlated between the wells, thus defining stratigraphically-equivalent / coeval channel packages or sequences. The deeper Missisauga sands tend to be slightly over-pressured

At Glenelg, only the Upper and Middle members of the Missisauga formation are fully developed. In place of the Lower member are the coeval shales of the Verrill Canyon Formation. The exception is a set of well developed channel sands found in the J-48 well which are gas-bearing and have been assigned gas in place.

The Middle member is about 200 m thick and is composed of abundant fluvial channel deposits, most of which are sand filled though some have been identified as being mud-filled. Lateral correlation of these channels between wells (and fields/pools) is difficult if at all possible. Their areal extent is expected to be limited, given the narrow, linear geometry of channel sand bodies.

The sediments of the Upper member of the formation are also about 200 m thick though represent delta-front to shallow marine depositional environments. The geometry of these sand deposits is sheet-like and laterally extensive, thus permitting good correlations from well to well even across faults.

Transgressive marginal marine to tidal flat shales of the Naskapi member, Logan Canyon formation overly the Missisauga sediments, and are followed in turn by sediments of the second deltaic progradational pulse. The sheet-like fluvial and shallow marine sands of the Cree member, Logan Canyon formation, are laterally continuous and reflect conditions of constant and unchanged sediment influx but reduced subsidence rates.

Details regarding the core and log-derived porosities and permeabilities for the reservoir sands from both formations will not be elaborated upon here. Generally however, the channel sandstones that dominate the Missisauga strata have an average porosity of 15%. The average porosity values for the fluvial and shallow marine Logan Canyon sands are about 30% for the Upper member and 20% for the Lower member. Permeabilities are variable.

## *Petrophysical Overview*

Petrophysical evaluation[1] of the five wells in the Glenelg field utilized log, core and pressure data. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Glenelg field using the cutoffs tabled below. Effective porosities were calculated from the neutron - density curves which were corrected for gas effects. The neutron - density curves were edited in 'washed out' intervals to correct for bad log readings. A 10% porosity cutoff, which corresponds to a permeability cutoff of 1.0 mD, was used to define net pay at Glenelg. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 65 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 40 |
| **Permeability Horizontal** | (mD) | N/A |

[1] Petrophysical evaluation provided by the Canada Oil and Gas Lands Administration, Glenelg Gas Field - Reserve Study, April, 1990.

## *Original Hydrocarbons in Place*

A study performed on Glenelg[2] has been incorporated in the determination of the parameters for a rigorous probabilistic gas in place analysis which is summarized below.

Areal extent of the pools remains a primary uncertain variable in the probabilistic calculations. The three wells have defined several pools within the field: Well N-49 defined pay in pools B, C-1, and D; E-58A has defined C-2 and E pools; and J-48 has defined Lower Logan Canyon ("LLC") pools C-3,F, G, and a small "Missisuga". In the B, C-1 and D pools, the minimum area was assigned based upon the well tests, the most-likely area based on the structure being half full, and the possible area extending to structural spill point. The F, G, C-3, Lower Logan Canyon Pools are limited to a deduced gas water contacts for the proven and most-likely inputs. However, uncertainties within the gas water contact would allow the possible area to expand to structural spill point. The C-2, E, and the minor Missisauga pools are arealy defined and limited based on closure at the E-58A location. Pools D, E, F, and G exist under slight over-pressure conditions.

Many of the pools of Glenelg contain a number of individual, but connected, sand units. The observed differences in porosity and water saturation within these included units has served as basis for their selection also as primary variables within the probabilistic analysis. Probabilistic distributions for these parameters were based on minimum, weighted average, and maximum observed values as the proven, most-likely, and possible inputs, respectively. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained by establishing a temperature gradient from maximum bottom hole log temperatures.

| **Pool B - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 718 | 1075 | 1327 | 1047 |
| **Top Reservoir** | (mSS) | | | | 3320 (N-49) |
| **Net Pay** | (m) | 15.4 | 15.4 | 15.4 | 15.4 |
| **Porosity** | (%) | 14.4 | 15.0 | 15.6 | 15.0 |
| **Sw** | (%) | 18.4 | 20.9 | 23.4 | 20.9 |
| **Pressure** | (kPa) | 35000 | 35000 | 35000 | 35000 |
| **Temp** | ($^{o}$C) | 109 | 109 | 109 | 109 |
| **Gas FVF** | | 246 | 253 | 260 | 253 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 3.297 | 4.949 | 6.144 | 4.827 |
| **OOIP** | (E6M3) | | | | |

[2] Weatherly, H., & Canada Oil and Gas Lands Administration, Glenelg Gas Field, Reserve Study, 1990.

| Pool C1-Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 718 | 1075 | 1327 | 1047 |
| **Top Reservoir** | (mSS) | | | | 3435 (N-49) |
| **Net Pay** | (m) | 11.2 | 11.2 | 11.2 | 11.2 |
| **Porosity** | (%) | 16.4 | 16.4 | 16.5 | 16.4 |
| **Sw** | (%) | 13.8 | 14.4 | 15.0 | 14.4 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^oC$) | 109 | 109 | 109 | 109 |
| **Gas FVF** | | 250 | 257 | 264 | 257 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.902 | 4.338 | 5.382 | 4.237 |
| **OOIP** | (E6M3) | | | | |

| Pool C2 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 210 | 210 | 210 | 210 |
| **Top Reservoir** | (mSS) | | | | 3455 (E-58A) |
| **Net Pay** | (m) | 7.0 | 7.0 | 7.0 | 7.0 |
| **Porosity** | (%) | 13.5 | 13.5 | 13.5 | 13.5 |
| **Sw** | (%) | 39 | 39 | 39 | 39 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^oC$) | 111 | 111 | 111 | 111 |
| **Gas FVF** | | 252 | 259 | 266 | 259 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.305 | 0.314 | 0.322 | 0.314 |
| **OOIP** | (E6M3) | | | | |

| Pool C3 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 367 | 450 | 582 | 463 |
| **Top Reservoir** | (mSS) | | | | 3425 (J-48) |
| **Net Pay** | (m) | 2.6 | 2.6 | 2.6 | 2.6 |
| **Porosity** | (%) | 16.8 | 16.8 | 16.8 | 16.8 |
| **Sw** | (%) | 25.4 | 25.4 | 25.4 | 25.4 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^oC$) | 110 | 110 | 110 | 110 |
| **Gas FVF** | | 250 | 257 | 264 | 257 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.307 | 0.377 | 0.487 | 0.388 |
| **OOIP** | (E6M3) | | | | |

| Pool D - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 718 | 1075 | 1327 | 1047 |
| **Top Reservoir** | (mSS) | | | | 3495 (N-49) |
| **Net Pay** | (m) | 9.2 | 9.2 | 9.2 | 9.2 |
| **Porosity** | (%) | 12.9 | 14.9 | 16.2 | 14.7 |
| **Sw** | (%) | 21.0 | 22.4 | 24.1 | 22.5 |
| **Pressure** | (kPa) | 37000 | 37000 | 37000 | 37000 |
| **Temp** | ($^oC$) | 117 | 117 | 117 | 117 |
| **Gas FVF** | | 250 | 257 | 264 | 257 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.891 | 2.856 | 3.646 | 2.819 |
| **OOIP** | (E6M3) | | | | |

| Pool E - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 210 | 210 | 210 | 210 |
| **Top Reservoir** | (mSS) | | | | 3600 (E-58A) |
| **Net Pay** | (m) | 12.8 | 12.8 | 12.8 | 12.8 |
| **Porosity** | (%) | 13.5 | 13.5 | 13.5 | 13.5 |
| **Sw** | (%) | 14.9 | 14.9 | 14.9 | 14.9 |
| **Pressure** | (kPa) | 37000 | 37000 | 37000 | 37000 |
| **Temp** | ($^oC$) | 113 | 113 | 113 | 113 |
| **Gas FVF** | | 256 | 263 | 270 | 263 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.790 | 0.812 | 0.835 | 0.812 |
| **OOIP** | (E6M3) | | | | |

| Pool F - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 367 | 450 | 582 | 463 |
| **Top Reservoir** | (mSS) | | | | 3535 (J-48) |
| **Net Pay** | (m) | 6.0 | 6.0 | 6.0 | 6.0 |
| **Porosity** | (%) | 14.2 | 14.2 | 14.2 | 14.2 |
| **Sw** | (%) | 30.8 | 30.8 | 30.8 | 30.8 |
| **Pressure** | (kPa) | 37000 | 37000 | 37000 | 37000 |
| **Temp** | ($^oC$) | 112 | 112 | 112 | 112 |
| **Gas FVF** | | 255 | 262 | 269 | 262 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.566 | 0.695 | 0.900 | 0.716 |
| **OOIP** | (E6M3) | | | | |

| Pool G - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 367 | 450 | 582 | 463 |
| **Top Reservoir** | (mSS) | | | | 3735 (J-48) |
| **Net Pay** | (m) | 16.8 | 16.8 | 16.8 | 16.8 |
| **Porosity** | (%) | 12.9 | 13.6 | 14.3 | 13.6 |
| **Sw** | (%) | 42.0 | 47.5 | 52.7 | 47.4 |
| **Pressure** | (kPa) | 38000 | 38000 | 38000 | 38000 |
| **Temp** | ($^oC$) | 121 | 121 | 121 | 121 |
| **Gas FVF** | | 254 | 261 | 268 | 261 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.120 | 1.412 | 1.847 | 1.453 |
| **OOIP** | (E6M3) | | | | |

| Pool "LLC" | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 367 | 450 | 582 | 463 |
| **Top Reservoir** | (mSS) | | | | 2715 (J-48) |
| **Net Pay** | (m) | 19.8 | 19.8 | 19.8 | 19.8 |
| **Porosity** | (%) | 14.1 | 16.8 | 19.4 | 16.8 |
| **Sw** | (%) | 51.1 | 43.7 | 35.0 | 43.4 |
| **Pressure** | (kPa) | 30000 | 30000 | 30000 | 30000 |
| **Temp** | ($^oC$) | 98 | 98 | 98 | 98 |
| **Gas FVF** | | 231 | 238 | 245 | 238 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.494 | 2.008 | 2.733 | 2.071 |
| **OOIP** | (E6M3) | | | | |

| "Missisauga" Pool | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 210 | 210 | 210 | 210 |
| **Top Reservoir** | (mSS) | | | | 3870 (E-58A) |
| **Net Pay** | (m) | 19.8 | 19.8 | 19.8 | 19.8 |
| **Porosity** | (%) | 13.5 | 13.5 | 13.5 | 13.5 |
| **Sw** | (%) | 33.4 | 25.6 | 19.6 | 26.1 |
| **Pressure** | (kPa) | 60000 | 60000 | 60000 | 60000 |
| **Temp** | ($^oC$) | 121 | 121 | 121 | 121 |
| **Gas FVF** | | 324 | 333 | 342 | 333 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.238 | 1.389 | 1.506 | 1.381 |
| **OOIP** | (E6M3) | | | | |

## *Depletion Scenario and Recoverable Resource*

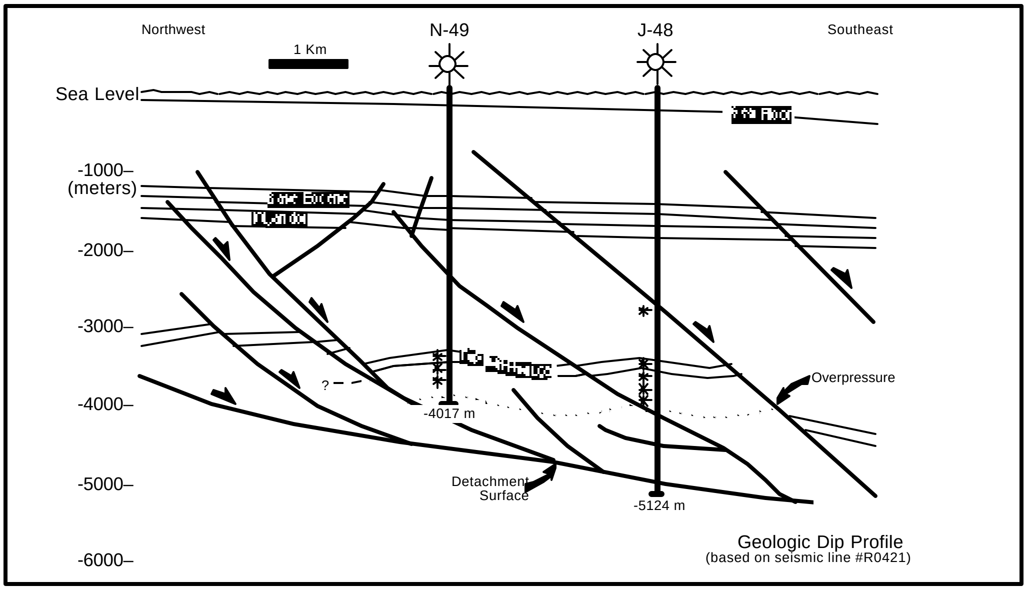
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 54 M3/E6M3 of recoverable gas and is based on DST observations.

At the time of writing (November 2000), Glenelg is planned to be the third and last field for development in the Sable Offshore Energy Project's Tier 2 phase. Like the currently producing fields at Venture and North Triumph, and planned fields at South Venture and Alma, it will be linked via a subsea gathering pipeline to the project's central processing complex located at the Thebaud field, ~30 km to the north. SOEI's approved development plan indicates that following development of the South Venture and Alma fields, gas from Glenelg will assist in sustaining plateau production for the Project. The field will be placed under compression during its late life from a central compression facility located approximately 35 km away at the Thebaud location.

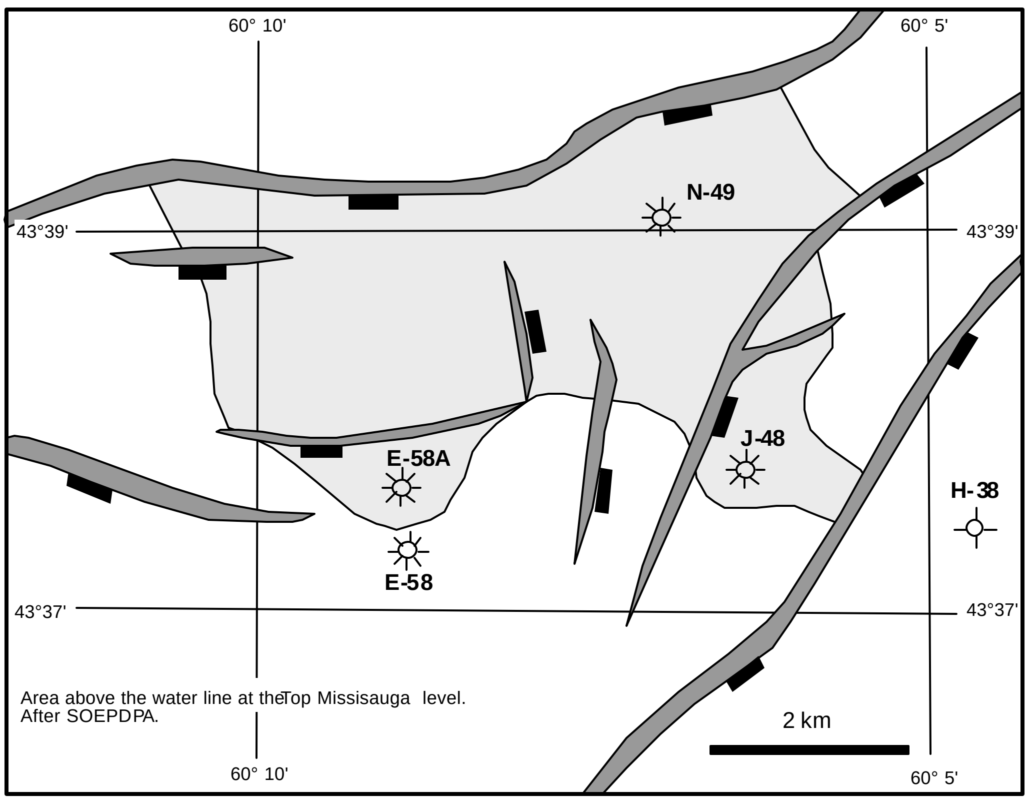
| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 14.55 (514) | 18.56 (659) | 23.93 (845) | 19.02 (672) |
| **Condensate** | (E6M3) | 0.786 (4.94) | 1.008 (6.34) | 1.293 (8.13) | 1.027 (6.46) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 7.274 (257) | 12.13 (428) | 19.14 (676) | 12.362(437) |
| **Condensate** | (E6M3) | 0.393 (2.47) | 0.655 (4.12) | 1.034 (6.50) | 0.668 (4.20) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Glenelg




Geologic Dip Profile
(based on seismic line #R0421)




Area above the water line at the Top Missisauga level.
After SOEPDPA.

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# Intrepid - Significant Discovery

## *Overview*

The Intrepid gas field is located approximately 19 km south of Sable Island. The field was discovered in 1979 and has been assessed based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Texaco & Shell Intrepid L-80 |
| Spud: | 74-05-18 |
| R.R.: | 74-08-14 |
| T.D.: | 4162 m |

The discovery well is located in 43.58 m of water at approximately 43°49’35.78”N latitude, 59°56’43.83”W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a large rollover structure bounded to the north and south by large down-to-the-basin faults.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| **Well** | **Test #** | **Depth (M)** | **Interval** | **Gas (E3M3/D)** | **Oil/Cond (M3/D)** | **Water (M3/D)** |
|---|---|---|---|---|---|---|
| L-80 | PD#1 | 3965-3968 | Missisauga | Rec Salt Water | | |
| L-80 | PD#2 | 3953-3956 | Missisauga | Rec Gassy Salt Water | | |
| L-80 | PD#3 | 3841-3845 | Missisauga | 47 | | |
| L-80 | PD#4 | 3447-3501 | Missisauga | Rec Water | | |
| L-80 | PD#5 | 3383-3389 | Missisauga | 120 | 11 | 144 |
| L-80 | PD#6 | 3045-3054 | Missisauga | Rec Salt Water | | |
| L-80 | PD#7 | 2937-2941 | Missisauga | 130 | 4 | 30 |
| L-80 | PD#8 | 2908-2911 | Logan Canyon | 217 | 11 | 25 |

## *Geological/Geophysical Overview*

The Intrepid gas field is located in the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at Intrepid consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Early Cretaceous Logan Canyon and Missisauga formations.

### Structure

The Intrepid structure was formed through the rotation of the large fault block bounded to the north and south by major growth faults which likely sole into deep Jurassic age marine shales of the Verrill Canyon formation. This block also contains the South Sable structure 7 km to the northeast and separated from it by a structurally lower saddle. However, unlike South Sable, the Intrepid structure is located on the footwall side of the southern east-west trending bounding fault, not the hanging wall. It is a semi-circular to hour glass-shaped low relief anticline with both fault and fault-drag related closure. The southern fault has an which then swings to southwest. The structural crest of the field is adjacent to this fault and has a maximum vertical closure of approximately 60 m.

One regional and several internal field seismic reflectors common to Intrepid and South Sable define the structure. These include the ubiquitous ‘O’ Marker (i.e. top of the Middle Missisauga member), and the Missisauga ‘A’ and ‘B’ Markers, both located within the bottom half of the Middle Missisauga member. These latter reflectors are both within the known overpressure section.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the Intrepid-South Sable area occupied a position that was distal to deltaic sedimentation and thus no Mic Mac formation sands were deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the South Sable area and beyond. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed deltaic progradation followed and is represented by the strandplain succession of the Logan Canyon formation.

### Reservoir Description

The Intrepid gas reservoirs are found within Early Cretaceous strata of the Middle and Upper members of the Missisauga formation, and the Naskapi shale member of the Logan Canyon formation. A single exploratory well has been drilled on the structural crest at Intrepid and a number of reservoir quality sands were encountered, with at least four containing significant gas pays. All major gas sands occur in hydropressure conditions with the highest two found at the base of the shale dominated Naskapi member and top of the Upper Missisauga member respectively. The remaining two are located in the Middle Missisauga member, one of which is just above the onset of overpressure conditions. Only 200 m of strata below the top of overpressure were drilled. Seismic mapping and comparison with those at South Sable show that although the reservoir sands thin somewhat towards and into the Intrepid field, this in turn reveals good sand continuity throughout the field area.

Reservoir sands in the Intrepid field consist of stacked sequences of delta front, channel and strandplain-shoreface facies in a dominantly marine setting. Well data shows that these coarsening upward progradational sands are medium to coarse grained (occasionally pebbly), moderate to well sorted, siliceous and variably argillaceous and dolomitic. The reservoir characteristics of the gas sands are fair to very good with effective average porosities ranging from 12-28% and an average permeability of 10 mD based on well logs and drillstem test results.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the Intrepid L-80 well was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Intrepid field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | ~ 10 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

As gas/water contacts were not discernible in the Logan Canyon and Missisauga gas sands, area uncertainty was determined to be the primary variable in the probabilistic calculations. To define the possibilities, structural spill point was used to determine the maximum areal extent of each reservoir. A half full structure was assigned as the most-likely value, and the minimum area was inferred from DST observations. In zones with discernible gas/water contacts, Missisauga and Naskapi Zones I, the areal extent was determined by projecting the water line onto the nearest structure map. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained from DST temperature measurements or from available temperature gradient graphs.

| **Zone I - Logan Can.** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 566 | 850 | 1223 | 875 |
| **Top Reservoir** | (mSS) | | | | 2880 (L-80) |
| **Net Pay** | (m) | 4 | 4 | 4 | 4 |
| **Porosity** | (%) | 19 | 19 | 19 | 19 |
| **Sw** | (%) | 33 | 33 | 33 | 33 |
| **Pressure** | (kPa) | 29000 | 29000 | 29000 | 29000 |
| **Temp** | ($^oC$) | 88 | 88 | 88 | 88 |
| **Gas FVF** | | 241 | 248 | 255 | 248 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.714 | 1.072 | 1.540 | 1.105 |
| **OOIP** | (E6M3) | | | | |

| **Zone I - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 350 | 350 | 350 | 350 |
| **Top Reservoir** | (mSS) | | | | 2910 (L-80) |
| **Net Pay** | (m) | 8.5 | 8.5 | 8.5 | 8.5 |
| **Porosity** | (%) | 18.5 | 18.5 | 18.5 | 18.5 |
| **Sw** | (%) | 31 | 31 | 31 | 31 |
| **Pressure** | (kPa) | 30000 | 30000 | 30000 | 30000 |
| **Temp** | ($^oC$) | 93 | 93 | 93 | 93 |
| **Gas FVF** | | 239 | 246 | 253 | 246 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.908 | 0.934 | 0.960 | 0.934 |
| **OOIP** | (E6M3) | | | | |

| Zone II - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 350 | 350 | 350 | 350 |
| **Top Reservoir** | (mSS) | | | | 3815 (L-80) |
| **Net Pay** | (m) | 5.8 | 5.8 | 5.8 | 5.8 |
| **Porosity** | (%) | 12 | 12 | 12 | 12 |
| **Sw** | (%) | 46 | 46 | 46 | 46 |
| **Pressure** | (kPa) | 34000 | 34000 | 34000 | 34000 |
| **Temp** | ($^{o}$C) | 104 | 104 | 104 | 104 |
| **Gas FVF** | | 250 | 257 | 264 | 257 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.329 | 0.338 | 0.347 | 0.338 |
| **OOIP** | (E6M3) | | | | |

| Zone III - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 566 | 850 | 1223 | 875 |
| **Top Reservoir** | (mSS) | | | | 3930 (L-80) |
| **Net Pay** | (m) | 5.5 | 5.5 | 5.5 | 5.5 |
| **Porosity** | (%) | 10.8 | 10.8 | 10.8 | 10.8 |
| **Sw** | (%) | 43.0 | 43.0 | 43.0 | 43.0 |
| **Pressure** | (kPa) | 40000 | 40000 | 40000 | 40000 |
| **Temp** | ($^{o}$C) | 110 | 110 | 110 | 110 |
| **Gas FVF** | | 273 | 281 | 289 | 281 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.540 | 0.806 | 1.163 | 0.833 |
| **OOIP** | (E6M3) | | | | |

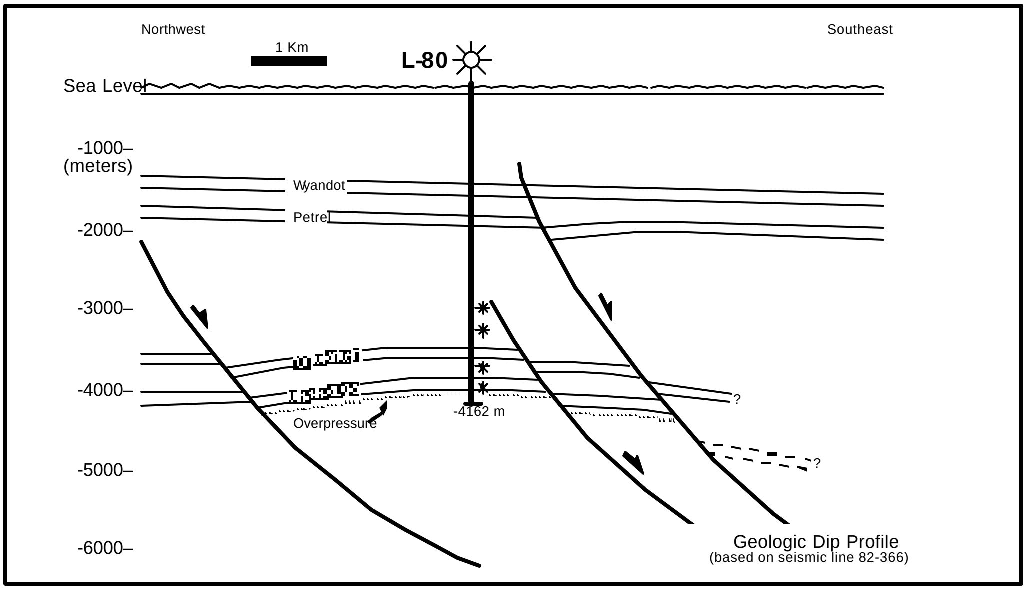
## *Depletion Scenario and Recoverable Resource*

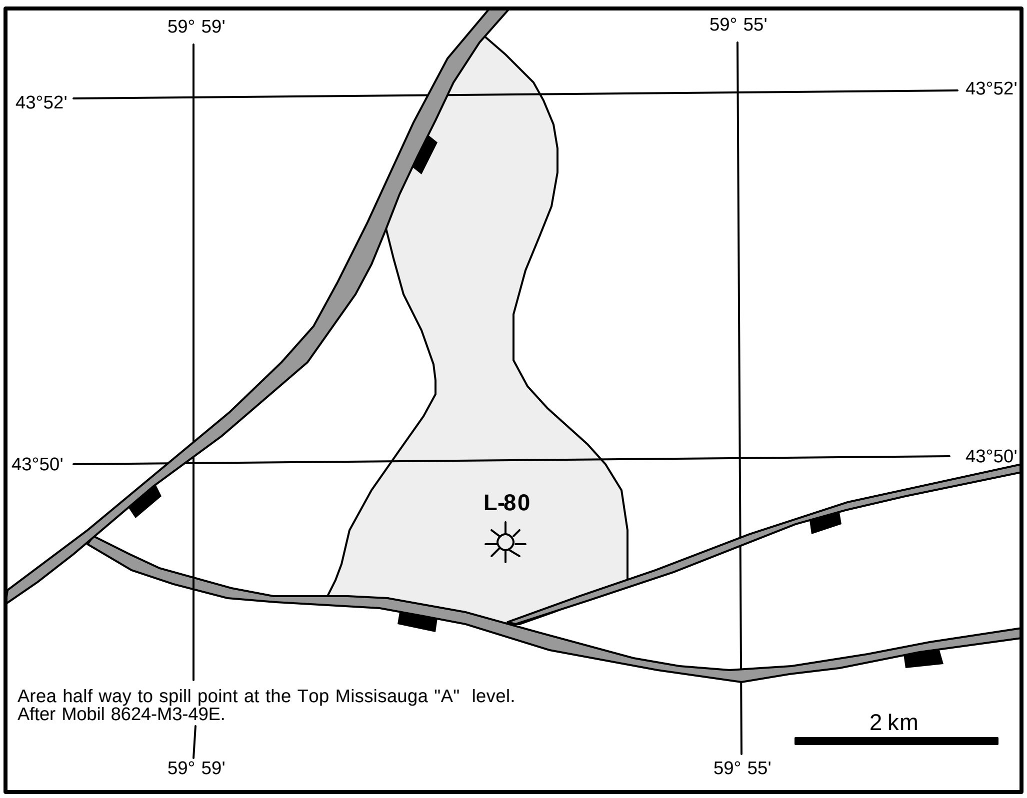
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 92 M3/E6M3 of recoverable gas.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 2.524 (89) | 3.161 (112) | 3.957 (140) | 3.210 (113) |
| **Condensate** | (E6M3) | 0.232 (1.46) | 0.291 (1.83) | 0.364 (2.29) | 0.295 (1.86) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 1.262 (45) | 2.055 (73) | 3.166 (112) | 2.087 (74) |
| **Condensate** | (E6M3) | 0.116 (0.73) | 0.189 (1.19) | 0.291(1.83) | 0.192 (1.21) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Intrepid

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# North Triumph - Commercial Discovery

## *Overview*

The North Triumph gas field is located approximately 25 km south of Sable Island. The field was discovered in 1986 and has been delineated via one additional well. This accumulation is located within the late Jurassic to middle Cretaceous age Sable Delta complex in the Sable Subbasin.

North Triumph is the third of three fields completed and now producing gas in the Sable Offshore Energy Project's Tier 1 phase. Like the other producing field at Venture, it is linked via a subsea gathering pipeline to the project's central processing complex at the Thebaud field, ~35 km to the northwest. During this field's development phase, a total of production 2 wells were drilled. Two more slots are available in the well jacket for future wells if required.

### Discovery Well:

Well: Shell PCI et al N. Triumph G-43
Spud: 85-09-26
R.R.: 86-01-31
T.D.: 4504 m

The discovery well is located in 73.6 m of water at approximately 43°42'19.06"N latitude, 59°51'23.02"W longitude. It was drilled to test for hydrocarbons in the Missisauga formation where it is incorporated in a large closure against a down-to-the-basin fault.

### Additional Wells:

Field was delineated by an additional well located approximately 3 km from the discovery location.

Well: Shell PCI et al N. Triumph B-52 (43°41'02.38"N, 59°52'56.88"W)

Two production wells have since been drilled are currently in production with hydropressured gas flowing from stacked Upper Missisauga formation reservoir sand sequences.

Well: SOEI North Triumph NT1
SOEI North Triumph NT2

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| G-43 | DST#1 | 3835-3846 | Missisauga | 997 | 28 | 0 |
| G-43 | DST#2 | 3795-3809 | Missisauga | 1045 | 31 | 0 |
| B-52 | DST#1 | 3810-3822 | Missisauga | No Flow | | |
| B-52 | DST#2 | 3795-3800 | Missisauga | TSTM | | |
| B-52 | DST#4 | 3771-3777 | Missisauga | 782 | 19 | 5 |

## *Geological/Geophysical Overview*

The North Triumph field is located on the southwestern flank of the Jurassic to Early Cretaceous age Sable Delta complex in the Sable Subbasin. North Triumph's distal position on the delta resulted in the deposition of a relatively thin sequence of fine grain fluvial sandstones that were extensively reworked by marine forces such as currents and tides. The sequence is limited to the top of the Missisauga formation, the Cretaceous phase of maximum progradation of the Sable Delta.

