RESERVOIR CHARACTERIZATION AND PRODUCIBILITY OF THE JEAN MARIE LIMESTONE, NORTHEAST BRITISH COLUMBIA, CANADA

By

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INTRODUCTION

General Statement

Devonian platform carbonates can be found in sedimentary basins throughout the world and are very prolific hydrocarbons producing reservoirs. However, the stromatoporoid carbonate buildups discussed in this study are not so common. They are found mainly in western Canada and southern Poland. In western Canada, they contain large reserves of natural gas. Some Canadian wells produce in excess of 30 BCF, and total production volumes of 5 to 10 BCF per well are common. Stromatoporoid carbonate reservoirs are very erratically distributed. Porosity is enhanced by dissolution and fracturing; pinpointing areas of high productivity can be very difficult. Reservoirs in the Devonian Jean Marie Member of the Red Knife Formation are productive with as little as 3% porosity water saturation values around 50%. These wells produce very small volumes of water, which indicates most formation water is bound or immovable.

Objectives

This study was initiated by Chesapeake Energy Corporation. The intent was to examine all available data and develop a better understanding of reservoir characteristics of the Jean Marie Member and their relation to productivity. Specific objectives were developed for this investigation, including:

1. Determine the location, orientation, geometry and lateral extent of carbonate buildups within the Jean Marie Member.
2. Delineate areas containing porous, permeable and productive reservoirs.
3. Examine cores to identify biofacies and lithofacies.
4. Determine susceptibility of individual facies to dissolution and fracturing and the impact of dissolution and fracturing on porosity and permeability.
5. Identify major rock constituents and diagenetic components using thin section petrography, and
6. Integrate these data with productivity and deliverability values to determine the general combinations of productive biofacies and lithofacies and diagenetic processes that yield the highest production cumulative volumes of gas.

Location of Study

The area contained within this study is located in the northeast corner of British Columbia, Canada (Figure 1). The study area is situated on the eastern shelf margin of the Devonian Western Canada Sedimentary Basin (Figure 2) and encompasses major portions of the Helmet North and July Lake Fields (Figure 3). Production in these fields is primarily from the Jean Marie Member of the Red Knife Formation. Minor production is reported from several Keg River wells. Most of Jean Marie production is from wells located within the 94 P block. The study is centered mainly within 94 P 10 (Figure 2)

Figure 1. Landform map of Canada and northern U.S. demonstrating the general location of the study area.

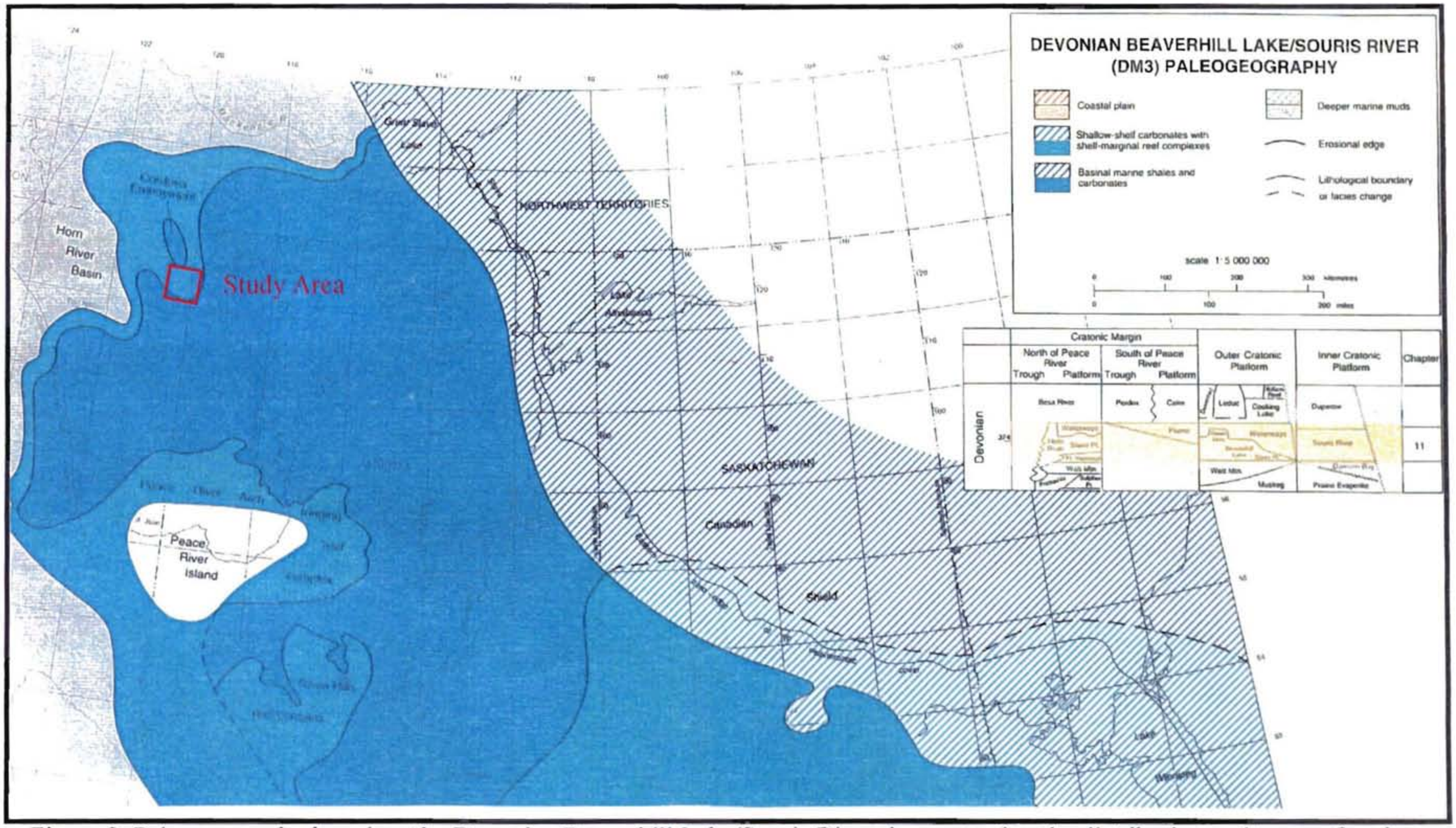


Figure 2. Paleogeography based on the Devonian Beaverhill Lake/Souris River demonstrating the distribution and types of various depositional environments (AGS and CSPG, 1994).

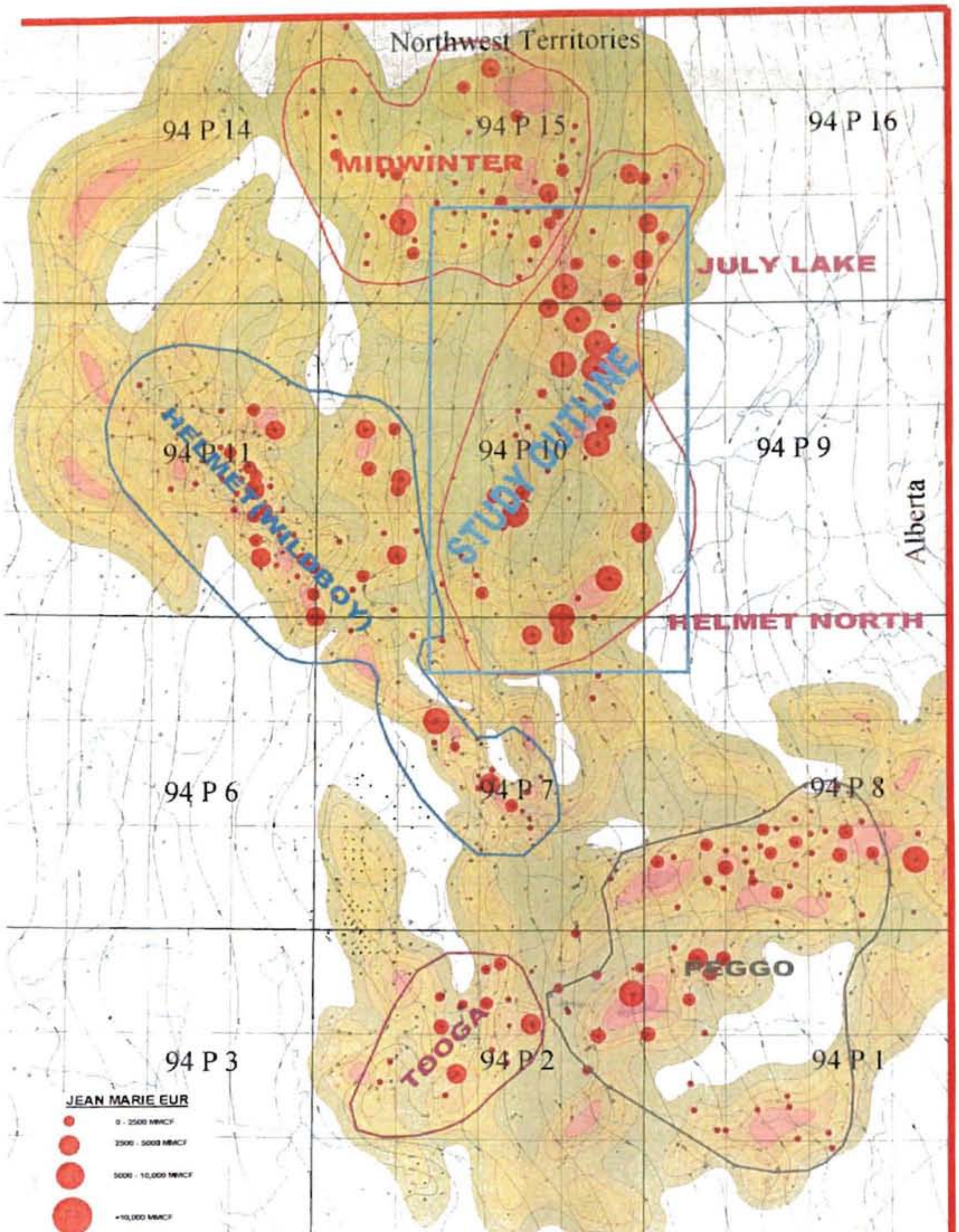


Figure 3. Map illustrating the Jean Marie intra-shelf play and fields. The study area is contained within the blue square. The color filled area represents net pay and the black contours indicate structure. Estimated ultimate recovery (EUR) for wells producing the Jean Marie is represented by the diameters of the red circles.

and includes smaller areas from blocks 7,8,9,15 and 16 of 94 P. The total area involved is roughly 350 square miles.

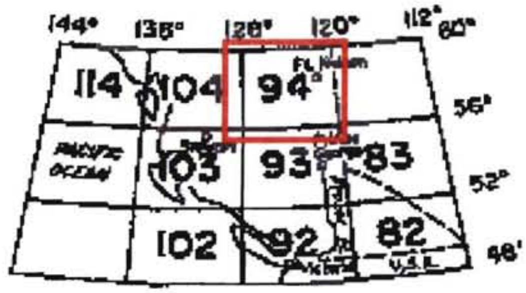
Geological Setting

Jean Marie sediments were deposited on the eastern shelf edge of the Western Canada Sedimentary Basin during a period of shallowing, or marine progradation that was concurrent with extensional tectonics of the Devonian-Mississippian Antler orogeny. Jean Marie represents both intra-shelf bioherms and shelf edge reefs that developed on top of thousands of meters of Ft. Simpson shale. The platform bioherms formed along the margin of the Cordova embayment (Figure 2), which was a small intra-shelf basin formed by differential compaction of the Ft. Simpson Shale. These areas of carbonate deposition mimic structural highs within the deeper Keg River and Slave Point Formations (Munroe et al, 2000). This subtle tectonism is believed to have exerted a greater control over localized Jean Marie deposition than the initiation of the Antler orogeny, which influenced regional water depth.

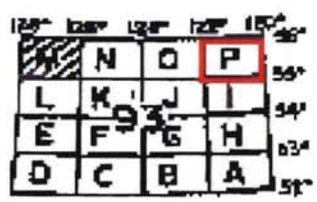
Land Grid

Within the province of British Columbia, three land grids are used. Most of the surveyed areas use the lot system. The township system is used in portions of northeast British Columbia, as well as the Vancouver area. Since much of the unpopulated northeastern region is still un-surveyed, including areas of intense petroleum exploration, the National Topographic System (NTS) or the grid system was implemented.

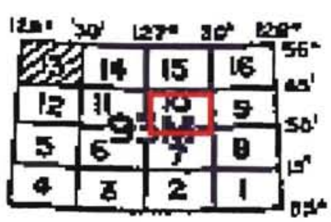
The NTS system uses blocks, which are divided into numbered primary quadrangles of 4 degrees latitude by 8 degrees longitude.



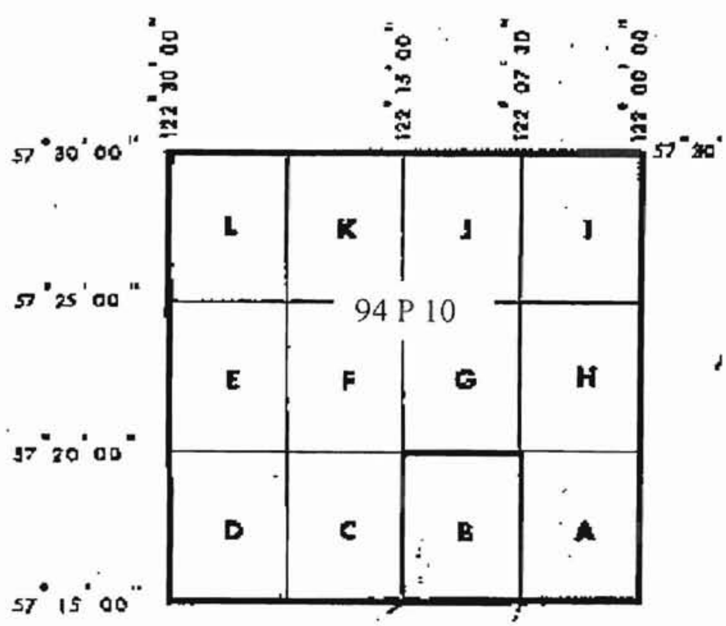
For example, the study area is located in NTS block of 94. Each block is then divided into sixteen units that are lettered A through P. Each of these units measures 1 degree latitude by 2 degrees longitude. The Jean Marie shelf complex resides within 94 P.



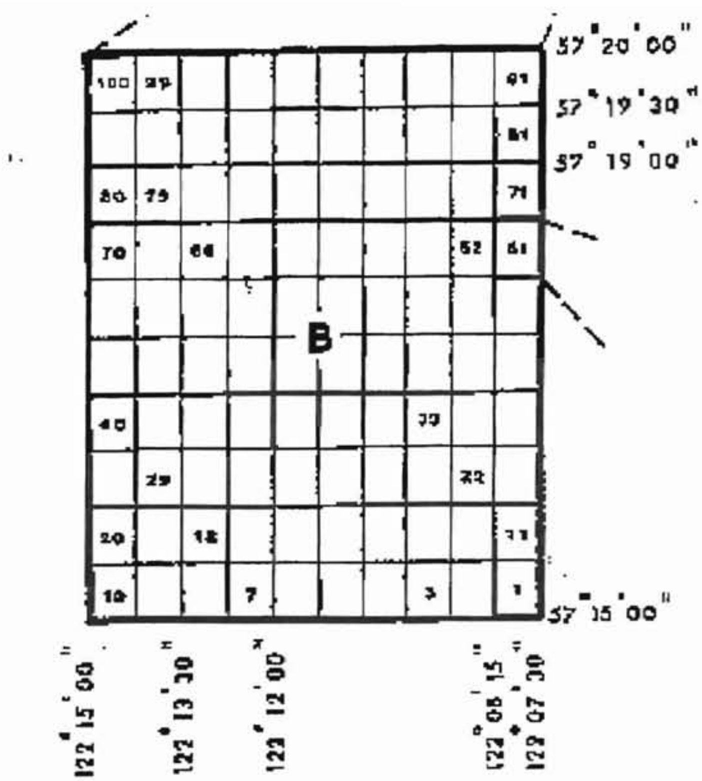
Lettered blocks are subdivided into eight numbered units, numbered 1 through 16. Each of these units is 15 minutes latitude by 30 minutes longitude. Most of the study area is located in 94 P 10.