### Structure

The Structure defined at North Triumph exists as a simple rollover anticline bounded on the north and south by large listric growth faults, with the stratigraphic section thickening into the former. Sub-parallel to the bounding faults are two en-echelon, southerly dipping intra-field faults which almost divide the Structure into two separate closures: that to the north representing the greatest area and structural relief (250 m), and the smaller southern closure which has minimal relief (100 m). Both the G-43 and B-52 wells were drilled in the northern area. The major listric fault that bounds the northern extent of the field has a displacement of 600-650m at the Top Missisauga level. The south bounding faults have up to 1250 m of displacement at his level. A small fault runs through the center. Depending on the interpretation, this central fault may or may not subdivide the field.

The area under closure containing gas reserves in the North Triumph field is fault bounded on the east side by a third, westerly dipping intra-field fault, and to the south by the major listric fault. The west and north closures are defined by the structural elevation of the estimated free water level. The major north bounding fault offsets porous Missisauga formation strandplain sandstones against Verrill Canyon marine shales. A similar sealing scenario exists to the south, though the Missisauga sands here are offset against younger Logan Canyon formation sand/shale sequence.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the North Triumph area occupied a position that was distal to deltaic sedimentation and thus no Mic Mac formation sands were deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the North Triumph area and beyond. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed deltaic progradation followed and is represented by the strandplain succession of the Logan Canyon formation.

### Reservoir Description

The North Triumph reservoir section can be subdivided into two major sequences, and they in turn into separate coarsening-upward cycles; four in lower sequence and five in the upper. However, gamma profiles of the top two sands in upper sequence indicate fining-upward patterns for the deposited sands. These most likely define the establishment of inner shelf shallow marine sands reflecting a renewed and more vigorous marine transgression. These sands cap the top of the Missisauga formation, and grade into the thick marine shales of the overlying Naskapi shales. Therefore, based on the interpreted depositional environments for these sand cycles, and well to well correlations, it is highly probable that the reservoir sands in the North Triumph field have sheet-like geometries and are laterally continuous.

The reservoir qualities of these sands tend to be rather good. The sands are very fine to fine grained, (rarely medium grained), with fair to moderate porosities (15-20%) and good permeabilities (30 - 100 mD). Cementation is generally calcitic, but silica tends to dominate at the tops of cycles. The two marine sand cycles at the top of the upper sequence are cleaner and have better overall reservoir parameters. However, these two sands were not cored in either well. Fossils tend to concentrated in lag deposits at the base of these marine sands and are chiefly made up of large pelycepod shell fragments. Coals and organic debris are very rare in all sands.

## Petrophysical Overview

Petrophysical evaluation[1] of the two wells in the North Triumph field utilized available log, core and pressure data. The results of this evaluation are tabled below under the heading Original Hydrocarbons in Place.

The North Triumph field consists of a single primary reservoir with a common gas/water contact. The North Triumph G-43 discovery well is located near the crest of the structure. A total net pay of 40 m was calculated in the North Triumph G-43 well. The down-dip B-52 well contains 7 m of net pay. The log analysis and pressure data indicate the presence of a common gas/water contact between 3765-3770m subsea. This contact was used to define the areal extent of the pool. In addition, log analysis indicates that reservoir quality slightly decreases at the B-52 well location. Reservoir quality, generally, improves in a north easterly direction, toward the north bounding fault.

Net pay was defined using the cutoffs tabled below. Effective porosities were calculated using the standard neutron - density crossplotting technique. A 10% porosity cutoff, which corresponds to a permeability cutoff of 0.5 mD, was used to define net pay at North Triumph. Water saturations were calculated from the log data using the Simandoux water saturation equation. The gamma ray log was used to determine shale volume.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 60 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | 30-100 |

[1] Petrophysical evaluation provided by the Petroleum Development Agency, Department of Natural Resources, Nova Scotia.

## Original Hydrocarbons in Place

The discovery well encountered a good sand sequence at the top of the Missisauga formation. In the delineation well, a gas water contact was encountered, and this defined the areal extent of the accumulation. The variations in net pay, porosity, and water saturation that were observed between the discovery and delineation wells has served as basis for their selection as primary variables within the probabilistic analysis. Justifiable ranges on these parameters were based on mapped variations of the properties, averaged over the reservoir extent. Formation pressures were obtained from extrapolated DST shut-in pressures. Formation temperatures were derived by extrapolating a temperature gradient from maximum bottom hole log temperature measurements.

| **Pool A - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 2425 | 2425 | 2425 | 2425 |
| **Top Reservoir** | (mSS) | | | | 3550 (G-43) |
| **Net Pay** | (m) | 15.5 | 22.7 | 32.2 | 23.3 |
| **Porosity** | (%) | 16.1 | 18.8 | 22.2 | 19.0 |
| **Sw** | (%) | 56.8 | 40.4 | 28.7 | 41.7 |
| **Pressure** | (kPa) | 38000 | 38000 | 38000 | 38000 |
| **Temp** | ($^{o}$C) | 118 | 118 | 118 | 118 |
| **Gas FVF** | | 257 | 264 | 271 | 264 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 9.66 | 15.82 | 24.41 | 16.54 |
| **OOIP** | (E6M3) | | | | |

## *Depletion Scenario and Recoverable Resource*

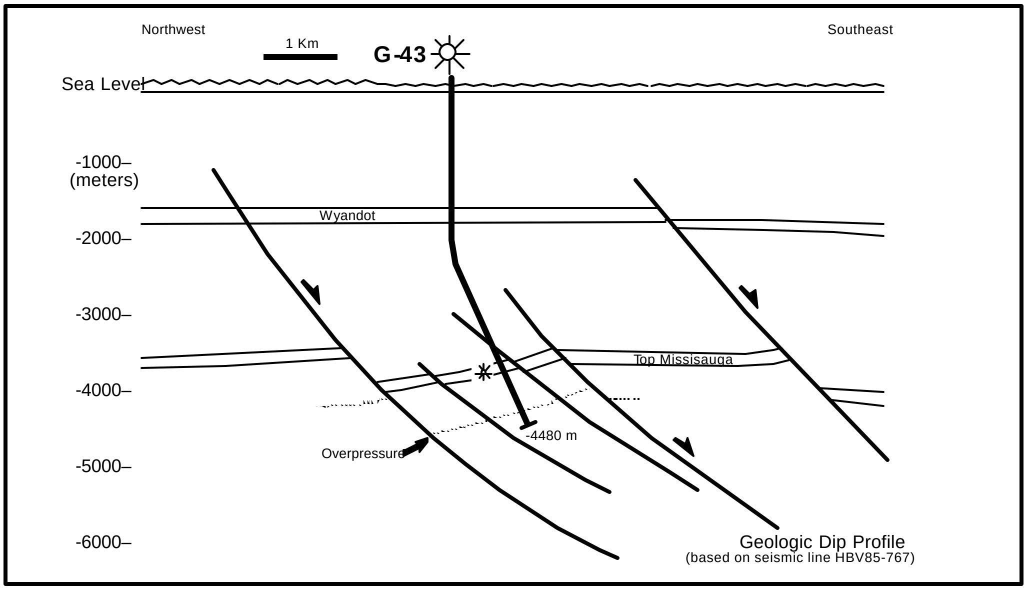
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 30 M3/E6M3 of recoverable gas based on DST observations.

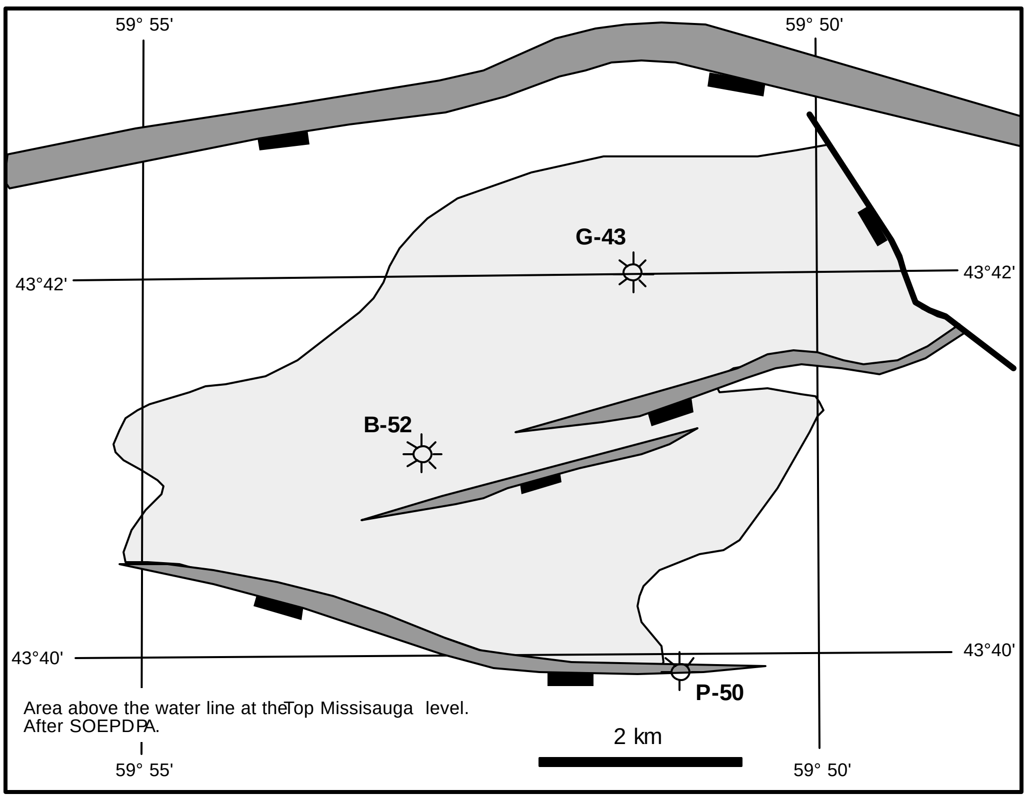
North Triumph is the third of three fields completed and now producing gas in the Sable Offshore Energy Project's Tier 1 phase. Like the other producing field at Venture, it is linked via a subsea gathering pipeline to the project's central processing complex at the Thebaud field, ~35 km to the northwest. During this field's development phase, a total of production 2 wells were drilled. Two more slots are available in the well jacket for future wells if required. The field will be placed under compression during its late life from a central compression facility located approximately 35 km away at the Thebaud location.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 9.660 (341) | 15.82 (559) | 24.41 (862) | 16.54 (584) |
| **Condensate** | (E6M3) | 0.290 (1.82) | 0.475 (2.99) | 0.732 (4.61) | 0.496 (3.12) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 4.830 (171) | 10.28 (363) | 19.53 (690) | 10.75 (380) |
| **Condensate** | (E6M3) | 0.145 (0.91) | 0.308 (1.94) | 0.586 (3.68) | 0.323 (2.03) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# North Triumph

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# Olympia - Significant Discovery

## *Overview*

The Olympia gas field is located 5 km due north of the eastern end of Sable Island. The field was discovered in 1983 and its current assessment is based on the discovery well. The field is within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex

### Discovery Well:

| | |
|---|---|
| Well: | Mobil Texaco PEX Olympia A-12 |
| Spud: | 82-04-23 |
| R.R.: | 83-01-10 |
| T.D.: | 6064 m |

Discovery Well is located in 40 m of water depth at approximately 44°01’03.27”N latitude, 59°46’44.09”W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a rollover anticline against a down-to-the-basin fault.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| A-12 | DST#2 | 5694-5704 | Mic Mac | No Rec | | |
| A-12 | DST#3 | 5199-5210 | Mic Mac | No Rec | | |
| A-12 | DST#4 | 5167-5182 | Mic Mac | No Rec | | |
| A-12 | DST#5 | 4664-4678 | Missisauga | 419 | 75 | |
| A-12 | DST#6 | 4640-4648 | Missisauga | 413 | 6 | 67 |
| A-12 | DST#7 | 4622-4633 | Missisauga | 496 | 17 | 13 |
| A-12 | DST#8 | 4525-4538 | Missisauga | 210 | 17 | 1 |
| A-12 | DST#9 | 4450-4462 | Missisauga | 0.5 | | 140 |

## *Geological/Geophysical Overview*

The Olympia gas field is located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. With its proximity to sediment source, basin hinge-line position and resultant rapid subsidence, the progradational strata deposited at Olympia consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Early Cretaceous Missisauga formation.

### Structure

The Olympia structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic age salts of the Argo formation. Such a combination resulted in the formation of significant overpressure conditions which are manifested in the reservoir sands.

The structure is a rhomboidal-shaped rollover anticlinal feature bound on the north by a major down-to-the-basin listric growth fault. This east-west trending basin hinge-line fault is the major structural feature in the Sable Subbasin and bounds a number of important gas fields on trend with Olympia including West Venture and Venture to the east and West Olympia to the west. The eastern convergence of major growth fault to the south with the main north bounding fault results in fault closure at the field's eastern end, and simple structural closure to the south. A southeast-dipping fault splay from the northern fault separates Olympia from the adjacent West Olympia Field.

Seismic profiles and mapping indicates the structure has two pairs of structural crests: the main anticlinal closures to the northeast, and a smaller pair against the field's western fault. The field's highest relief is present on the easternmost closure, and maximum height of field closure in the reservoir section is about 110 m. Several regional seismic markers are prominent in the area, but internal field reflections define its structure and include the #3 Sand, #9 Limestone and the 'Y' Limestone which are also common to the Venture Field further to the east. For undetermined reasons, while these lithologic zones are recognized and well developed in the intervening West Venture field wells, they have very poor seismic attributes and thus cannot be used for mapping purposes there.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is represented by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

The reservoir sands at Olympia are located stratigraphically in the Lower member of the latest Jurassic-Early Cretaceous Missisauga formation. Seismic mapping and well data indicate that the majority of the reservoir sands can be correlated with equivalent sands of the Venture and West Venture fields to the east. The single exploratory well drilled on the apex of Olympia's eastern high encountered 6 major gas-bearing reservoirs over a 300 m thick Lower Missisauga section which were extensively logged, and tested (#3, #4, #6 & #7 Sands; the #5 & #8 Sands were not tested). No cores were recovered in the O-51 well.

All Olympia reservoir sands are found in overpressure conditions, with the transition from hydropressure to overpressure occurring immediately above the shallowest reservoir sand (#3). Like other fields, the preservation/enhancement of porosity and permeability in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size. Given their ability to be correlated with sands in other the fields along strike, Olympia reservoirs have excellent east-west lateral continuity. It is suspected that they likely thin and deteriorate toward the field's southern margin.

Olympia sand reservoirs 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, which provide effective top seals. Log profiles of the Lower Missisauga member strata reflect delta front and channel depositional environments with increasing current and tidal influences that are manifested as strandplain shoreface and tidal deposits. Although penetrated by a single well, the data show that the reservoir characteristics of these generally coarsening upward sands have good reservoir characteristics with effective porosities ranging from 12-22%. Drillstem test results indicate fair to excellent permeabilities.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the Olympia A-12 well was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Olympia field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | Excellent |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

The Olympia well tested significant gas from three zones. Sands 4, 6 and 7 have no apparent water lines and therefore the areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The proven area was assigned based upon the single well test, most likely based on the structure being half full, and possible area extending to structural spill point. Zone II had a gas water contact observed within the well and therefore its areal extent is limited and defined. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| Sand 4 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 575 | 810 | 1191 | 850 |
| **Top Reservoir** | (mSS) | | | | 4480 (A-12) |
| **Net Pay** | (m) | 4.6 | 4.6 | 4.6 | 4.6 |
| **Porosity** | (%) | 20.8 | 20.8 | 20.8 | 20.8 |
| **Sw** | (%) | 38.8 | 38.8 | 38.8 | 38.8 |
| **Pressure** | (kPa) | 56000 | 56000 | 56000 | 56000 |
| **Temp** | ($^{o}$C) | 123 | 123 | 123 | 123 |
| **Gas FVF** | | 305 | 314 | 323 | 314 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.055 | 1.492 | 2.196 | 1.563 |
| **OOIP** | (E6M3) | | | | |

| Sand 6 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 125 | 125 | 125 | 125 |
| **Top Reservoir** | (mSS) | | | | 4585 (A-12) |
| **Net Pay** | (m) | 11.9 | 11.9 | 11.9 | 11.9 |
| **Porosity** | (%) | 23.7 | 23.7 | 23.7 | 23.7 |
| **Sw** | (%) | 38.3 | 38.3 | 38.3 | 38.3 |
| **Pressure** | (kPa) | 69000 | 69000 | 69000 | 69000 |
| **Temp** | ($^{o}$C) | 127 | 127 | 127 | 127 |
| **Gas FVF** | | 340 | 350 | 360 | 350 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.740 | 0.761 | 0.782 | 0.761 |
| **OOIP** | (E6M3) | | | | |

| Sand 7 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 375 | 688 | 1137 | 725 |
| **Top Reservoir** | (mSS) | | | | 4626 (A-12) |
| **Net Pay** | (m) | 11.0 | 11.0 | 11.0 | 11.0 |
| **Porosity** | (%) | 20.6 | 20.6 | 20.6 | 20.6 |
| **Sw** | (%) | 42.8 | 42.8 | 42.8 | 42.8 |
| **Pressure** | (kPa) | 70000 | 70000 | 70000 | 70000 |
| **Temp** | ($^{o}$C) | 130 | 130 | 130 | 130 |
| **Gas FVF** | | 343 | 353 | 363 | 353 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.706 | 3.142 | 5.193 | 3.317 |
| **OOIP** | (E6M3) | | | | |

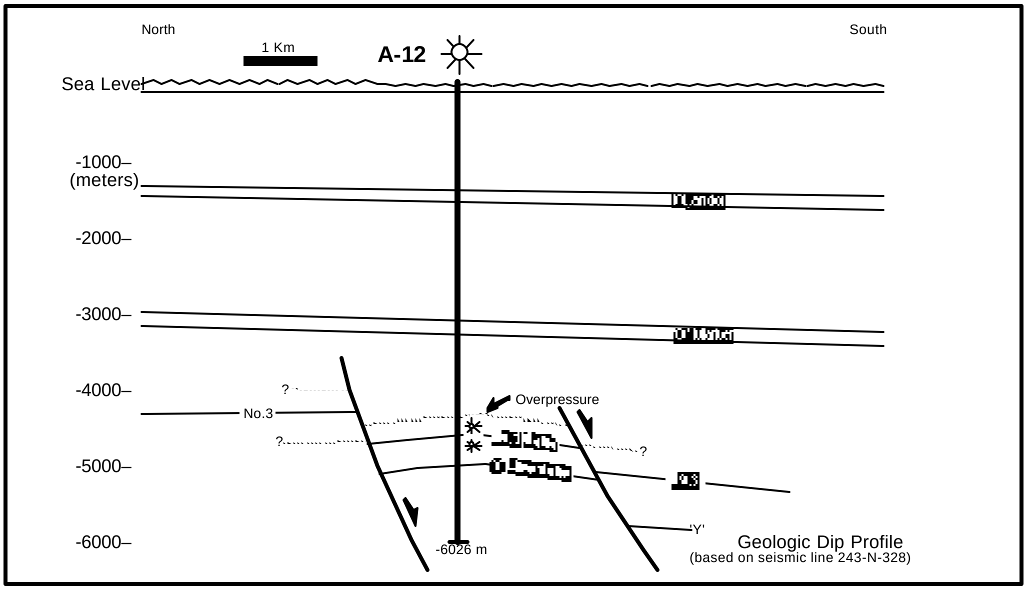
## *Depletion Scenario and Recoverable Resource*

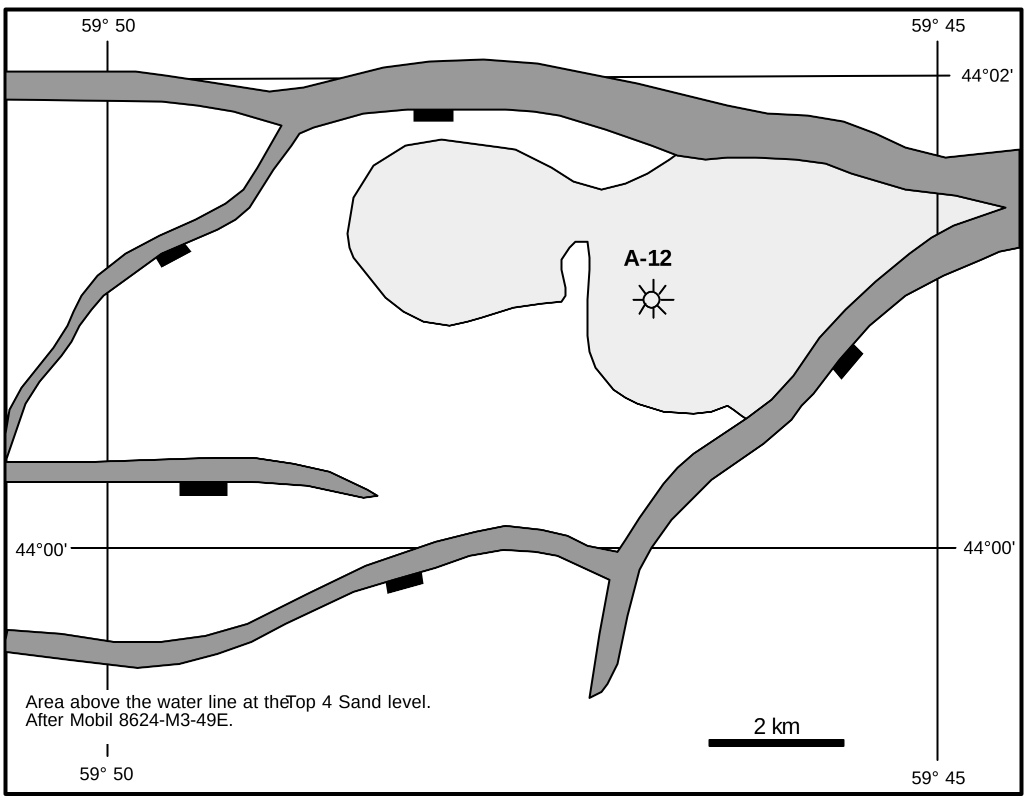
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 145 M3/E6M3 of recoverable gas and is based on DST observations.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 3.658 (129) | 5.389 (190) | 7.933 (280) | 5.640 (199) |
| **Condensate** | (E6M3) | 0.530 (3.34) | 0.781 (4.91) | 1.150 (7.24) | 0.818 (5.14) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 1.829 (65) | 3.503 (124) | 6.346 (224) | 3.666 (129) |
| **Condensate** | (E6M3) | 0.265 (1.67) | 0.508 (3.19) | 0.921 (5.79) | 0.532 (3.34) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Olympia

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# Onondaga - Significant Discovery

## Overview

The Onondaga gas field is located approximately 35 km south-west of Sable Island. The field was discovered in 1969 and has been delineated via three additional wells. This accumulation is located within the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Shell Onondaga E-84 |
| Spud: | 69-09-01 |
| R.R.: | 69-11-11 |
| T.D.: | 3988.3 m |

The discovery well is located in 57.9 m of water at approximately 43°43’16.13”N latitude, 60°13’17.18”W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a large salt diapir.

### Additional Wells:

The field was further delineated by an additional three wells located within approximately 3 to 5 km of the discovery location.

| | |
|---|---|
| Well: | Shell Onondaga O-95 (43°44’48.096”N, 60°13’52.601”W) |
| | Shell Onondaga F-75 (43°44’17.84”N, 60°11’36.25”W) |
| | Shell Onondaga B-96 (43°45’08.209”N, 60°14’09.764”W) |

### Significant Tests:

Five (5) formation tests attempted. No tests successfully conducted. In all tests, it was felt that the seal valve in the tool malfunctioned, not sealing the recovery. However, log analysis indicated that 38 m of net gas pay was justified at the E-84 location.

## *Geological/Geophysical Overview*

The Onondaga gas field is located in the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at Onondaga consist of a relatively thin sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits, where these sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Early Cretaceous Missisauga formation.

### Structure

The Onondaga structure is a large salt diapir composed of latest Triassic to earliest Jurassic age evaporites of the Argo formation. The overlying Early Cretaceous and younger strata are draped and tilted over this feature and form a circular structure that is complexly faulted across its crest. These faults are northeast-southwest trending and appear to sole into the top of the salt diapir. They do not exhibit any evidence of being syndepositional, and the seismic data suggest that salt movement occurred in the Late Cretaceous. The structure has high relief with a maximum closure of approximately 300 m.

Several regional and internal field seismic reflectors define the Onondaga structure. These include the Wyandot Limestone, Top Missisauga formation, and the ‘O’ Marker equivalent (i.e., top of the Middle Missisauga member. Overpressure conditions were encountered in two of the wells below the reservoir interval and above the salt within marine shales of the Verrill Canyon formation.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the Onondaga-Intrepid area occupied a position that was distal to deltaic sedimentation and thus no Mic Mac formation sands were deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the South Sable area and beyond. In this distal region, the resultant sedimentary section is considerably thinner and has a low sand/shale ratio. It appears that only the Upper and Middle Missisauga formation were deposited in this area. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed deltaic progradation followed and is represented by the strandplain succession of the Logan Canyon and Dawson Canyon formations. Cessation of deltaic sedimentation in the Late Cretaceous permitted the establishment of a regional carbonate facies of the Wyandot formation.

### Reservoir Description

The Onondaga gas reservoirs are located within Early Cretaceous strata of the Middle and Upper members of the Missisauga formation. Four exploratory wells have been drilled on the structural crest and flanks at Onondaga and a number of reservoir quality sands were encountered, with at least five containing significant gas pays. All major gas sands occur in hydropressure conditions with all but one found at the top of the Upper Missisauga member. The remaining reservoir is an isolated sand located in the mostly shaley Middle Missisauga member. Seismic mapping and well results show that although the reservoir sands have good sand continuity throughout the field area, the complex nature of the faulting severely limits the areal extent of the gas pays.

Reservoir sands in the Onondaga 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 coaly stringers. The reservoir characteristics of the gas sands are fair to very good with effective average porosities ranging from 12-24% and average permeabilities between 10-100 mD based on well logs and repeat formation tests. No successful drillstem tests were run in any of the wells over prospective gas pay zones.

## Petrophysical Overview

A petrophysical evaluation[1] of the four wells in the Onondaga field was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Onondaga field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | 10 - 100 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

Two zones have been defined within the Onondaga field; the Middle and Upper Missisauga formation sands. The areal extent of the Upper Missisauga zone is limited and defined by a gas water contact observed in the E-84 well. The proven and most likely areal extent of the Middle Missisauga was assigned based upon gas down to the base of porosity in the E-84 well, with possible area extending to structural spill point. Net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **Upper Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 450 | 450 | 450 | 450 |
| **Top Reservoir** | (mSS) | | | | 2640 (E-84) |
| **Net Pay** | (m) | 38 | 38 | 38 | 38 |
| **Porosity** | (%) | 21.5 | 21.5 | 21.5 | 21.5 |
| **Sw** | (%) | 42 | 42 | 42 | 42 |
| **Pressure** | (kPa) | 28000 | 28000 | 28000 | 28000 |
| **Temp** | ($^{o}$C) | 90 | 90 | 90 | 90 |
| **Gas FVF** | | 221 | 227 | 233 | 227 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 4.706 | 4.840 | 4.974 | 4.840 |
| **OOIP** | (E6M3) | | | | |

| **Middle Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 830 | 1256 | 1689 | 1258 |
| **Top Reservoir** | (mSS) | | | | 3340 (O-95) |
| **Net Pay** | (m) | 6 | 6 | 6 | 6 |
| **Porosity** | (%) | 14 | 14 | 14 | 14 |
| **Sw** | (%) | 33 | 33 | 33 | 33 |
| **Pressure** | (kPa) | 32000 | 32000 | 32000 | 32000 |
| **Temp** | ($^{o}$C) | 91 | 91 | 91 | 91 |
| **Gas FVF** | | 271 | 279 | 287 | 279 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.305 | 1.970 | 2.657 | 1.976 |
| **OOIP** | (E6M3) | | | | |

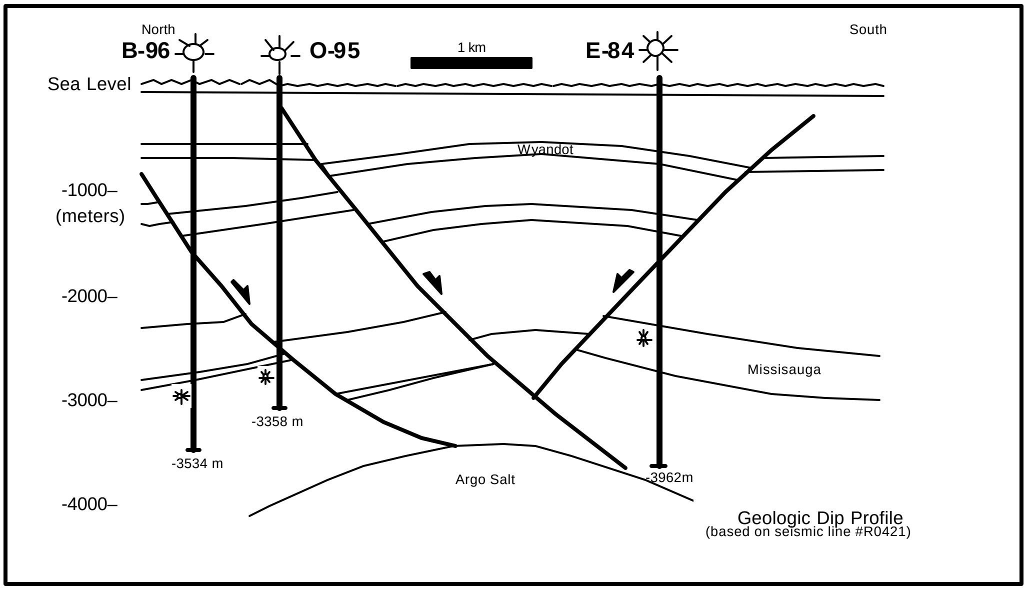
## *Depletion Scenario and Recoverable Resource*

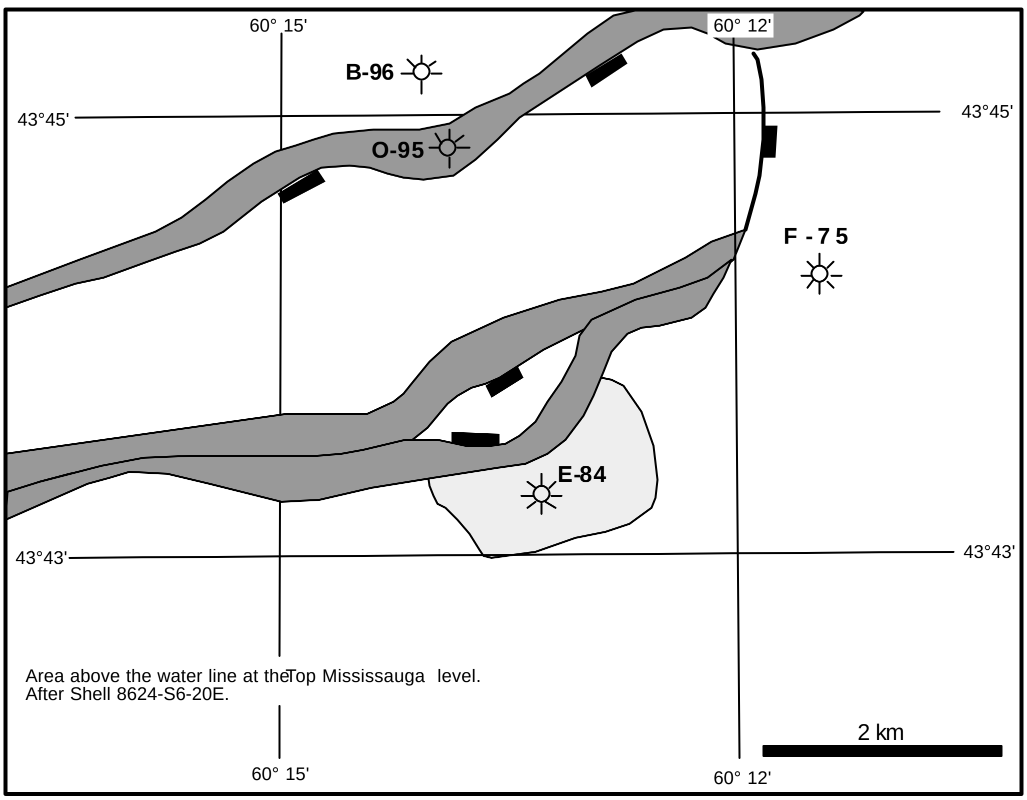
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio has not been estimated as no successful tests have been performed on this resource.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 6.067 (214) | 6.790 (240) | 7.596 (268) | 6.816 (241) |
| **Condensate** | (E6M3) | - | - | - | - |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 3.034 (107) | 4.414 (156) | 6.077 (215) | 4.430 (156) |
| **Condensate** | (E6M3) | | | | |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Onondaga

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# Panuke - Commercial Discovery

## *Overview*

The Panuke oil field is located approximately 60 km south-west of Sable Island. The field was discovered in 1986 and was delineated via one additional well. This accumulation is located within the late Early Cretaceous Missisauga formation, on the western edge of the Sable Delta complex

Production began in 1992, when four producing wells were placed on stream. A sequential production strategy approved in 1994 and realized in 1997 saw the production rig, move from the Cohasset field to Panuke to pump wells and recover the remaining reserves after depletion of the Cohasset field. Panuke wells were produced under natural flow conditions until mid 1995, when the last producer ceased flowing and then under pump until December 1999. Abandonment of the Panuke field is currently underway, the Cohasset field to be abandoned later in 2000.

The field has been subject to zonal abandonment and the wellbores are suspended. Pending additional exploration in the area, the jacket will remain on location for an additional time period.

### Discovery Well:

Well: Shell PCI et al Panuke B-90
Spud: 86-08-06
R.R.: 86-09-25
T.D.: 3445 m

The discovery well is located in 47 m of water at approximately 43°49'11.99"N latitude, 60°42'34.59"W longitude. It was drilled to test for the presence of hydrocarbons in the Logan Canyon and Missisauga formations where they were gently draped over a high along the Abenaki carbonate bank edge.

### Additional Wells:

The field was delineated with an additional well located approximately 4 km from the discovery location.

Well: Petro-Canada et al Panuke F-99 (43°48'24.90"N, 60°44'34.01"W)

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| B-90 | DST#1 | 2294-2300 | Missisauga | 11 | 952 | |
| F-99 | DST#1 | 2308-2311 | Missisauga | | TSTM | 7 |
| F-99 | DST#2 | 2303-2305 | Missisauga | 1.7 | 181 | 1 |
| F-99 | DST#3 | 2292-2298 | Missisauga | 11 | 635 | |
| F-99 | DST#4 | 2228-2230 | Logan Canyon | | 12 | 12 |

## Geological/Geophysical Overview

The Panuke oil field is located on the edge of a marine embayment on the western edge of the Sable Delta complex. The field's distal position on the delta and its high stratigraphic position resulted in the deposition of an interlayered sand/shale sequence. The sandstones have fluvial affinities but were significantly reworked by marine currents and tides and generally fine upward in the section. The reservoir sequence occurs in the topmost 40 m of the late Early Cretaceous Missisauga formation. However, the transgression the sand facies would infer that they could be recognized as the basal sequence of the Naskapi shale member.

### Structure

The Panuke structure exists as an elongate, simple drape structure with low relief, four-way closure. It was formed through differential compaction of marine and deltaic clastic sediments over the edge of the buried Jurassic age carbonate fringing reef complex of the Abenaki formation.

In seismic profiles the Panuke structure exhibits subtle drape closure, with the maximum relief of the structure estimated as being approximately 24 m. No seismic reflectors are present within the reservoir sequence. This requires that the pay sands be derived from another horizon that can be mapped. The Panuke reservoir section was mapped based on projecting up from the Missisauga formation oolitic limestone ("O Marker") datum, located about 125 m below the reservoir sequence. Although directionally drilled, survey data from the 6 wells in the field also assists in better defining the structure.

### Stratigraphy

Up to earliest Cretaceous time the southwesterly progradation of the Sable Delta complex in the Cohasset area was limited and influenced by the presence of the Jurassic Abenaki reef complex, as well as the distance from the locus of sedimentation in the Sable Subbasin. However, by the Early Cretaceous clastic sedimentation overwhelmed and buried the Abenaki carbonates. These clastic sediments of the Middle and Upper members of the Missisauga formation represent fluvial and shoreface deposition in a marine dominated setting, such that sand bodies are interbedded with inner shelf shales, though the lower sands tend to represent channel facies. A major regional marine transgression in the Sable Subbasin (Naskapi member, Logan Canyon formation) then followed, blanketing the deltaic sediments with marine shales and silts.

### Reservoir Description

The reservoir sands at Panuke occupy the top 40 m of the Late Cretaceous deltaic Missisauga formation. Two exploration wells were drilled prior to field development, and since then 4 additional wells were completed. All 5 reservoir sands have been extensively cored and exhibit considerable lateral and vertical continuity across the field.

Within the Missisauga formation, the reservoir sands consist of stacked coarsening upward cycles ranging from 2-8 m thick. Five oil-bearing sands are present (Panuke 1-5; "P1", etc.), with the main (thickest) reservoir being the P2 sand. The reservoir sands are coarsening upward cycles of well sorted fine to medium grain sands and record lower to upper shoreface depositional environments interlayered with thin marine shales. These strandplain sand cycles have excellent reservoir characteristics, with porosities and permeabilities generally ranging from 20-28% and 200-300 mD respectively. Intervals within the main P2 Sand have permeabilities exceeding 2 Darcies.

## Petrophysical Overview

A petrophysical evaluation of the Panuke wells was completed. This data was used to calculate a deterministic assessment of oil in place.

Net pay was defined for the Panuke field using the cutoffs tabled below. Effective porosities were calculated from the density log. Water saturations were determined from the log data using the Archie water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 60 |
| **Porosity Cutoff** | (%) | 16 |
| **Volume of Shale Cutoff** | (%) | 40 |
| **Permeability Horizontal** | (mD) | 200 - 300 |

## *Original Hydrocarbons in Place*

Original oil in place has been determined deterministically and rationalized against production history to arrive at a Best Current Estimate value. No probabilistic calculations have been undertaken on this asset.

Oil/water contacts have been determined in the Panuke reservoirs and are used to define the areal extent of each pool. Deterministic calculations define the oil in place at 6.676 E6M3. The Gas-Oil Ratio is 17 M3/M3 based on production history.

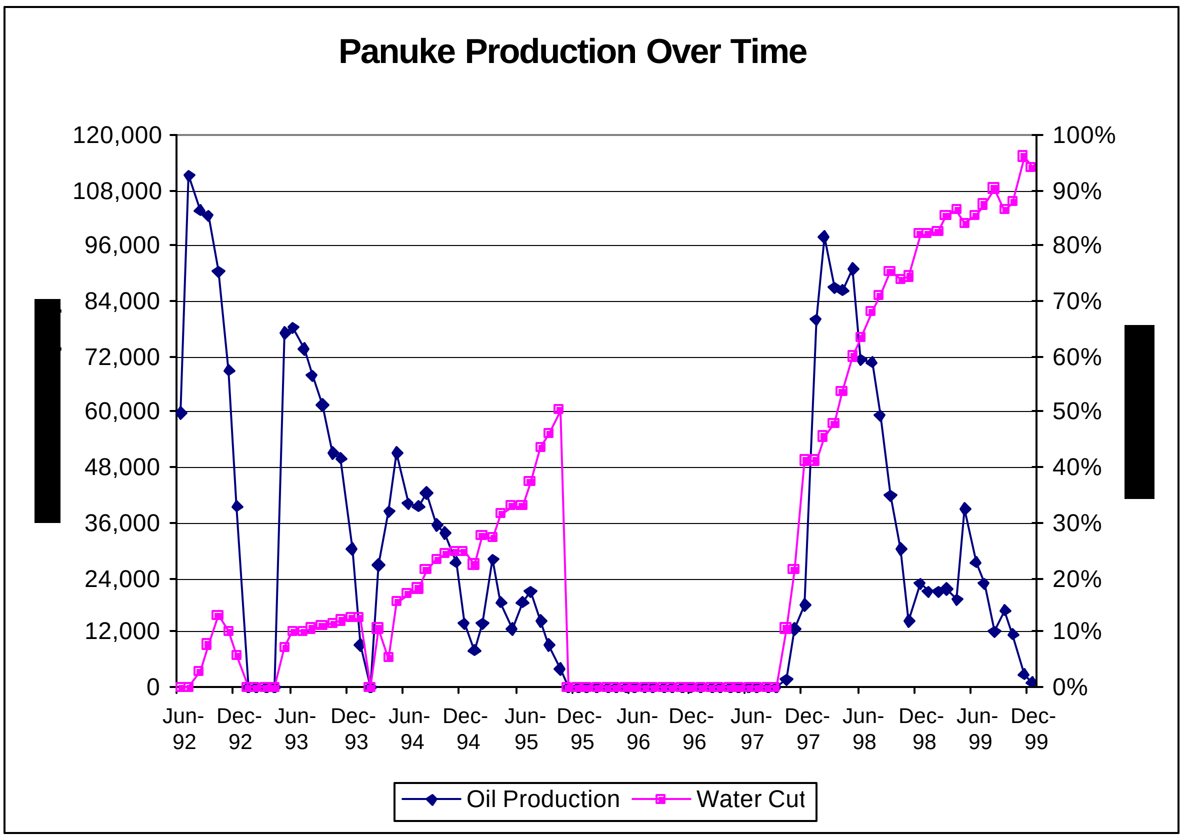
## Depletion Scenario and Recoverable Resource

The Panuke field was produced under an approved development plan along with the Cohasset field. Production began in 1992, and terminated in December 1999, having produced 2.5684224 E6M3 (16.155 MMbls) or an estimated 38.5% of the OOIP.

The Panuke field was originally planned for concurrent production with the Cohasset field. Panuke wells were to be pumped remotely using cable deployed pumping equipment not needing rig intervention for maintenance. This proved not to be feasible. A sequential production strategy approved in 1994 and realized in 1997 saw the production rig, move from the Cohasset field to Panuke to pump wells and recover the remaining reserves after depletion of the Cohasset field. Panuke wells were produced under natural flow conditions until mid 1995, when the last producer ceased flowing and then under pump until December 1999. Abandonment of the Panuke field is currently underway, the Cohasset field to be abandoned later in 2000.

The field has been subject to zonal abandonment and the wellbores are suspended. Pending additional exploration in the area, the jacket will remain on location for an additional time period.

A Plot of monthly production for the field in included below.

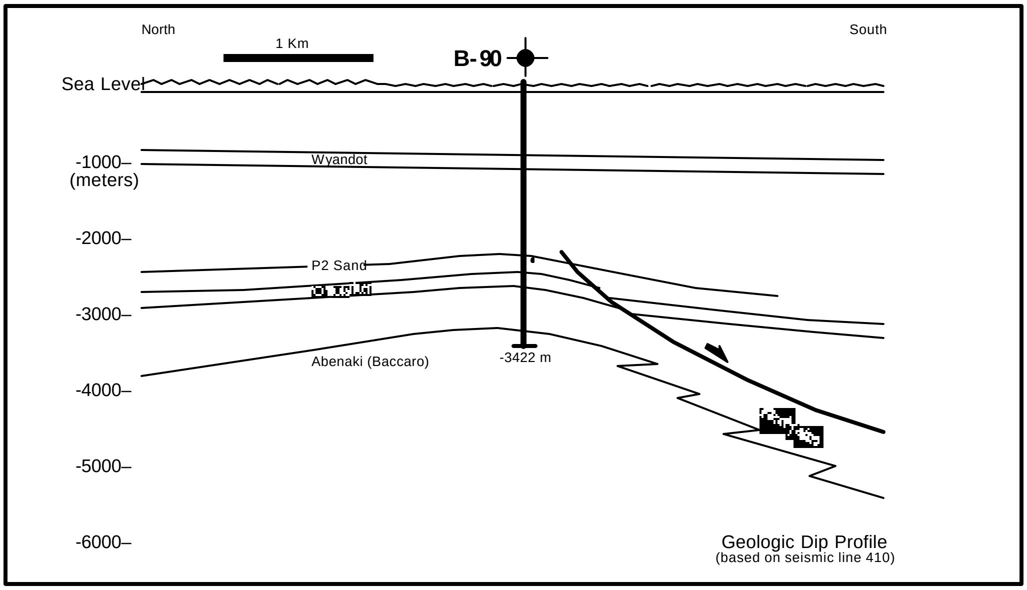



| Total Stock Tank Hydrocarbons * | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|
| **In Place** | | | | |

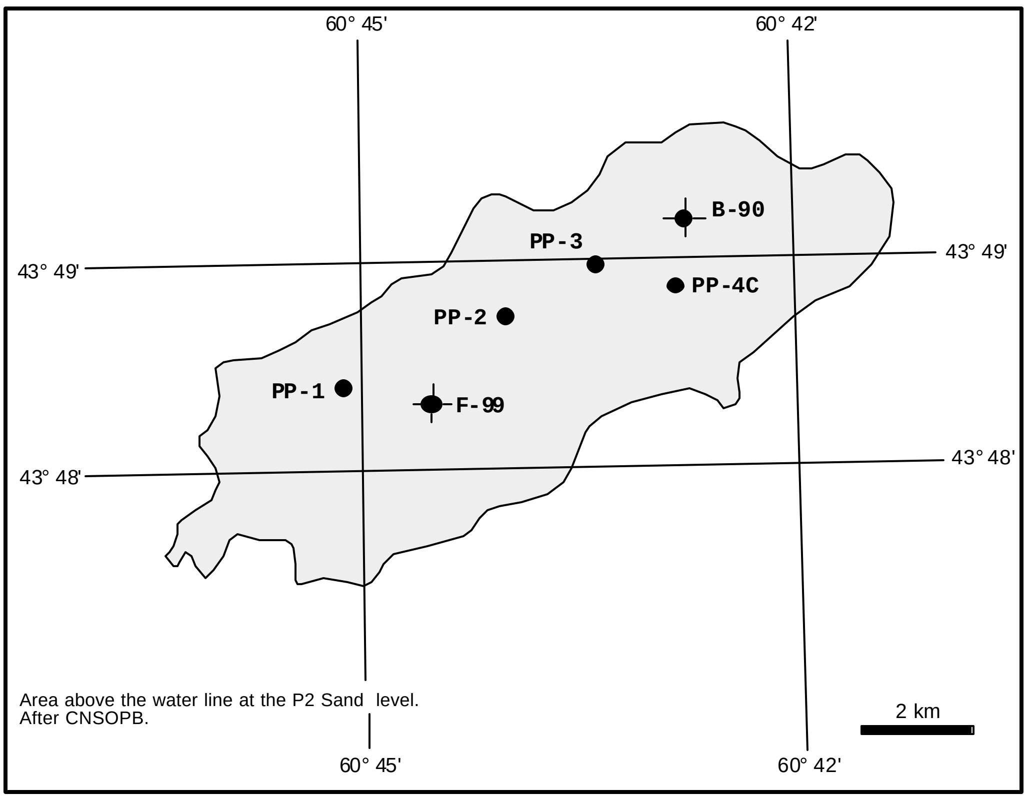
| | | |
|---|---|---|
| **Gas** | (E9M3) | |
| **Condensate** | (E6M3) | |
| **Oil** | (E6M3) | 6.676 (42.0) |
| **Assoc. Gas** | (E9M3) | 0.113 (4) |
| | | |
| **R.F. Gas** | | 0.538 |
| **R.F. Oil** | | 0.385 |
| | | |
| **Recoverable Resource** | | |
| | | |
| **Gas** | (E9M3) | |
| **Condensate** | (E6M3) | |
| **Oil** | (E6M3) | 2.568 (16.2) |
| **Assoc. Gas** | (E9M3) | 0.061 (2.15) |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Panuke




Geologic Dip Profile
(based on seismic line 410)




Area above the water line at the P2 Sand level.
After CNSOPB.

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# Primrose - Significant Discovery

## *Overview*

The Primrose gas/oil field is located 64.4 km east of Sable Island. The field was discovered in 1973 and was delineated via two additional wells. This accumulation is located within the Mesozoic age Sable Subbasin near the eastern edge of the Sable Delta complex.

### Discovery Well:

Well: Shell Primrose N-50
Spud: 72-03-14
R.R.: 73-04-21
T.D.: 1713.59 m

The discovery well is located in 90.8 m of water at approximately 43°59'48.43"N latitude, 59°06'51.63"W longitude. It was drilled to test for the presence of hydrocarbons in the sands associated with a large salt diapir.

### Additional Wells:

Well: Shell Primrose A-41 (44°00'05.68"N, 59°06'18.26"W)
Shell Primrose F-41 (44°00'29.55"N, 59°07'06.52"W)

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil*/Con (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| N-50 | PT#1 | 1643-1650 | Iroquois/Caprock | 6.8 | 48* | |
| N-50 | PT#2 | 1612-1650 | Iroquois/Caprock | 71 | 56* | |
| N-50 | PT#3 (1st Flow Test) | 1498-1532 | Logan Canyon | 476 | 9 | |
| | PT#3 (2nd Flow Test) | 1498-1532 | Logan Canyon | 282 | 7 | |
| | PT#3 (3rd Flow Test) | 1498-1532 | Logan Canyon | 173 | 0.85 | |
| N-50 | PT#4 | 1391-1400 | Wyandot | 385 | 71 | |
| N-50 | PT#5 (1st Flow Test) | 1372-1400 | Wyandot | 493 | 17 | |
| | PT#5 (2nd Flow Test) | 1372-1400 | Wyandot | 272 | 11 | |
| A-41 | PT#1 | 1551-1561 | Wyandot | 93 | | 4 |
| A-41 | PT#2 | 1512-1530 | Wyandot | 195 | | 2 |
| A-41 | PT#3 | 1422-1475 | Wyandot | No Rec | | |
| F-41 | PT#1 | 1509-1530 | Wyandot | 123 | | |

## Geological/Geophysical Overview

The Primrose gas/oil field is located in the Mesozoic age Sable Subbasin near the eastern edge of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. Prior to delta development, in the Late Triassic the area was blanketed by thick marine salts and later in the Jurassic by shallow marine dolomites and fluvial sandstones and shales. The Late Jurassic to Early Cretaceous progradational deltaic strata deposited at Primrose consist of a relatively thin sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits, where these sediments record episodic delta advances punctuated by marine incursions. Upon cessation of deltaic sedimentation, extensive carbonate deposition took place, which was eventually buried by coastal plain and marine shelf clastics. The reservoirs are located in the limestones of the Late Cretaceous Wyandot formation (gas) and thin sandstones of the Logan Canyon formation (gas), and dolomites of the Early Jurassic Iroquois formation (oil).

### Structure

The Primrose structure is a small salt diapir composed of latest Triassic to earliest Jurassic age evaporites of the Argo formation. The diapir penetrates through Cretaceous and older strata with only a thin veneer of Late Cretaceous sediments draped over this feature. Between these sediments and the salt is a thin caprock interval of Early Jurassic dolomites and shales. The top of the salt is quite shallow, being only about 1300 m below the present day water bottom. The structure is circular in shape and faulted across its crest and around its flanks that appear to sole into the top of the salt. They do not exhibit any evidence of being syndepositional, and the seismic data suggest that salt movement occurred in the latest Cretaceous or Tertiary. The structure has high relief with a maximum closure of approximately 225 m.

Two regional carbonate seismic reflectors define the Primrose structure. These include the Wyandot formation limestone and the Petrel limestone (Dawson Canyon formation). Overpressure conditions were not encountered in any of the three wells drilled on the structure.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Late Triassic to the Tertiary. In the Triassic, rift related, fine grain clastic sediments of the formation were deposited and then overlain by thick marine salts of the Argo formation. In the Early Jurassic, shallow marine dolomites and fluvial sandstones and shales of the Iroquois and Mohican formations respectively were deposited.

Beginning in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the Primrose area occupied a position that was beyond the eastern limit deltaic sedimentation and thus no Mic Mac formation sands were deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the South Sable area and beyond. In this distal region, the resultant sedimentary section is considerably thinner and has a low sand/shale ratio. It appears that only the Upper and Middle Missisauga formation were deposited in this area. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed deltaic progradation followed and is represented by the strandplain succession of the Logan Canyon and Dawson Canyon formations. Cessation of deltaic sedimentation in the Late Cretaceous permitted the establishment of a regional carbonate facies of the Wyandot formation. Upon cessation of deltaic sedimentation, extensive carbonate deposition took place, which was eventually buried by Tertiary age coastal plain and marine shelf clastics.

## Reservoir Description

The Primrose gas reservoirs are located within Late Cretaceous limestones of the Wyandot formation and thin sandstones of the same age Logan Canyon formation. The oil reservoirs are Early Jurassic shallow marine dolomites of the Iroquois formation which form the cap rock of the salt diapir. Three exploratory wells have been drilled on the structural crest and flanks at Primrose and all reservoirs are hydropressured. Seismic and geological mapping, and well results, confirm the continuity of the main reservoir intervals across the field. However, the complex nature of the faulting severely limits the extent of the porous intervals and hence areal extent of the hydrocarbon pays.

The main Primrose Wyandot formation 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. The reservoir characteristics of the limestones are fair to good with effective average porosities ranging from 16-26% and an average (fracture) permeability of 1-10-mD based on well logs and drillstem tests.

Secondary gas pays are in thin shallow marine shelfal sandstones of the Late Cretaceous Marmora member, Logan Canyon formation. The sands are very fine to fine grained, well sorted, calcareous, and variably argillaceous and pyritic. The have good to very good reservoir characteristics with average porosities and permeabilities ranging from 22-27 % and 5-30 mD respectively.

The Primrose oil reservoirs are the shallow water, restricted marine dolomites of the Early Jurassic Iroquois formation, and form the caprock of the salt diapir. They are microcrystalline, anhydritic, argillaceous, pyritic and are interbedded with grey dolomitic shales. The dolomites have fair to good reservoir characteristics with an average porosity (microcrystalline and occasionally vuggy) of 18%. Permeabilities have not been quantified but drillstem tests indicate that they are good (5 - 30 mD).

## *Petrophysical Overview*

A petrophysical evaluation[1] of the three wells in the Primrose field was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined, for the Primrose field using the cutoffs tabled below. Effective porosities were calculated using, the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | 5 - 30 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

In the Wyandot formation, the maximum possible area is based on an observed gas water contact in the A-41 well. The minimum and most-likely values are restricted to the N-50 fault block, as both delineation wells had to be acidized to perform adequately, and even then were declining noticeably at the end of testing. In the Logan Canyon zones, the areal extent is limited to the N-50 fault block. Possible area is assigned based on water up to the top of the wet F-41 well, with minimum and most-likely values taken at half this. The variations in net pay and water saturation that were observed between the discovery and delineation wells have also served as basis for their selection as primary variables within the probabilistic analysis on the Wyandot zone. For all other zones, these values were held constant at the discovery well's observed values. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **Wyandot** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 317 | 395 | 522 | 408 |
| **Top Reservoir** | (mSS) | | | | 1335 (N-50) |
| **Net Pay** | (m) | 47.0 | 47.0 | 47.0 | 47.0 |
| **Porosity** | (%) | 26.3 | 26.3 | 26.3 | 26.3 |
| **Sw** | (%) | 33 | 30 | 28 | 30 |
| **Pressure** | (kPa) | 16000 | 16000 | 16000 | 16000 |
| **Temp** | ($^oC$) | 52 | 52 | 52 | 52 |
| **Gas FVF** | | 155 | 159 | 163 | 159 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 4.338 | 5.412 | 8.982 | 5.590 |
| **OOIP** | (E6M3) | | | | |

| **Logan Canyon** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 131 | 162 | 210 | 167 |
| **Top Reservoir** | (mSS) | | | | 1470 (N-50) |
| **Net Pay** | (m) | 13 | 13 | 13 | 13 |
| **Porosity** | (%) | 26.6 | 26.6 | 26.6 | 26.6 |
| **Sw** | (%) | 20 | 20 | 20 | 20 |
| **Pressure** | (kPa) | 16000 | 16000 | 16000 | 16000 |
| **Temp** | ($^oC$) | 54 | 54 | 54 | 54 |
| **Gas FVF** | | 156 | 160 | 164 | 160 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.581 | 0.715 | 0.932 | 0.738 |
| **OOIP** | (E6M3) | | | | |

| Lower Logan Canyon | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 131 | 162 | 210 | 167 |
| **Top Reservoir** | (mSS) | | | | 1470 (1aA-41) |
| **Net Pay** | (m) | 6.2 | 6.2 | 6.2 | 6.2 |
| **Porosity** | (%) | 22 | 22 | 22 | 22 |
| **Sw** | (%) | 39 | 39 | 39 | 39 |
| **Pressure** | (kPa) | 17000 | 17000 | 17000 | 17000 |
| **Temp** | ($^oC$) | 67 | 67 | 67 | 67 |
| **Gas FVF** | | 152 | 156 | 160 | 156 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.171 | 0.210 | 0.274 | 0.216 |
| **OOIP** | (E6M3) | | | | |

| Iroquois | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 125 | 125 | 125 | 125 |
| **Top Reservoir** | (mSS) | | | | 1580 (N-50) |
| **Net Pay** | (m) | 6 | 6 | 6 | 6 |
| **Porosity** | (%) | 18 | 18 | 18 | 18 |
| **Sw** | (%) | 40 | 40 | 40 | 40 |
| **Pressure** | (kPa) | | | | |
| **Temp** | ($^oC$) | | | | |
| **Gas FVF** | | | | | |
| **Oil Bo** | | 1.23 | 1.20 | 1.17 | 1.20 |
| **OGIP** | (E9M3) | | | | |
| **OOIP** | (E6M3) | 0.657 | 0.675 | 0.694 | 0.675 |

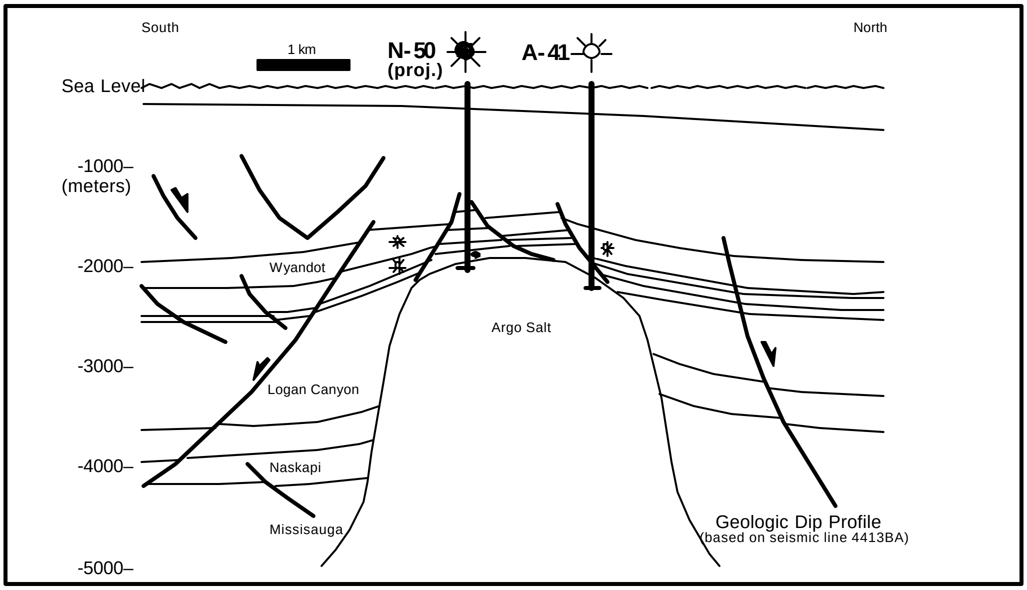
## *Depletion Scenario and Recoverable Resource*

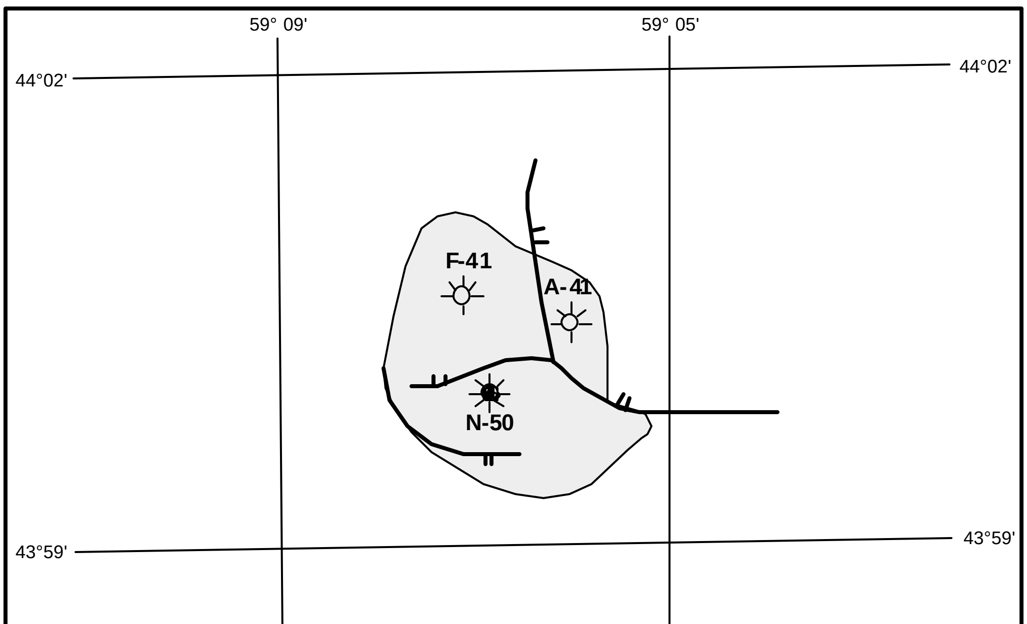
Recoverable resource for the gas accumulation of this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case, respectively. Recovery factors of 20%, 30% and 40% for the oil accumulations are similarly assigned. The Best Current Estimate is based on a factor of 65% for the gas and 30% for the oil accumulations. The Condensate-Gas Ratio is estimated at 34 M3/E6M3 of recoverable gas, and the Gas-Oil Ratio in the oil column at 1268 M3/M3 based on observations from the DSTs.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 5.062 (179) | 6.430 (227) | 8.163 (288) | 6.544 (231) |
| **Condensate** | (E6M3) | 0.172 (1.08) | 0.219 (1.38) | 0.278 (1.75) | 0.222 (1.40) |
| **Oil** | (E6M3) | 0.657 (4.13) | 0.675 (4.25) | 0.694 (4.37) | 0.675 (4.25) |
| **Assoc. Gas** | (E9M3) | 0.833 (29) | 0.856 (30) | 0.880 (31) | 0.856 (30) |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | 0.2 | 0.3 | 0.4 | 0.3 |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 2.531 (89) | 4.180 (148) | 6.530 (231) | 4.254 (150) |
| **Condensate** | (E6M3) | 0.086 (0.54) | 0.142 (0.89) | 0.222 (1.40) | 0.145 (0.91) |
| **Oil** | (E6M3) | 0.131 (0.83) | 0.203 (1.27) | 0.278 (1.75) | 0.203 (1.27) |
| **Assoc. Gas** | (E9M3) | 0.167 (6) | 0.257 (9) | 0.352 (12) | 0.257 (9) |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Primrose




Area above the water line at the Top Wyandot level.
After Shell 8624-S6-12E and 15E.