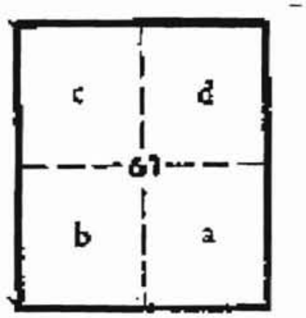
Each numbered unit is divided into twelve subdivisions. They are indicated by upper case letters A through L. Each measures 5 minutes' latitude and 7.5 minutes longitude. This block designation is the last letter of the legal description.



The lettered block is then divided into 100 units beginning with the southeastern most unit and ending with the northwestern unit. These are 30 seconds latitude by 45 seconds longitude.



These blocks are subdivided into four units shown by lower case letters beginning with "a" in the southeast and ending with a "d" in the northeast. These blocks are 15 seconds latitude by 22.5 minutes longitude.



For example, the largest gas producing well within the study area is located at b-66-I/94 P 10. The portion of the description located in front of the backslash designates the smallest unit first and the largest last. The description following the backslash begins with the largest unit (94 block) and ends with the smaller 10 block.

Methodology

The primary purpose of this study is to examine the Jean Marie Limestone, and correlate rock characteristics to well log response and production. To achieve this, an area 14 miles (22.5 km) wide by 25 miles (40.2 km) long was selected for detailed analysis (Figure 3). The area encompasses large portions of the July Lake and the Helmet North fields, which contain many vertical wells that were drilled in the late 1970's to early 1990's. Some of these wells have cumulated nearly 30 BCF gas. Variability in initial production rates and produced volumes suggests that producibility in the July Lake and North Helmet Fields is related to something other than total limestone thickness. Determining the interrelationship between facies, diagenesis and production will help define the factors that control deliverability and cumulative production of Jean Marie reservoirs.

As a result of the inability to effectively explain gas production rate and volume with a single thickness map, a set of maps was generated that illustrate a variety of reservoir parameters calculated from wireline logs. These calculations and equations that were used in mapping are located in each thickness map section. Values for gross interval, net pay, hydrocarbon pore volume (HPV), permeability-feet (K*H), gas saturation, average permeability and average porosity were mapped along with structure. The comparison of these maps to each other and production data demonstrates how subtle changes in these reservoir parameters is greatly reflected in productivity. Conventional wireline logs are somewhat limited in their ability to completely define changes in reservoir characteristics, but overall provide acceptable estimates of the mapped parameters. Values for the estimated ultimate recovery (EUR) were calculated, in

MMCF for wells that produced from the Jean Marie and plotted as red circles on these maps. Four cross sections were constructed, one crossing the study area in the north south direction and three crossing east west.

Core analysis was used to develop a better understanding of the influence of lithofacies, biofacies and diagenesis on reservoir evolution in the Jean Marie. Two trips were made to Charlie Lake, B.C. to the provincial core storage facility. A total of six days were utilized to describe, sample and photograph 20 cores. Core descriptions included determination of biofacies and lithofacies, stratigraphy, fossil assemblages, porosity types, fracture orientation, degree of dolomitization and mineral precipitation. Core features were correlated back to wireline log responses and overall well productivity. The locations of thin sections were selected based on this correlation; 175 thin sections were made from 20 cores. These thin sections were analyzed and described for composition, porosity types and porosity percentage.

Wireline log, core and thin section data were compiled to develop an understanding of the controls and relationship of various reservoir parameters or combinations of parameters to gas production volume and deliverability. Hopefully, these results will improve the ability to predict reservoir quality and producibility.

Previous Investigations

Belyea and McClaren (1962) identified and named the Red Knife Formation and the Jean Marie Member from their outcrop and subsurface work in the southern Northwest Territories. Griffin (1967) defined the transition of the Jean Marie from basinal shales in the west to continuous shelf carbonate to the east. Law (1971) first discussed the potential for oil and gas exploration in the Jean Marie and the first mapping of the unit was done by Torrie (1973). He interpreted the Jean Marie to be the result of vigorous organic growth across a stable platform. Torrie (1973) also determined that the major components were stromatoporoids and algae. He correlated the Jean Marie with the lower part of the Winterburn Group. Klapper and Lane (1985) used conodant biostratigraphy from outcrops in the Northwest Territories to determine that the Jean Marie is equivalent to the upper Fort Simpson and the lower part of the Redknife Formations. Hudema (1991) established that the Jean Marie was deposited during an over-all transgressive episode and formed a north-south trending shelf-edge barrier reef. His findings were based on core and outcrop data and focussed on depositional settings and microfaunal dating. Hudema (1991) used ostracodes to establish that the Jean Marie is equivalent to the Cynthia Member of the Nisku Formation in west–central Alberta.

CHAPTER II

STRATIGRAPHY AND DEPOSITIONAL SETTING

Stratigraphy

The stratigraphic column in the study area includes Cambrian to Cretaceous sedimentary rock units (Figure 4). The basement is made up of granitic and quartzitic Precambrian rocks. These are directly overlain by Pre-Devonian argillaceous sandy and evaporitic deposits that are mainly detritus and weathered products of Cambrian, Ordovician and Silurian age.

Devonian Stratigraphic nomenclature is illustrated in Figure 5. Major stratigraphic units include the Lower-Devonian Chinchaga Formation dolomite and evaporites. The top of the Chinchaga marks the base of the Middle Devonian as well as the base of the Keg River Platform, which according to one hypothesis is responsible for the topographic highs that influenced Jean Marie deposition. The Lower Keg River is a platform carbonate much like the Jean Marie. However, unlike the Jean Marie, the Keg River is nearly completely dolomitized. The upper Keg River consists of mainly reefal material. The Watt Mountain Formation is shale that is relatively thin and pinches out to the northeast. The Slave Point Formation contains both limestones and dolomites of reef and backreef origin. The Slave Point represents the last clean carbonate within the Middle

Devonian. The Otter Park Formation is the basinal equivalent to the Middle Devonian carbonates and represents a transgressive event.

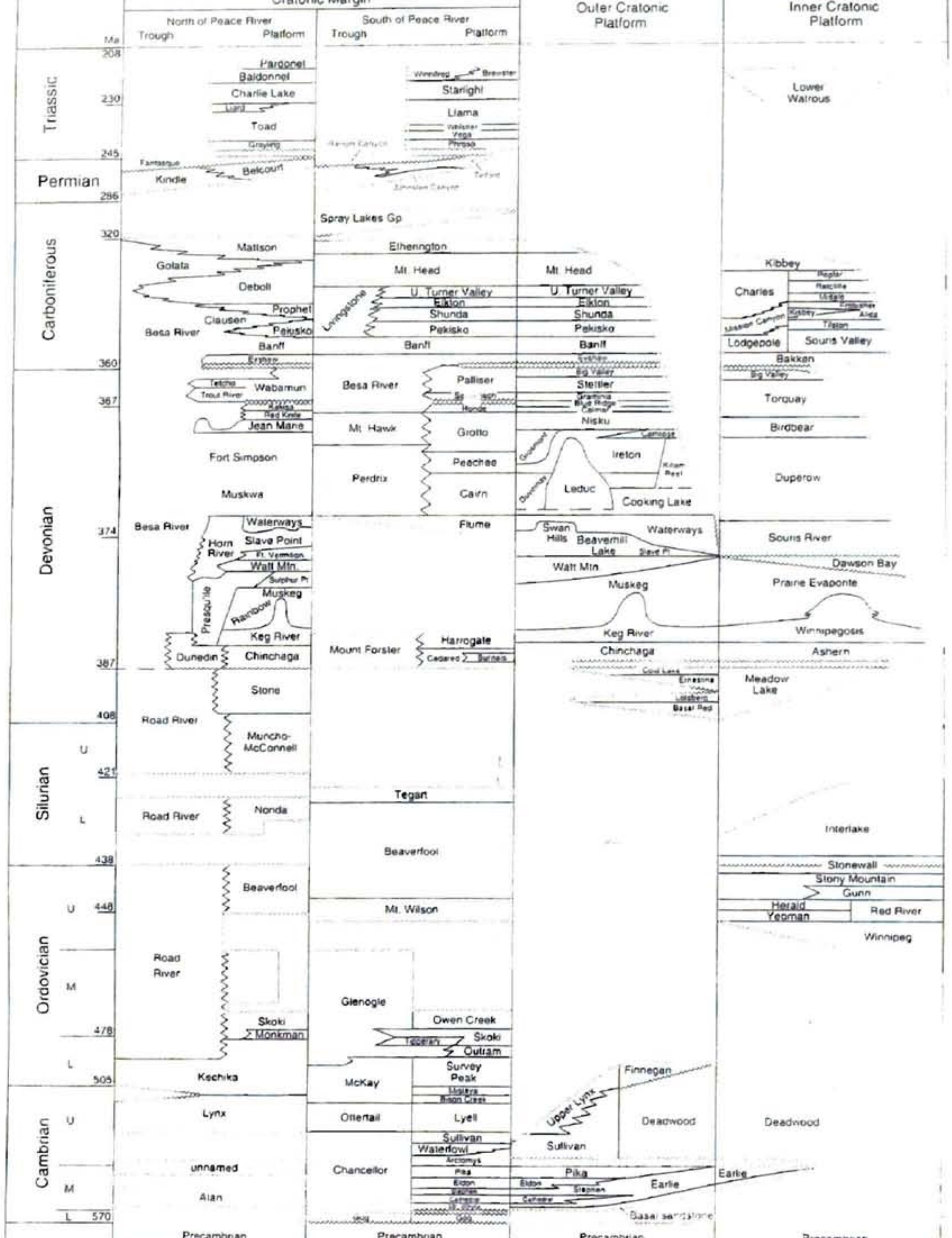


Figure 4. Stratigraphic column representing the entire cratonic platform (CSPG and AGS, 1994).

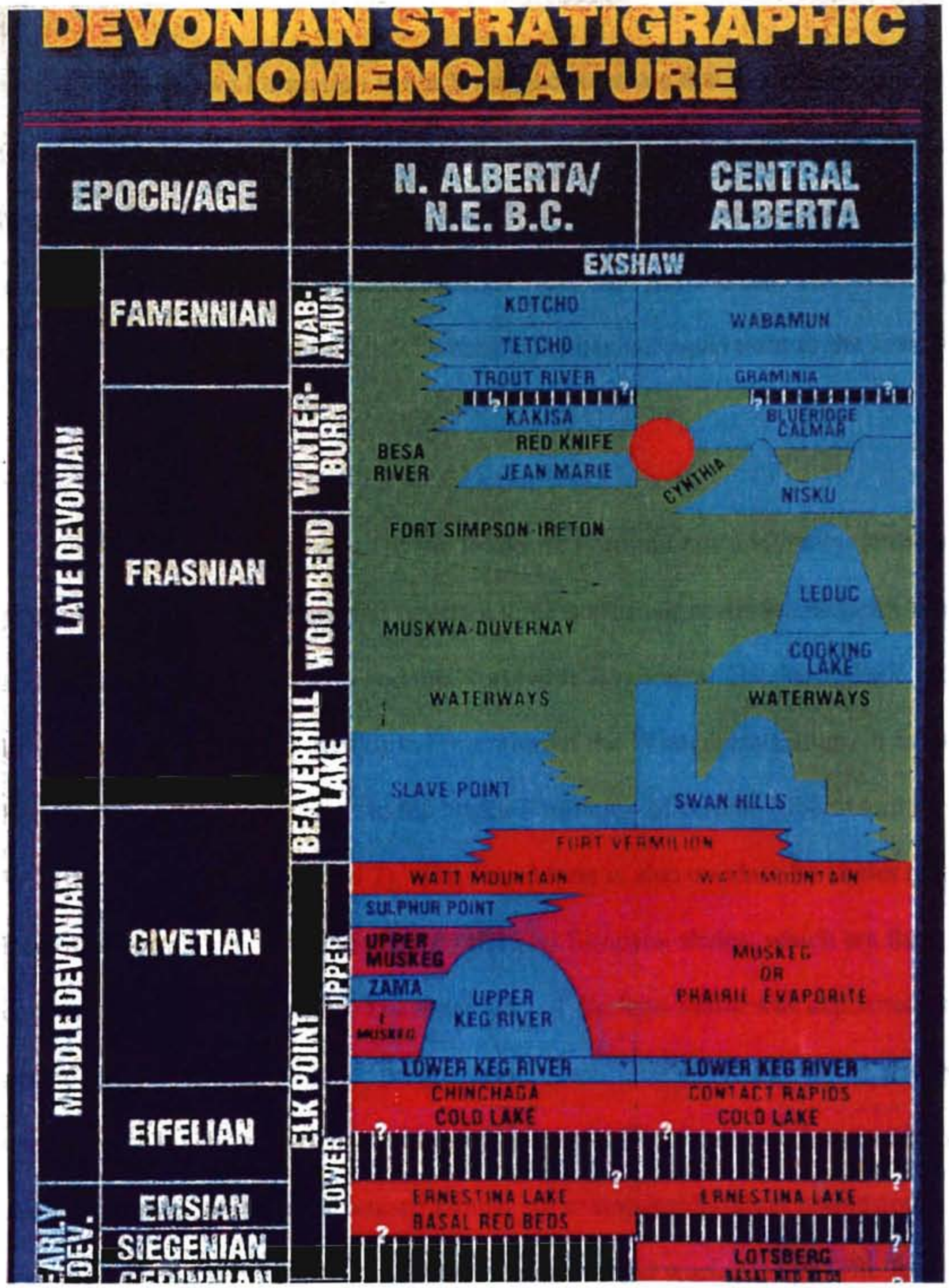


Figure 5. Devonian stratigraphic column (Source unknown, CEC in-house).

The Muskwa Formation is black radioactive shale that overlies the Middle Devonian. It represents the lowest unit of the Upper Devonian section and marks the begining of Frasnian transgressions. The Muskwa is rich in organic carbon (bitumen) and considered an important source rock for Devonian gas and oil. The Muskwa is overlain by the Fort Simpson Shale, which is the basinal equivalent to the Jean Marie.