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# South Sable - Significant Discovery

The South Sable gas field is located 6 km immediately south of Sable Island. The field was discovered in 1988 and has been assessed based on the single discovery well. The reservoir is located within the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex.

## Discovery Well:

| | |
|---|---|
| Well: | Mobil et al South Sable B-44 |
| Spud: | 88-03-27 |
| R.R.: | 88-07-13 |
| T.D.: | 5207.57 m |

The discovery well is located in 35.05 m of water at approximately 43°53’06.56”N latitude, 59°51’42.09”W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a closure against a down-to-the-basin listric fault.

## Additional Wells:

No delineation drilling conducted.

## Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| B-44 | DST#1 | 3641-3648 | Missisauga | 606 | 19 | 7 |

## *Geological/Geophysical Overview*

The South Sable gas field is located in the Mesozoic age Sable Subbasin in a south-central position on the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at South Sable consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Early Cretaceous Missisauga formation.

### Structure

The South Sable structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Jurassic age marine shales of the Verrill Canyon formation. It is an irregular shaped faulted anticline on the downthrown block of a major down-to-the-basin fault, with both fault and rollover related closure. The fault has an east west trend which then swings to southwest. A small synthetic splay from its eastern end goes nearly bisects the structure. The faulted structural crest of the field is near its center and has a maximum vertical closure of approximately 100 m.

One regional and several internal field seismic reflectors exclusive to South Sable define the structure. These include the ubiquitous ‘O’ Marker (i.e. top of the Middle Missisauga member), and the Missisauga ‘A’ and ‘B’ Markers, both located within the bottom half of the Middle Missisauga member. These latter reflectors are both within the known overpressure section.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. At this time, the South Sable-Intrepid area occupied a position that was distal (south) to deltaic sedimentation and thus no Mic Mac formation sands were deposited. The equivalent section is represented by coeval deep marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the South Sable area and beyond. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

The South Sable gas reservoirs are found within strata of the Middle member of the Early Cretaceous Missisauga formation. Only one exploratory well has been drilled on the structural crest at South Sable and a number of reservoir quality sands were encountered but only two contained significant gas pays. The highest sand is in hydropressure conditions while the lower one is slightly overpressured. The un-named hydropressured sand was the only gas reservoir tested, and a wet sand immediately above the overpressured sand was the only sand cored. Seismic mapping suggests that the reservoir sands thicken slightly towards the north bounding growth fault and have good continuity throughout the field area.

Reservoir sands in the South Sable field consist of stacked sequences of delta front, channel and strandplain-shoreface deposits in a dominantly marine setting. Well data shows that these coarsening upward progradational sands are medium to coarse grained (occasionally pebbly), moderate to well sorted, siliceous and variably argillaceous and dolomitic. The reservoir characteristics of the two gas sands are poor to good with effective average porosities ranging from 12-16% and permeabilities .01-20 mD based on well logs, drillstem test and core analysis results.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the South Sable B-44 well, was completed. The results of this evaluation, for each reservoir in the field, are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined, for the South Sable field, using the cutoffs tabled below. Effective porosities were calculated using, the neutron - density crossplotting technique. Water saturations were determined, from the log data, using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| | | |
| **Permeability Horizontal** | (mD) | 0.01 - 20 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

The areal extent of this pool is defined and very limited due to an observed gas water contact located at the base of the sand penetrated by the discovery well. Due to this limited areal extent, all reservoir properties were held constant at the well observed values within the analysis. The magnitude and uncertainty of this accumulation is thus very limited. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| All Zones | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 75 | 75 | 75 | 75 |
| **Top Reservoir** | (mSS) | | | | 3598 (B-44) |
| **Net Pay** | (m) | 10 | 10 | 10 | 10 |
| **Porosity** | (%) | 15.3 | 15.3 | 15.3 | 15.3 |
| **Sw** | (%) | 33.2 | 33.2 | 33.2 | 33.2 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^{o}$C) | 108 | 108 | 108 | 108 |
| **Gas FVF** | | 257 | 264 | 271 | 264 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.197 | 0.202 | 0.208 | 0.202 |
| **OOIP** | (E6M3) | | | | |

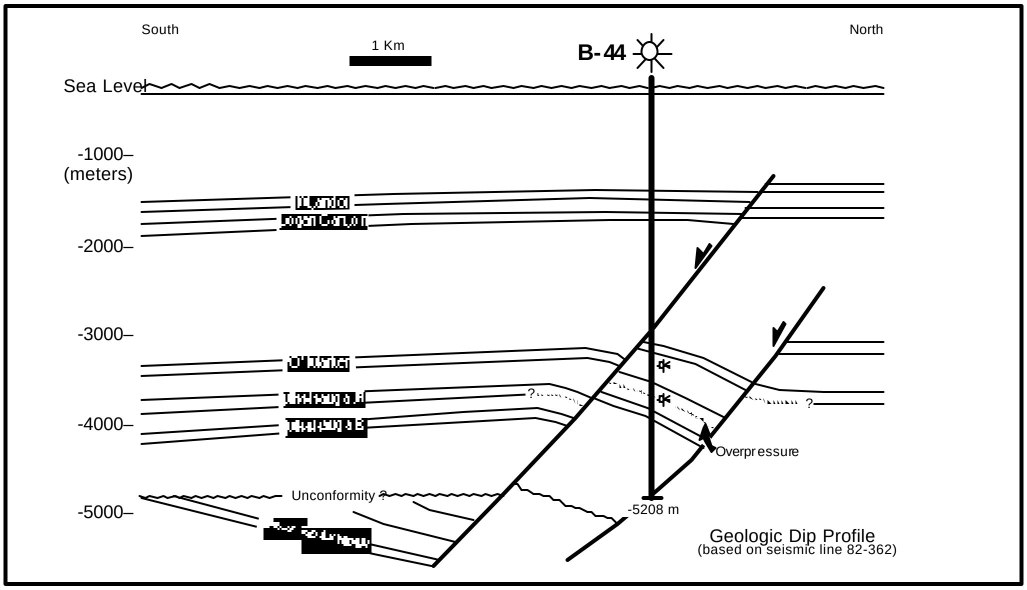
## *Depletion Scenario and Recoverable Resource*

Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 31 M3/E6M3 of recoverable gas based on DST measurements.

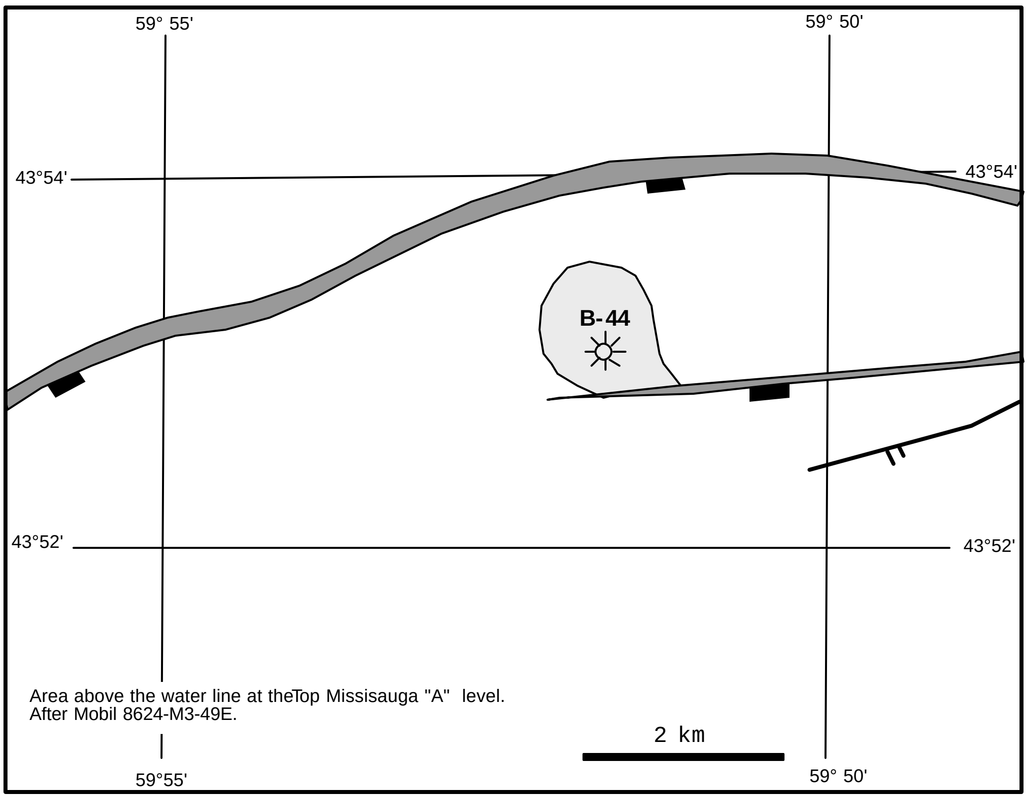
| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 0.197 (7) | 0.202 (7) | 0.208 (7) | 0.202 (7) |
| **Condensate** | (E6M3) | 0.006 (0.04) | 0.006 (0.04) | .007 (0.04) | 0.006 (0.04) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 0.099 (3) | 0.131 (5) | 0.166 (6) | 0.131 (5) |
| **Condensate** | (E6M3) | 0.003 (0.02) | 0.004 (0.03) | 0.005 (0.03) | 0.004 (0.03) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# South Sable




Geologic Dip Profile
(based on seismic line 82-362)




Area above the water line at theTop Missisauga "A" level.
After Mobil 8624-M3-49E.

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# South Venture - Significant Discovery

## *Overview*

The South Venture gas field is located approximately 10 km from the eastern end of Sable Island. The field was discovered in 1983 and has been assessed based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex.

At the time of writing (November 2000), South Venture is planned to be the first of three fields for development in the Sable Offshore Energy Project's Tier 2 phase. Like the currently producing fields at Venture and North Triumph, it will be linked via a subsea gathering pipeline to the project's central processing complex located at the Thebaud field, ~50 km to the west. SOEI's approved development plan indicates that gas from South Venture will assist in sustaining plateau production for the Project, with staged development of the remaining Tier 2 fields at Alma and Glenelg following later.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil et al South Venture O-59 |
| Spud: | 82-04-29 |
| R.R.: | 83-01-02 |
| T.D.: | 6176 m |

The discovery well is located in 24 m of water at approximately 43°58'52.83"N latitude, 59°38'08.49"W longitude. It was drilled to test for the presence of hydrocarbons in sands located in a rollover anticline associated with a down-to-the-basin fault.

### Additional Wells:

No delineation drilling.

### Significant Tests:

| **Well** | **Test #** | **Depth (M)** | **Interval** | **Gas (E3M3/D)** | **Oil/Cond (M3/D)** | **Water (M3/D)** |
|---|---|---|---|---|---|---|
| O-59 | DST#2 | 5925-5943 | Mic Mac | No Rec | | |
| O-59 | DST#3 | 5849-5861 | Mic Mac | No Rec | | |
| O-59 | DST#4 | 5667-5674 | Missisauga | No Rec | | |
| O-59 | DST#5 | 5035-5050 | Missisauga | 183 | 11 | |
| O-59 | DST#6 | 4865-4890 | Missisauga | No Rec | | |
| O-59 | DST#7 | 4747-4765 | Missisauga | 224 | 47 | 2 |
| O-59 | DST#8 | 4602-4607 | Missisauga | No Rec | | |
| O-59 | DST#9 | 4603-4607 | Missisauga | No Rec | | |
| O-59 | DST#10 | 4255-4267 | Missisauga | 379 | 114 | 6 |
| O-59 | DST#11 | 4209-4217 | Missisauga | 391 | 73 | 5 |
| O-59 | DST#12 | 4020-4030 | Missisauga | 515 | 85 | 9 |
| O-59 | DST#13 | 3985-3991 | Missisauga | 484 | 96 | 6 |
| O-59 | DST#14 | 3926-3932 | Missisauga | 46 | 144 | 15 |

## *Geological/Geophysical Overview*

The South Venture gas field is located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at Venture consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Early Cretaceous Missisauga formation.

### Structure

The South Venture structure is an oval-shaped simple rollover anticline bound on the north by a major down-to-the-basin listric growth fault. The field has two structural crests at each end of the field separated by a shallow structural saddle and offset toward the northeast-southwest trending bounding fault. Of the two, the western is the highest and has maximum vertical closure in the order of 70+ m.

The South Venture structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic age salts of the Argo formation or Jurassic age marine shales of the Verrill Canyon formation. These processes resulted in the formation of significant overpressure conditions which are manifested in the deeper reservoir sands.

Although several regional seismic markers are well developed in this area, internal field reflections exclusive to South Venture define the structure. Sands in the Venture field immediately to the north are recognized in the South Venture sequence, but unlike West Venture there are no equivalent seismic markers. Two seismic events are mapped in the field; the Missisauga ‘B’ (Middle Missisauga member) and the No.2 Sand Equivalent (Lower Missisauga member). The latter reflector is a thin calcareous sand within a shaly interval which lies about 40 m above the first reservoir zone, the No.2 Sand. Mapping of all subsequent and deeper gas reservoirs are based on this seismic event.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

The South Venture gas reservoirs are found within strata of the Middle and Lower members of the Early Cretaceous Missisauga formation. Mapping and well data indicate that most of the South Venture reservoir sands can be correlated with equivalent sands in adjacent Venture Field to the north. A single exploratory well has been drilled at South Venture and was positioned on the field’s higher western crest. Seven major gas sands were encountered over a 1100 meter interval and were extensively logged and tested, although no cores were taken.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the reservoir sands in the South Venture 0-59 well was conducted. This evaluation utilized available log and pressure data. To date only one well has been drilled on the structure and therefore the data available to evaluate the field is limited. In addition, no conventional core was cut in the 0-59 well and therefore core data was not incorporated into the evaluation. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined in the South Venture 0-59 well using the cutoffs tabled below. Effective porosities were calculated using the standard neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Porosity Cutoff (Sand 2-6)** | (%) | 10 |
| **Porosity Cutoff (Sand 7)** | (%) | 7 |
| **Porosity Cutoff (Sand 8)** | (%) | 6 |
| **Water Saturation Cutoff** | (%) | 70 |
| **Volume of Shale Cutoff** | (%) | 40 |
| **Permeability Horizontal** | (mD) | Good |

[1] Petrophysical evaluation conducted by the Petroleum Development Agency, Department of Natural Resources, Nova Scotia.

## *Original Hydrocarbons in Place*

The areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The proven area was assigned based upon the single well, assuming gas down to the base of porosity in each zone, most likely based on the structure being half full, and possible area extending to structural spill point. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were obtained from DST and RFT pressure data. Formation temperatures were derived by extrapolating a temperature gradient from maximum bottom hole log temperature measurements.

| **Sand 2 - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 3870 (O-59) |
| **Net Pay** | (m) | 14.5 | 14.5 | 14.5 | 14.5 |
| **Porosity** | (%) | 15.24 | 15.24 | 15.24 | 15.24 |
| **Sw** | (%) | 46.55 | 46.55 | 46.55 | 46.55 |
| **Pressure** | (kPa) | 40000 | 40000 | 40000 | 40000 |
| **Temp** | ($^oC$) | 111 | 111 | 111 | 111 |
| **Gas FVF** | | 269 | 277 | 285 | 277 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 3.544 | 5.407 | 7.306 | 5.426 |
| **OOIP** | (E6M3) | | | | |

| **Sand 3 - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 3920 (O-59) |
| **Net Pay** | (m) | 4.8 | 4.8 | 4.8 | 4.8 |
| **Porosity** | (%) | 15.79 | 15.79 | 15.79 | 15.79 |
| **Sw** | (%) | 26.34 | 26.34 | 26.34 | 26.34 |
| **Pressure** | (kPa) | 40000 | 40000 | 40000 | 40000 |
| **Temp** | ($^oC$) | 112 | 112 | 112 | 112 |
| **Gas FVF** | | 270 | 278 | 286 | 278 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.678 | 2.575 | 3.463 | 2.573 |
| **OOIP** | (E6M3) | | | | |

| Sand 4a - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 3960 (O-59) |
| **Net Pay** | (m) | 6.5 | 6.5 | 6.5 | 6.5 |
| **Porosity** | (%) | 13.48 | 13.48 | 13.48 | 13.48 |
| **Sw** | (%) | 40.14 | 40.14 | 40.14 | 40.14 |
| **Pressure** | (kPa) | 41000 | 41000 | 41000 | 41000 |
| **Temp** | ($^{o}$C) | 114 | 114 | 114 | 114 |
| **Gas FVF** | | 271 | 279 | 287 | 279 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.584 | 2.428 | 3.272 | 2.427 |
| **OOIP** | (E6M3) | | | | |

| Sand 5 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 4145 (O-59) |
| **Net Pay** | (m) | 4.0 | 4.0 | 4.0 | 4.0 |
| **Porosity** | (%) | 13.75 | 13.75 | 13.75 | 13.75 |
| **Sw** | (%) | 42.85 | 42.85 | 42.85 | 42.85 |
| **Pressure** | (kPa) | 43000 | 43000 | 43000 | 43000 |
| **Temp** | ($^{o}$C) | 116 | 116 | 116 | 116 |
| **Gas FVF** | | 276 | 284 | 292 | 284 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.962 | 1.475 | 1.995 | 1.480 |
| **OOIP** | (E6M3) | | | | |

| Sand 6 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 4200 (O-59) |
| **Net Pay** | (m) | 5.8 | 5.8 | 5.8 | 5.8 |
| **Porosity** | (%) | 15.91 | 15.91 | 15.91 | 15.91 |
| **Sw** | (%) | 24.72 | 24.72 | 24.72 | 24.72 |
| **Pressure** | (kPa) | 44000 | 44000 | 44000 | 44000 |
| **Temp** | ($^{o}$C) | 122 | 122 | 122 | 122 |
| **Gas FVF** | | 276 | 284 | 292 | 284 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.140 | 3.267 | 4.410 | 3.272 |
| **OOIP** | (E6M3) | | | | |

| Sand 7 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 4690 (O-59) |
| **Net Pay** | (m) | 4.6 | 4.6 | 4.6 | 4.6 |
| **Porosity** | (%) | 7.83 | 7.83 | 7.83 | 7.83 |
| **Sw** | (%) | 16.29 | 16.29 | 16.29 | 16.29 |
| **Pressure** | (kPa) | 72000 | 72000 | 72000 | 72000 |
| **Temp** | ($^{o}$C) | 128 | 128 | 128 | 128 |
| **Gas FVF** | | 345 | 355 | 365 | 355 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.161 | 1.767 | 2.395 | 1.775 |
| **OOIP** | (E6M3) | | | | |

| Sand 8 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1086 | 1656 | 2233 | 1658 |
| **Top Reservoir** | (mSS) | | | | 4980 (O-59) |
| **Net Pay** | (m) | 4.8 | 4.8 | 4.8 | 4.8 |
| **Porosity** | (%) | 6.75 | 6.75 | 6.75 | 6.75 |
| **Sw** | (%) | 25.52 | 25.52 | 25.52 | 25.52 |
| **Pressure** | (kPa) | 75000 | 75000 | 75000 | 75000 |
| **Temp** | ($^{o}$C) | 140 | 140 | 140 | 140 |
| **Gas FVF** | | 342 | 352 | 362 | 352 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.921 | 1.407 | 1.900 | 1.409 |
| **OOIP** | (E6M3) | | | | |

## *Depletion Scenario and Recoverable Resource*

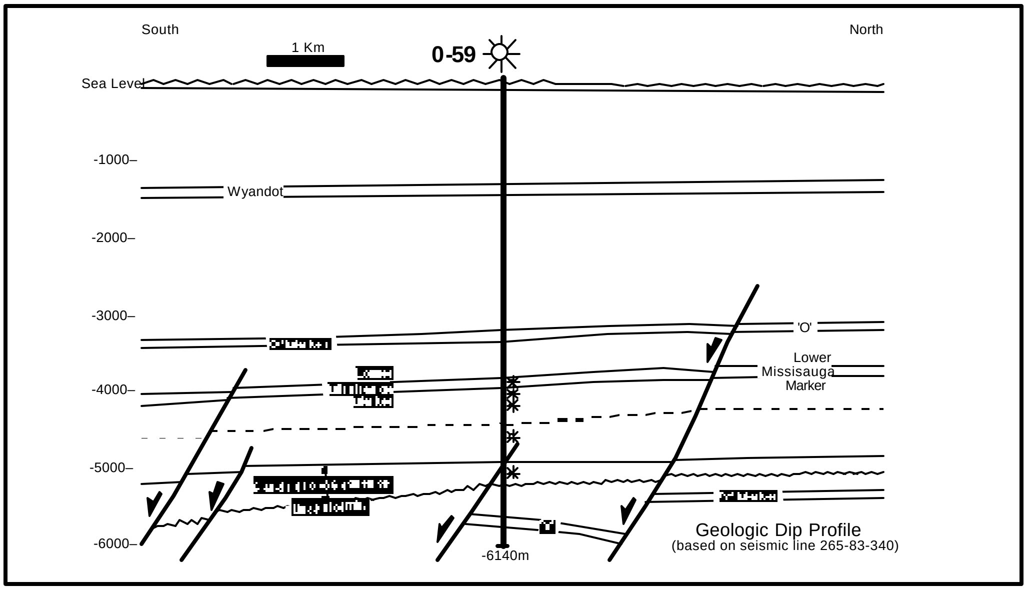
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 196 M3/E6M3 of recoverable gas and is based on DST observations.

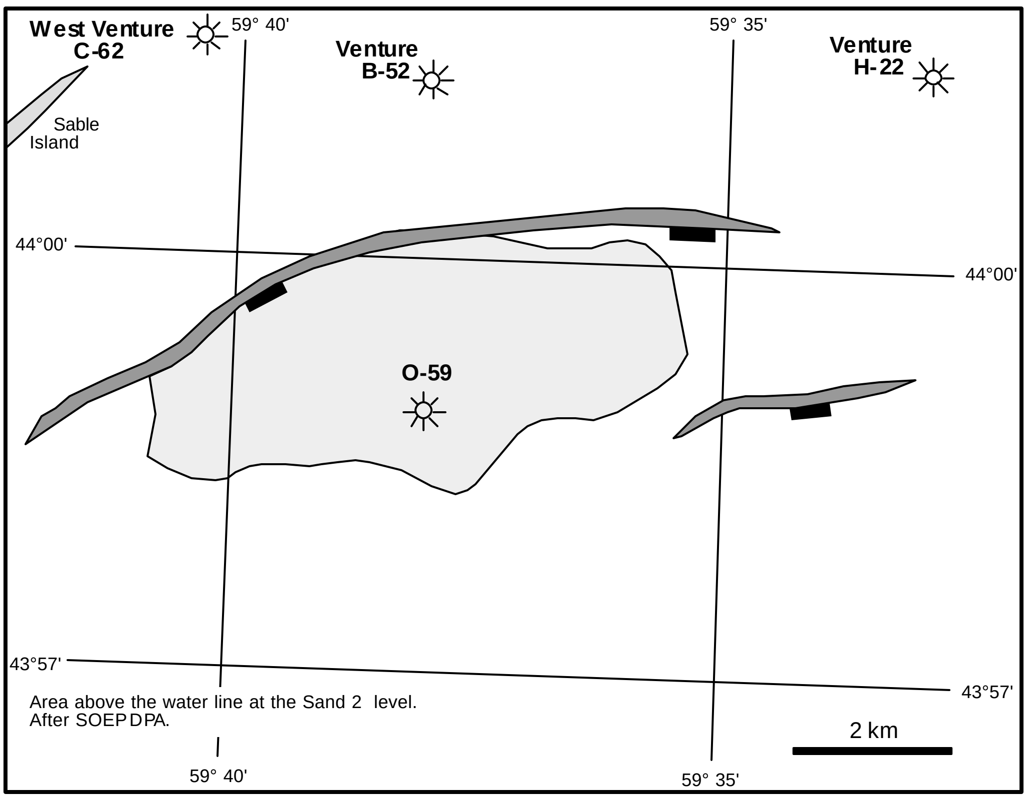
At the time of writing (November 2000), South Venture is planned to be the first of three fields for development in the Sable Offshore Energy Project's Tier 2 phase. Proposed within this plan is the drilling of 2 development wells within the structure to sustain plateau production, tied in to the production platform at Venture approximately 5 km away. Gas will then be routed to a central facility located approximately 50 km away at the Thebaud location. SOEI's approved development plan indicates that gas from South Venture will assist in sustaining plateau production for the Project, with staged development of the remaining Tier 2 fields at Alma and Glenelg following later. The field will be placed under compression during its late life from the Thebaud facility.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 12.87 (454) | 17.79 (628) | 24.57 (868) | 18.36 (648) |
| **Condensate** | (E6M3) | 2.522 (15.9) | 3.486 (21.9) | 4.816 (30.3) | 3.599 (22.6) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 6.434 (227) | 11.56 (408) | 19.66 (694) | 11.94 (421) |
| **Condensate** | (E6M3) | 1.261 (7.93) | 2.226 (14.3) | 3.853 (24.2) | 2.339 (14.7) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# South Venture




CANADA - NOVA SCOTIA
OFFSHORE PETROLEUM BOARD

# Thebaud - Commercial Discovery

## *Overview*

The Thebaud gas field is located approximately 9 km southwest of the western end of Sable Island. The field was discovered in 1972 and has been delineated via three additional wells. This accumulation is located within the Mesozoic age Sable Subbasin near the western margin of the Sable Delta complex.

Thebaud is the first of three fields completed and now producing gas for the Sable Offshore Energy Project's Tier 1 phase. Adjacent to the Thebaud well jacket is the project's central processing complex which collects gas from this and the Venture and North Triumph fields, the latter two connected to the complex by subsea gathering pipelines. During this field's development phase, a total of 4 production wells were drilled and completed in various reservoir zones. Five more slots available in the well jacket for future wells if required.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil - Tetco Thebaud P-84 |
| Spud: | 72-07-08 |
| R.R.: | 72-10-13 |
| T.D.: | 4114.8 m |

The discovery well is located in 26 m of water at approximately 43°53'59.53"N latitude, 60°12'19.34"W longitude. It was drilled to test for the presence of hydrocarbons in a large domal feature that is probably salt cored, faulted on the crest, and is bounded on the north by a large down-to-the-basin listric fault.

### Additional Wells:

The field was delineated by an additional three wells approximately 2 to 3 km from the discovery location.

| | |
|---|---|
| Well: | Mobil-Tetco-Pex Thebaud I-94 (43°53'43.67"N, 60°13'38.13"W) |
| | Mobil et al Thebaud I-93 (43°52'44.54"N, 60°13'50.94"W) |
| | Mobil et al Thebaud C-74 (43°53'05.34"N, 60°11'35.62"W) |

Four production wells have since been drilled are currently in production with geopressured gas flowing from Lower Missisauga and Upper MicMac formation reservoir sand sequences.

| | |
|---|---|
| Well: | SOEI Thebaud T1 |
| | SOEI Thebaud T2 |
| | SOEI Thebaud T3 |
| | SOEI Thebaud T5 |

## Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| P-84 | DST#1 | 2935-3002 | Missisauga | 300 | | |
| P-84 | PT#1 | 4027-4034 | Missisauga | No Flow to Surface | | |
| P-84 | PT#2 | 4020-4024 | Missisauga | Rec Water | | |
| P-84 | PT#3 | 4020-4034 | Missisauga | No Flow to Surface | | |
| P-84 | PT#5 | 3830-3837 | Missisauga | 598 | | |
| P-84 | PT#6 | 3830-3837 | Missisauga | Rec Water Cushion | | |
| P-84 | PT#7 | 3402-3404 | Missisauga | 195 | 14 | |
| P-84 | PT#8 | 3364-3368 | Missisauga | 88 | | |
| P-84 | PT#10 | 3364-3368 | Missisauga | 150 | 24 | |
| P-84 | PT#11 | 3213-3216 | Missisauga | 150 | 17 | |
| P-84 | PT#12 | 3139-3146 | Missisauga | Rec Salt Water | | |
| I-94 | DST#2 | 3769-3914 | Missisauga | 388 | 64 | |
| I-93 | DST#1 | 4652-4660 | Missisauga | No Rec | | |
| I-93 | DST#2 | 4615-4625 | Missisauga | No Rec | | |
| I-93 | DST#4 | 4318-4334 | Missisauga | Flowed | | |
| I-93 | DST#5 | 4080-4093 | Missisauga | 0.4 | | 12 |
| I-93 | DST#6 | 3997-4000 | Missisauga | TSTM | | 13 |
| I-93 | DST#7 | 3931-3933 | Missisauga | 748 | 111 | 3 |
| I-93 | DST#8 | 3912-3920 | Missisauga | 167 | 23 | |
| I-93 | DST#9 | 3711-3720 | Missisauga | No Flow to Surface | | |
| I-93 | DST#10 | 3453-3465 | Missisauga | No Flow to Surface | | |
| C-74 | DST#1 | 5016-5022 | Missisauga | Rec Gas and Form Water | | |
| C-74 | DST#2 | 4748-4761 | Missisauga | 1331 | 29 | |
| C-74 | DST#3 | 4682-4697 | Missisauga | 742 | 41 | 37 |
| C-74 | DST#4 | 4508-4521 | Missisauga | 872 | 50 | 15 |
| C-74 | DST#5 | 4508-4521 | Missisauga | 1348 | 62 | 10 |
| C-74 | DST#6 | 4405-4421 | Missisauga | 1314 | 54 | |
| C-74 | DST#7 | 4311-4318 | Missisauga | 184 | 9 | |
| C-74 | DST#8 | 3914-3930 | Missisauga | 951 | 115 | |
| C-74 | DST#9 | 3865-3888 | Missisauga | 878 | 95 | 5 |

# Geological/Geophysical Overview

The Thebaud gas field is located in the Mesozoic age Sable Subbasin near the western margin of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. Although in a near marginal position, the progradational strata deposited at Thebaud are similar to those at the centrally located Venture field, consisting of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sequences record episodic delta advances punctuated by marine incursions, with the reservoir sands present in the Early Cretaceous Missisauga formation.

## Structure

The Thebaud structure is an oval shaped rollover anticlinal feature positioned between two east-west trending major down-to-the-basin listric growth faults. The central structural crest is broken by several intrafield faults both subparallel and normal to the main north and south bounding growth faults. The Thebaud structure was formed through a combination of rapid sediment loading/subsidence and syndepositional movement along the north bounding growth fault which likely soles into deep Late Triassic age salts of the Argo formation or marine shales of the coeval Verrill Canyon formation. This process resulted in the formation of significant overpressure conditions which are manifested in many of the reservoir sands. Significantly, the age of the faulting at Thebaud is longer lived than at related fields such as Venture located near the basin and delta centers.

The seismic expression of the Thebaud structure shows that it has significant structural relief with about 175 m of vertical closure. Several regional seismic markers within the Sable Subbasin are prominent in the Thebaud area, and as opposed to Venture, both these (e.g. Top Missisauga) and internal field reflectors exclusive to Thebaud define its structural configuration and that of the main reservoir zones. These latter reflectors represent siliceous sand sequences capped by clean shales and include the 5B Sand, B Sand and the F1 Sand. The seismic attributes of deeper reflectors tend to deteriorate and thus confidence in the structural expression of related reservoir intervals is compromised.

## Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation. Over this period, the delta's axis of deposition trended to the southwest, its morphology and facies being dominated by strong tidal and current forces. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

## Reservoir Description

The main reservoir sands in the Thebaud field are found in the Lower and Middle members of the Early Cretaceous Missisauga formation. Four exploratory wells have been drilled at Thebaud and discovered gas pays in sands under normal and overpressure conditions, with the majority in the latter. Of the 11 major gas-bearing reservoirs encountered over a 1000 meter thick section, the data are restricted to open hole logs and a limited number of drillstem tests and cores, the latter mostly in the main A/B Sand reservoir sequence at the top of the overpressure zone. Deeper overpressure reservoirs were penetrated in 2 of the 4 wells and are less well understood (e.g. F, G, and H Sands).

The geometry of shallower hydropressured reservoir sands in the Middle Missisauga member shows them to thicken into the bounding growth fault and have excellent lateral continuity along strike. Deeper overpressured reservoirs of the Lower Missisauga member (below the topmost A/B Sands) are interpreted to mimic this geometry, though they tend to thin and deteriorate laterally toward the field's southern and western boundaries. The preservation/enhancement of porosity and permeability at depth in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size.

Thebaud reservoirs consist of stacked sequences of cyclic deltaic and strandplain and minor valley-fill sands interfingering with marine and prodelta shales, which provide effective top seals within the succession. The log profiles of overpressured Lower Missisauga sands indicate coarsening-upward delta front/channel depositional facies dominated at this time and tend to increase in thickness upward in the section. Although penetrated by only two wells, the data shows that the reservoir characteristics of these coarsening upward very fine to medium grained sands are fair at depth and improve vertically, with effective porosities ranging from 8-18%. (Permeabilities are unknown due to a lack or core data.) Thick strandplain, shoreface and valley-fill facies of the A/B Sand sequence cap the top of the member and are followed by a shale dominated marine flooding event. The A/B sequence has good reservoir characteristics with effective porosities and permeabilities in the ranges of 10-20% and 35-100 mD respectively.

The hydropressured sands in the sand-dominated overlying Middle Missisauga member generally reflect renewed progradation of deltaic fluvial-channel and strandplain shoreface sand cycles. These sands are fine to medium grained, well sorted and have fair to good reservoir characteristics with effective porosities in the 12-20% range, although their permeabilities are interpreted from the few test results as being rather low.

## Petrophysical Overview

A petrophysical evaluation of the four wells, in the Thebaud field, was conducted by the C-NSOPB. This evaluation utilized log, core and pressure data. The results of this evaluation, for each reservoir in the field, are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined, for the Thebaud field, using the cutoffs tabled below. Effective porosities were calculated using the neutron - density cross plotting techniques. All log curves were edited in 'washed out' intervals to correct for bad readings. A 10% porosity cutoff which corresponds, for the Thebaud reservoirs, to a permeability cutoff of 0.1 mD was used to define net pay. In certain sands an 8% porosity cutoff was used to calculate net pay. This lower porosity cutoff was justified as these sands had high flow rates when tested and significant log gas shows yet calculated only negligible net pay using a 10% porosity cutoff. Water saturations were determined, from the log data, using the Archie water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 70 |
| **Porosity Cutoff** | (%) | 8 & 10 |
| **Volume of Shale Cutoff** | (%) | 30 |
| **Permeability Horizontal** | (mD) | Variable |

## *Original Hydrocarbons in Place*

An extensive review of the Thebaud wells and reservoir architecture has been executed. This review has been incorporated in the determination of the parameters for a rigorous probabilistic gas in place analysis which is summarized below.

Even though Thebaud is rather well delineated, the areal extent of the reservoirs is remains an uncertain variable in the determination of gas in place. Very few gas/water contacts have been observed in the discovery and delineation wells, so Pressure/Depth plots[1] were created to assist in defining the field's fluid contacts. The contacts obtained from these plots were used in conjunction with the log defined contacts to determine the areal extent of the reservoirs. The uncertainty in these contacts justified the minimum, most-likely and maximum areal extents for the probabilistic calculations.

The variations in net pay, porosity, and water saturation that were observed between the discovery and delineation wells has also served as a basis for their selection as primary variables within the probabilistic analysis. Justifiable ranges on these parameters were based on mapped variations of properties, averaged over the reservoir extent. Formation pressures were obtained from DST and RFT pressure measurements. Formation temperatures were derived by extrapolating a temperature gradient from maximum bottom hole log temperature measurements.

| **Sand 1u - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 226 | 261 | 304 | 263 |
| **Top Reservoir** | (mSS) | | | | 2570 (P-84) |
| **Net Pay** | (m) | 3.0 | 4.3 | 5.8 | 4.3 |
| **Porosity** | (%) | 14.4 | 16.3 | 18.3 | 16.3 |
| **Sw** | (%) | 40.5 | 35.0 | 29.5 | 35.0 |
| **Pressure** | (kPa) | 27000 | 27000 | 27000 | 27000 |
| **Temp** | ($^{o}$C) | 66 | 66 | 66 | 66 |
| **Gas FVF** | | 246 | 246 | 246 | 246 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.197 | 0.290 | 0.420 | 0.299 |
| **OOIP** | (E6M3) | | | | |

[1] Pressure/Depth plots provided by the Petroleum Development Agency, Department of Natural Resources, Nova Scotia.

| **Sand 2 - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 226 | 261 | 304 | 263 |
| **Top Reservoir** | (mSS) | | | | 2915 (P-84) |
| **Net Pay** | (m) | 5.0 | 6.3 | 7.8 | 6.3 |
| **Porosity** | (%) | 13.1 | 14.5 | 16.5 | 14.7 |
| **Sw** | (%) | 36.1 | 31.3 | 27.7 | 31.7 |
| **Pressure** | (kPa) | 30000 | 30000 | 30000 | 30000 |
| **Temp** | ($^oC$) | 72 | 72 | 72 | 72 |
| **Gas FVF** | | 263 | 263 | 263 | 263 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.324 | 0.429 | 0.571 | 0.440 |
| **OOIP** | (E6M3) | | | | |

| **Sand 4 - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 148 | 226 | 302 | 226 |
| **Top Reservoir** | (mSS) | | | | 3150 (P-84) |
| **Net Pay** | (m) | 5.3 | 7.1 | 9.8 | 7.3 |
| **Porosity** | (%) | 13.5 | 15.5 | 16.9 | 15.3 |
| **Sw** | (%) | 62.3 | 52.7 | 45.5 | 53.3 |
| **Pressure** | (kPa) | 33000 | 33000 | 33000 | 33000 |
| **Temp** | ($^oC$) | 80 | 80 | 80 | 80 |
| **Gas FVF** | | 267 | 267 | 267 | 267 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.171 | 0.303 | 0.478 | 0.317 |
| **OOIP** | (E6M3) | | | | |

| **Sand 5B - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 18 | 25 | 29 | 24.3 |
| **Top Reservoir** | (mSS) | | | | 3230 (P-84) |
| **Net Pay** | (m) | 1.2 | 2.2 | 3.7 | 2.3 |
| **Porosity** | (%) | 16.5 | 17.3 | 18.2 | 17.3 |
| **Sw** | (%) | 65.5 | 60.0 | 54.5 | 60.0 |
| **Pressure** | (kPa) | 34000 | 34000 | 34000 | 34000 |
| **Temp** | ($^oC$) | 83 | 83 | 83 | 83 |
| **Gas FVF** | | 268 | 268 | 268 | 268 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.005 | 0.010 | 0.018 | 0.011 |
| **OOIP** | (E6M3) | | | | |

| Sand 5C - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 148 | 226 | 302 | 226 |
| **Top Reservoir** | (mSS) | | | | 3295 (P-84) |
| **Net Pay** | (m) | 1.0 | 1.6 | 2.4 | 1.7 |
| **Porosity** | (%) | 11.9 | 13.0 | 14.1 | 13.0 |
| **Sw** | (%) | 64.5 | 57.7 | 53.2 | 58.3 |
| **Pressure** | (kPa) | 34000 | 34000 | 34000 | 34000 |
| **Temp** | ($^oC$) | 85 | 85 | 85 | 85 |
| **Gas FVF** | | 272 | 272 | 272 | 272 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.028 | 0.052 | 0.087 | 0.055 |
| **OOIP** | (E6M3) | | | | |

| Sand 5D - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 148 | 226 | 302 | 226 |
| **Top Reservoir** | (mSS) | | | | 3305 (P-84) |
| **Net Pay** | (m) | 2.3 | 4.0 | 5.7 | 4.0 |
| **Porosity** | (%) | 12.2 | 13.7 | 15.0 | 13.7 |
| **Sw** | (%) | 64.5 | 57.7 | 53.2 | 58.3 |
| **Pressure** | (kPa) | 34000 | 34000 | 34000 | 34000 |
| **Temp** | ($^oC$) | 85 | 85 | 85 | 85 |
| **Gas FVF** | | 271 | 271 | 271 | 271 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.068 | 0.132 | 0.223 | 0.140 |
| **OOIP** | (E6M3) | | | | |

| Sand 5E - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 148 | 226 | 302 | 226 |
| **Top Reservoir** | (mSS) | | | | 3330 (P-84) |
| **Net Pay** | (m) | 5.1 | 6.5 | 8.4 | 6.7 |
| **Porosity** | (%) | 14.2 | 15.7 | 17.0 | 15.7 |
| **Sw** | (%) | 59.9 | 53.6 | 48.7 | 54.0 |
| **Pressure** | (kPa) | 35000 | 35000 | 35000 | 35000 |
| **Temp** | ($^oC$) | 86 | 86 | 86 | 86 |
| **Gas FVF** | | 272 | 272 | 272 | 272 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.175 | 0.285 | 0.428 | 0.295 |
| **OOIP** | (E6M3) | | | | |

| Sand 5F - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 411 | 491 | 573 | 492 |
| **Top Reservoir** | (mSS) | | | | 3355 (P-84) |
| **Net Pay** | (m) | 3.6 | 4.4 | 5.6 | 4.5 |
| **Porosity** | (%) | 10.9 | 12.0 | 13.1 | 12.0 |
| **Sw** | (%) | 66.5 | 62.2 | 58.2 | 62.3 |
| **Pressure** | (kPa) | 35000 | 35000 | 35000 | 35000 |
| **Temp** | ($^o$C) | 88 | 88 | 88 | 88 |
| **Gas FVF** | | 271 | 271 | 271 | 271 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.197 | 0.263 | 0.355 | 0.271 |
| **OOIP** | (E6M3) | | | | |

| Sand 5G - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 411 | 491 | 573 | 492 |
| **Top Reservoir** | (mSS) | | | | 3425 (P-84) |
| **Net Pay** | (m) | 3.5 | 4.3 | 5.2 | 4.3 |
| **Porosity** | (%) | 12.5 | 13.3 | 14.2 | 13.3 |
| **Sw** | (%) | 60.5 | 55.0 | 49.5 | 55.0 |
| **Pressure** | (kPa) | 36000 | 36000 | 36000 | 36000 |
| **Temp** | ($^o$C) | 90 | 90 | 90 | 90 |
| **Gas FVF** | | 273 | 273 | 273 | 273 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.261 | 0.341 | 0.450 | 0.349 |
| **OOIP** | (E6M3) | | | | |

| Sand 5H - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 411 | 491 | 573 | 492 |
| **Top Reservoir** | (mSS) | | | | 3515 (P-84) |
| **Net Pay** | (m) | 2.1 | 3.5 | 5.4 | 3.7 |
| **Porosity** | (%) | 11.4 | 12.0 | 12.6 | 12.0 |
| **Sw** | (%) | 57.3 | 53.7 | 48.9 | 53.3 |
| **Pressure** | (kPa) | 37000 | 37000 | 37000 | 37000 |
| **Temp** | ($^o$C) | 94 | 94 | 94 | 94 |
| **Gas FVF** | | 277 | 277 | 277 | 277 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.151 | 0.268 | 0.428 | 0.280 |
| **OOIP** | (E6M3) | | | | |

| **'A' Mark - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 148 | 226 | 302 | 226 |
| **Top Reservoir** | (mSS) | | | | 3715 (P-84) |
| **Net Pay** | (m) | 1.9 | 2.4 | 3.3 | 2.5 |
| **Porosity** | (%) | 15.1 | 16.5 | 18.4 | 16.7 |
| **Sw** | (%) | 41.1 | 36.3 | 32.7 | 36.7 |
| **Pressure** | (kPa) | 47000 | 47000 | 47000 | 47000 |
| **Temp** | ($^{o}$C) | 99 | 99 | 99 | 99 |
| **Gas FVF** | | 309 | 309 | 309 | 309 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.109 | 0.177 | 0.269 | 0.184 |
| **OOIP** | (E6M3) | | | | |

| **Sand A - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 1677 | 1758 | 1883 | 1770 |
| **Top Reservoir** | (mSS) | | | | 3750 (P-84) |
| **Net Pay** | (m) | 15.4 | 19.6 | 22.7 | 19.3 |
| **Porosity** | (%) | 15.5 | 17.5 | 18.9 | 17.3 |
| **Sw** | (%) | 49.5 | 42.3 | 32.7 | 41.7 |
| **Pressure** | (kPa) | 54000 | 54000 | 54000 | 54000 |
| **Temp** | ($^{o}$C) | 118 | 118 | 118 | 118 |
| **Gas FVF** | | 316 | 316 | 316 | 316 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 8.204 | 10.902 | 13.642 | 10.937 |
| **OOIP** | (E6M3) | | | | |

| **Sand B - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 561 | 731 | 866 | 721 |
| **Top Reservoir** | (mSS) | | | | 3795 (P-84) |
| **Net Pay** | (m) | 15.8 | 19.3 | 23.0 | 19.3 |
| **Porosity** | (%) | 11.1 | 12.5 | 14.5 | 12.7 |
| **Sw** | (%) | 578.9 | 51.3 | 45.0 | 51.7 |
| **Pressure** | (kPa) | 54000 | 54000 | 54000 | 54000 |
| **Temp** | ($^{o}$C) | 120 | 120 | 120 | 120 |
| **Gas FVF** | | 317 | 317 | 317 | 317 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.856 | 2.661 | 3.640 | 2.706 |
| **OOIP** | (E6M3) | | | | |

| Sand F1 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 404 | 809 | 1234 | 816 |
| **Top Reservoir** | (mSS) | | | | 4180 (C-74) |
| **Net Pay** | (m) | 5.3 | 7.0 | 9.2 | 7.2 |
| **Porosity** | (%) | 11.6 | 12.6 | 13.9 | 12.7 |
| **Sw** | (%) | 47.9 | 39.2 | 33.5 | 40.0 |
| **Pressure** | (kPa) | 82000 | 82000 | 82000 | 82000 |
| **Temp** | ($^oC$) | 132 | 132 | 132 | 132 |
| **Gas FVF** | | 370 | 370 | 370 | 370 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.749 | 1.548 | 2.651 | 1.644 |
| **OOIP** | (E6M3) | | | | |

| Sand F3 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 404 | 809 | 1234 | 816 |
| **Top Reservoir** | (mSS) | | | | 4290 (C-74) |
| **Net Pay** | (m) | 11.3 | 13.1 | 15.8 | 13.3 |
| **Porosity** | (%) | 13.8 | 16.0 | 18..2 | 16.0 |
| **Sw** | (%) | 26.1 | 21.3 | 17.7 | 21.7 |
| **Pressure** | (kPa) | 83000 | 83000 | 83000 | 83000 |
| **Temp** | ($^oC$) | 137 | 137 | 137 | 137 |
| **Gas FVF** | | 372 | 372 | 372 | 372 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.393 | 4.904 | 8.018 | 5.078 |
| **OOIP** | (E6M3) | | | | |

| Sand G2 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 491 | 1002 | 1345 | 958 |
| **Top Reservoir** | (mSS) | | | | 4365 (C-74) |
| **Net Pay** | (m) | 6.4 | 8.3 | 10.3 | 8.3 |
| **Porosity** | (%) | 14.5 | 16.5 | 17.9 | 16.3 |
| **Sw** | (%) | 29.8 | 25.8 | 22.5 | 26.0 |
| **Pressure** | (kPa) | 84000 | 84000 | 84000 | 84000 |
| **Temp** | ($^oC$) | 140 | 140 | 140 | 140 |
| **Gas FVF** | | 372 | 372 | 372 | 372 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.717 | 3.535 | 5.392 | 3.589 |
| **OOIP** | (E6M3) | | | | |

| Sand G3 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 404 | 809 | 1235 | 816 |
| **Top Reservoir** | (mSS) | | | | 4395 (C-74) |
| **Net Pay** | (m) | 7.1 | 9.7 | 12.1 | 9.7 |
| **Porosity** | (%) | 13.3 | 15.0 | 16.7 | 15.0 |
| **Sw** | (%) | 45.5 | 40.0 | 34.5 | 40.0 |
| **Pressure** | (kPa) | 84000 | 84000 | 84000 | 84000 |
| **Temp** | ($^oC$) | 140 | 140 | 140 | 140 |
| **Gas FVF** | | 372 | 372 | 372 | 372 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.189 | 2.543 | 4.280 | 2.652 |
| **OOIP** | (E6M3) | | | | |

| Sand H1 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 954 | 1478 | 1802 | 1424 |
| **Top Reservoir** | (mSS) | | | | 4570 (C-74) |
| **Net Pay** | (m) | 4.1 | 6.7 | 9.1 | 6.7 |
| **Porosity** | (%) | 9.1 | 10.5 | 12.4 | 10.7 |
| **Sw** | (%) | 57.8 | 48.7 | 38.3 | 48.3 |
| **Pressure** | (kPa) | 87000 | 87000 | 87000 | 87000 |
| **Temp** | ($^oC$) | 143 | 143 | 143 | 143 |
| **Gas FVF** | | 375 | 375 | 375 | 375 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.005 | 1.852 | 3.084 | 1.964 |
| **OOIP** | (E6M3) | | | | |

| Sand H2 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 954 | 1478 | 1802 | 1424 |
| **Top Reservoir** | (mSS) | | | | 4635 (C-74) |
| **Net Pay** | (m) | 3.8 | 6.0 | 8.2 | 6.0 |
| **Porosity** | (%) | 9.0 | 10.3 | 11.8 | 10.3 |
| **Sw** | (%) | 52.7 | 43.7 | 33.4 | 43.3 |
| **Pressure** | (kPa) | 90000 | 90000 | 90000 | 90000 |
| **Temp** | ($^oC$) | 143 | 143 | 143 | 143 |
| **Gas FVF** | | 383 | 383 | 383 | 383 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.991 | 1.857 | 2.969 | 1.922 |
| **OOIP** | (E6M3) | | | | |

## *Depletion Scenario and Recoverable Resource*

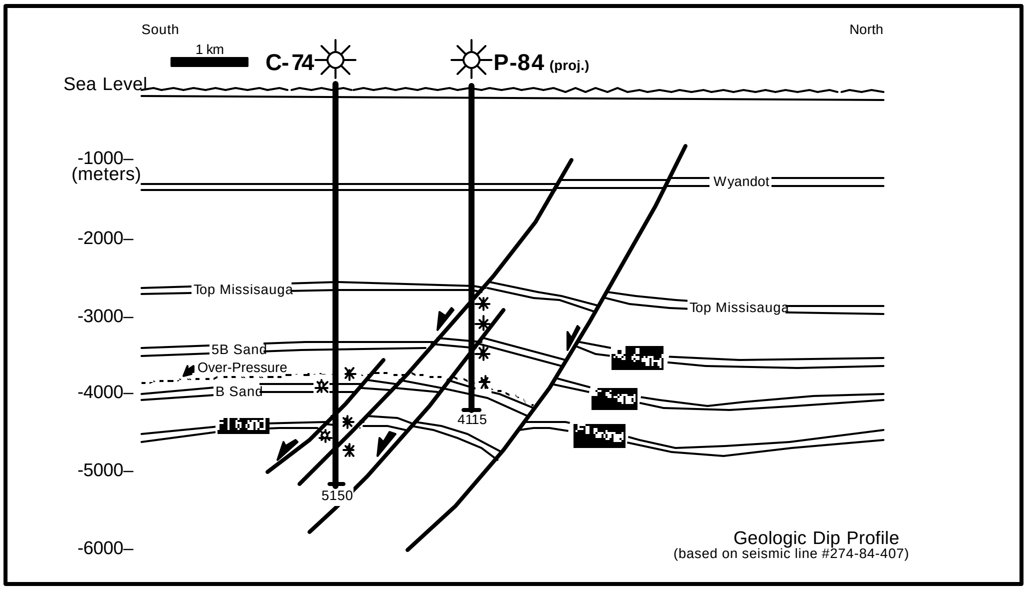
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 150 M3/E6M3 of recoverable gas.

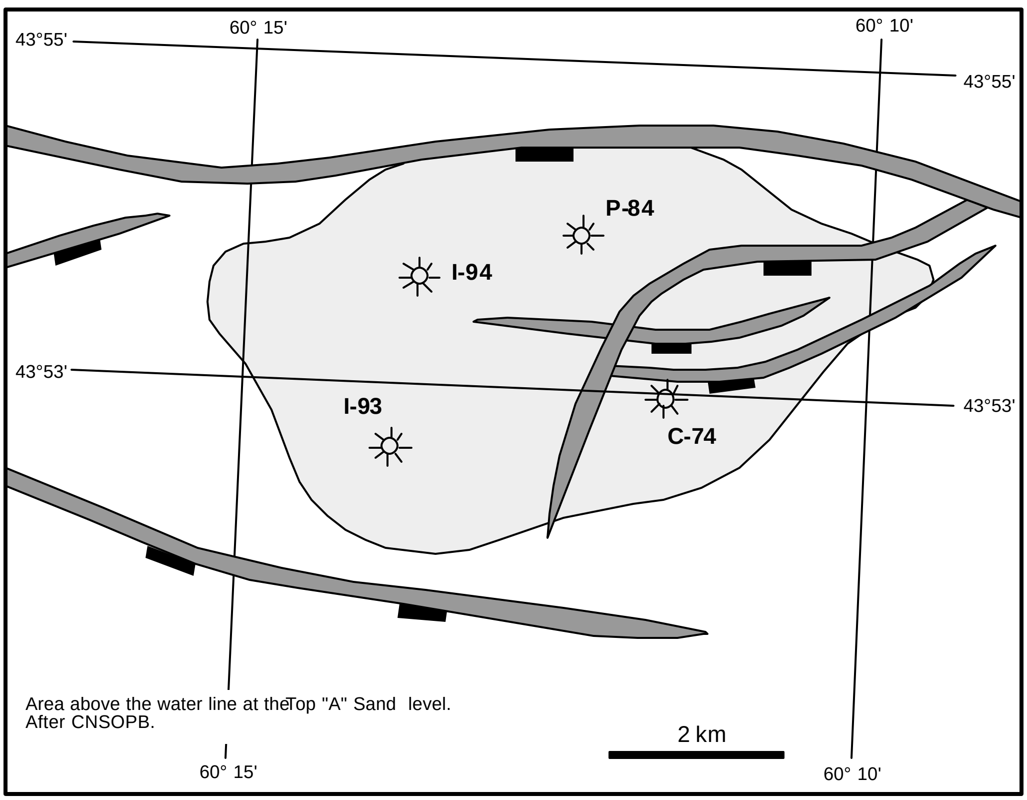
Thebaud is the first of three fields completed and now producing gas for the Sable Offshore Energy Project's Tier 1 phase. Adjacent to the Thebaud well jacket is the project's central processing complex which collects gas from this and the Venture and North Triumph fields, the latter two connected to the complex by subsea gathering pipelines. During this field's development phase, a total of 4 production wells were drilled and completed in various reservoir zones. Five more slots available in the well jacket for future wells if required. The field will be placed under compression during its late life from the central compression facility located at this location.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 21.13 (746) | 31.6 (1114) | 47.0 (1661) | 33.1 (1170) |
| **Condensate** | (E6M3) | 3.170 (19.9) | 4.733 (29.8) | 7.057 (44.4) | 4.970 (31.3) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 10.57 (373) | 20.51 (724) | 37.64 (1329) | 21.54 (761) |
| **Condensate** | (E6M3) | 1.585 (9.97) | 3.076 (19.4) | 5.646 (35.5) | 3.231 (20.3) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Thebaud

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# Uniacke - Significant Discovery

## Overview

The Uniacke gas field is located approximately 35 km north of Sable Island's eastern tip. The field was discovered in 1984 and its current assessment is based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin in a north-central position of the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Shell Petro-Can et al Uniacke G-72 |
| Spud: | 83-05-09 |
| R.R.: | 84-04-04 |
| T.D.: | 5735 m |

The discovery well is located in 152.9 m of water at approximately 44°11'29.17"N latitude, 59°41'09.75"W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a closure against a large down-to-the-basin fault.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| **Well** | **Test #** | **Depth (M)** | **Interval** | **Gas (E3M3/D)** | **Oil/Cond (M3/D)** | **Water (M3/D)** |
|---|---|---|---|---|---|---|
| G-72 | DST#1 | 5110-5237 | Mic Mac | 583 | | |
| G-72 | DST#2 | 5290-5320 | Mic Mac | | | 25 |
| G-72 | DST#3 | 5242-5260 | Mic Mac | 1.4 | | 358 |
| G-72 | DST#4 | 5216-5226 | Mic Mac | 227 | | |
| G-72 | DST#5 | 5215-5226 | Mic Mac | 354 | 20 | 19 |
| G-72 | DST#6 | 5191-5199 | Mic Mac | 399 | 23 | 9 |
| G-72 | DST#7 | 4364-4371 | Mic Mac | | | 5 |
| G-72 | DST#8 | 4077-4082 | Mic Mac | No Flow to Surface | | |

## Geological/Geophysical Overview

The Uniacke gas field is located in the Mesozoic age Sable Subbasin in a north-central position of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. The progradational strata deposited at Uniacke consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits, formed as a result of its proximity to sediment source, basin hinge-line position and resultant rapid subsidence. This sedimentary sequence records episodic delta advances punctuated by marine incursions, with the reservoir sands are located in the Late Jurassic Mic Mac formation.

### Structure

The Uniacke structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic – Early Jurassic age salts of the Argo formation. Like the adjacent Citnalta field to the south, the possibility exists that the Uniacke structure may have been affected by the motion of an underlying salt piercement feature towards the south. However, it may differ from Citnalta as salt evacuation might have been a contributing factor to increased subsidence of the fault block.

The Uniacke structure occurs on the edge of a platformal region which bounds the zone of major down-to-the-basin hinge-line faults to the south. It is a northwest-southeast orientated, slightly bent oval-shaped anticline formed between listric faults that are connected by a short northwest-southeast oriented fault splay. The northern fault is the main listric fault which formed the Uniacke structure, whereas the southern is the main bounding fault for the Citnalta field to the south. An intrafield fault that affects the reservoir zone is antithetic to and parallels the north-bounding fault. This fault converges with the fault splay that links the two larger features. The southwestern edge of the Uniacke field is defined by simple dip closure. Total structural closure in the field is about 250 m.

The Uniacke field has two structural crests at each end of the field. Only the western high has been tested. The higher eastern crest is located at the juncture of the southern Citnalta fault and eastern fault splay. Seismic data indicate that it has a relief of about 180 m. Although several regional seismic markers are prominent in the area the Uniacke field is mapped utilizing three internal field operator-defined reflectors, all within the Late Jurassic Mic Mac formation; the “T Limestone Marker”, “Jurassic ‘A’ Event/Brown Marker”, and the “Pink Marker”.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales. In the Uniacke-Citnalta-Arcadia area this deltaic pulse overwhelmed buried a pre-existing succession of reefal and platformal carbonate facies of the Abenaki formation.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by the deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. Like the Citnalta and Arcadia fields, Uniacke is located on the north-central part of the delta and in an area of relative stability due to the underlying Abenaki carbonate facies. However, unlike the Citnalta field to the south, the rapid loading in the Uniacke area caused the evacuation of deep Argo formation salt and resulted in a thick Mic Mac and Missisauga section being deposited.

## Reservoir Description

At Uniacke, the reservoir sands are all located within the Late Jurassic Mic Mac formation. One exploratory well has been drilled on the structure and gas pay was encountered in a single major reservoir over a 50 m thick interval that was logged, cored and tested. Good to excellent sand continuity is expected across the entire structure.

The Uniacke reservoir section is under hard overpressure conditions. It is a thick (120 m) sand sequence of strandplain-shoreface and 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 (agradational-tidal delta(?)). The sands are very fine to fine grained, well sorted, dolomitic and calcareous, variably argillaceous and have fair to good effective porosities ranging from 9-20% and a wide range of permeabilities from 0.1-200 mD.

## Petrophysical Overview

A petrophysical evaluation[1] of the Uniacke G-72 well, was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Uniacke field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| | | |
| **Permeability Horizontal** | (mD) | 0.1 - 200 |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

A gas water contact observed in the lower zone of the discovery well defines and limits the areal extent of the accumulation. The probabilistic areal distribution for the upper zone is based on a proved minimum from the well test, most likely based on the structure being half full, and possible area extending to structural spill point. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| Zone I - Mic Mac | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1244 | 2259 | 3091 | 2208 |
| **Top Reservoir** | (mSS) | | | | 5075 (G-72) |
| **Net Pay** | (m) | 5 | 5 | 5 | 5 |
| **Porosity** | (%) | 16.3 | 16.3 | 16.3 | 16.3 |
| **Sw** | (%) | 45.7 | 45.7 | 45.7 | 45.7 |
| **Pressure** | (kPa) | 99000 | 99000 | 99000 | 99000 |
| **Temp** | ($^{o}$C) | 136 | 136 | 136 | 136 |
| **Gas FVF** | | 392 | 403 | 414 | 403 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.219 | 4.040 | 5.519 | 3.938 |
| **OOIP** | (E6M3) | | | | |

| Zone II - Mic Mac | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 425 | 425 | 425 | 425 |
| **Top Reservoir** | (mSS) | | | | 5095 (G-72) |
| **Net Pay** | (m) | 9 | 9 | 9 | 9 |
| **Porosity** | (%) | 18.9 | 18.9 | 18.9 | 18.9 |
| **Sw** | (%) | 40.2 | 40.2 | 40.2 | 40.2 |
| **Pressure** | (kPa) | 99000 | 99000 | 99000 | 99000 |
| **Temp** | ($^{o}$C) | 136 | 136 | 136 | 136 |
| **Gas FVF** | | 392 | 403 | 414 | 403 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.694 | 1.742 | 1.790 | 1.742 |
| **OOIP** | (E6M3) | | | | |

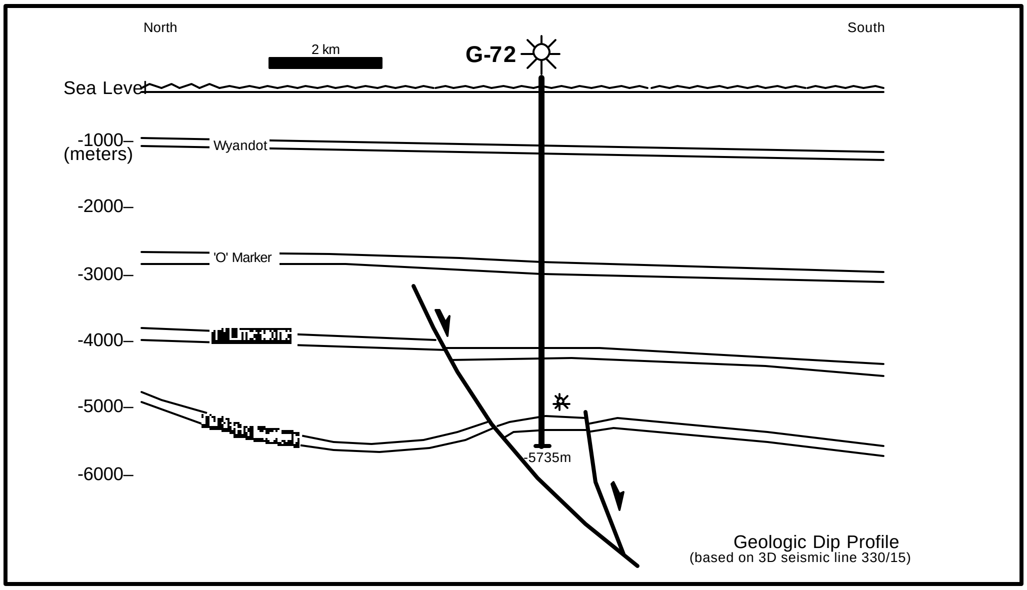
## Depletion Scenario and Recoverable Resource

Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 57 M3/E6M3 of recoverable gas and is based on DST observations.