Deposition

The Jean Marie Member of the Redknife Formation is a laterally continuous platform and shelf carbonate that covers a large portion of northeast British Columbia and adjoining areas of Alberta and the Northwest Territories. The Jean Marie is the lowermost member of the Redknife Formation of the Winterburn Group. It is latest Frasnian in age and equivalent to the Nisku Formation of central Alberta and the Williston Basin (Figures 6 and 7). The Jean Marie is also overlain by shales of the Redknife Formation. It is underlain by the Fort Simpson shales, which are the basinal equivalents to the Jean Marie. The lower part of the Jean Marie was deposited during a period of general shallowing or progradation. Over most of its extent, the Jean Marie consists of a brachiopod-rich, occasionally silty platform limestone overlain by a clean shelf limestone containing scattered tabular stromatoporoidal-algal boundstones and framestones encased in stylolitized lime mudstones and wackestones. The Jean Marie is predominantly limestone with some dolostone. It was deposited in a shallow marine, moderate energy environment. To the west, roughly paralleling the 122nd meridian, the Jean Marie terminates in a shelf edge build-up, and shales out into a thick sequence of

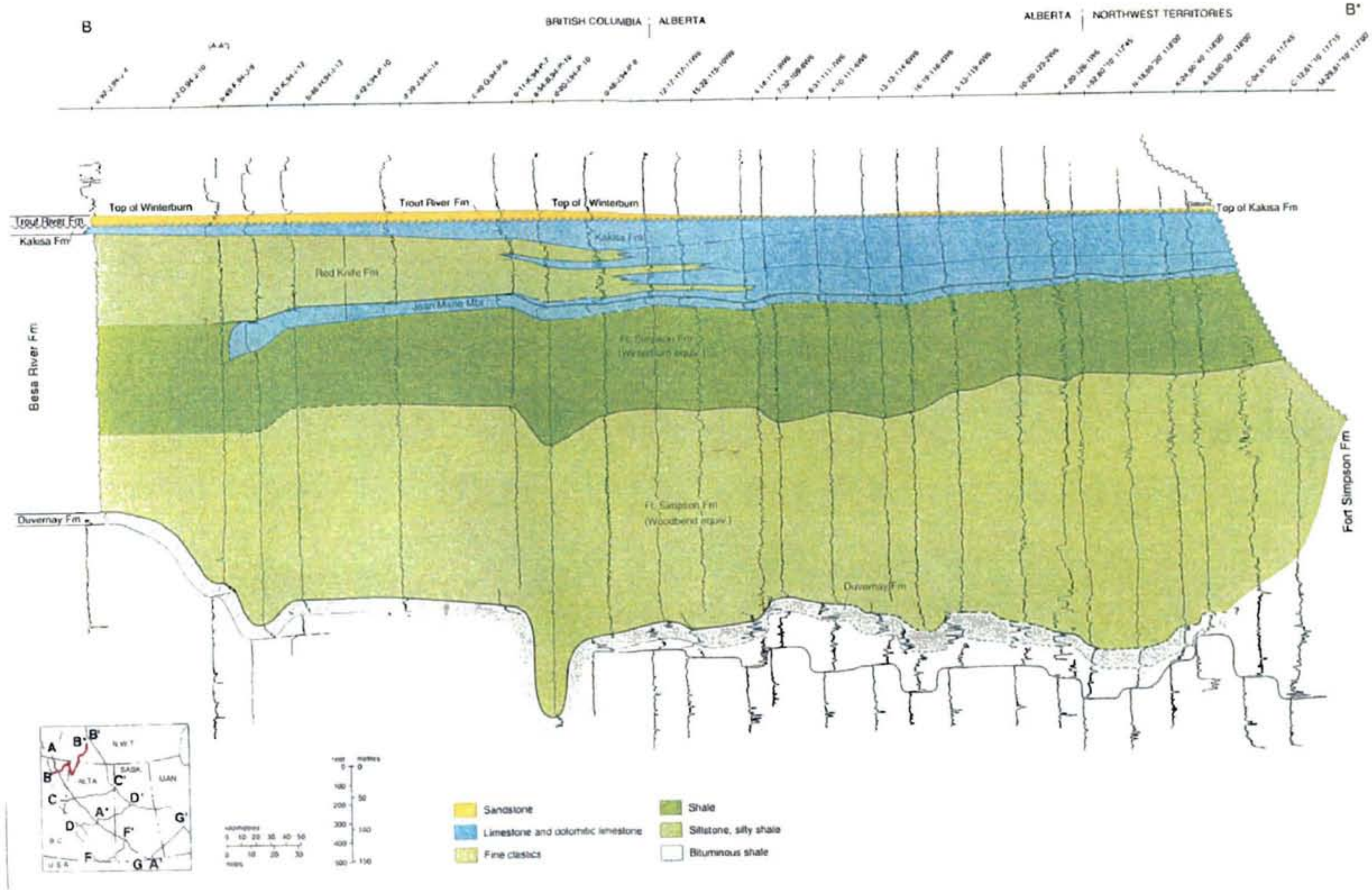


Figure 6. Regional cross section B-B', Woodbend and Winterburn groups. Northeast British Columbia, northern Alberta and southern Northwest Territories (CSPG and AGS, 1994).

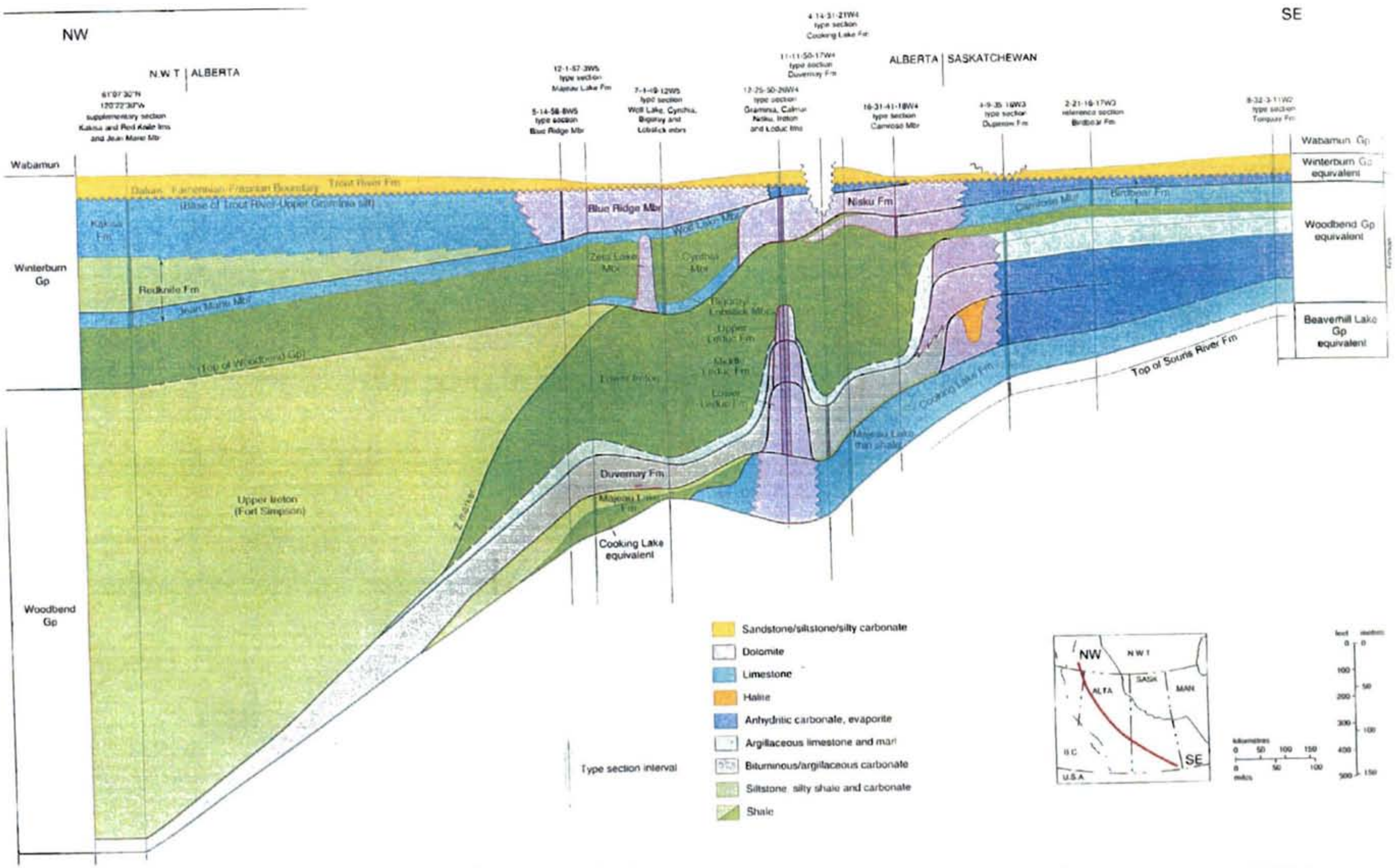


Figure 7. Northwest to southeast cross section demonstrating the sub-divisions of Woodbend and Winterburn groups (CSPG and AGS, 1994).

undifferentiated Fort Simpson/Redknife shales. To the north, the Jean Marie or its equivalent outcrops along the Poplar River in the Northwest Territories. The Jean Marie extends south and east to the Peace River Arch where it thins. To the south of the Peace River Arch, the Jean Marie is equivalent to the Nisku (CSPG and AGS, 1994). Jean Marie intra-shelf mound thicknesses within the study area range from around 9 m to greater than 20 m. Thicker deposits are interpreted to represent areas of shoaling, which promoted the build-up of stromatoporoidal/algal biostromes (Hamilton,et al, 1995). Stromatoporoids are an extinct group of large benthic mound building organisms common in the Devonian of Western Canada and southern Poland. Several different types of stromatoporoids and corals are present in the Jean Marie (Figure 8). *Renalcis* is a very important algal component of the Jean Marie, and plays an important role in porosity development since it is commonly leached. Jean Marie gas pools are proximal to the Cordova embayment, which is interpreted as a small intra-shelf basin that was created due to compaction of shales between Keg River highs.

Jean Marie deposition was terminated by continued marine transgression and deposition of Red Knife shales (Hudema, 1991). Wendte (1994) divided the Jean Marie into four upward-shoaling cycles. The lowermost cycle (cycle 1) consists of widespread, open-marine micritic carbonates deposited along a carbonate ramp. Succeeding cycles either shoal up into platey stromatoporoid-*renalcis* patch reefs or into surrounding inter-reef facies. These reefs more closely resemble Carboniferous age phylloid-algal mounds than the typical Devonian Givetian and Frasnian age buildups (Wendte, 1994). Reef to off-reef relief generally increased during cycles 2 through 4 as a result of differential buildup on the reefs and inter-reef areas (Wendte (1994). The reefs were subsequently

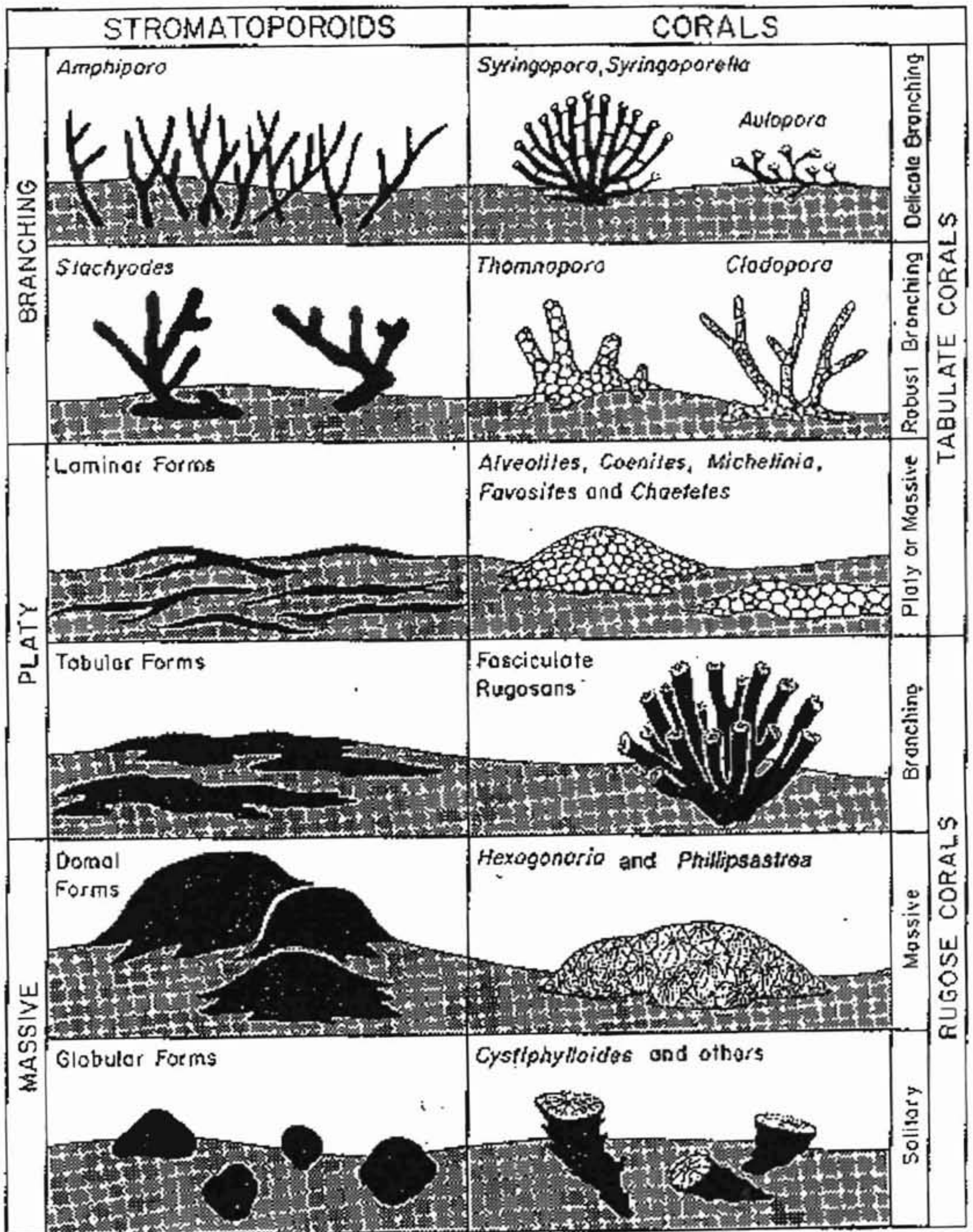


Figure 8. Diagram illustrating the various types of corals and stromatoporoids found within the Jean Marie (Source unknown, CEC in-house).

drowned and covered by mud during the transgression that formed the upper part of the Redknife Formation. Optimum reservoir targets correspond to shoals within many isolated platy stromatoporoid/renalcis reefs. Porosity is mainly of leached secondary origin, while fractures of probable tectonic origin provided permeability. In the literature the Jean Marie carbonate buildups in the study area have been described as patch reefs, mounds, biostromes, shoals and buildups. Buildup was chosen as the generic term for use in this thesis.

Facies

Biofacies and the resultant lithofacies are the most important controls of Jean Marie productivity. Facies analysis is essential in developing an understanding of the genesis of porosity and permeability and predicting the lateral extent of reservoir development. The Jean Marie can be categorized based on distinct allochem assemblages. depositional systems and depositional environments. Due to the inconsistent nature and lack of significant natural depositional breaks within the Jean Marie, creating a greater number of biofacies divisions would make the boundaries unclear and less defined. Therefore, the Jean Marie was divided into four general lithofacies groups, consisting of the Marine Shelf /Amphipora Shoal, Shallow Stromatoporoid Bank, Deep Stromatoporoid Bank and Normal Marine Shelf facies.

Normal Marine Shelf Facies

The Normal Marine Shelf (NMS) lithofacies is made up of sparse nodular-bedded mudstone, skeletal wakestones and rare skeletal packstone that commonly contains brachiopods at the base (Figure 9 and 10). Bed thickness typically decreases with depth. It contains sparse to rare stromatoporoids, crinoids and corals. NMS lithofacies contains various amounts of ostracodes, gastropods, foramanifera and oncolites. Burrows are rare. As a result of its mud rich nature, porosity is minimal in this non-reservoir facies. NMS lithofacies is the basal unit of the Jean Marie. However it is also found throughout, perhaps indicating small transgressive events. NMS is interpreted to have been deposited in a mud-rich, level-bottom shelf floor with normal marine salinity and circulation at subtidal depths ranging from 5 to 15 meters. Fracturing is less common in the normal marine shelf facies than the others, indicating that the mud-dominated rocks are less brittle than those containing larger amounts skeletal material.

Deep Stromatoporoid Bank Facies

The Deep Stromatoporoid Bank (DSB) biofacies is dominated by in situ tabular and laminar stromatoporoids (Figures 11 and 12). These are usually floatstones, wakestones and boundstones containing thamnopora, solitary and rugose corals with no *renalcis*. Common brachiopods, and sparse gastropods, crinoids, foramanifera, ostracodes and bivalves are present. The DSB biofacies was deposited in deeper, low energy water. The DSB is believed to have been deposited in well-circulated, near normal marine, subtidal conditions at depths of 10 to 15 meters. Intercrystalline, microvugular and moldic porosity are common, making this a very productive reservoir facies. The DSB biofacies is present in all but the a-20-H/ 94 P 10, which did not produce. The d-37-I/ 94 P 10, which is dominated by this facies and contains the shallow stromatoporoid bank and the marine shelf/amphipora shoal facies, has cumulated17 BCF of gas. DSB is the only reservoir facies represented in the d-53-C/ 94 P 10, which only cumulated 0.1 BCF. The d-53-C contains little evidence of dissolution and sparse fractures. Typically, fracturing is common in this facies; vuggy porosity is the predominant type with a lesser amount of intercrystalline and microvugular porosity.