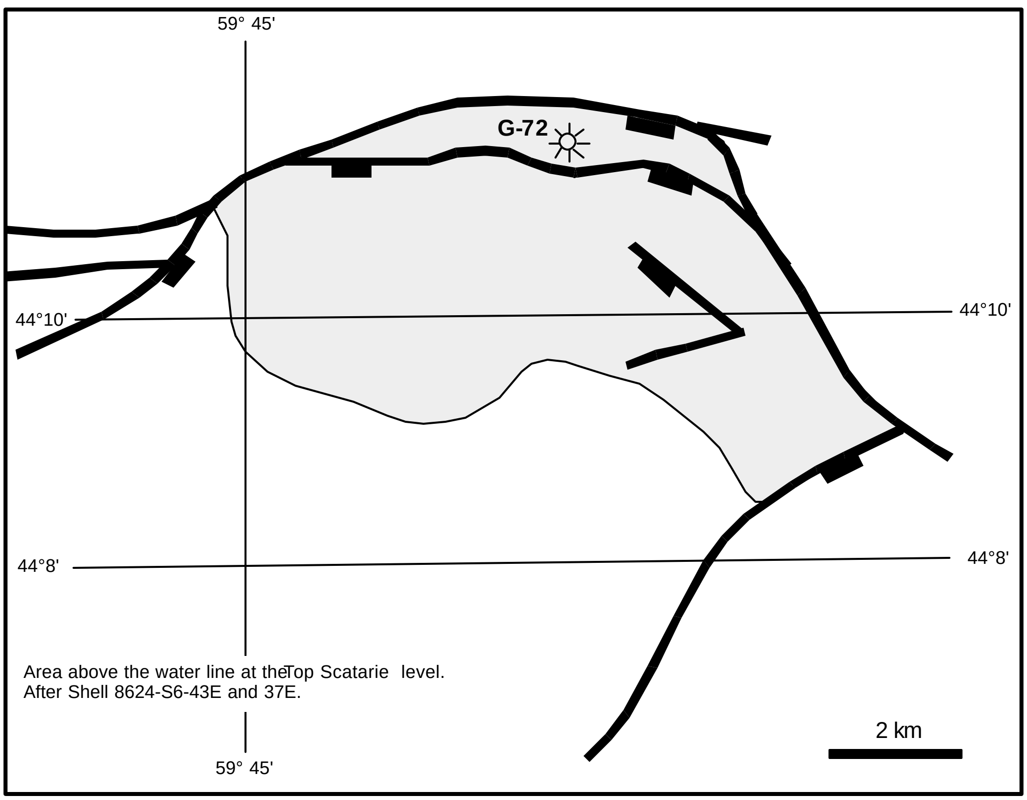
| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 4.188 (148) | 5.545 (196) | 7.338 (259) | 5.680 (201) |
| **Condensate** | (E6M3) | 0.239 (1.50) | 0.316 (1.99) | 0.418 (2.63) | 0.324 (2.04) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 2.094 (74) | 3.604 (127) | 5.870 (207) | 3.692 (130) |
| **Condensate** | (E6M3) | 0.119 (0.75) | 0.205 (1.29) | 0.335 (2.10) | 0.210 (1.32) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Uniacke




Geologic Dip Profile
(based on 3D seismic line 330/15)




Area above the water line at the Top Scatarie level.
After Shell 8624-S6-43E and 37E.

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# Venture - Commercial Discovery

## *Overview*

The Venture gas field is located approximately 11.3 km east of Sable Island. The field was discovered in 1979 and has been delineated via four additional wells. This accumulation is located within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex.

Venture is the second of three fields completed and now producing gas for the Sable Offshore Energy Project's Tier 1 phase. Like the other producing field at North Triumph, it is linked to the project's central processing complex located at the Thebaud field, ~50 km to the west. During this field's development phase, a total of 4 production wells were drilled and completed in various reservoir zones. Five more slots are available in the well jacket for future wells if required.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil-Texaco-Pex Venture D-23 |
| Spud: | 78-11-28 |
| R.R.: | 79-06-16 |
| T.D.: | 4945m |

The discovery well is located in 20.1 m of water depth at approximately 44°02'14.86"N latitude, 59°34'24.72"W longitude. It was drilled to test a large rollover anticline associated with a down-to-the-basin growth fault.

### Additional Wells:

Field was delineated by an additional four wells ranging from 2 to 5 km from the discovery location.

| | |
|---|---|
| Well: | Mobil-Texaco-Pex Venture B-13 (44°02'11.61"N, 59°32'03.54"W) |
| | Mobil-Texaco-Pex Venture B-43 (44°02'00.72"N, 59°36'37.37"W) |
| | Mobil et al Venture B-52 (44°01'12.88"N, 59°38'07.76"W) |
| | Mobil et al Venture H-22 (44°01'24.13"N, 59°33'06.14"W) |

Four production wells have since been drilled are currently in production with hydro- and geopressured gas flowing from Lower Missisauga and Upper MicMac formation reservoir sand sequences.

| | |
|---|---|
| Well: | SOEI Venture V1 |
| | SOEI Venture V2 |
| | SOEI Venture V3 |
| | SOEI Venture V5 |

## Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| D-23 | DST#3 | 4899-4910 | Missisauga | Flow rate Not Obtained | | |
| D-23 | DST#4 | 4899-4910 | Missisauga | 283 | 25 | 5 |
| D-23 | DST#5 | 4829-4846 | Missisauga | Flow rate Not Obtained | | |
| D-23 | DST#8 | 4643-4659 | Missisauga | 623 | 50 | |
| D-23 | DST#9A | 4414-4419 | Missisauga | 328 | 28 | |
| B-13 | DST#1 | 5168-5174 | Mic Mac | 4 | | 191 |
| B-13 | DST#2 | 5056-5063 | Missisauga | 17 | | 191 |
| B-13 | DST#3 | 4949-4960 | Missisauga | 523 | 2 | |
| B-13 | DST#4 | 4882-4888 | Missisauga | 128 | | 246 |
| B-13 | DST#5 | 4853-4862 | Missisauga | 0.1 | | 73 |
| B-13 | DST#6 | 4572-4579 | Missisauga | 81 | 4 | 4 |
| B-13 | DST#8 | 4714-4726 | Missisauga | | | 382 |
| B-13 | DST#9 | 4531-4536 | Missisauga | 195 | 38 | 18 |
| B-13 | DST#10 | 4495-4502 | Missisauga | 433 | 32 | 17 |
| B-13 | DST#11 | 4478-4485 | Missisauga | 527 | 61 | 5 |
| B-13 | DST#12 | 4418-4430 | Missisauga | 388 | 46 | 1 |
| B-13 | DST#13 | 4126-4136 | Missisauga | | | 17 |
| B-13 | DST#14 | 4107-4116 | Missisauga | | | 191 |
| B-13 | DST#15 | 4068-4073 | Missisauga | | | 350 |
| B-13 | DST#16 | 3755-3763 | Missisauga | | | 301 |
| B-43 | DST#1 | 5510-5523 | Mic Mac | | | 16 |
| B-43 | DST#2 | 5479-5495 | Mic Mac | 261 | 18 | 139 |
| B-43 | DST#3 | 5279-5294 | Mic Mac | 447 | 43 | 6 |
| B-43 | DST#4 | 5090-5101 | Missisauga | 425 | | 14 |
| B-43 | DST#5 | 5090-5101 | Missisauga | 139 | 28 | |
| B-43 | DST#6 | 5036-5043 | Missisauga | 280 | 19 | 5 |
| B-43 | DST#7 | 4953-4962 | Missisauga | 300 | 398 | 9 |
| B-43 | DST#8 | 4883-4891 | Missisauga | 391 | 129 | |
| B-43 | DST#9 | 4788-4805 | Missisauga | 178 | 25 | |
| B-43 | DST#10 | 4680-4690 | Missisauga | 348 | 28 | |
| B-43 | DST#12 | 4607-4616 | Missisauga | 1 | Trace | 16 |
| B-43 | DST#16 | 4251-4263 | Missisauga | 74 | 7 | 29 |
| B-43 | DST#17 | 3700-3706 | Missisauga | | Trace | 25 |
| B-52 | DST#1 | 5800-5804 | Mic Mac | 13 | | 2 |
| B-52 | DST#2 | 5725-5732 | Mic Mac | 311 | 1 | 9 |
| B-52 | DST#5 | 5453-5460 | Mic Mac | 1 | | 271 |
| B-52 | DST#6 | 5284-5293 | Mic Mac | 1393 | 32 | 21 |
| B-52 | DST#7 | 5126-5131 | Missisauga | 1 | | 231 |
| B-52 | DST#8 | 5065-5080 | Missisauga | 1 | | 283 |
| B-52 | DST#9 | 5043-5048 | Missisauga | 2 | | 852 |
| B-52 | DST#10 | 5031-5036 | Missisauga | 1 | | 379 |
| B-52 | DST#11 | 5023-5026 | Missisauga | 1 | | 336 |
| B-52 | DST#12 | 4963-4972 | Missisauga | 3 | | 76 |
| B-52 | DST#13 | 4920-4925 | Missisauga | 44 | | 129 |
| B-52 | DST#14 | 4848-4858 | Missisauga | | | 14 |
| B-52 | DST#15 | 4711-4727 | Missisauga | 12 | | 363 |

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| H-22 | DST#1 | 5692-5710 | Mic Mac | Rec Water Cushion | | |
| H-22 | DST#2 | 5520-5546 | Mic Mac | Rec Gas Cut Mud | | |
| H-22 | DST#3 | 5246-5260 | Mic Mac | Rec Gas Cut Mud | | |
| H-22 | DST#4 | 5056-5070 | Missisauga | 283 | | |
| H-22 | DST#5 | 5021-5025 | Missisauga | 164 | 9 | 233 |
| H-22 | DST#6 | 4976-4983 | Missisauga | 702 | 47 | 104 |
| H-22 | DST#7 | 4957-4962 | Missisauga | 1093 | 66 | 42 |
| H-22 | DST#9 | 4837-4843 | Missisauga | | | 38 |

## Geological/Geophysical Overview

The Venture gas field is located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. With its proximity to sediment source, basin hinge-line position and resultant rapid subsidence, the progradational strata deposited at Venture consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Late Jurassic Mic Mac and Early Cretaceous Missisauga formations.

### Structure

The structure at Venture is defined as an elongate rollover anticlinal feature bound on the north by a major down-to-the-basin listric growth fault. Two structural crests are present at each end of the field and are separated by subtle structurally lower saddle. Several minor intrafield faults are also present and are synthetic and subparallel to the main east-west trending growth fault. The Venture structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic age salts of the Argo formation. Such a combination resulted in the formation of significant overpressure conditions which are manifested in the reservoir sands.

In seismic profiles the structure reveals pronounced closure with noticeable relief. Although several regional seismic markers are prominent in the area, internal field reflections exclusive to Venture define its structural configuration. These reflections are either sand sequences capped by limey intervals or isolated limestones and include the #3a Sand, #6 Limestone, #9 Limestone and the ‘Y’ Limestone. Beyond this last reflection, seismic attributes of lower reflectors tend to deteriorate and thus confidence in the structural expression of deeper reservoir intervals is impaired.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

The reservoir sands at Venture are located stratigraphically at the top of Late Jurassic Mic Mac formation, and the Lower and Middle members of the Early Cretaceous Missisauga formation. Mapping and well data indicate that many of the Venture reservoir sands can be correlated with equivalent sands in adjacent structures/fields such as South Venture (south) and West Venture (west). Five exploratory wells have been drilled at Venture and most of the 16 major reservoirs encountered over a 1000 meter thick section have been extensively logged, cored and tested, although very deep overpressured sands are less well studied (e.g. Sands 11, 13, 17 and 18).

Except for a few modest hydropressure gas zones in the Middle Missisauga, all other reservoirs are deeper and exist in an overpressure regime. The preservation/enhancement of porosity and permeability at depth in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size. The geometry of the reservoir sands shows them to thicken into the bounding growth fault and have excellent lateral continuity along strike, though well data suggests that they tend to thin and deteriorate toward the field's southern margin.

Venture reservoirs consist of stacked sequences of cyclic deltaic and strandplain sands interfingering with marine and prodelta shales. These capping shales and occasional tight oolitic limestones provide effective top seals within the succession. Log profiles and cores of the deeper Mic Mac strata reflect delta front and channel depositional conditions which increase over time. Although penetrated by only two wells, the data shows that the reservoir characteristics of these coarsening upward sands (e.g., Sands 10-18) are fair at depth and improve upwards, with porosities and permeabilities ranging from 8-15% and 0.1-60 mD respectively.

The overlying Missisauga section generally reflects the continuing progradation of fluvial sand bodies though showing the increasing influence of both current and tidal energies (e.g., Sands 2-8). The resultant strandplain nearshore and tidal facies dominate the upper reservoirs though channel sands begin to reappear. These sands are fine to medium grained, well sorted and have fair to very good reservoir characteristics with porosities and permeabilities ranging from 8-24% and 0.1-200 mD (avg. ~17% and ~40 mD respectively).

## Petrophysical Overview

Petrophysical evaluation[1] of the five wells in the Venture field utilized all available log, core and pressure data. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the Venture field using the cutoffs tabled below. Effective porosities were calculated using the standard neutron - density crossplotting technique. The Sonic log was used to determine effective porosities where the quality of the neutron and density data was poor. Core analysis data was used to determine the minimum porosity cutoff. A 10% porosity cutoff, which generally corresponds to a permeability cutoff of 0.1 mD, was used to define net pay at Venture.

Many reservoir zones in the Venture field were excessively invaded by mu d filtrate prior to logging. This was evidenced by DSTs conducted in gas bearing zones which produced only mud filtrate. In highly invaded zones, standard water saturation equations (i.e. Simandoux, Archie etc.) which rely on accurate resistivity readings are unreliable. In these circumstances, capillary pressure data can be used to determine the water saturation of the required zones. In simple terms this technique involves saturating a core plug with a wetting phase, typically brine or mercury, and under controlled conditions increasing the pressure until the fluid is displaced. This data was then normalized using the Leverett J-function and water saturation is then calculated for each sand using the 'J-curve'. The Simandoux water saturation equation was used to calculate water saturation in zones which were not excessively invaded by mud filtrate. A water saturation cutoff of 70% was used to define net pay. The use of this cutoff is supported by a Special Core Analysis (i.e. Gas Imbibition) study conducted on core samples from the Venture field. This study suggests that at water saturations less than 70%, gas will flow preferentially to water. In addition, the study suggests that at water saturations in excess of 70% the converse is true and water will flow preferentially to gas. A shale cutoff was not used to define net pay as the Venture sands have only minor amounts of dispersed or interbedded shale.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 70 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | N/A |
| **Permeability Horizontal** | (mD) | .1-200 |

[1] Canada Oil and Gas Lands Administration, 1986, Venture Gas Field Study, Geological and Reservoir Description, Volume 1.

## *Original Hydrocarbons in Place*

An extensive study[2] performed on Venture has been incorporated in the determination of the parameters for a rigorous probabilistic gas in place analysis which is summarized below.

Even though Venture is rather well delineated, the areal extent of the reservoirs is still determined to be an uncertain variable in the determination of gas in place. Very few gas/water contacts have been observed in the discovery and delineation wells. Thus Pressure/Depth plots were created to assist in defining the fluid contacts in the Venture field. The contacts obtained from these plots were used, in conjunction with the log defined contacts, to determine the areal extent of the reservoirs. The uncertainty in these contacts, coupled with reservoir continuity and test observations, justified the minimum, most-likely and maximum areal extents for the probabilistic calculations.

The variations in net pay and porosity that were observed between the discovery and delineation wells has also served as basis for their selection as primary variables within the probabilistic analysis. Justifiable ranges on these parameters were based on mapped variations of properties, averaged over the reservoir extent. Formation pressures were obtained from extrapolated DST shut-in pressures and from RFT pressure measurements. Formation temperatures were obtained, by establishing a temperature gradient, from maximum bottom hole log temperatures and from DST recorded temperatures.

| **Sand 2 - Missisauga** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 2190 | 2399 | 2736 | 2434 |
| **Top Reservoir** | (mSS) | | | | 4355 (D-23) |
| **Net Pay** | (m) | 11.4 | 17.1 | 23.0 | 17.2 |
| **Porosity** | (%) | 15.9 | 16.9 | 17.6 | 16.8 |
| **Sw** | (%) | 35.4 | 35.4 | 35.4 | 35.4 |
| **Pressure** | (kPa) | 47000 | 47000 | 47000 | 47000 |
| **Temp** | ($^{o}$C) | 128 | 128 | 128 | 128 |
| **Gas FVF** | | 286 | 294 | 302 | 294 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 8.707 | 13.258 | 18.095 | 13.355 |
| **OOIP** | (E6M3) | | | | |

[2] Canada Oil and Gas Lands Administration, 1986, Venture Gas Field Study, Geological and Reservoir Description, Volume 1.

| Sand 2A - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1244 | 1374 | 1584 | 1396 |
| **Top Reservoir** | (mSS) | | | | 4415 (D-23) |
| **Net Pay** | (m) | 6.0 | 6.4 | 7.0 | 6.4 |
| **Porosity** | (%) | 17.9 | 18.2 | 18.5 | 18.2 |
| **Sw** | (%) | 47.7 | 47.7 | 47.7 | 47.7 |
| **Pressure** | (kPa) | 51000 | 51000 | 51000 | 51000 |
| **Temp** | ($^o$C) | 129 | 129 | 129 | 129 |
| **Gas FVF** | | 305 | 314 | 323 | 314 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.313 | 2.649 | 3.069 | 2.676 |
| **OOIP** | (E6M3) | | | | |

| Sand 2B - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 2122 | 2360 | 2745 | 2400 |
| **Top Reservoir** | (mSS) | | | | 4465 (D-23) |
| **Net Pay** | (m) | 3.2 | 4.6 | 5.9 | 4.6 |
| **Porosity** | (%) | 18.3 | 19.3 | 20.4 | 19.3 |
| **Sw** | (%) | 35.2 | 35.2 | 35.2 | 35.2 |
| **Pressure** | (kPa) | 52000 | 52000 | 52000 | 52000 |
| **Temp** | ($^o$C) | 130 | 130 | 130 | 130 |
| **Gas FVF** | | 294 | 302 | 310 | 302 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.886 | 4.097 | 5.467 | 4.144 |
| **OOIP** | (E6M3) | | | | |

| Sand 2C - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 408 | 408 | 408 | 408 |
| **Top Reservoir** | (mSS) | | | | 4505 (D-23) |
| **Net Pay** | (m) | 3.4 | 4.9 | 6.5 | 5.0 |
| **Porosity** | (%) | 14.3 | 14.6 | 14.9 | 14.6 |
| **Sw** | (%) | 49.9 | 49.9 | 49.9 | 49.9 |
| **Pressure** | (kPa) | 63000 | 63000 | 63000 | 63000 |
| **Temp** | ($^o$C) | 130 | 130 | 130 | 130 |
| **Gas FVF** | | 304 | 313 | 322 | 313 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.320 | 0.463 | 0.604 | 0.462 |
| **OOIP** | (E6M3) | | | | |

| Sand 3 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1497 | 1551 | 1638 | 1560 |
| **Top Reservoir** | (mSS) | | | | 4605 (D-23) |
| **Net Pay** | (m) | 16.1 | 17.5 | 18.9 | 17.5 |
| **Porosity** | (%) | 20.9 | 22.0 | 23.1 | 22.0 |
| **Sw** | (%) | 39.3 | 39.3 | 39.3 | 39.3 |
| **Pressure** | (kPa) | 71000 | 71000 | 71000 | 71000 |
| **Temp** | ($^o$C) | 134 | 134 | 134 | 134 |
| **Gas FVF** | | 337 | 347 | 357 | 347 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 11.420 | 12.599 | 13.970 | 12.652 |
| **OOIP** | (E6M3) | | | | |

| Sand 4A+B Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 816 | 1046 | 1417 | 1084 |
| **Top Reservoir** | (mSS) | | | | 4695 (D-23) |
| **Net Pay** | (m) | 9.9 | 11.2 | 12.2 | 11.1 |
| **Porosity** | (%) | 17.4 | 18.0 | 18.6 | 18.0 |
| **Sw** | (%) | 45.6 | 45.6 | 45.6 | 45.6 |
| **Pressure** | (kPa) | 80000 | 80000 | 80000 | 80000 |
| **Temp** | ($^o$C) | 137 | 137 | 137 | 137 |
| **Gas FVF** | | 344 | 354 | 364 | 354 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 3.100 | 4.038 | 5.562 | 4.182 |
| **OOIP** | (E6M3) | | | | |

| Sand 4C - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 289 | 430 | 659 | 454 |
| **Top Reservoir** | (mSS) | | | | 4735 (D-23) |
| **Net Pay** | (m) | 3.8 | 3.8 | 3.8 | 3.8 |
| **Porosity** | (%) | 16.7 | 16.7 | 16.7 | 16.7 |
| **Sw** | (%) | 39.5 | 39.5 | 39.5 | 39.5 |
| **Pressure** | (kPa) | 80000 | 80000 | 80000 | 80000 |
| **Temp** | ($^o$C) | 137 | 137 | 137 | 137 |
| **Gas FVF** | | 344 | 354 | 364 | 354 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.394 | 0.585 | 0.896 | 0.617 |
| **OOIP** | (E6M3) | | | | |

| Sand 4D - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1448 | 1576 | 1783 | 1598 |
| **Top Reservoir** | (mSS) | | | | 4755 (D-23) |
| **Net Pay** | (m) | 3.3 | 4.0 | 4.7 | 4.0 |
| **Porosity** | (%) | 15.5 | 16.4 | 17.3 | 16.4 |
| **Sw** | (%) | 38 | 38 | 38 | 38 |
| **Pressure** | (kPa) | 80000 | 80000 | 80000 | 80000 |
| **Temp** | ($^oC$) | 137 | 137 | 137 | 137 |
| **Gas FVF** | | 344 | 354 | 364 | 354 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.852 | 2.283 | 2.759 | 2.300 |
| **OOIP** | (E6M3) | | | | |

| Sand 5 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1038 | 1454 | 1985 | 1486 |
| **Top Reservoir** | (mSS) | | | | 4775 (D-23) |
| **Net Pay** | (m) | 9.7 | 11.3 | 12.8 | 11.3 |
| **Porosity** | (%) | 19.8 | 20.3 | 20.7 | 20.3 |
| **Sw** | (%) | 37.1 | 37.1 | 37.1 | 37.1 |
| **Pressure** | (kPa) | 82000 | 82000 | 82000 | 82000 |
| **Temp** | ($^oC$) | 140 | 140 | 140 | 140 |
| **Gas FVF** | | 352 | 362 | 372 | 362 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 5.291 | 7.557 | 10.548 | 7.729 |
| **OOIP** | (E6M3) | | | | |

| Sand 6 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1300 | 1391 | 1447 | 1382 |
| **Top Reservoir** | (mSS) | | | | 4845 (D-23) |
| **Net Pay** | (m) | 16.4 | 20.7 | 23.8 | 20.4 |
| **Porosity** | (%) | 17.4 | 19.2 | 20.3 | 19.0 |
| **Sw** | (%) | 43.3 | 43.3 | 43.3 | 43.3 |
| **Pressure** | (kPa) | 85000 | 85000 | 85000 | 85000 |
| **Temp** | ($^oC$) | 142 | 142 | 142 | 142 |
| **Gas FVF** | | 358 | 368 | 378 | 368 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 8.867 | 11.251 | 13.379 | 11.172 |
| **OOIP** | (E6M3) | | | | |

| Sand 7 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 1104 | 1229 | 1433 | 1251 |
| **Top Reservoir** | (mSS) | | | | 4920 (B-43) |
| **Net Pay** | (m) | 3.3 | 5.1 | 7.8 | 5.3 |
| **Porosity** | (%) | 16.9 | 18.0 | 19.1 | 18.0 |
| **Sw** | (%) | 35.0 | 35.0 | 35.0 | 35.0 |
| **Pressure** | (kPa) | 86000 | 86000 | 86000 | 86000 |
| **Temp** | ($^{o}$C) | 144 | 144 | 144 | 144 |
| **Gas FVF** | | 365 | 375 | 385 | 375 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.740 | 2.784 | 4.335 | 2.929 |
| **OOIP** | (E6M3) | | | | |

| Sand 8 - Missisauga | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 63 | 94 | 145 | 99 |
| **Top Reservoir** | (mSS) | | | | 4965 (B-43) |
| **Net Pay** | (m) | 12.2 | 12.2 | 12.2 | 12.2 |
| **Porosity** | (%) | 19.3 | 19.3 | 19.3 | 19.3 |
| **Sw** | (%) | 44.9 | 44.9 | 44.9 | 44.9 |
| **Pressure** | (kPa) | 85000 | 85000 | 85000 | 85000 |
| **Temp** | ($^{o}$C) | 144 | 144 | 144 | 144 |
| **Gas FVF** | | 352 | 362 | 372 | 362 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.295 | 0.442 | 0.679 | 0.467 |
| **OOIP** | (E6M3) | | | | |

| Sand 11 - Mic Mac | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 315 | 534 | 888 | 571 |
| **Top Reservoir** | (mSS) | | | | 5170 (B-43) |
| **Net Pay** | (m) | 7.7 | 10.6 | 15.1 | 11.0 |
| **Porosity** | (%) | 14.9 | 16.0 | 17.1 | 16.0 |
| **Sw** | (%) | 47.0 | 47.0 | 47.0 | 47.0 |
| **Pressure** | (kPa) | 102000 | 102000 | 102000 | 102000 |
| **Temp** | ($^{o}$C) | 149 | 149 | 149 | 149 |
| **Gas FVF** | | 371 | 382 | 393 | 382 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.994 | 1.836 | 3.414 | 2.035 |
| **OOIP** | (E6M3) | | | | |

| **Sand 13 - Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 259 | 259 | 259 | 259 |
| **Top Reservoir** | (mSS) | | | | 5270 (B-43) |
| **Net Pay** | (m) | 14.2 | 14.2 | 14.2 | 14.2 |
| **Porosity** | (%) | 17.4 | 17.4 | 17.4 | 17.4 |
| **Sw** | (%) | 59.0 | 59.0 | 59.0 | 59.0 |
| **Pressure** | (kPa) | 107000 | 107000 | 107000 | 107000 |
| **Temp** | ($^oC$) | 157 | 157 | 157 | 157 |
| **Gas FVF** | | 375 | 386 | 397 | 386 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.985 | 1.013 | 1.041 | 1.013 |
| **OOIP** | (E6M3) | | | | |

| **Sand 17 - Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 259 | 259 | 259 | 259 |
| **Top Reservoir** | (mSS) | | | | 5485 (H-22) |
| **Net Pay** | (m) | 4.2 | 4.2 | 4.2 | 4.2 |
| **Porosity** | (%) | 15.8 | 15.8 | 15.8 | 15.8 |
| **Sw** | (%) | 55.2 | 55.2 | 55.2 | 55.2 |
| **Pressure** | (kPa) | 118000 | 118000 | 118000 | 118000 |
| **Temp** | ($^oC$) | 163 | 163 | 163 | 163 |
| **Gas FVF** | | 387 | 398 | 409 | 398 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.298 | 0.306 | 0.315 | 0.306 |
| **OOIP** | (E6M3) | | | | |

| **Sand 18 - Mic Mac** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 259 | 259 | 259 | 259 |
| **Top Reservoir** | (mSS) | | | | 5570 (H-22) |
| **Net Pay** | (m) | 4.0 | 4.0 | 4.0 | 4.0 |
| **Porosity** | (%) | 15.0 | 15.0 | 15.0 | 15.0 |
| **Sw** | (%) | 61.2 | 61.2 | 61.2 | 61.2 |
| **Pressure** | (kPa) | 118000 | 118000 | 118000 | 118000 |
| **Temp** | ($^oC$) | 163 | 163 | 163 | 163 |
| **Gas FVF** | | 392 | 403 | 414 | 403 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.236 | 0.243 | 0.250 | 0.243 |
| **OOIP** | (E6M3) | | | | |

## *Depletion Scenario and Recoverable Resource*

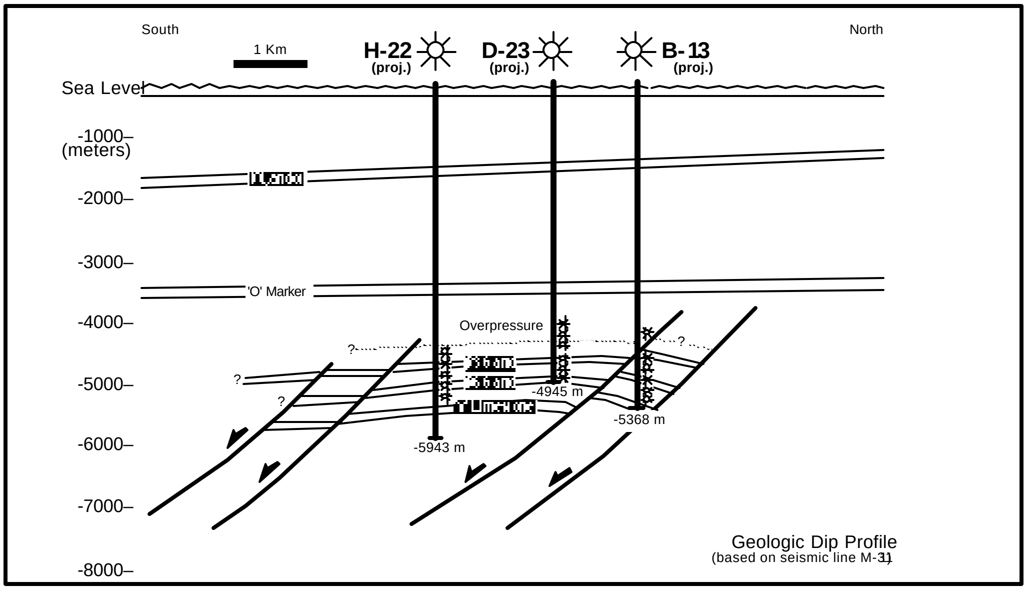
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 100 M3/E6M3 of recoverable gas and is based on DST observations.