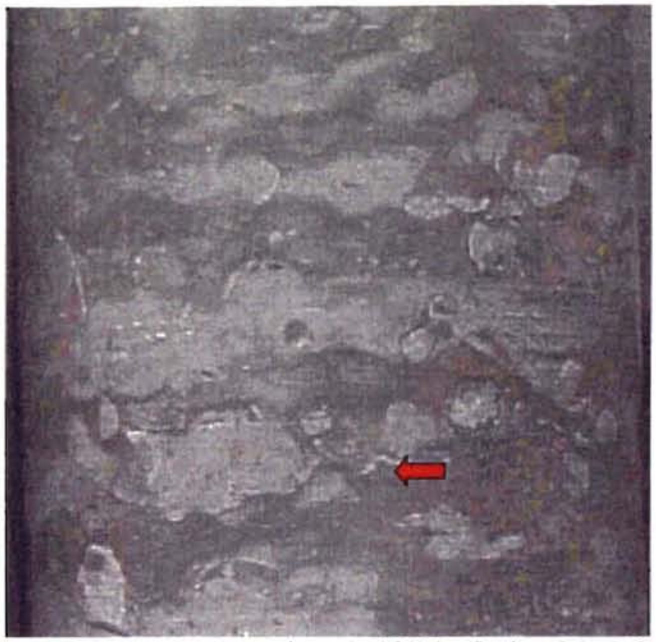


Figure 9. Core photo of the normal marine shelf lithofacies. Nodular bedded limestone within lime mud matrix, abundant brachiopod shells (red). CZAR d-53-C/94 P 10, depth 1184.4 m.

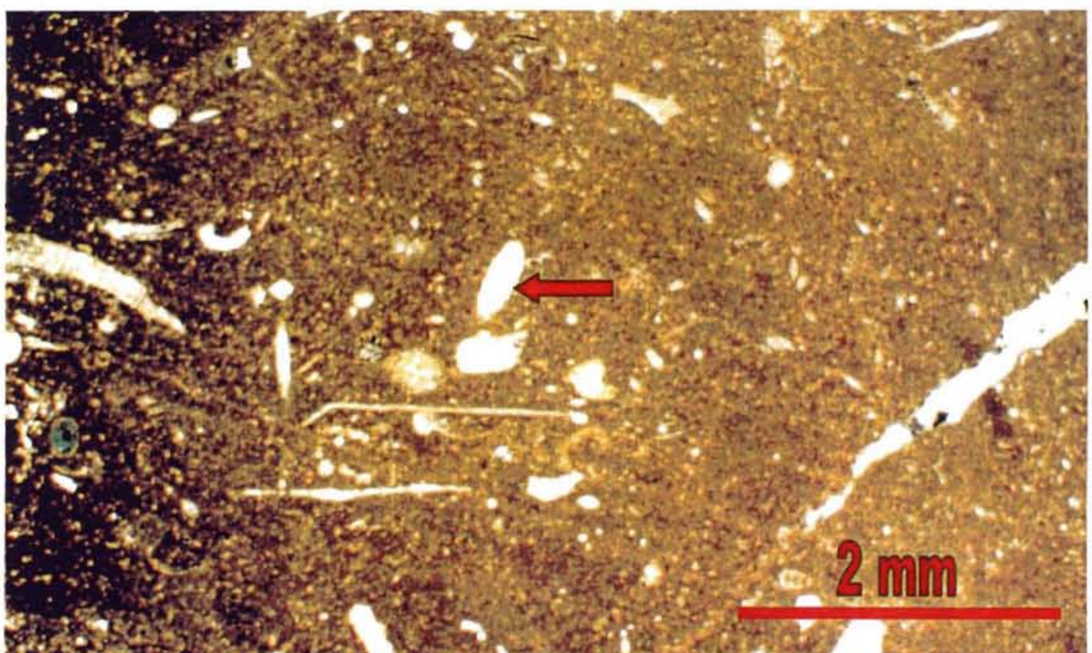


Figure 10. Photomicrograph of the normal marine shelf lithofacies. Wackestone, thamnopora branch (RED) and various fossil fragments within micritic matrix. CZAR a-71-G/94 P 10, depth 1143.5 m. 2x, Plain polarized light (PPL).

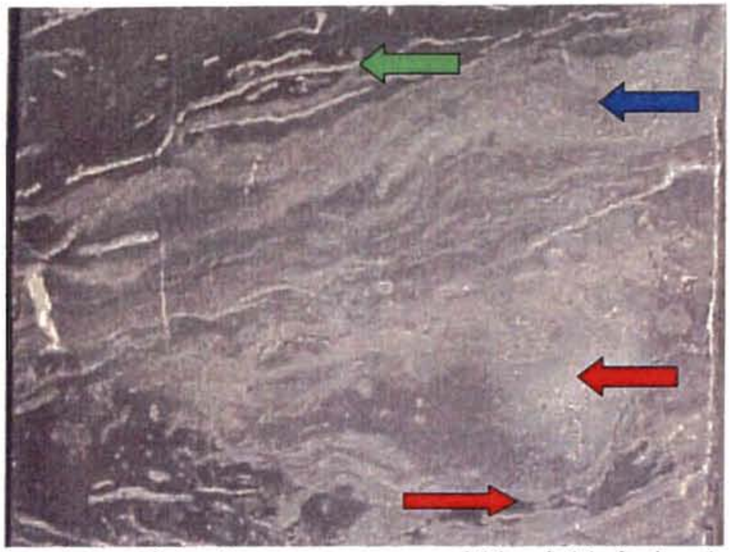


Figure 11. Core photo of the deep stromatoporoid bank biofacies dominated by tabular stromatoporoid (blue), bulbous stromatoporoid (red) and laminar stromatoporoids (green). CZAR d-53-C/94 P 10, depth 1178 m.

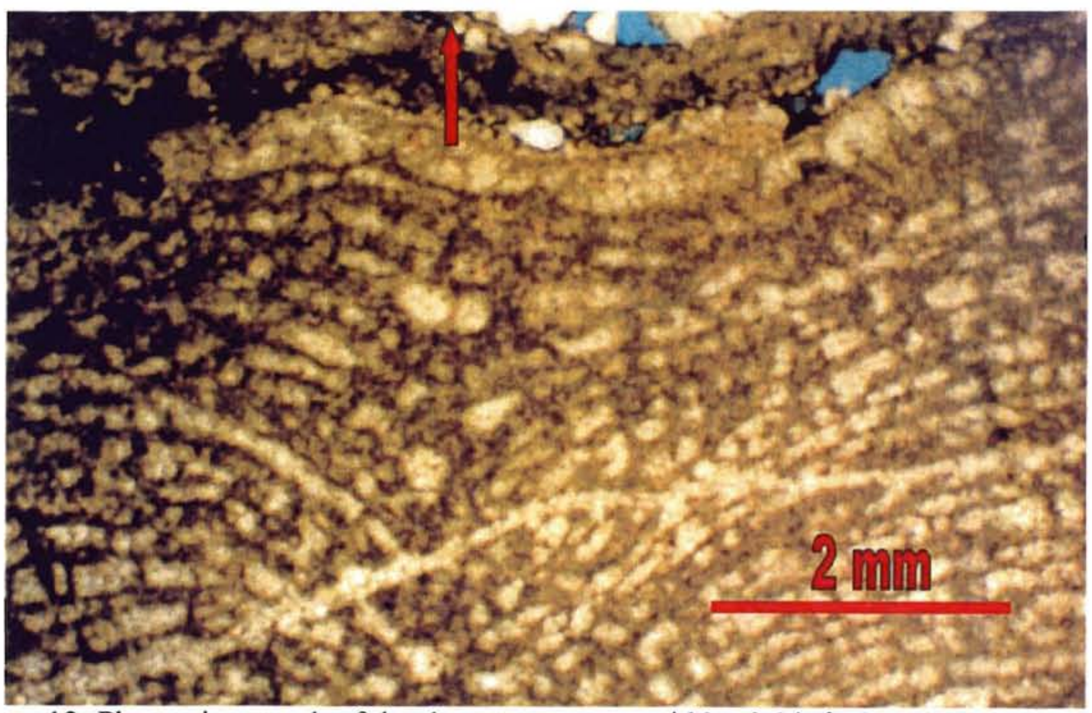


Figure 12. Photomicrograph of the deep stromatoporoid bank biofacies. Tabular stromatoporoid partially leached at the top with calcite and dolomite crystals (red) linning vug. CNRL b-50-I/94 P 10, depth 1150.65m. 2X, Cross-polarized light (CPL).

Shallow Stromatoporoid Bank Facies

The Shallow Stromatoporoid Bank (SSB) biofacies contains floatstones and wackestones along with small amounts of boundstone (Figures 13 and 14). SSB is dominated by tabular and laminar stromatoporoids and *renalcis*. Other bioclasts common to SSB biofacies include brachiopods, gastropods, crinoids, formanifera, rugose corals and bryozoans and amphipora. SSB is interpreted to have been deposited as shallow banks in relatively high energy waters. This is also a reservoir facies, containing intercystaline, microvugular and moldic porosity. Wells that contain small amounts of the SSB facies are normally highly productive.

Marine Shelf / Amphipora Shoal Facies

The Marine Shelf / Amphipora Shoal (MSAS) biofacies is characterized by packstones, grainstones, nodular-bedded wackestones and rare floatstones that are

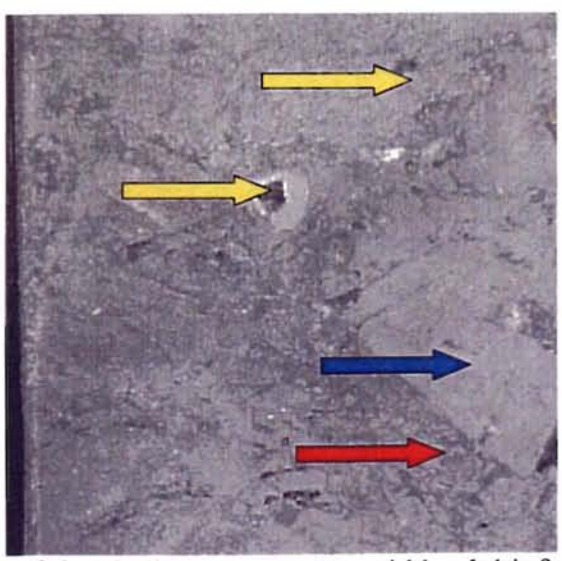


Figure 13. Core photo of the shallow stromatoporoid bank biofacies. Tabular stromatoporoids (blue) with abundant *renalcis* (red) and solution enlarged fractures and pores (yellow). CNRL a-41-A/94 P 15, depth 1130.2m.

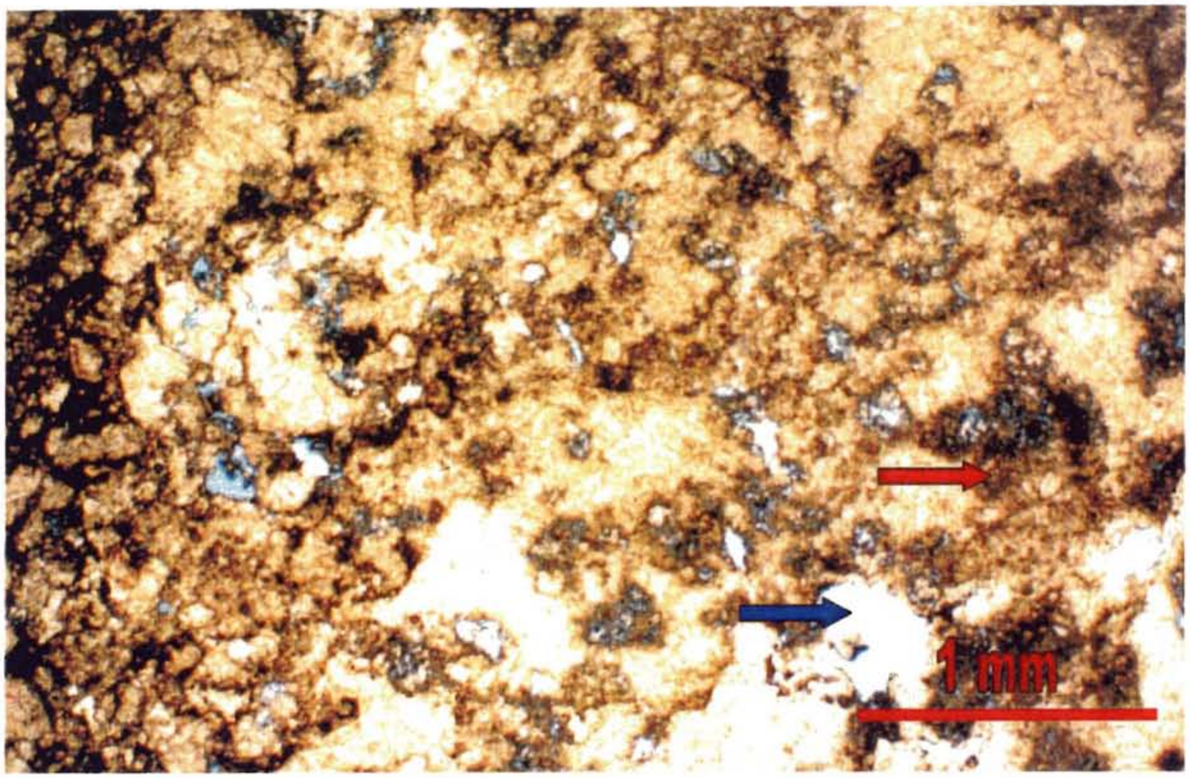


Figure 14. Photomicrograph of the shallow stromatoporoid biofacies with abundant *renalcis* (red) and porosity (blue) within micritic matrix. Canadian Hunter a-89-I/ 94 P 10. Depth 1149.5m. 4X, PPL.

dominated by amphipora fragments (Figures 15 and 16). Peloids, solitary rugose corals, thamnopora and laminar stromatoporoids are sparse, whereas brachiopods and gastropods are relatively common. Other forms include fenestrate bryozoans, ostracodes, bivalves, globular stromatoporoids, branching rugose corals, foramanifera, oncolites and burrows. The MSAS facies is commonly located immediately leeward (lagoonal) to the shallow stromatoporoid facies. MSAS is interpreted as representing deposition in moderate energy water with slightly higher temperature and salinity that may be intratidal to a few meters in depth. The MSAS facies is commonly found in the upper portions of the Jean

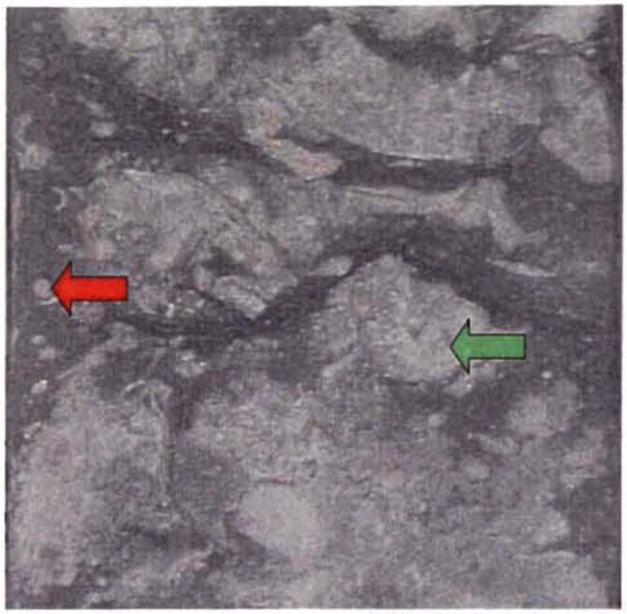


Figure 15. Core photo of the amphipora shoal biofacies, abundant bulbous stromatoporoids (green), amphipora stems (red) and large mound debris within lime mud matrix. Canadian Hunter d-37-I/94 P 10. Depth 1128.54m.

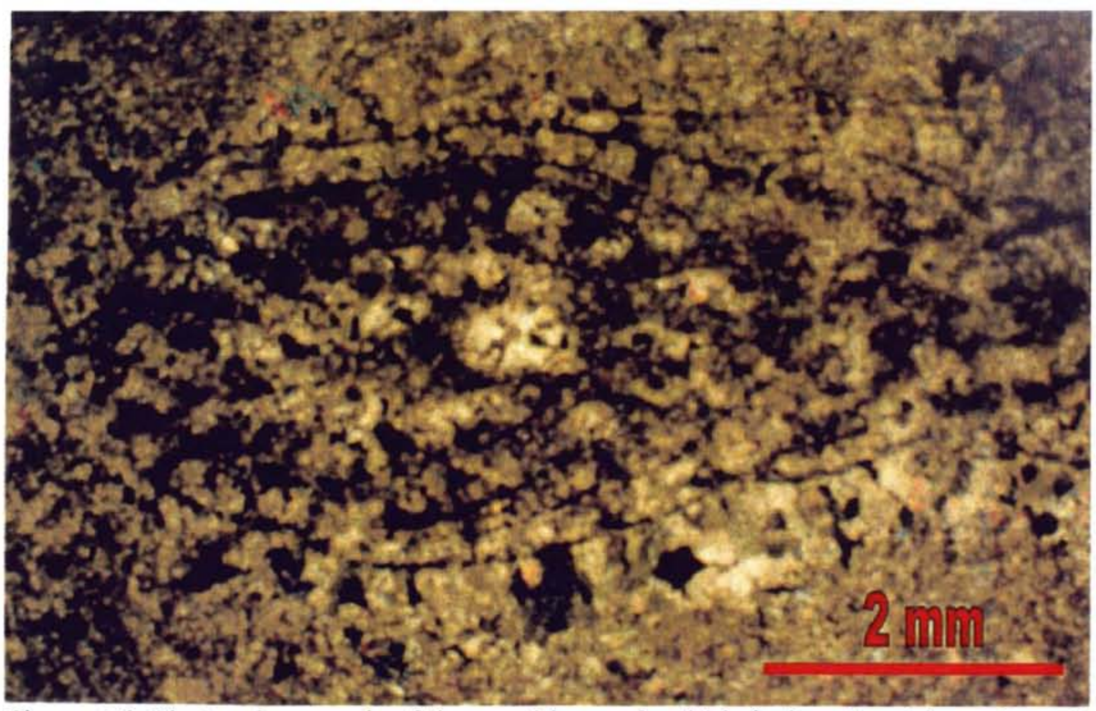


Figure 16. Photomicrograph of the amphipora shoal biofacies. Amphipora branch is the large circular object in the center of the photo. CZAR a-71-G/94 P 10, depth 1133.9m. 2X, CPL.

Marie. Fracture porosity is common in the MSAS facies, but the dominant porosity types are intercrystalline and microvugular, with very little moldic and intraskeletal porosity. MSAS is a reservoir facies when accompanied by the shallow stromatoporoid bank facies or is fractured.

The distribution of biofacies and resultant lithofacies can be correlated to Jean Marie productivity and deliverability (Figure 17 and Plate 1). The deep stromatoporoid bank, as well as the marine shelf / amphipora shoal facies produce when they are fractured. Shallow stromatoporoid is the most productive biofacies. This is likely the result of the dissolution of *renalcis*, differential dissolution of stromatoporoids and related fabrics. DSB, SSB, MSAS are all productive as a result of fracturing related to the more brittle nature of these facies. However, when deep stromatoporoid bank and marine shelf / amphipora shoal are present without solution enlarged fractures, production volume is typically reduced. The shallow stromatoporiod facies normally produces with or without the other reservoir facies. Dissolution of *renalcis* in SSB greatly enhances porosity development. When DSB, SSB and MSAS are all absent there is no production.

Munroe, et al, (2000) divided the Jean Marie into eleven major lithofacies, which were then grouped into three lithofacies associations. These three groups include reef, carbonate platform and a platform to basin transition. The reef association is dominated by boundstones, the carbonate platform predominantly lime mud to floatstone and the platform to basin transition is made up of siliciclasics and shales. Munroe et al (2000) focused on a large area that included 115 cored wells and included a wider range of depositional settings and environments. This study is contained with the carbonate platform area of Jean Marie deposition.

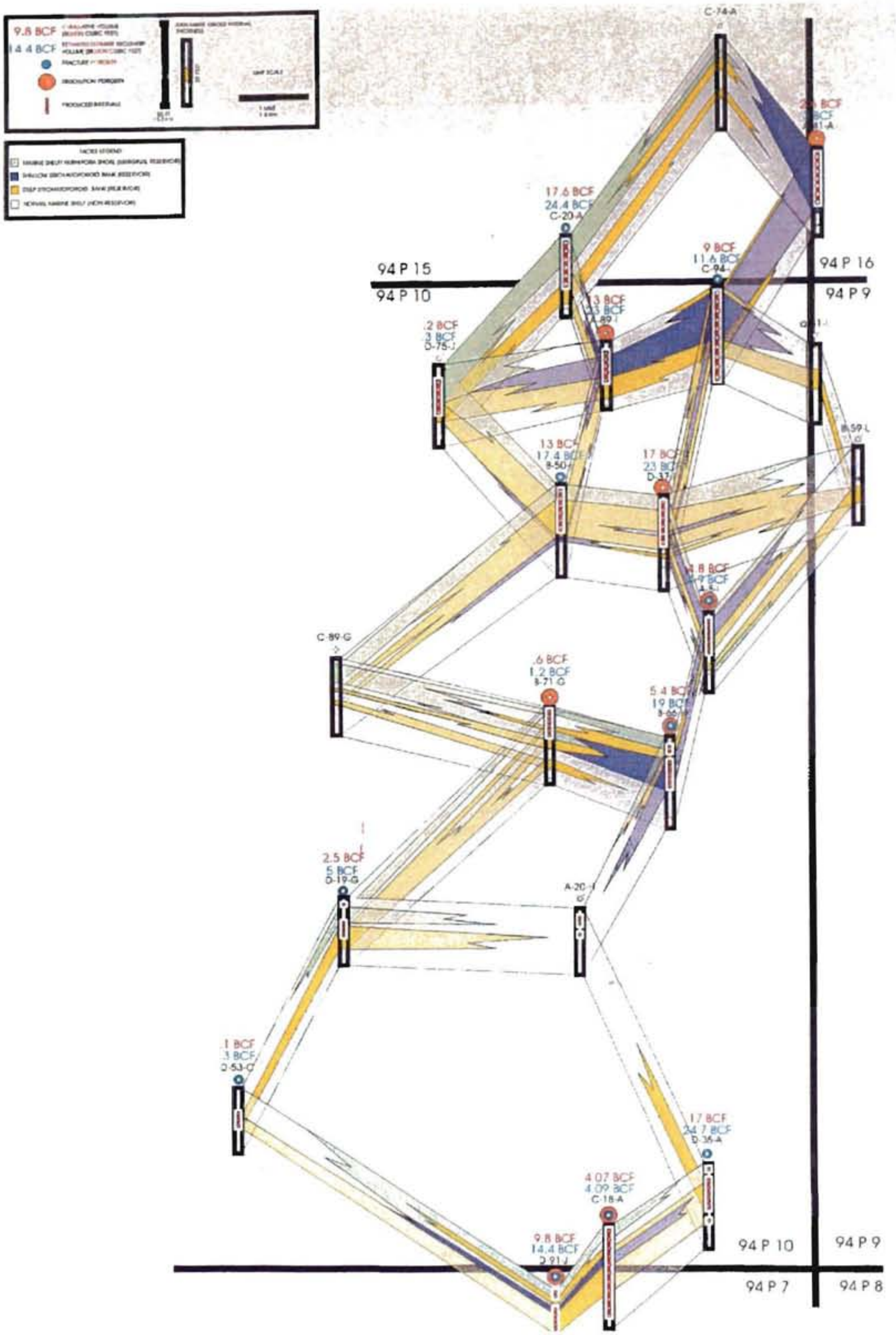


Figure 17. Fence diagram demonstrating the distribution and arrangement of Jean Marie biofacies/lithofacies and the deliverability in various locations.

CHAPTER III

DIAGENESIS AND HYDROCARBON SOURCE

Introduction

Productive reservoirs of the Jean Marie Limestone were formed by or strongly over-printed by burial diagenesis (Reimer, 1994). However, the absence of oil in these reservoirs is problematic. While the specific reactions and mechanisms remain poorly understood; several hypotheses have been proposed to explain the existence of large amounts of dry gas in the Jean Marie. These include simple burial diagenesis, hydrothermal fluid migration and thermochemical sulfate reduction (Reimer, 1994).

The Jean Marie is regionally gas saturated, pressure compartmentalized and underpressured with depth. Reservoirs are characterized by variably leached limestones with intercrystalline, pinpoint, vuggy and fracture porosity. Replacive dolomitization and secondary pore-filing cements occur in minor volumes. Permeability is greatly enhanced by solution enlarged, subvertical natural fractures. Fracturing in the Jean Marie has been attributed to either compactional drape over major subsurface structures of the Keg River Platform or to stresses associated with the evolution of the Canadian Cordillera (Munroe et al, 2000). A Laramide connection is supported by the location of the study area, which is about 200 km east of the Cordilleran orogenic front (McAdam, 1993). The increase in production rate attributed to fractures is significant considering the Jean Marie has typical matrix permeabilities that range from 1 to 3 millidarcies (md), while fracture-enhanced permeabilities attain values of several hundred md. Porosity within pay intervals is commonly 6 to 10 per cent (Hamilton et al, 1995).

Fracturing

Hamilton et al, (1995) observed two types of natural fractures in Jean Marie cores: mineralized natural fractures and "cleat-like" fractures occurring primarily in silty/shaly intervals. Most mineralized natural fractures, dip >77degrees and likely represent subvertical extension fractures. Orthogonal fracture systems form when the maximum principal stress is vertical, and the intermediate and minimum principal stresses switch in a horizontal plane. One mechanism for generating orthogonal fractures is by compactional draping over deeper structures. Fort Simpson shales differentially compacted over highs that developed on the Slave Point. These highs are related to block faulting over the Keg River carbonate bank edge along the southern end of the Cordova Embayment. Ft. Simpson compaction caused the overlying Jean Marie carbonates to drape over these same basement highs, creating the observed natural fracture pattern that was subsequently enlarged by dissolution (Figure 18).

The study area is approximately 200 km east of the Cordilleran orogenic front. Fracturing of reservoirs is believed to occur hundreds of kilometers beyond areas deformed by orogenic compressive stresses. The east-striking natural fractures and the one east-southeast-striking conjugate shear fracture may reflect weak Laramide orogenic compression (McAdam, 1993).

McAdam (1993) reported that the fracture intensity appears to be related, in part, to lithofacies. He proposed that the more competent the lithofacies, the more intense the fracturing. Using example wells, McAdam (1993) showed that fracturing significantly increased reservoir permeability. The example wells with natural fracture enhancement were the Czar et al, b-66-I/94-P-10 with a deliverability of 22 MMCFD and the Canadian Hunter et al, c-94-I/94-P-10, which flowed up to 12 MMCFD with only a 10 psi pressure drop. McAdam (1993) attributed fracturing in the Jean Marie Member at Helmet North

Figure 18. Core photo demonstrating solution enlarged fractures in the c-18-A/94 P 10 at 1134 m.

field to be related to mechanics of compaction in the underlying Fort Simpson shale.

Hydrocarbon Sources

Two theories have been proposed to explain the presence of dry gas in the Jean Marie; deep burial and hydrothermal fluid flow. According to the deep burial theory, the Jean Marie was sourced by the upward migration of hydrocarbons from the Fort Simpson Shale. Heat and pressure generated during deep burial matured organic matter and generated the gas and oil that migrated into the Jean Marie. Burial history curves (Figure 19) created by the Alberta Geological Society and the Canadian Society of Petroleum Geologist (AGS and CSPG, 1994) demonstrate that the study area was buried no deeper than 8200 ft (2500 m). Presently, the Jean Marie is currently at a depth of 1500 to 2500 meters and there is little evidence to support deep burial as a possible cause of gas generation.

The hydrothermal fluid flow theory is based on the movement of large amounts of hydrothermal fluids from the deeper, warmer part of the basin into the shallower, cooler part. Direct evidence for the hydrothermal fluid flow theory is the presence of thermal or baroque dolomite lining many fractures and vugs in the Jean Marie (Figure 20). The AGS and CSPG (1994) published several maps demonstrating basement heat flow and the heat generation at the Precambrian surface. The basement heat flow map (Figure 21) shows the study area within values ranging from 40 to 80 mW/m^2. Heat generation at the Precambrian surface (Figure 22) demonstrates a definite heat flow anomaly adjoining the northwest corner of the study area. This anomaly has a value of greater than 8 mega watts per cubic meter and is related to the Great Bear Magmatic Arc (Munroe et al,

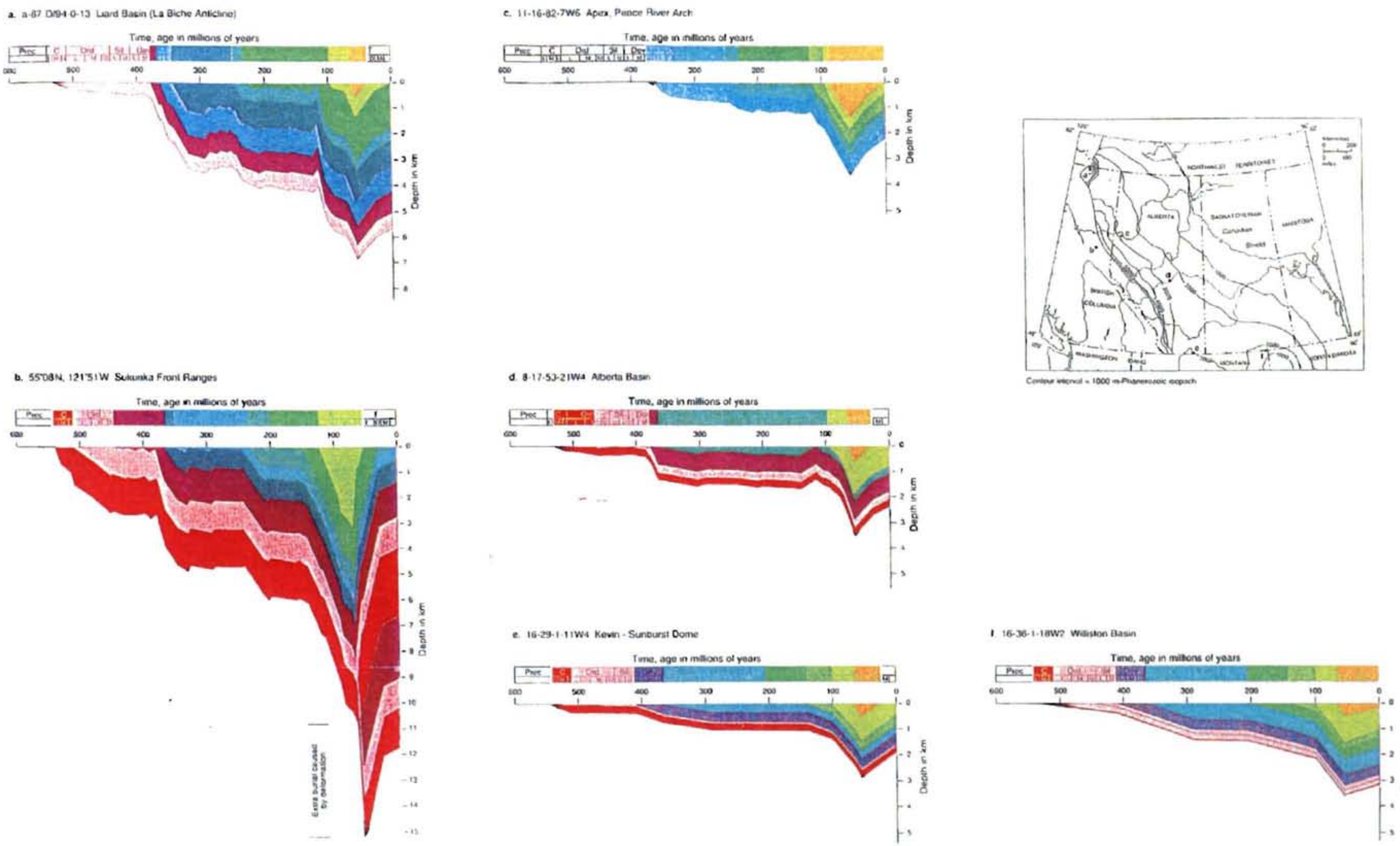


Figure 19. Burial history curves from various locations within the Western Canada Sedimentary Basin and Phanerozoic isopach index map (Issler, et al, 1994). Curve D is representative of the burial history of the study area.