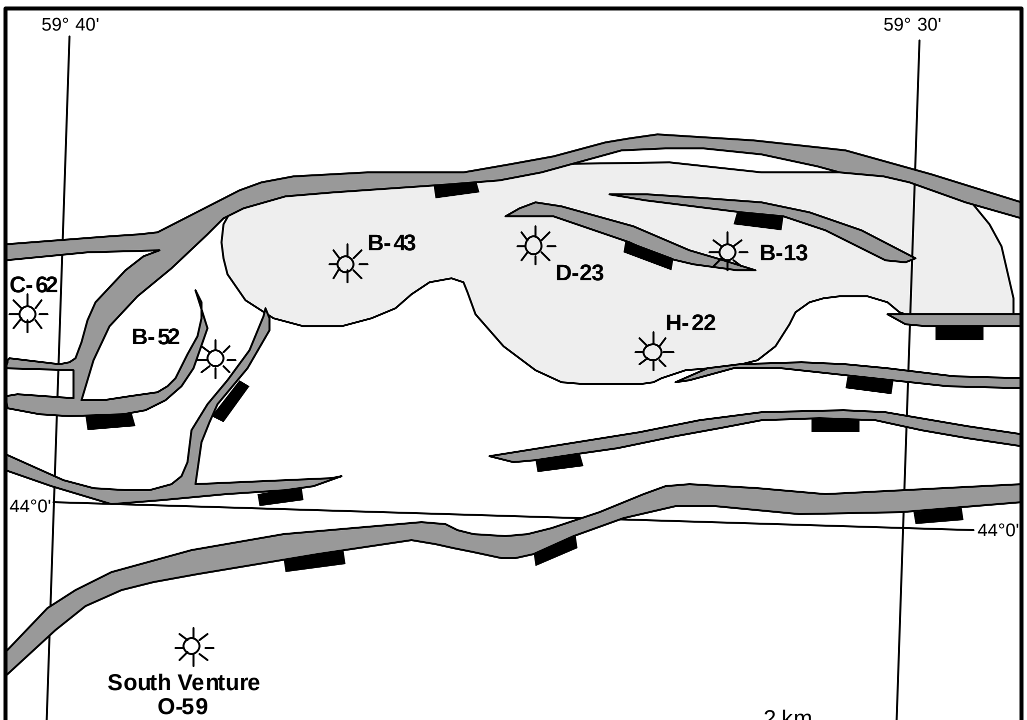
Venture is the second of three fields completed and now producing gas for the Sable Offshore Energy Project's Tier 1 phase. Like the other producing field at North Triumph, it is linked to the project's central processing complex located at the Thebaud field, ~50 km to the west. During this field's development phase, a total of 4 production wells were drilled and completed in various reservoir zones. Five more slots are available in the well jacket for future wells if required. The field will be placed under compression during its late life from a central compression facility located approximately 50 km away at the Thebaud location.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 50.4 (1781) | 65.0 (2295) | 83.7 (2957) | 66.3 (2341) |
| **Condensate** | (E6M3) | 5.044 (31.7) | 6.499 (40.9) | 8.374 (52.7) | 6.628 (41.7) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 25.22 (891) | 42.2 (1492) | 67.0 (2366) | 43.1 (1521) |
| **Condensate** | (E6M3) | 2.522 (15.9) | 4.224 (26.6) | 6.695 (42.1) | 4.308 (27.1) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# Venture




Area above the water line at the Top Sand 6 level.
After SOEP DPA.

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# West Olympia - Significant Discovery

## *Overview*

The West Olympia gas field is located approximately 10 km due north of Sable Island. The field was discovered in 1985 and its current assessment is based on the discovery well. This accumulation is located within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex

### Discovery Well:

| | |
|---|---|
| Well: | Mobil et al West Olympia O-51 |
| Spud: | 85-06-23 |
| R.R.: | 85-11-12 |
| T.D.: | 4816 m |

The discovery well is located in 38 m of water at approximately 44°00'47.802"N latitude, 59°53'03.639"W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a closure against a down-to-the-basin fault.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil/Cond (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| O-51 | DST#1 | 4356-4386 | Missisauga | 501 | 65 | |
| O-51 | DST#2 | 4356-4386 | Missisauga | 532 | 73 | |
| O-51 | DST#3 | 4257-4262 | Missisauga | No Flow to Surface | | |

## *Geological/Geophysical Overview*

The West Olympia gas field is located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. Proximity to sediment source, basin hinge-line position and resultant rapid subsidence influenced the progradational strata deposited at West Olympia, consisting of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions with the reservoir sands located within the Late Jurassic Mic Mac and Early Cretaceous Missisauga formation.

### Structure

The West Olympia structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic – Early Jurassic age salts of the Argo formation. Such a combination resulted in the formation of significant overpressure conditions which are manifested in the known reservoir sands. It is the westernmost structure/field along the Venture-Olympia basin hinge-line fault line trend.

The West Olympia structure is a very narrow, elongate, northeast-dipping fault block formed by the westerly convergence of two major down-to-the-basin listric growth faults. The northeast-southwest trending fault is the major structural feature in the Sable Subbasin, formed along the basin's hinge-line. The convergence of the growth faults resulted in the formation of the western updip and highest structural elevation of the gas fields of Venture-Olympia trend of about 300 m. A southeast-dipping fault splay from the northern fault separates this field from the adjacent Olympia field to the east.

Several regional seismic markers are prominent in the area, but internal field reflections at West Olympia define its structural configuration. These include the #3 Sand, #9 Limestone and the 'Y' Limestone that are also mapped at Venture and other related fields.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by a thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

The reservoir zone at West Olympia is stratigraphically located within the Lower member of the Early Cretaceous Missisauga formation. Seismic mapping and well data indicate that the majority of the Missisauga formation sands can be correlated with equivalent sands of the Venture, West Venture and Olympia fields. The single exploratory well drilled near the center of the structure encountered only one major gas-bearing reservoir at 4300 m, the #4 Sand. This and other potential zones were extensively logged, and several zones were cored (#3, #6M, #6L & #7 Sands). Only the #3A and #4 Sands were tested.

The West Olympia reservoir sands are found in overpressure conditions, with the transition from hydropressure to overpressure occurring about 100 m above the #4 reservoir sand. Like other related overpressured gas fields, the preservation/enhancement of porosity and permeability in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size. Given their ability to be correlated with sands in other the fields along strike, the West Olympia #4 Sand and other potential reservoir zones have excellent east-west lateral continuity. The very narrow nature of the field would suggest that there is little or no reservoir degradation toward the field's southern margin.

The reservoir and other sands at West Olympia 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, which provide effective top seals. Log profiles of the Lower Missisauga member strata reveal delta front and channel depositional environments with increasing current and tidal influences that are manifested as strandplain shoreface and tidal deposits. Although penetrated by a single well, the data show that these generally coarsening upward sands are thick, fine to coarse grained, siliceous, occasionally calcareous and variably argillaceous. They have fair to very good reservoir characteristics with effective porosities ranging from 12-24%. Drillstem test results of the #4 Sand indicate good effective permeabilities.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the West Olympia O-51 well was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined, for the West Olympia field, using the cutoffs tabled below. Effective porosities were calculated using, the neutron - density crossplotting technique. Water saturations were determined, from the log data, using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | Good |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## *Original Hydrocarbons in Place*

The areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The proven area was assigned based upon the single well test that demonstrated limited areal extent, most likely based on the structure containing gas down to the base of porosity in discovery well, and possible area extending to structural spill point. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **Sand 4 (Missisauga)** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 633 | 832 | 1063 | 842 |
| **Top Reservoir** | (mSS) | | | | 3670 (O-51) |
| **Net Pay** | (m) | 3 | 3 | 3 | 3 |
| **Porosity** | (%) | 16.7 | 18.9 | 20.2 | 18.7 |
| **Sw** | (%) | 38.6 | 39.5 | 40.9 | 39.7 |
| **Pressure** | (kPa) | 58000 | | | |
| **Temp** | ($^oC$) | 120 | | | |
| **Gas FVF** | | 320 | 329 | 338 | 329 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.686 | 0.925 | 1.196 | 0.936 |
| **OOIP** | (E6M3) | | | | |

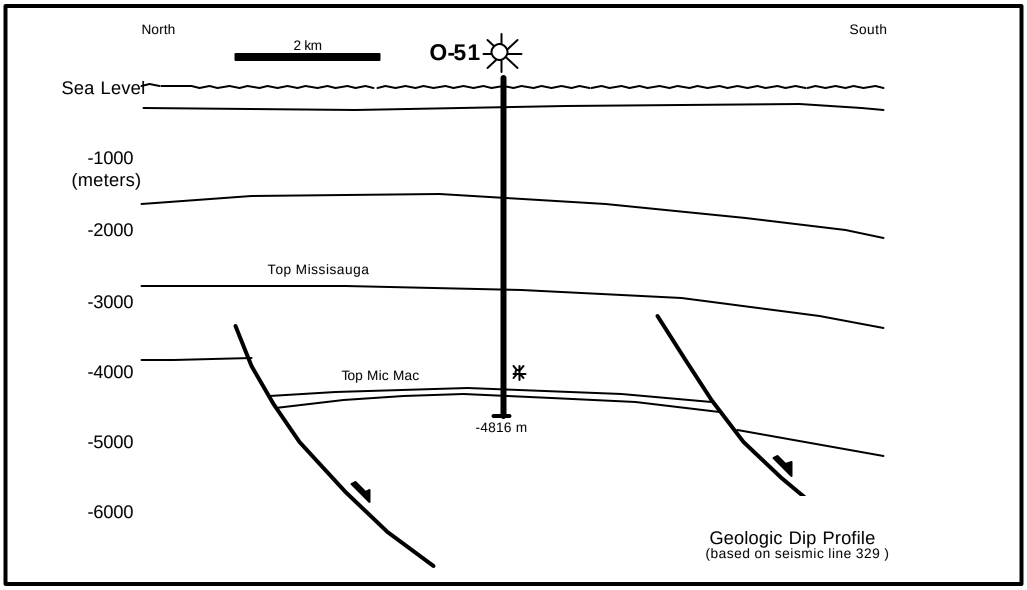
## *Depletion Scenario and Recoverable Resource*

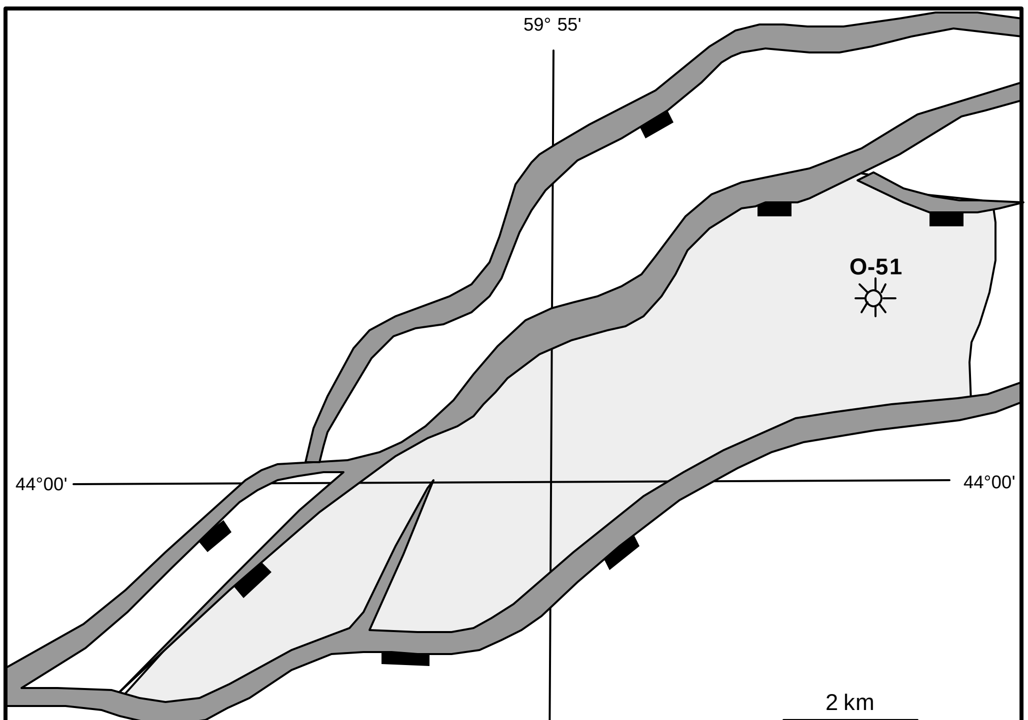
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 153 M3/E6M3 of recoverable gas and is based on DST observations.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 0.686 (24) | 0.925 (33) | 1.196 (42) | 0.936 (33) |
| **Condensate** | (E6M3) | 0.105 (0.66) | 0.142 (0.89) | 0.183 (1.15) | 0.143 (0.90) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 0.343 (12) | 0.601 (21) | 0.957 (34) | 0.608 (21) |
| **Condensate** | (E6M3) | 0.052 (0.33) | 0.092 (0.58) | 0.146 (0.92) | 0.093 (0.59) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# West Olympia




Area above the water line at the Top 4 Sand level.
After Mobil 8624-M3-49E.

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# West Sable - Significant Discovery

## *Overview*

The West Sable gas/oil field is located onshore at the western end of Sable Island. The field was discovered in 1971 and been delineated via seven additional wells. Six of these wells were drilled from the same surface location. The field is within the Mesozoic age Sable Subbasin in a west-central position on the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil-Tetco Sable Island E-48 |
| Spud: | 71-05-28 |
| R.R.: | 71-10-15 |
| T.D.: | 3602.74 m |

The discovery well is located on the western end of Sable Island at approximately 43°57'20.35"N latitude, 60°07'24.44"W longitude. It was drilled to test for the presence of hydrocarbons in the sands associated with a large salt dome that has been complexly faulted at its crest.

### Additional Wells:

A delineation well and 6 additional wells from one location were drilled to access the various fault blocks associated with the structure.

| | |
|---|---|
| Well: | Mobil - Tetco Sable Island O-47 (43°56'56.70"N, 60°06'38.08"W) |
| | Mobil - Tetco Sable Island 1H-58 (43°57'27.17"N, 60°07'37.81"W) |
| | Mobil - Tetco Sable Island 2H-58 (43°57'27.14"N, 60°07'37.75"W) |
| | Mobil - Tetco Sable Island 3H-58 (43°57'27.21"N, 60°07'37.88"W) |
| | Mobil - Tetco Sable Island 4H-58 (43°57'27.24"N, 60°07'37.95"W) |
| | Mobil - Tetco Sable Island 5H-58 (43°57'27.10"N, 60°07'37.68"W) |
| | Mobil - Tetco Sable Island 6H-58 (43°57'27.07"N, 60°07'37.61"W) |

### Significant Tests:

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil*/Con (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| E-48 | CT | 1460-1462 | Logan Canyon | 37 | 458* | |
| E-48 | DST#1 | 1134-1173 | Wyandot | Rec Mud | | |
| E-48 | DST#3 | 1716-1768 | Logan Canyon | 130 | | |
| E-48 | DST#4 | 1806-1824 | Logan Canyon | 396 | | |
| E-48 | DST#5 | 2227-2240 | Logan Canyon | 425 | | |
| E-48 | DST#7 | 2974-2983 | Iroquois | TSTM | | |
| E-48 | PT#1 | 2285-2287 | Logan Canyon | 137 | 54 | |
| | | | | 218 | 80 | |
| | | | | 259 | 90 | |
| | | | | 299 | 101 | |

| Well | Test # | Depth (M) | Interval | Gas (E3M3/D) | Oil*/Con (M3/D) | Water (M3/D) |
|---|---|---|---|---|---|---|
| E-48 | PT#2 | 2236-2240 | Logan Canyon | 152 | 66 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | 218 | 101 | |
| | | | | 251 | 120 | |
| | | | | 286 | 132 | |
| E-48 | PT#3 | 2206-2211 | Logan Canyon | 122 | 150 | |
| | | | | 199 | 264 | |
| E-48 | PT#4 | 2195-2198 | Logan Canyon | 105 | 114 | |
| | | | | 82 | 181 | |
| | | | | 105 | 250 | |
| E-48 | PT#5 | 2173-2177 | Logan Canyon | 10 | 58 | 173 |
| | | | | 20 | | |
| E-48 | PT#6 | 2002-2003 | Logan Canyon | 13 | 64* | |
| | | | | 28 | 126 | |
| | | | | 16 | 64 | |
| E-48 | PT#7 | 2147-2148 | Logan Canyon | Rec Form | Water | |
| E-48 | PT#8 | 2134-2134 | Logan Canyon | 22 | 87* | |
| | | | | 15 | 60 | |
| E-48 | PT#9 | 2059-2069 | Logan Canyon | 71 | 65* | 88 |
| E-48 | PT#10 | 2032-2035 | Logan Canyon | 144 | 43 | |
| E-48 | PT#11 | 1973-1974 | Logan Canyon | 40 | 21 | 61 |
| E-48 | PT#12 | 1909-1910 | Logan Canyon | 51 | 0.1 | 0.1 |
| | | | | 81 | 20 | 5 |
| E-48 | PT#13 | 1810-1812 | Logan Canyon | 125 | 117 | 2 |
| E-48 | PT#14 | 1631-1632 | Logan Canyon | 8 | 82* | 10 |
| E-48 | PT#15 | 1586-1588 | Logan Canyon | 6 | 59* | |
| E-48 | PT#16 | 1460-1462 | Logan Canyon | 6 | 62* | |
| E-48 | PT#17 | 1534-1535 | Logan Canyon | 6 | 62* | |
| E-48 | PT#18 | 1397-1398 | Logan Canyon | 157 | | |
| | | | | 110 | | |
| E-48 | PT#19 | 1366-1369 | Dawson Cany. | 69 | | |
| E-48 | PT#20 | 1144-1148 | Wyandot | TSTM | | |
| E-48 | PT#21 | 1431-1433 | Logan Canyon | 114 | | |
| O-47 | DST#3 | 1908-1943 | Logan Canyon | Rec Muddy | Salt Water | |
| O-47 | DST#4 | 3530-3536 | Missisauga | Rec Water | Cushion | |
| O-47 | DST#5 | 3712-3726 | Missisauga | 71 | | 155 |
| O-47 | DST#6 | 3731-3737 | Missisauga | Rec Mud | | |
| O-47 | DST#7 | 3730-3801 | Missisauga | 20 | | |
| O-47 | DST#8 | 3736-3894 | Missisauga | 391 | | |
| O-47 | DST#9 | 3570-3571 | Missisauga | 7 | | |
| O-47 | DST#10 | 3382-3391 | Missisauga | 6 | | |
| O-47 | DST#12 | 3510-3515 | Missisauga | .4 | | |
| O-47 | DST#13 | 3803-3809 | Missisauga | 261 | | |
| H-58 | DST#1 | 1503-1518 | Logan Canyon | 150 | | |
| H-58 | DST#4 | 1700-1719 | Logan Canyon | Rec Water | | |
| H-58 | DST#6 | 1734-1750 | Logan Canyon | Rec Salt | Water | |
| H-58 | DST#7 | 2050-2070 | Logan Canyon | Rec Watery | mud | |
| H-58 | DST#12 | 1539-1541 | Logan Canyon | 207 | | 3 |

| **Well** | **Test #** | **Depth (M)** | **Interval** | **Gas (E3M3/D)** | **Oil*/Con (M3/D)** | **Water (M3/D)** |
|---|---|---|---|---|---|---|
| 2H-28 | PT#1 | 2046-2049 | Logan Canyon | Rec Form Water | | |
| 2H-28 | PT#2 | 2028-2031 | Logan Canyon | Rec Salt Water | | |
| 2H-28 | PT#3 | 2010-2014 | Logan Canyon | Rec Water | | |
| 2H-28 | PT#4 | 1910-1914 | Logan Canyon | No Rec | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2H-28 | PT#5 | 1910-1914 | Logan Canyon | 37 | 95 | 95 |
| 2H-28 | PT#6 | 1745-1747 | Logan Canyon | Rec Salt Water | | |
| 2H-28 | PT#7 | 1745-1747 | Logan Canyon | Rec Salt Water | | |
| 2H-28 | PT#8 | 1692-1693 | Logan Canyon | Rec Gas and Salt Water | | |
| 2H-28 | PT#9 | 1559-1567 | Logan Canyon | 59 | 2 | |
| | | | | 147 | 53 | |
| | | | | 61 | 23 | |
| 2H-28 | PT#10 | 1471-1472 | Dawson Cany. | 82 | Nil | Nil |
| 3H-58 | DST#1 | 1956-2004 | Logan Canyon | Rec Water with trace of Cond | | |
| 3H-58 | PT#1 | 1662-1663 | Logan Canyon | Oil Cut salt water | | |
| 3H-58 | PT#2 | 1648-1649 | Logan Canyon | 12 | 162* | |
| 3H-58 | PT#3 | 1637-1639 | Logan Canyon | 48 | 58* | |
| 3H-58 | PT#4 | 1632-1633 | Logan Canyon | 53 | 22* | |
| 3H-58 | PT#5 | 1629-1630 | Logan Canyon | 74 | 12* | |
| 3H-58 | PT#6 | 1611-1612 | Logan Canyon | 88 | | |
| 5H-58 | PT#1 | 1914-1919 | Logan Canyon | 88 | 30 | |
| 5H-58 | PT#2 | 1904-1906 | Logan Canyon | 261 | 80 | |
| 5H-58 | PT#3 | 1758-1760 | Logan Canyon | 42 | 216 | |
| 5H-58 | PT#4 | 1640-1642 | Logan Canyon | 20 | 245* | |
| 5H-58 | PT#5 | 1492-1496 | Logan Canyon | Rec Salt Water | | |

## *Geological/Geophysical Overview*

The West Sable gas/oil field is located beneath the western tip of Sable Island. It is located in the Mesozoic age Sable Subbasin in a west-central position on the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. Prior to delta development, in the Late Triassic the area was blanketed by thick marine salts and later in the Jurassic by shallow marine dolomites and fluvial sandstones and shales. The Late Jurassic to Early Cretaceous progradational deltaic strata deposited at West Sable consist of a thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits, where these sediments record episodic delta advances punctuated by marine incursions. Upon cessation of deltaic sedimentation, extensive carbonate deposition took place, which was eventually buried by coastal plain and marine shelf clastics. The reservoirs are located in the sandstones of the Late Cretaceous Dawson Canyon and Logan Canyon formations.

### Structure

The West Sable structure is a large salt diapir composed of latest Triassic to earliest Jurassic age evaporites of the Argo formation. The diapir penetrates through Cretaceous and older strata with Late Cretaceous sediments draped over this feature. Between these sediments and the salt is a thin caprock interval of Early Jurassic sandstones, dolomites, limestones and shales. The top of the salt is about 3000 m below the surface of Sable Island. The structure is circular in plan view and complexly faulted across its crest and around its flanks, and the faults appear to sole into the top of the salt. They do not exhibit any evidence of being syndepositional, and the seismic data suggest that salt movement occurred in the latest Cretaceous or Tertiary. The strata draped over the structure have modest relief with a maximum closure of approximately 150 m.

A number of regional and local seismic reflectors assist in defining the West Sable structure. The former include the Wyandot formation limestone, the Petrel limestone (Dawson Canyon formation), and the Missisauga ‘O’ Marker, the latter being the Top Naskapi Shale (Lower Logan Canyon formation), and the Top Jurassic/Mic Mac formation. Slight overpressure conditions were encountered in the two wells which penetrated the Lower Missisauga/Mic Mac section on the structure.

A number of regional and local seismic reflectors assist in defining the West Sable structure. The former include the Wyandot formation limestone, the Petrel limestone (Dawson Canyon formation), and the Missisauga ‘O’ Marker, the latter being the Top Naskapi Shale (Lower Logan Canyon formation), and the Top Jurassic/Mic Mac formation. Slight overpressure conditions were encountered in the two wells which penetrated the Lower Missisauga/Mic Mac section on the structure.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Late Triassic to the Tertiary. In the Triassic, rift related, fine grain clastic sediments of the Eurydice formation were deposited and then overlain by thick marine salts of the Argo formation. In the Early Jurassic, shallow marine dolomites and fluvial sandstones and shales of the Iroquois and Mohican formations respectively were deposited.

Beginning in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales of the Verrill Canyon formation.

Increased sediment influx and concurrent delta advance at the end of the Late Jurassic are represented by a thick deltaic and strandplain succession of the Missisauga formation, which rapidly prograded to the southwest into the Sable Island area and beyond. In this region, the resultant sedimentary section is thick and has a high sand/shale ratio. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation. A renewed deltaic progradation followed and is represented by the strandplain succession of the Logan Canyon and Dawson Canyon formations. Cessation of deltaic sedimentation in the Late Cretaceous permitted the establishment of a regional carbonate facies of the Wyandot formation. Upon cessation of deltaic sedimentation, extensive carbonate deposition took place, which was eventually buried by Tertiary age coastal plain and marine shelf clastics.

## Reservoir Description

The West Sable reservoirs are located within Late Cretaceous sandstones of the Dawson Canyon (gas) and Logan Canyon (gas and oil) formations. Eight exploratory wells have been drilled into separate fault blocks on the structural crest and flanks at West Sable and most reservoirs are hydropressured. Several slightly overpressured gas sands were tested in the deeper Early Cretaceous Lower Missisauga formation. Seismic and geological mapping, and well results, confirm the continuity of the main reservoir intervals across the field, although non reservoir caprock distribution appears variable as it was encountered in only one of the two wells which penetrated the salt. The complex nature of the faulting limits the areal extent of the individual pay zones.

The main West Sable gas reservoirs are found in the sands of the Logan Canyon and overlying Dawson Canyon 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 reservoir characteristics of the sandstones are good to excellent with effective average porosities ranging from 16-29%. Drillstem tests results infer good to excellent permeabilities. The Logan Canyon pay sands range from thin to thickly bedded and also 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. Reservoir characteristics are also similar.

Secondary gas pays that are slightly overpressured occur in the Lower member of the Early Cretaceous Missisauga formation. The sands exist as thick coarsening-upward fluvial deposits and are medium to coarse grained, moderate to poorly sorted, siliceous, calcareous, and variably argillaceous, carbonaceous and sideritic. The sandstones have good effective average porosities averaging 15% and a fair to good permeabilities based on drillstem tests results.

The West Sable oil reservoirs are located within the Late Cretaceous Marmora member, Logan Canyon formation. The sands have the same characteristics as the above described Logan Canyon gas reservoirs.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the West Sable Island wells was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined, for the West Sable Island field, using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | Good |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

The areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The minimum and most-likely areas were assigned based upon the well tests, defined water contacts, and limited to the tested fault blocks. Maximum areas assumed that areal extent was limited to the water up to the top of porosity in the 6H-58 well, and included untested fault blocks.

The variations in net pay, porosity, and water saturation that were observed between the discovery and delineation wells has also served as the basis for their selection as primary variables within the probabilistic analysis. Justifiable ranges on these parameters were based on minimum well values, weighted average values, and maximum well values, defining the minimum, most-likely, and maximum probabilistic input values, respectively. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **Zone I - Dawson Can.** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 219 | 424 | 756 | 458 |
| **Top Reservoir** | (mSS) | | | | 1350 (E-48) |
| **Net Pay** | (m) | 8.0 | 9.7 | 11.6 | 9.8 |
| **Porosity** | (%) | 22.0 | 24.4 | 26.9 | 24.4 |
| **Sw** | (%) | 48.2 | 36.2 | 26.0 | 36.7 |
| **Pressure** | (kPa) | 14000 | 14000 | 14000 | 14000 |
| **Temp** | ($^o$C) | 48 | 48 | 48 | 48 |
| **Gas FVF** | | 142 | 146 | 150 | 146 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.456 | 0.905 | 1.699 | 1.008 |
| **OOIP** | (E6M3) | | | | |

| **Zone II - Logan Can.** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 290 | 477 | 780 | 508 |
| **Top Reservoir** | (mSS) | | | | 1420 (E-48) |
| **Net Pay** | (m) | 5.9 | 9.6 | 13.6 | 9.7 |
| **Porosity** | (%) | 20.5 | 22.5 | 25.0 | 22.7 |
| **Sw** | (%) | 43.5 | 35.4 | 28.0 | 35.6 |
| **Pressure** | (kPa) | 15000 | 15000 | 15000 | 15000 |
| **Temp** | ($^o$C) | 51 | 51 | 51 | 51 |
| **Gas FVF** | | 147 | 151 | 155 | 151 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.499 | 0.968 | 1.807 | 1.085 |
| **OOIP** | (E6M3) | | | | |

| Zone II - Logan Can. | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 313 | 494 | 787 | 525 |
| **Top Reservoir** | (mSS) | | | | 1450 (E-48) |
| **Net Pay** | (m) | 3.5 | 5.4 | 7.1 | 5.4 |
| **Porosity** | (%) | 22.0 | 24.4 | 26.4 | 24.3 |
| **Sw** | (%) | 56.5 | 44.78 | 35.3 | 45.4 |
| **Pressure** | (kPa) | N/A | N/A | N/A | N/A |
| **Temp** | ($^o$C) | N/A | N/A | N/A | N/A |
| **Gas FVF** | | | | | |
| **Oil Bo** | | 1.13 | 1.10 | 1.07 | 1.10 |
| **OGIP** | (E9M3) | | | | |
| **OOIP** | (E6M3) | 1.699 | 3.092 | 5.536 | 3.395 |

| Zone III - Logan Can. | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 219 | 424 | 756 | 458 |
| **Top Reservoir** | (mSS) | | | | 1525 (E-48) |
| **Net Pay** | (m) | 24.7 | 26..7 | 28.5 | 26.7 |
| **Porosity** | (%) | 20.9 | 22.0 | 23.1 | 22.0 |
| **Sw** | (%) | 46.9 | 43.0 | 39.1 | 43.0 |
| **Pressure** | (kPa) | N/A | N/A | N/A | N/A |
| **Temp** | ($^o$C) | N/A | N/A | N/A | N/A |
| **Gas FVF** | | | | | |
| **Oil Bo** | | 1.23 | 1.20 | 1.17 | 1.20 |
| **OGIP** | (E9M3) | | | | |
| **OOIP** | (E6M3) | 6.022 | 11.717 | 21.189 | 12.779 |

| Zone IV - Logan Can. | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 219 | 424 | 756 | 458 |
| **Top Reservoir** | (mSS) | | | | 1800 (E-48) |
| **Net Pay** | (m) | 5.7 | 6.8 | 8.4 | 6.9 |
| **Porosity** | (%) | 18.1 | 20.7 | 23.2 | 20.7 |
| **Sw** | (%) | 41.8 | 37.9 | 33.5 | 37.8 |
| **Pressure** | (kPa) | 18000 | 18000 | 18000 | 18000 |
| **Temp** | ($^o$C) | 61 | 61 | 61 | 61 |
| **Gas FVF** | | 177 | 182 | 187 | 182 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 0.340 | 0.676 | 1.255 | 0.746 |
| **OOIP** | (E6M3) | | | | |

| Zone V - Logan Can. | | P90/Low | P50/Med | P10/High | Mean/BCE |
|---|---|---|---|---|---|
| **Area** | (ha) | 219 | 424 | 756 | 458 |
| **Top Reservoir** | (mSS) | | | | 1890 (E-48) |
| **Net Pay** | (m) | 23.2 | 37.4 | 51.5 | 37.4 |
| **Porosity** | (%) | 21.9 | 23.7 | 25.4 | 23.7 |
| **Sw** | (%) | 42.3 | 39.0 | 35.7 | 39.0 |
| **Pressure** | (kPa) | 20000 | 20000 | 20000 | 20000 |
| **Temp** | ($^{o}$C) | 71 | 71 | 71 | 71 |
| **Gas FVF** | | 188 | 193 | 198 | 193 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.019 | 4.185 | 8.564 | 4.777 |
| **OOIP** | (E6M3) | | | | |