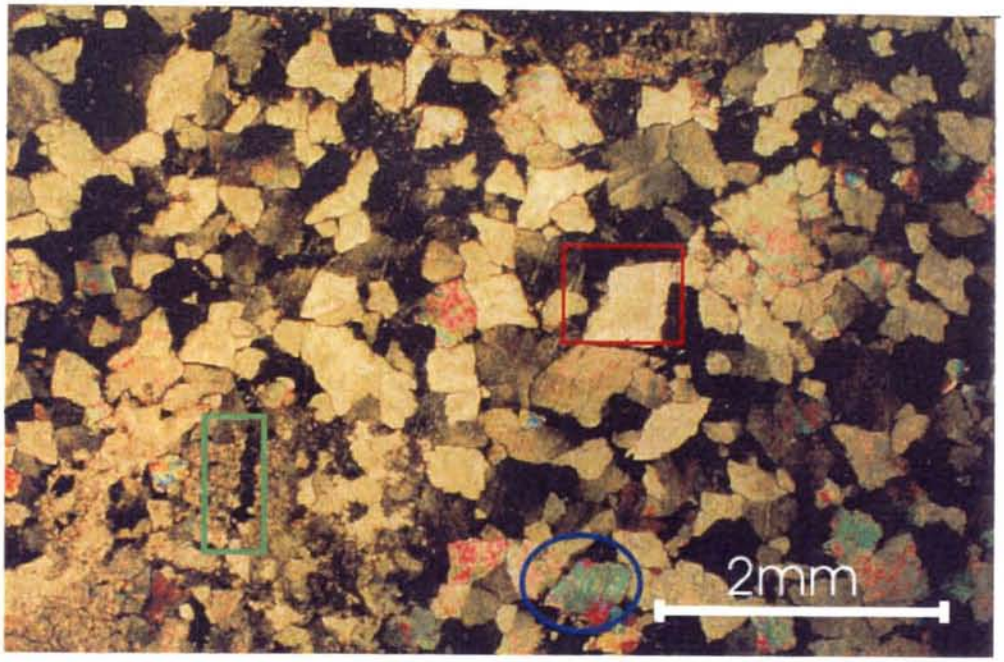


Figure 20. Photomicrograph dominated by thermal or baroque dolomite, white and black rhombs (red box), with small amounts calcite (blue circle) and traces of micrite (green rectangle). CNRL b-50-I/92 P 10. Depth 1153.65. 4X, PPL.

2000).

Riemer and Teare (1991) reported on the basis of core and literature, that the Debolt, Jean Marie, Slave Point, Keg River, Pine Point, and Nahanni reservoirs exhibit similar diagenetic fabrics. These fabrics include intense fracturing, leached pinpoint to locally cavernous porosity, saddle dolomite cement (Figure 23), occasional sulfide/sulfate mineralization, and the presence of bitumen. The widespread distribution of these fabrics suggests that a common diagenetic mechanism has affected these rocks on a regional scale. Thermochemical sulfate reduction (TSR), combined with active paleohydrogeological flow, is one possible mechanism.

In the Reimer and Teare (1994) model, the TSR reaction involves oxidation within pre-existing oil pools of the Keg River and Slave Point. This oxidation

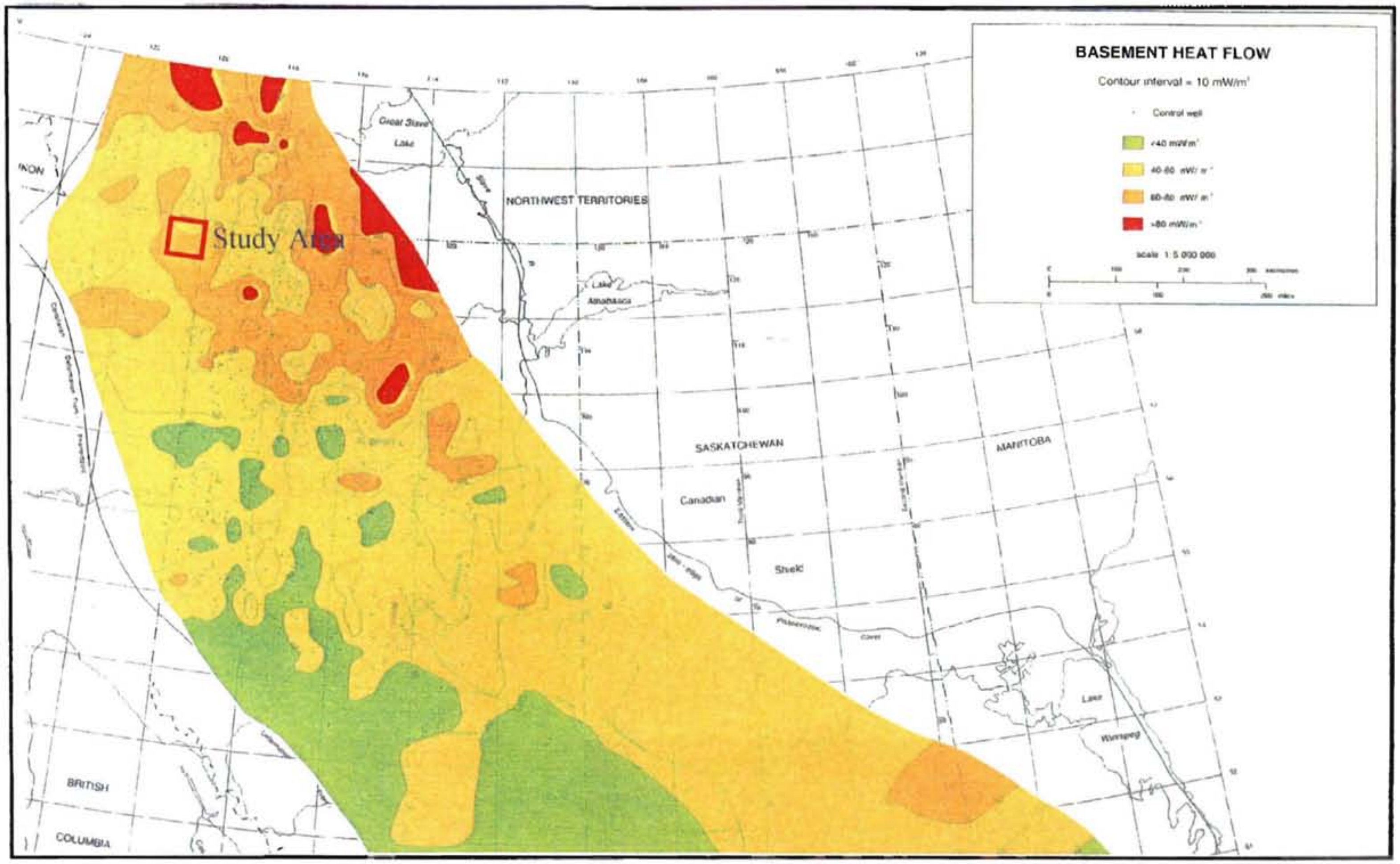


Figure 21. Basement heat flow maps of the Western Canada Sedimentary Basin (AGS and CSPG, 1994).

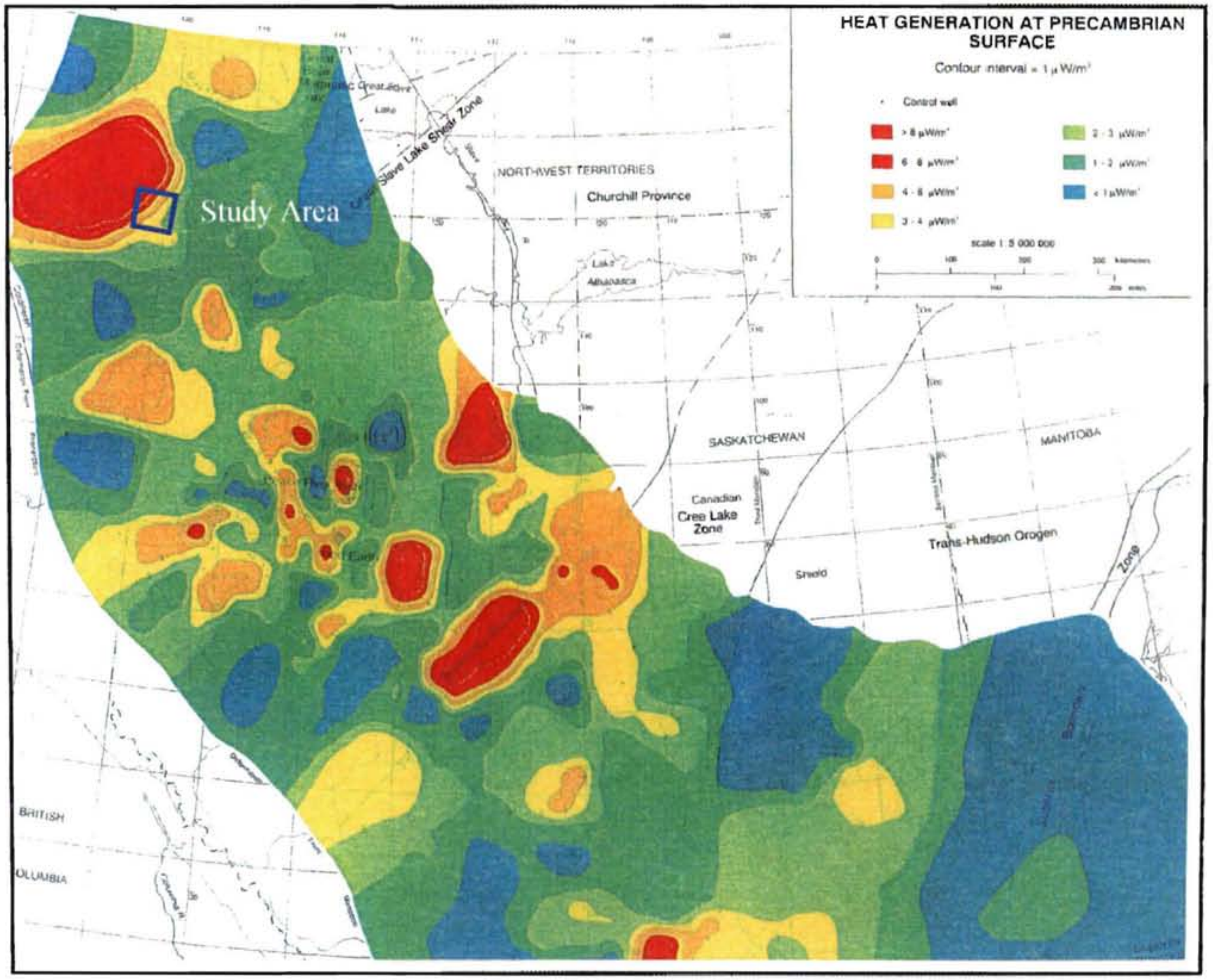


Figure 22. Heat generation map of the Western Canada Sedimentary Basin (AGS and CSPG, 1994).

Figure 23. Large dissolution vug lined with thermal dolomite (yellow) within the shallow stromatoporoid bank facies. *Renalcis*, small white dots inside red square, is abundant among the dominant tabular stromatoporoids. CZAR Resources a-41-A/94 P 15, depth 1139.3 m.

resulted in the dissolution of limestone, which was followed by precipitation of dolomite and pyrobitumen. Methane and carbon dioxide, being the principal products of this reaction, were transported by hydrothermal fluids through fractures in the Ft. Simpson Shale and into the Jean Marie. The carbon dioxide dissolved into the micropore waters of the Jean Marie, creating carbonic acid and enlarging these micropores and fractures. Reimer and Teare (1994) define four main stages to this process:

1. Fracturing of the surrounding rock, due to a pressure increase from the hydrocarbon phase change, which opened new vertical and lateral conduits for fluid migration;
2. Porosity enhancement in and around these conduits by thermal cooling and weak acid leaching from excess carbonic acid;
3. Precipitation of dolomite cement and sulfur minerals in the emerging void space, and
4. Concurrent infusion of methane and other byproducts.

Reimer and Teare (1994) concluded that the TSR process both created and was the source for its own reservoirs. As a result of pore enlargement and hydraulic isolation and cooling during during uplift, Jean Marie reservoirs are regionally underpressured.

Timing of Hydrocarbon Genesis and Migration

Hydrocarbons are found in fluid inclusions in calcite cements that were formed at temperatures from 60 to 110 degrees Celsius (Monroe et al, 2000). Remnants of liquid hydrocarbons are present as methane and solid organic matter or bitumen. Once the liquid hydrocarbons were trapped in the fluid inclusions they were heated and transformed into methane and bitumen. Bitumen is also common in fractures, stylolites and vugs and formed as liquid hydrocarbons were heated in the reservoir, generating methane. Pyrite is commonly associated with bitumen (Figure 24) and may contribute to the production of hydrogen sulfide (H_2S).

A second fluid migrated through the Jean Marie after generation of liquid hydrocarbons. This hydrothermal phase contained fluids that were isotopically enriched with O^{18} and produced calcite cements at temperatures between 130 and 150 degrees Celsius (Monroe et al, 2000). Elevated temperatures during this migration caused the liquid hydrocarbons to be converted to methane, bitumen and pyrite. This migration of fluids probably caused bitumen in stylolites and in vugs to form as liquid hydrocarbons were heated during tectonism. Following the heating phase, meteoric waters migrated through the area (Munroe et al, 2000). These fluids were at a much lower temperature and produced a variety of cements such as calcite and kaolinite (Figure 25). Some vug-lining calcite cement (Figure 26) had fluid inclusion homogenization temperatures and salinities that indicated salinity of fluids near seawater composition. These salinities are much lower than salinities of waters that precipitated previous generations of cement (Munroe et al, (2000).

Diagenetic Features

Diagenetic features of the Jean Marie can be directly correlated to biofacies and lithofacies (Kissling, 1990), outlined diagenetic features and correlated them to the four facies used in this study. Nodular bedding and microstylolites are best developed in the marine shelf lithofacies, but are present in small amounts in the normal marine shelf/

Figure 24. Core photo of the deep stromatoporoid biofacies illustrating bitumen filled stylolites (red), short vertical fractures (blue) and pyrite (green), within tabular stromatoporoids. Canadian Hunter d-37-I/94 P 10, depth 1134.7m.

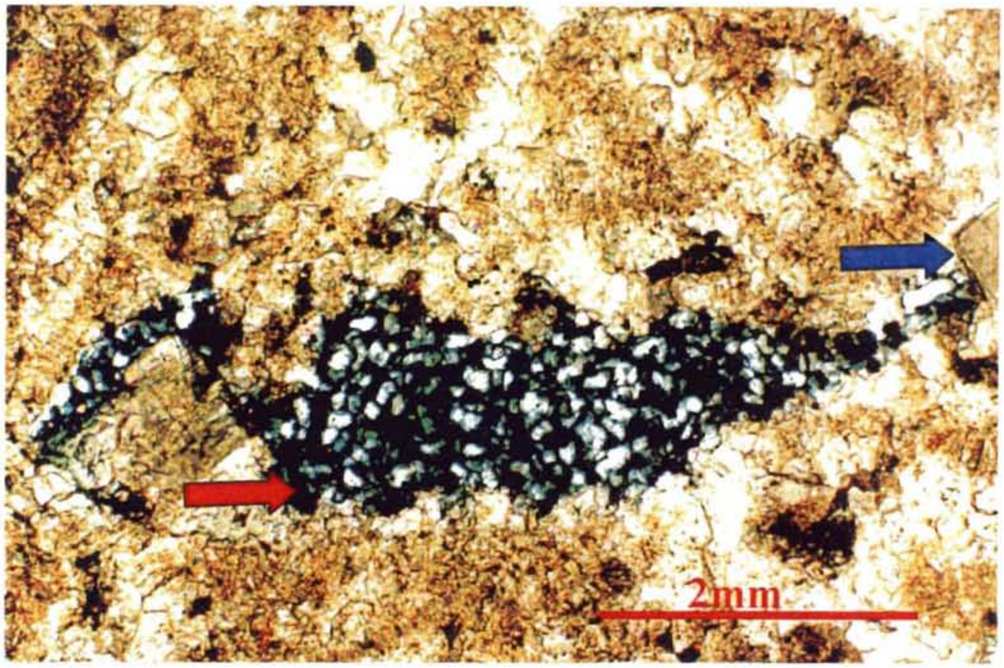


Figure 25. Photomicrograph of the shallow stromatoporoid bank biofacies. Tabular stromatoporoid with kaolinite filled vug (red) and dolomite rhomb (blue). CNRL b-50-I/94 P 10, depth 1146.85m. 2X, PPL.

amphipora shoal biofacies. Microstylolites are rare in the shallow stromatoporoid facies and nodular bedding is absent. Pyrite is present in all facies, but is more common in the marine shelf lithofacies. Dolomite and dolomitic limestone, represented by dolomicrospar, are most common in the deep stromatoporoid bank and normal marine/ amphipora shoal facies. Dolomite is least common in the marine shelf facies, in part the result of the lower permeability of the argillaceous strata that dominate the lower portion of the Jean Marie. The shallow stromatoporoid bank facies contains a distinct group of diagenetic features, including maximum development of brecciation, vugs, calcite cement and stylolites. These features are also common within the normal marine/amphipora

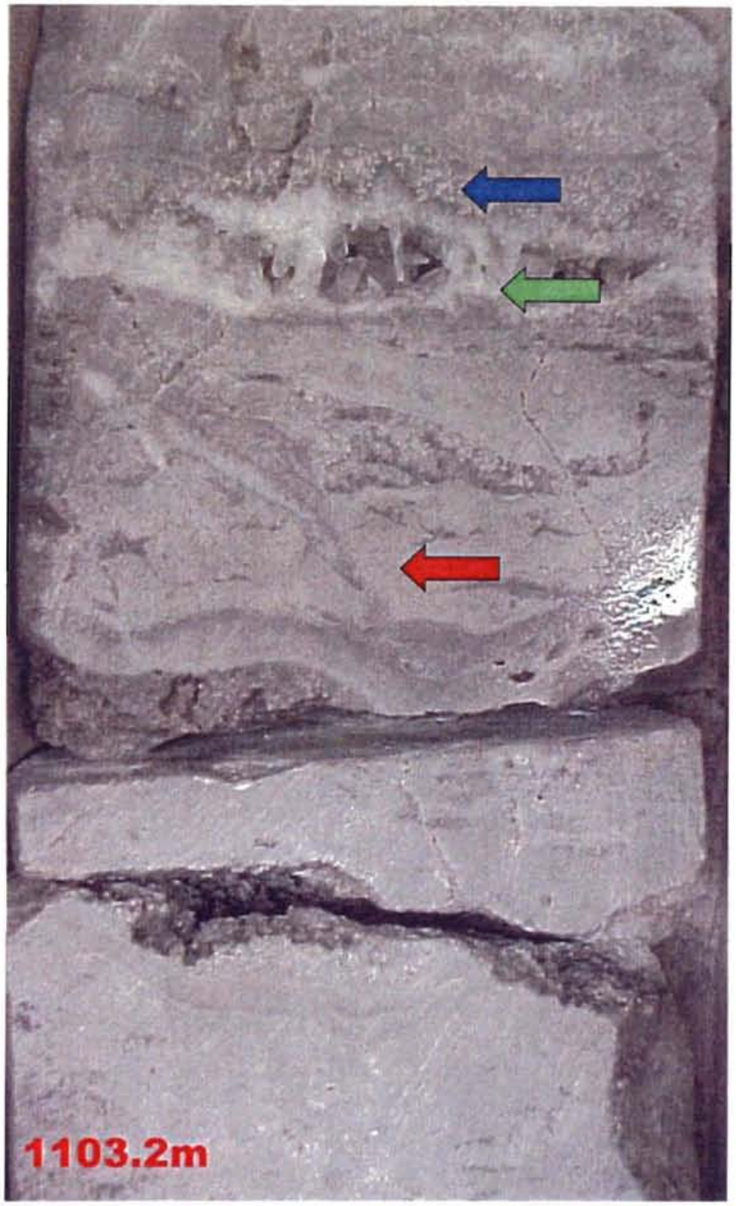


Figure 26. Core photo of the shallow stromatoporoid bank facies with large calcite filled vug (green) within tabular stromatoporoids (red) and *renalcis* (blue). CZAR b-66-H/94 P 10, depth 1103m.

shoal biofacies, which has also been subjected to subaerial exposure, leaching and cementation. Baroque dolospar is well developed in the normal marine/amphipora shoal facies and the least developed in the marine shelf facies (Kissling, 1990).

Porosity Development

The largest percentage of porosity is intercrystalline and microvugular (Munroe et al , 2000). Intercrystalline porosity is an artifact of volumetric reduction during dolomitization and results from the ill-fitting dolomicrospar and dolospar rhombs in many dolomite fabrics. Pore diameter is a function of rhomb size, packing and subsequent overgrowth and range from 0.005 - 0.2 mm. These pores are typically triangular or polygonal in cross section (Kissling, 1990).

Microvugular porosity is composed of an interconnected vug system formed by leaching of limestone, less commonly dolomite, matrix or grains (Figure 27). Pores are irregular in shape and slightly larger than the co-existing intercrystalline pores. These pores are typically 0.02 - 0.5 mm in diameter (Kissling, 1990). Permeability is provided by fractures, intercrystalline and microvugular pores. As a result of the sizable amount of dolomitization, intercrystalline and microvugular porosity provides the majority of the low mean porosity for the marine shelf/amphipoa shoal biofacies. Intercrystalline and microvugular porosity make up less than half of the mean porosity in the shallow stromatoporoid bank biofacies, and average 3-4%.

Small molds make up an average of < 1% in the marine shelf facies, and when combined with intraskeletal porosity average < 0.3% in other facies. Molds are formed by selective leaching of grains. Mold sizes, shapes and frequencies are dependent on the sizes, shapes and frequencies of the skeletons or peloids they mimic. Very few intraskeletal pores are present and are only found in the normal marine/amphipora shoal facies (Kissling, 1990).

Vugs are irregular in form and not as fabric selective as the moldic porosity.

Figure 27. Core photo demonstrating microvugular porosity (red) within the shallow stromatoporoid facies created by the leaching of *renalcis*. CNRL a-40-A/94P 15, 1131.85 m.

They formed by the indiscriminant leaching of carbonate matrix or grains or by solution enlargement of early molds or fractures (Figure 28). Vugs and shelter cavities are absent from the marine facies and sparse in the normal marine/amphipora shoal biofacies. Vugs make up a mean 2-3 % porosity in the shallow stromatoporoid bank facies (Figure 29)

(Kissling, 1990). Open fractures are present in 75 % of the porous intervals within the shallow stromatoporoid bank biofacies. Fractures make up 50% of the porosity in the deep stromatoporoid bank facies and 40% of the total porosity in the normal marine/amphipora shoal facies (Kissling, 1990).

The shallow stromatoporoid bank biofacies has a mean 6.4% porosity despite the presence of extensive calcite and dolospar cements. Fracture, vuggy, microvugular and moldic porosity was created by leaching and brecciation of limestone in the sparingly dolomitized stromatoporoid bank facies. Normal marine/amphipora shoal biofacies and the deep stromatoporoid bank biofacies have mean porosities of 3.7 % and 3.6 % respectively (Kissling, 1990). The marine shelf lithofacies has a total mean porosity of approximately < 1%.

Figure 28. Core photo showing shelter porosity within the marine shelf/amphipora shoal biofacies. Here the shelter is created by large ostracod shells. CZAR d-91-J/94 P 7, 1145.15m.

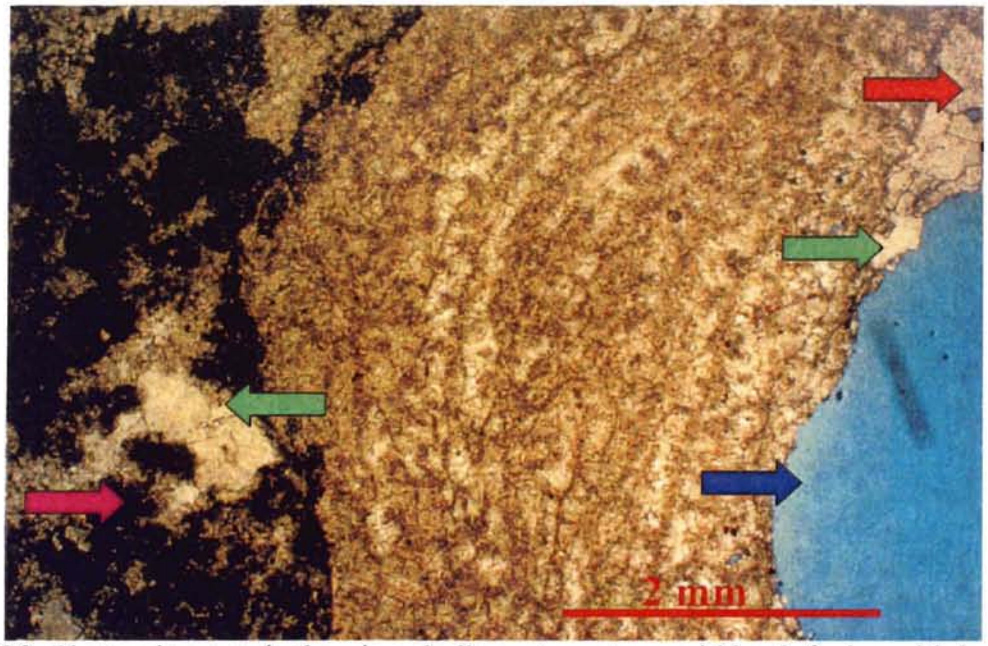


Figure 29. Photomicrograph showing shallow stromatoporoid bank facies with laminar stromatoporoid, intact *renalcis* (pink) and large solution vug (blue). Small amounts of calcite (green) and dolomite (red) are evident. CNRL b-50-I/94 P 10, depth 1146.85m. 2X, PPL.

CHAPTER IV

IMPLICATIONS FOR PETROLEUM EXPLORATION

Production

The first well to penetrate the Jean Marie was drilled near the end of the drilling season of 1956. Gas was first discovered in the Jean Marie in 1963 in the Chevron b-49-G/94 P 7 well in the Helmet field (Canadian Discovery Digest, 2001). In 1972, the c-33-A/94 P 15 well tested 25,000 cubic meters (875 MCF) gas per day from the Jean Marie and was the first commercially productive Jean Marie well drilled in the Helmet field (Munroe et al, 2000). Poor reservoir quality and the lack of a strong drive mechanism prevented these reserves from being actively exploited. During the 1970's and 1980's the low demand for natural gas and the lack of a gas-gathering infrastructure hindered development. Between 1974 and 1983, 94 wells were completed in the Jean Marie throughout the region.

Gas production in the area is predominantly from the Jean Marie, which has produced 480 BCF from five fields. A large portion of that production is from the Helmet field, which contains 108 wells that have produced 198 BCF gas. Helmet North has the highest average production per well at 2.6 BCF. Helmet North has cumulated 131 BCF from 48 wells (Canadian Discovery Digest, 2001.).

The Jean Marie is a regionally underpressured reservoir. Field observations by McAdam (1993) indicate that Jean Marie reservoir pressures register 50% to 60% of normal hydrostatic pressure. Typically, virgin bottom hole pressure is in the range of 800 psi, compared to a hydrostatic pressure of approximately 1700 psi. This low pressure makes the Jean Marie very susceptible to formation damage from invasion by drilling and fracturing fluids. Formation damage was a common problem before underbalanced drilling techniques and modern low-density stimulating fluids were developed (Chesapeake Energy, proprietary report). Horizontal drilling typically enhances Jean Marie productivity by increasing the amount of matrix reservoir in communication with the well bore and increasing the number of vertical fractures intersected. However, production from horizontal wells in the North Helmet field was not greater than that of vertical wells. This could be the result of these horizontal wells being drilled near field boundaries in poorer quality reservoirs.

Many Jean Marie wells appear to be in communication and existing wells drain extremely large areas (Chesapeake Energy, proprietary report). The extensive network of solution-enlarged fractures and other dissolution pathways facilitates drainage. Some wells with apparent higher-quality reservoirs do not produce as expected. These wells hinder developing an accurate understanding of the factors controlling Jean Marie productivity. Drilling, formation treatment and stimulation information is usually unavailable, so evaluating the effects of formation damage on production is difficult. Formation damage and drainage may explain anomalously low production rates for wells with apparently quality reservoirs, as determined from core and wireline log data.

The drive mechanism within the Jean Marie is gas depletion. Over much of the study area, Jean Marie water saturation is essentially the irreducible water saturation. Consequently, the reservoir produces very little water. However, it is believed this bound water reduces permeability in micropores and impedes migration (Figure 30).

LOG - DERIVED PERMEABILITY

JEAN MARIE PROJECT
NE BRITISH COLUMBIA, CANADA

	PHId									
Sw	*0.015*	*0.030*	*0.045*	*0.060*	*0.075*	*0.090*	*0.105*	*0.120*	*0.135*	*0.150*
0.950	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
0.900	0.000	0.000	0.000	0.000	0.001	0.001	0.002	0.003	0.005	0.008
0.850	0.000	0.000	0.000	0.001	0.002	0.005	0.009	0.016	0.025	0.037
0.800	0.000	0.000	0.001	0.003	0.008	0.016	0.028	0.048	0.076	0.114
0.750	0.000	0.001	0.002	0.008	0.018	0.037	0.068	0.114	0.180	0.272
0.700	0.000	0.001	0.005	0.016	0.037	0.076	0.138	0.232	0.368	0.555
0.650	0.000	0.002	0.009	0.028	0.068	0.138	0.252	0.424	0.671	1.012
0.600	0.000	0.003	0.016	0.048	0.114	0.232	0.424	0.713	1.130	1.704
0.550	0.000	0.005	0.025	0.076	0.180	0.368	0.671	1.130	1.789	2.699
0.500	0.001	0.008	0.037	0.114	0.272	0.555	1.012	1.704	2.699	4.071
0.450	0.001	0.011	0.054	0.165	0.395	0.804	1.468	2.472	3.915	5.906
0.400	0.001	0.016	0.076	0.232	0.555	1.130	2.062	3.472	5.497	8.293
0.350	0.001	0.021	0.103	0.317	0.758	1.544	2.818	4.745	7.513	11.334
0.300	0.002	0.028	0.138	0.424	1.012	2.062	3.762	6.336	10.033	15.136
0.250	0.002	0.037	0.180	0.555	1.325	2.699	4.925	8.293	13.133	19.813
0.200	0.003	0.048	0.232	0.713	1.704	3.472	6.336	10.669	16.895	25.488
0.150	0.004	0.060	0.294	0.904	2.159	4.398	8.027	13.517	21.405	32.291
0.100	0.005	0.076	0.368	1.130	2.699	5.497	10.033	16.895	26.754	40.361
0.050	0.006	0.093	0.454	1.395	3.333	6.789	12.390	20.864	33.039	49.843

NOTES. k = 10 exp. ((ln (Phi * (1 - Sw)) / 0.59) + 5)

k >= 0.001 md **k >= 0.01md** k >= 0.1md **k >= 1.0md** **k >= 10.0md**

Non-Pay. Pay = PHId >= 3.0% & Sw <= 50%

Low perm pay: Stimulated vertical wells

High perm pay: Good vertical & Horizontal wells (If sufficient BHP)

Figure 30. Log derived permeability calculations that demonstrate the impact of water saturation on the reduction of permeability. Based on k = 10^(((ln(Phi*(1-Sw))/.059)+5, derived from Heslop (1996).

Production Maps and Cross Sections Derived from Log Data

Maps and cross section were created to provide a visual representation of the location; distribution and regional trend of Jean Marie carbonate buildups. Eight maps, based on wireline log data (Figure 31), (gross interval, net pay, HPV (hydrocarbon pore volume), K*H (permeability feet), gas saturation, average porosity and average permeability) were constructed to analyze reservoir thickness and quality/productivity relationships. Four stratigraphic cross sections were constructed to illustrate changes in thickness of total carbonate and porosity zones across the study area.