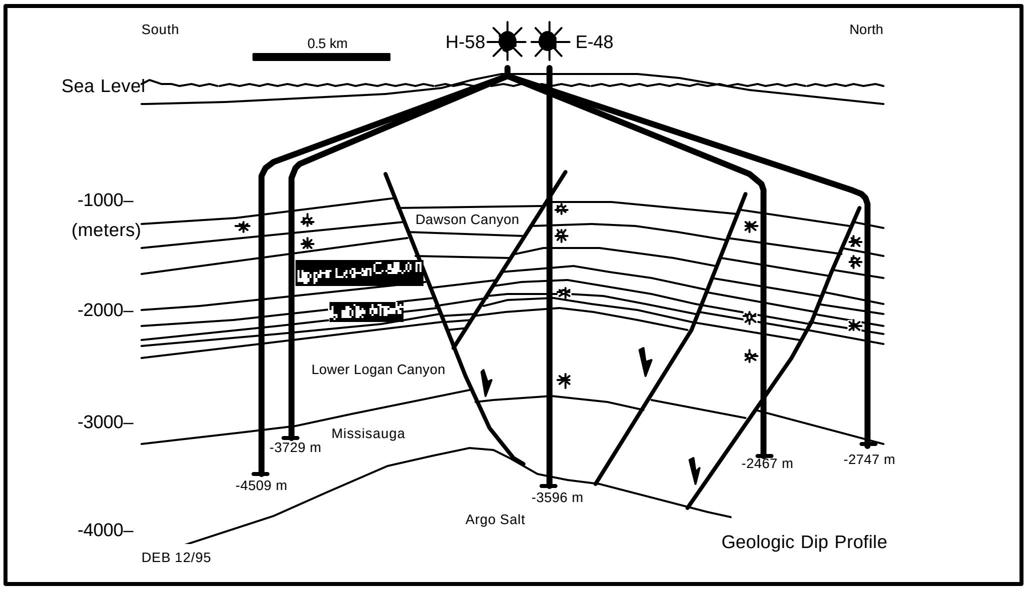
## *Depletion Scenario and Recoverable Resource*

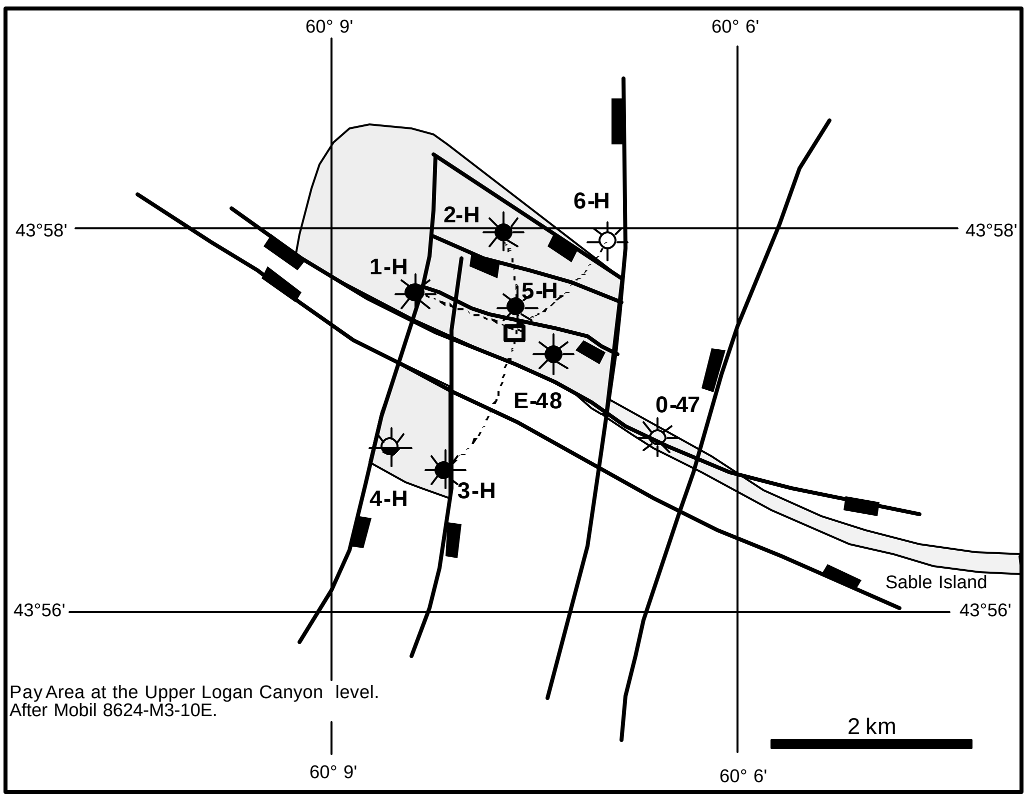
Recoverable resource for the gas accumulation of this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case, respectively. Recovery factors of 20%, 30% and 40% for the oil accumulations are similarly assigned. The Best Current Estimate is based on a factor of 65% for the gas and 30% for the oil accumulations. The Condensate-Gas Ratio is estimated at 280 M3/E6M3 of recoverable gas, and the Gas-Oil Ratio of the oil column at 81 M3/M3 based on observations from the DSTs.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 3.601 (127) | 6.749 (238) | 12.653 (447) | 7.616 (269) |
| **Condensate** | (E6M3) | 1.008 (6.34) | 1.890 (11.9) | 3.543 (22.3) | 2.132 (13.4) |
| **Oil** | (E6M3) | 8.513 (53.6) | 14.75 (92.8) | 25.55 (161) | 16.19 (102) |
| **Assoc. Gas** | (E9M3) | 0.690(24) | 1.195 (42) | 2.069 (73) | 1.311 (46) |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | 0.2 | 0.3 | 0.4 | 0.3 |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 1.801 (64) | 4.387 (155) | 10.122 (357) | 4.950 (175) |
| **Condensate** | (E6M3) | 0.504 (3.17) | 1.228 (7.73) | 2.834 (17.8) | 1.386 (8.72) |
| **Oil** | (E6M3) | 1.703 (10.7) | 4.424 (27.8) | 10.218(64.3) | 4.856 (30.5) |
| **Assoc. Gas** | (E9M3) | 0.138 (5) | 0.358 (13) | 0.828 (29) | 0.393 (14) |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# West Sable

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# West Venture C-62 - Significant Discovery

## Overview

The West Venture C-62 gas field is located 2.5 km due east of the eastern end of Sable Island. The field was discovered in 1985 and its current assessment is based on the discovery well. The field is within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex.

### Discovery Well:

| | |
|---|---|
| Well: | Mobil et al West Venture C-62 |
| Spud: | 84-05-19 |
| R.R.: | 85-03-23 |
| T.D.: | 5522 m |

The discovery well is located in 16 m of water at approximately 44°01'02.78"N latitude, 59°40'00.93"W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a prospect just west of Venture, and bounded on the north by extension of the same down-to-the-basin fault that bounds the northern limits of Venture.

### Additional Wells:

No delineation drilling conducted.

### Significant Tests:

No tests were conducted on potential gas-bering intervals (eg. #8 sand) below the #5 sand due to hole conditons and presence of a fishing tool left in the hole.

| **Well** | **Test #** | **Depth (M)** | **Interval** | **Gas (E3M3/D)** | **Oil/Cond (M3/D)** | **Water (M3/D)** |
|---|---|---|---|---|---|---|
| C-62 | DST#1 | 5016-5027 | Missisauga | 0.6 | | 76 |
| C-62 | DST#2 | 4923-4930 | Missisauga | 16 | | 105 |
| C-62 | DST#3 | 4741-4743 | Missisauga | 949 | 25 | 6 |
| C-62 | DST#4 | 4591-4601 | Missisauga | Rec Water Cushion | | |

## Geological/Geophysical Overview

The West Venture gas fields are located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. With their proximity to sediment source, basin hinge-line position and resultant rapid subsidence, the progradational strata deposited at West Venture consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Late Jurassic Mic Mac and Early Cretaceous Missisauga formations.

### Structure

The West Venture structures are a pair of small, slightly elongate rollover anticlinal features bound on the north by a shared major down-to-the-basin listric growth fault. The two isolated structural closures are present at each end of the feature (West Venture N-91 to the west and West Venture C-62 to the east) and are separated by a structurally lower faulted saddle. Two en echelon and separate faults, synthetic and subparallel to the main northeast-southwest trending growth fault, define the southern boundaries of the closures. Like the adjacent larger Venture field to the east, the West Venture structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic age salts of the Argo formation. This combination resulted in the formation of significant overpressure conditions which are manifested in the reservoir sands.

Seismic profiles indicate that the field's closures are separate and distinct, and are of variable relief: 65 m for the upper C sand to 330 m for the deep #13 sand in the C-62 closure. Although several regional seismic markers are prominent in the area, internal field reflections within the adjacent Venture field can be projected into and related to equivalent zones in the West Venture fields and thus define their structural expressions. These reflections are either sand sequences capped by limey intervals or isolated limestones and include the #3a Sand, #6 Limestone and #9 Limestone. Beyond the #9 Limestone, seismic attributes of lower reflectors such as the 'Y' Marker tend to lose character westwards and so reduce confidence in defining the structural nature of deeper reservoir intervals.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by the thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

At West Venture, the reservoir sands are lateral equivalents to those recognized at the larger Venture gas field to the east, and are located stratigraphically at the top of Late Jurassic Mic Mac formation, and the Lower member of the Early Cretaceous Missisauga formation. Two exploratory wells have been drilled at West Venture, one each on the respective closures. As opposed to Venture, only a few of the sands have gas pays. Although both wells recovered a number of cores and were extensively logged, most of the reservoir zones remain untested due to a blow-out at N-91 (from the #13 Sand) and poor hole conditions at C-62 (no drillstem tests below the #5 Sand).

All reservoir sands at West Venture are in overpressure conditions. The preservation/enhancement of porosity and permeability at depth in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size. The correlation of the reservoir sands with those at Venture to the east proves that they have excellent lateral continuity along strike, though they tend to thin and have poorer reservoir characteristics toward the field's southern margin.

The reservoirs discovered at West Venture 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 which increase over time. Although penetrated by two wells, the data shows that the reservoir characteristics of these coarsening upward sands (e.g., Sand #13 at N-91) are fair to good, with effective porosities ranging from 8-15%.

The overlying Missisauga section generally reflects the continuing progradation of fluvial sand bodies though showing the increasing influence of both current and tidal energies (e.g., Sands 3c, 4, 5 & 8 in C-62 , and Sand 4 in N-91). 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 with porosities averaging 23% and good permeabilities.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the West Venture C-62 well was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined, for the West Venture C-62 field, using the cutoffs tabled below. Effective porosities were calculated using, the neutron - density crossplotting technique. Water saturations were determined, from the log data, using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | Good |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

The areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The minimum and most likely area was based on the structure being half full, and possible area extending to structural spill point. Minimum and most-likely net pay inputs were limited to the tested intervals within the discovery wells. Possible net pay included an untested sand that appears to be water bearing on logs. Porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **All Zones** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 560 | 609 | 687 | 617 |
| **Top Reservoir** | (mSS) | | | | 4465 (C-62) |
| **Net Pay** | (m) | 5.3 | 6.5 | 8.4 | 6.7 |
| **Porosity** | (%) | 23 | 23 | 23 | 23 |
| **Sw** | (%) | 40 | 40 | 40 | 40 |
| **Pressure** | (kPa) | 81000 | 81000 | 81000 | 81000 |
| **Temp** | ($^{o}$C) | 131 | 131 | 131 | 131 |
| **Gas FVF** | | 363 | 373 | 383 | 373 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.632 | 2.048 | 2.701 | 2.116 |
| **OOIP** | (E6M3) | | | | |

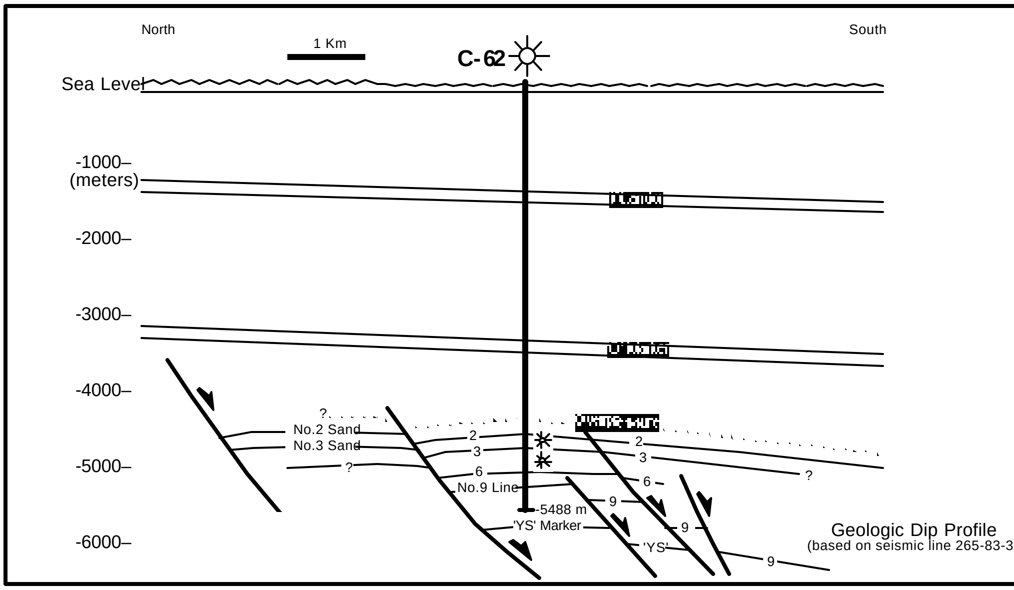
## *Depletion Scenario and Recoverable Resource*

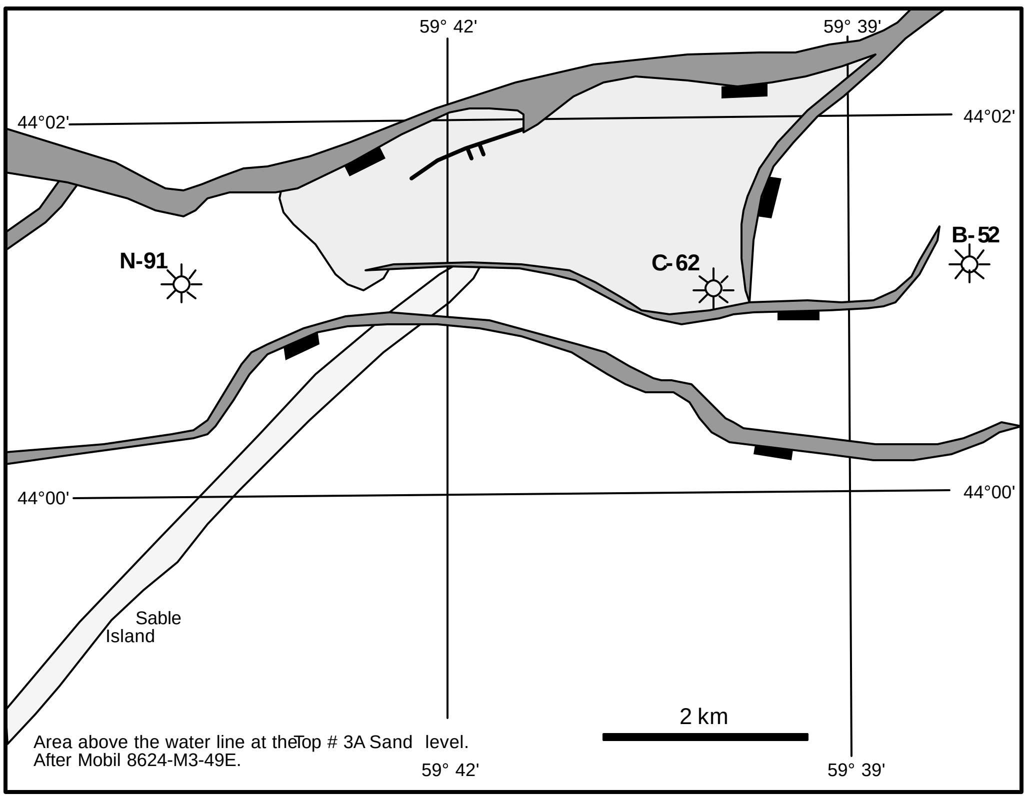
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio is estimated at 26 M3/E6M3 of recoverable gas and is based on DST observations.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 1.632 (58) | 2.048 (72) | 2.701 (95) | 2.116 (75) |
| **Condensate** | (E6M3) | 0.042 (0.27) | 0.053 (0.33) | 0.070 (0.44) | 0.055 (0.35) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 0.816 (29) | 1.331 (47) | 2.161 (76) | 1.375 (49) |
| **Condensate** | (E6M3) | 0.021 (0.13) | 0.035 (0.22) | 0.056 (0.35) | 0.036 (0.22) |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# West Venture C-62

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# West Venture N-91 - Significant Discovery

## *Overview*

The West Venture N-91 gas field is located 2.5 km due west of the eastern end of Sable Island. The field was discovered in 1985 and its current assessment is based on the discovery well. The field is within the Mesozoic age Sable Subbasin near the center of the Sable Delta complex

### Discovery Well:

| | |
|---|---|
| Well: | Mobil et al West Venture N-91 |
| Spud: | 84-04-19 |
| R.R.: | 85-07-07 |
| T.D.: | 5547 m |

The discovery well is located in 38 m of water at approximately 44°00’45.82”N latitude, 59°44’27.36”W longitude. It was drilled to test for the presence of hydrocarbons in the sands of a prospect bound on the north and south by down-to-the-basin faults.

### Additional Wells:

No delineation drilling conducted. Two relief wells were abandoned prior to intersecting target areas.

| | |
|---|---|
| Well: | Mobil et al West Venture B-92 (44°01’08.513”N, 59°43’59.678”W) |
| | Mobil et al West Venture N-01 (44°00’58.797”N, 59°45’51.689”W) |

### Significant Tests:

The Discovery Well experienced an underground blowout before testing could be commenced, and as a result no tests were run. The B-92 relief well had to be abandoned shortly after being spudded because of escaping gas at N-91 entering a shallow sand package, and migrating to the B-92 location. The N-01 relief well was abandoned before intersecting its target area when a “top kill” program was successful on N-91 itself. Although no tests were conducted on N-91, the blowout was deemed sufficient to justify Significant Discovery status.

## Geological/Geophysical Overview

The West Venture gas fields are located in the Mesozoic age Sable Subbasin near the center of the Sable Delta complex, which developed during the Late Jurassic to Early Cretaceous periods. With their proximity to sediment source, basin hinge-line position and resultant rapid subsidence, the progradational strata deposited at West Venture consist of a sand dominated, thick sequence of mixed energy deltaic and strandplain fluvial and nearshore marine deposits. These sediments record episodic delta advances punctuated by marine incursions. The reservoir sands are located in the Late Jurassic Mic Mac and Early Cretaceous Missisauga formations.

### Structure

The West Venture structures are a pair of small, slightly elongate rollover anticlinal features bound on the north by a shared major down-to-the-basin listric growth fault. The two isolated structural closures are present at each end of the feature (West Venture N-91 to the west and West Venture C-62 to the east) and are separated by a structurally lower faulted saddle. Two en echelon and separate faults, synthetic and subparallel to the main northeast-southwest trending growth fault, define the southern boundaries of the closures. Like the adjacent larger Venture field to the east, the West Venture structure was formed through a combination of sediment loading/subsidence and syndepositional movement along a major growth fault which likely soles into deep Late Triassic age salts of the Argo formation. This combination resulted in the formation of significant overpressure conditions which are manifested in the reservoir sands.

Seismic profiles indicates that the field's closures are separate and distinct, and are of variable relief: 55 m for the C sand to 300 m for the deep #13 sand in the N-97 closure. Although several regional seismic markers are prominent in the area, internal field reflections within the adjacent Venture field can be projected into and related to equivalent zones in the West Venture fields and thus define their structural expressions. These reflections are either sand sequences capped by limey intervals or isolated limestones and include the #3a Sand, #6 Limestone and #9 Limestone. Beyond the #9 Limestone, seismic attributes of lower reflectors such as the 'Y' Marker tend to lose character westwards and so reduce confidence in defining the structural nature of deeper reservoir intervals.

### Stratigraphy

The Sable Subbasin was the major locus for clastic sedimentation on the central part of the Scotian Shelf from the Middle Jurassic to the Tertiary. Starting in the Late Jurassic, regional uplift to the west resulted in progradation and establishment of the mixed energy (current and tidal) Sable Delta complex in the Sable Island area. Sediments of the older Mic Mac formation record the first phase of delta progradation and are represented by distributary channel and delta front fluvial sands cyclically interfingering with prodelta and shelf marine shales.

Increased sediment influx and concurrent delta advance at the beginning of the Cretaceous are represented by the thick deltaic and strandplain succession of the Missisauga formation. Coeval equivalents to the Mic Mac and Missisauga sequences are the deeper water marine shales of the Verrill Canyon formation. Deltaic sedimentation ceased following a late Early Cretaceous major marine transgression which is manifested by shales of the overlying Naskapi member, Logan Canyon formation.

### Reservoir Description

At West Venture, the reservoir sands are lateral equivalents to those recognized at the larger Venture gas field to the east, and are located stratigraphically at the top of Late Jurassic Mic Mac formation, and the Lower member of the Early Cretaceous Missisauga formation. Two exploratory wells have been drilled at West Venture, one each on the respective closures. As opposed to Venture, only a few of the sands have gas pays. Although both wells recovered a number of cores and were extensively logged, most of the reservoir zones remain untested due to a blow-out at N-91 (from the #13 Sand) and poor hole conditions at C-62 (no drillstem tests below the #5 Sand).

All reservoir sands at West Venture are in overpressure conditions. The preservation/enhancement of porosity and permeability at depth in overpressure conditions is an important feature of these reservoirs and is due to the ubiquitous presence of early authigenic chlorite grain coatings, dissolution of lithic fragments and sand grain size. The correlation of the reservoir sands with those at Venture to the east proves that they have excellent lateral continuity along strike, though they tend to thin and have poorer reservoir characteristics toward the field's southern margin.

The reservoirs discovered at West Venture 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 which increase over time. Although penetrated by two wells, the data shows that the reservoir characteristics of these coarsening upward sands (e.g., Sand #13 at N-91) are fair to good, with effective porosities ranging from 8-15%.

The overlying Missisauga section generally reflects the continuing progradation of fluvial sand bodies though showing the increasing influence of both current and tidal energies (e.g., Sands 3c, 4, 5 & 8 in C-62 , and Sand 4 in N-91). 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 with porosities averaging 23%, and good permeabilities.

## *Petrophysical Overview*

A petrophysical evaluation[1] of the West Venture N-91 well was completed. The results of this evaluation for each reservoir in the field are tabled below under the heading Original Hydrocarbons in Place.

Net pay was defined for the West Venture N-91 field using the cutoffs tabled below. Effective porosities were calculated using the neutron - density crossplotting technique. Water saturations were determined from the log data using the Simandoux water saturation equation. Shale volume was calculated from the gamma ray log.

| **Basic Parameters:** | | |
|---|---|---|
| **Water Saturation Cutoff** | (%) | 50 |
| **Porosity Cutoff** | (%) | 10 |
| **Volume of Shale Cutoff** | (%) | 35 |
| **Permeability Horizontal** | (mD) | Good |

[1] Petrophysical evaluation conducted by the Canada Oil and Gas Lands Administration, Department of Energy, Mines and Resources.

## Original Hydrocarbons in Place

The areal extent of the reservoirs was determined to be the primary uncertain variable in the determination of OGIP. The minimum and most likely area was based on the structure being filled with gas down to the base of porosity in the discovery well in each sand. Possible area extended to structural spill point. In the absence of additional well control, net pay, porosity, and water saturation were held constant at the well observed values within the probabilistic calculations. Formation pressures were determined from DST and RFT pressure measurements. Formation temperatures were obtained, from DST temperature measurements or from available temperature gradient graphs.

| **Sand 4** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 465 | 606 | 755 | 608 |
| **Top Reservoir** | (mSS) | | | | 4690 (N-91) |
| **Net Pay** | (m) | 5 | 5 | 5 | 5 |
| **Porosity** | (%) | 19 | 19 | 19 | 19 |
| **Sw** | (%) | 37 | 37 | 37 | 37 |
| **Pressure** | (kPa) | 82000 | 82000 | 82000 | 82000 |
| **Temp** | ($^oC$) | 137 | 137 | 137 | 137 |
| **Gas FVF** | | 362 | 372 | 382 | 372 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 1.028 | 1.352 | 1.682 | 1.354 |
| **OOIP** | (E6M3) | | | | |

| **Sand 12** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **Area** | (ha) | 465 | 606 | 755 | 608 |
| **Top Reservoir** | (mSS) | | | | 5295 (N-91) |
| **Net Pay** | (m) | 10 | 10 | 10 | 10 |
| **Porosity** | (%) | 20 | 20 | 20 | 20 |
| **Sw** | (%) | 34 | 34 | 34 | 34 |
| **Pressure** | (kPa) | 105000 | 105000 | 105000 | 105000 |
| **Temp** | ($^oC$) | 153 | 153 | 153 | 153 |
| **Gas FVF** | | 389 | 400 | 411 | 400 |
| **Oil Bo** | | | | | |
| **OGIP** | (E9M3) | 2.455 | 3.194 | 3.996 | 3.212 |
| **OOIP** | (E6M3) | | | | |

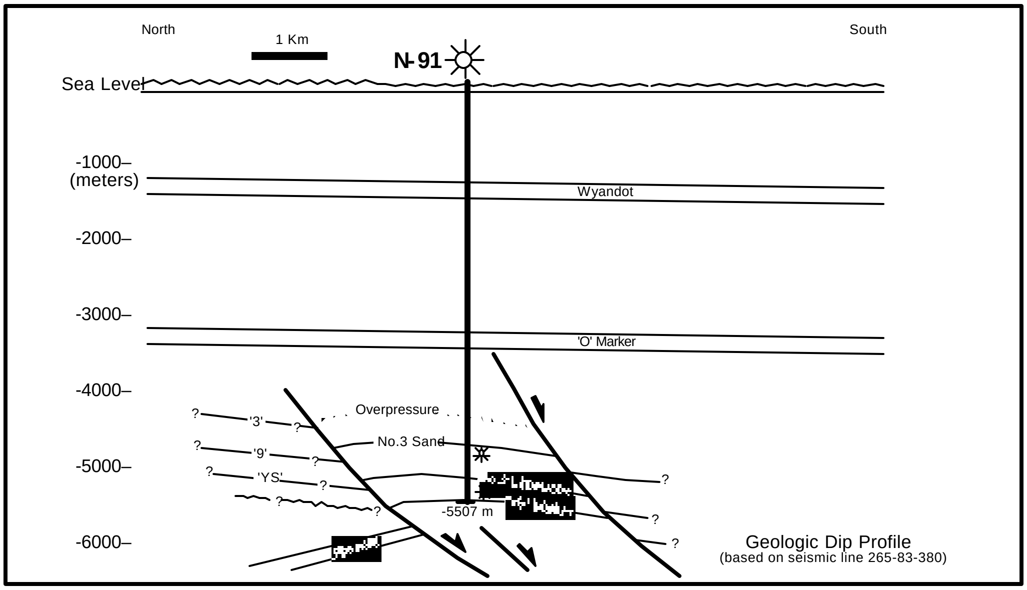
## *Depletion Scenario and Recoverable Resource*

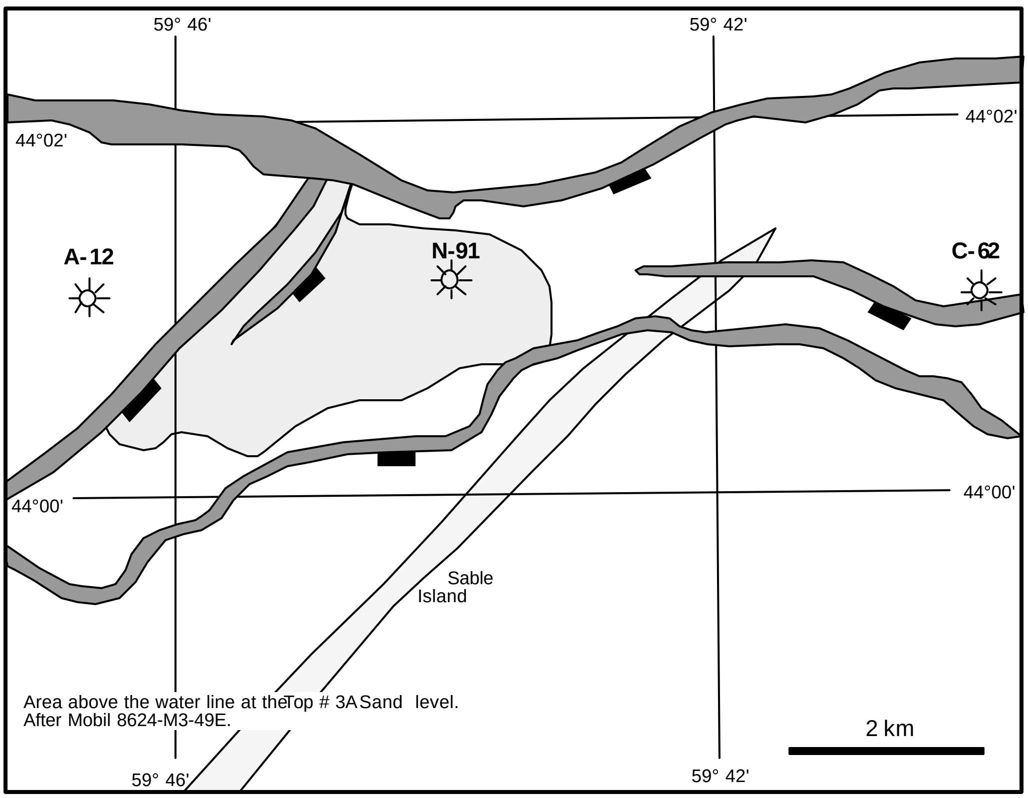
Recoverable resource for this field is currently calculated based on a 50%, 65% and 80% recovery factor for the Low, Medium, and High case respectively. The Best Current Estimate is based on a factor of 65%. The Condensate-Gas Ratio has not been estimated as there has not been any successful testing of this resource.

| **Total Stock Tank Hydrocarbons *** | | **P90/Low** | **P50/Med** | **P10/High** | **Mean/BCE** |
|---|---|---|---|---|---|
| **In Place** | | | | | |
| **Gas** | (E9M3) | 3.585 (127) | 4.495 (159) | 5.635 (199) | 4.566 (161) |
| **Condensate** | (E6M3) | N/A | N/A | N/A | N/A |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |
| **R.F. Gas** | | 0.50 | 0.65 | 0.80 | 0.65 |
| **R.F. Oil** | | | | | |
| **Recoverable Resource** | | | | | |
| **Gas** | (E9M3) | 1.793 (63) | 2.922 (103) | 4.508 (159) | 2.968 (105) |
| **Condensate** | (E6M3) | N/A | N/A | N/A | N/A |
| **Oil** | (E6M3) | | | | |
| **Assoc. Gas** | (E9M3) | | | | |

* Figures in (...) are expressed in Imperial Units (BCF for gas volumes, MMBbl for liquid volumes)

# West Venture N-91

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