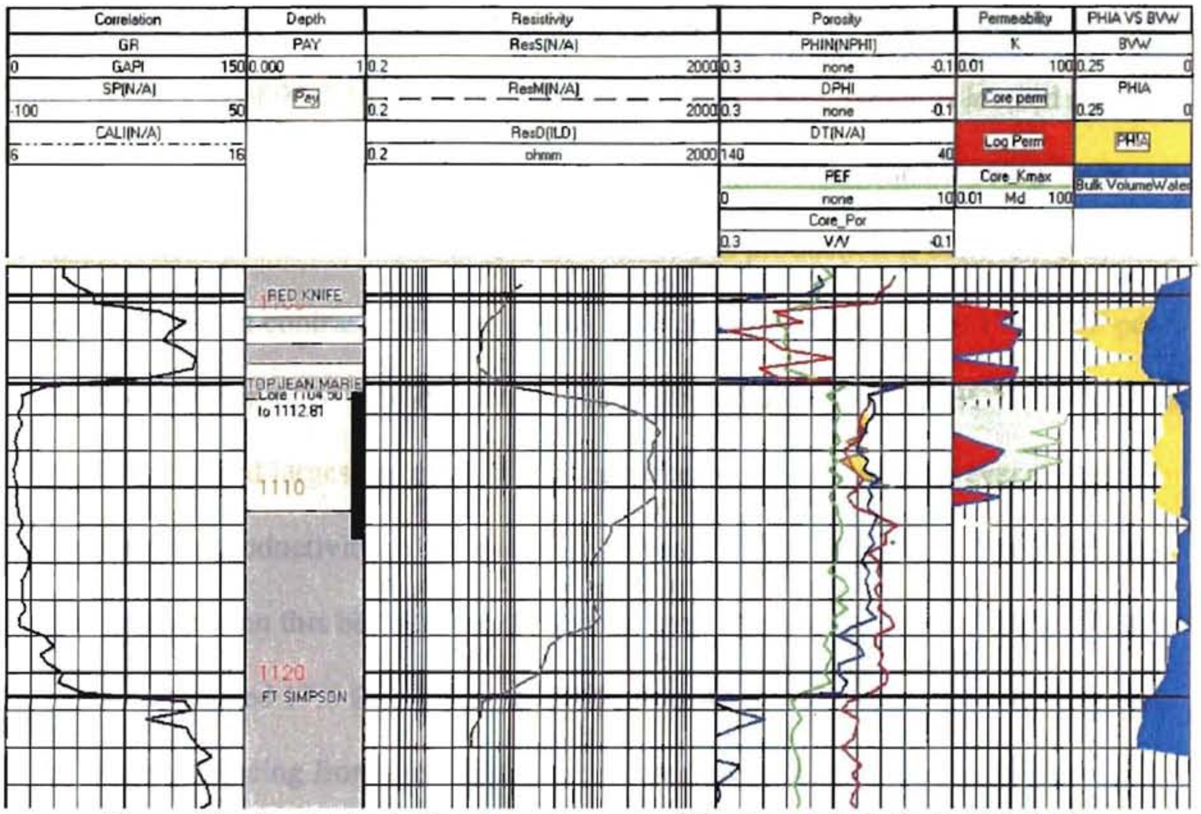


Figure 31. Typical wireline log response of the Jean Marie (a-5-I/94 P 10).

Gross Interval Map

The gross interval map demonstrates the thickness; spatial arrangement and geometry of the Jean Marie carbonate buildups (Figure 32 and Plate 2). The overall thickness is measured from the base of the Red Knife Shale to the top of the Ft. Simpson Shale Figure 31). The units of measure are feet. Carbonate buildups in the July Lake Field trend in a north-south direction that broadens and narrows from east to west in an asymmetrical fashion. Gross thickness of the Jean Marie ranges from 30 feet (9.14m) to

66 feet (20.12m). There are three main carbonate buildups in the field: northern, middle, which is divided into two subunits and southern (Figure 32).

The northernmost carbonate buildup is 66 feet (20.12m) thick and located on the north end of block I of 94 P 10, the southern part of block A of 94 P 15 and the western edge of block D of 94 P 16 (Plate 2). The b-7-A/ 94 P15 well, which is located on the crest of the buildup, has cumulated 4.2 BCF from the Jean Marie and the Keg River. Based on results of drill stem tests (DST), most of this production is believed to be from the Keg River. In contrast, nine flank wells have cumulated from 1.2 to 17.6 BCF per well. The total cumulative production for the northern buildup is 53.8 BCF from the nine wells. This is third largest in terms of total cumulative production. However it is the second largest productivity value on a per well basis. The c-20-A/94 P 15 well is the largest producer on this buildup and the second largest in the study area. The c-20-A/94 P 15 has cumulated 17.6 BCF gas since 1992, from 44 feet (13.41m) of total carbonate. Most wells producing from this buildup are located on the flank of the maximum thickness where the slope is very gentle. The average slope calculated 0.1%, with steepest being 0.43% where the a-89-I/94 P 10 well is located. The a-89-I 94 P 10 is a 13.3 BCF well.

The middle carbonate buildup has the shape of a rotated H and contains two smaller units, which are located in blocks G, H, I and J of 94 P 10. The northerly unit has a maximum thickness of 56 feet (17 m). The Canadian Natural Resources d-37-I/ 94 P 10 well, which penetrated the crest of the buildup, has produced 17.4 BCF since 1990. The d-37-I/94 P 10 is the third largest producer within the study area. This well is atypical in terms of productivity since most of the better wells are located just off the

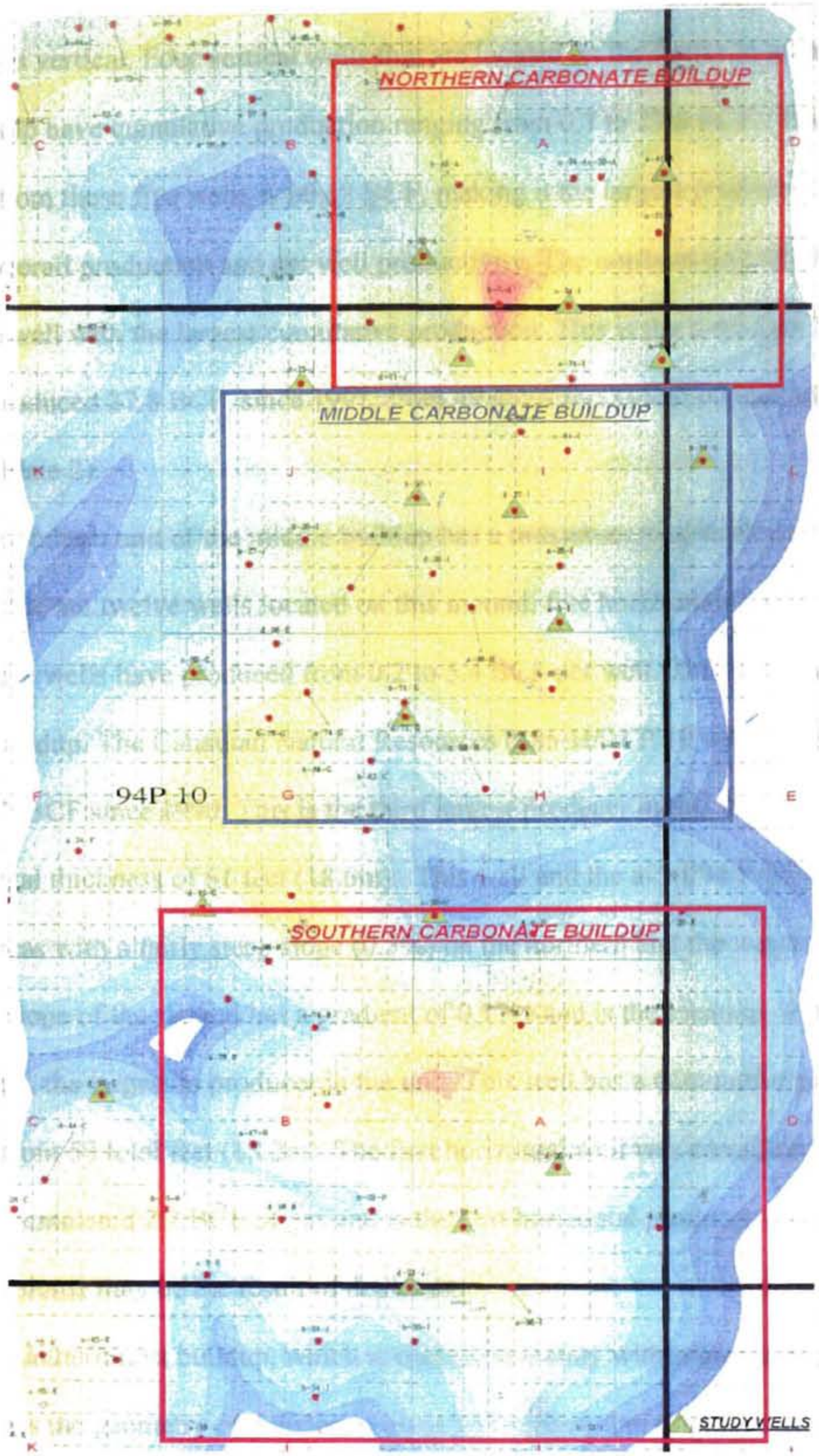


Figure 32. Gross thickness map demonstrating the location of the three main Jean Marie carbonate buildups.

crest of the buildups. The d-37-I/94 P 10 was the first producing well drilled on this buildup and is vertical. Four vertical wells that are located on the flanks in areas with very gentle dip have cumulative production ranging from 0.7 to 27.8 BCF. The total production from these five wells is 60.68 BCF, making it the largest producing mound interms of overall production and per well productivity. The northern unit of the buildup contains the well with the largest cumulative production. This is the b-66-I/94 P 10, which has produced 27.8 BCF, since 1991, from 49 gross feet (15m) of Jean Marie (Figure 32; Plate 2).

The southern unit of the middle buildup has a maximum total thickness of 61 feet (18.6m). There are twelve wells located on this mound, five horizontals and seven vertical. These wells have produced from 0.2 to 5.4 BCF per well. This is the poorest producing buildup. The Canadian Natural Resources b-85-H/94 P 10 well has only produced 4.7 BCF since 1990. This is the third largest producer in this unit and it has a maximum total thickness of 61 feet (18.6m). This well and the a-5-I/94 P 10 well are located in areas with a fairly steep slope (0.3%) on the northern and the western flanks. The eastern slope of the mound has a gradient of 0.17% and is the location of the b-66 I/94 P 10 well, the largest in producer in the unit. This well has a cumulative production of 5.4 BCF from 50 total feet (15.2m). The first horizontal well was completed in January 1994. It has cumulated 2.2 BCF of gas and is the best horizontal producer. This low production volume may be the result of depletion.

The southernmost buildup, which is contained mainly within the blocks A and B of 94 P 10, has the geometry of a distorted cross and a maximum thickness of 62 feet (19 m). This buildup was the first discovered, is the largest in overall land area, and the second most productive. It contains 15 wells, none of which were drilled on the crest. Cumulative production ranges from 0.004 to 16.9 BCF per well. The ten producing wells are vertical and have a combined total production of 59.18 BCF. The southern and western margins are fairly steep slopes and non-productive. The northern and eastern fringes are characterized by a very gentle incline. Production trends are defined by seven wells. The first well drilled on this buildup was the a-81-A/94 P 10. This well was completed in 1978, and has a cumulative production 6.4 BCF from 46 gross feet (14m) of limestone. The second well drilled on the southern buildup was the c-18-A/94 P 10. Since 1980, it has produced a total of 4 BCF from 58 gross feet (17.6m). This is the thickest interval of Jean Marie. The b-90-I/94 P 7 and the b-84-J/94 P 7 both have a gross thickness of 41 feet. The b-90-I, drilled in 1981, has produced 8.4 BCF, whereas the b-84-J has produced 9.1 BCF since 1985. The largest producing well completed in this buildup is the d-35-A/94 P 10. This well was completed in 1989 and has produced 16.9 BCF from 47 feet (14.3m) of Jean Marie. Plate 2 illustrates the premise that overall interval thickness does not directly predict areas of high productivity. Total thickness does indicate maximal areas of carbonate production and mound geometry. Some carbonate producing organisms prospered on the more gentle slopes. Furthermore, some organisms may have proliferated on specific areas of mounds. *Renalcis* seems to fit this pattern and is one of the major constituents responsible for porosity development. Anomalous producing wells such as the CNRL d-37-I/94 P 10, which has produced 17.4 BCF from a mound crest, may have abundant solution-enlarged fracture porosity.

Net Pay Map

The net pay map (Figure 33; Plate 3) was generated by summing the intervals in each well that have porosity > 3% and a water saturation of <50%. Water saturation (Sw) was calculated using the standard Archie ([(1/Phi^2) * (Rw/Rt)]^0.5), where PHI is Porosity, Rw is formation water resistively, Rt is true formation resistivity (uninvaded zone). The net pay map closely mimics the gross interval map with respect to basic mound geometry and the location of thick pay areas (Figure 33; Plate 3). Contoured values range from 0 to 49 feet (15m). The thickest net pay area is located on the southernmost buildup where the c-18-A/94 P 10 has the maximum thickness of 49 feet (15 m). However, most of the larger producing wells have values that range from 23 - 36 feet (7 – 11 m) of net pay. The d-37-C/94 P 10 well has 36 feet (11m) of net pay and a cumulated production of 17.5 BCF. Net pay partially defines productivity and gives an indication of reservoir quality. Typically, low net-pay values of approximately 14 feet (4.59 m) have low production rates, whereas values from 15 to 40 feet (4.6 – 12.2m) have varied, but much higher production. The b-66-I/94 P10, which is the largest producing well within the study area at 28 BCF, has only 23 feet (7 m) of net pay. The d-35-A/94 P 10, with the highest net pay value of 39 feet (12m) has cumulated 17 BCF.

HPV Map

Hydrocarbon pore volume, (HPV) is a measure of hydrocarbon saturation. HPV is the product of average water saturation, average porosity, and feet of pay (Figure 34; Plate 4). HPV is calculated as (1-Swa)(PHI*H). This calculation makes the assumption that the pore volume not filled with water must be filled with gas. HPV values range from 0 to 2.4 feet (0.73m) with no well having an absolute zero value. HPV spatial distribution reflects the gross interval and the net pay maps. There are several obvious changes in the geometry in the southern portion of 94 P 10 and northern part of 94 P 7. For example, a zone of zero HPV cuts through the southwest corner of block H / 94 P 10, northwest corner of block A / 94 P 10 and into the northeast part of block B / 94 P 10. Another difference is the zone of zero HPV that extends from the west into the C / 94 P 10. With a few exceptions, thick pay areas are still thick on the HPV map. For instance, the southern mound of the middle buildup is much smaller and the small mound in west central portion of block G / 94 P 10 that had a gross interval value of 52 feet (16m), has a maximum HPV value of 1.8 feet (0.55m). In addition, the buildup located in the northern portions of blocks I and J of 94 P 7 now appears as a linear northwest/southeast trend. The edge of the buildup that partially extended into the southwest corner of the study are (Plate 4) is isolated from other buildups in terms of HPV. The area contained within the southern portion of block A / 94 P 15 has the highest value for HPV at 2.6 feet (0.8m). Eight of the nine wells drilled in close proximity to this high HPV area have cumulative production in excess of 1 BCF. The highest value is 17.6 BCF.

The relation of HPV to production is not always obvious. The d-37-I/94 P 10 has a HPV value of 2.85 and produced 17 BCF gas. The d-35-A/94 P 10 has an HPV value of 2.1 and a cumulative production of 17 BCF. Production from other wells is not as predictable. The a-89-I/94 P 10 is a 13.8 BCF well that is not defined effectively by HPV or any other maps. The a-89-I/94 P 10 has an HPV value of only 0.198, but has produced 13 BCF gas. The HPV map is another tool that demonstrates reservoir quality. HPV

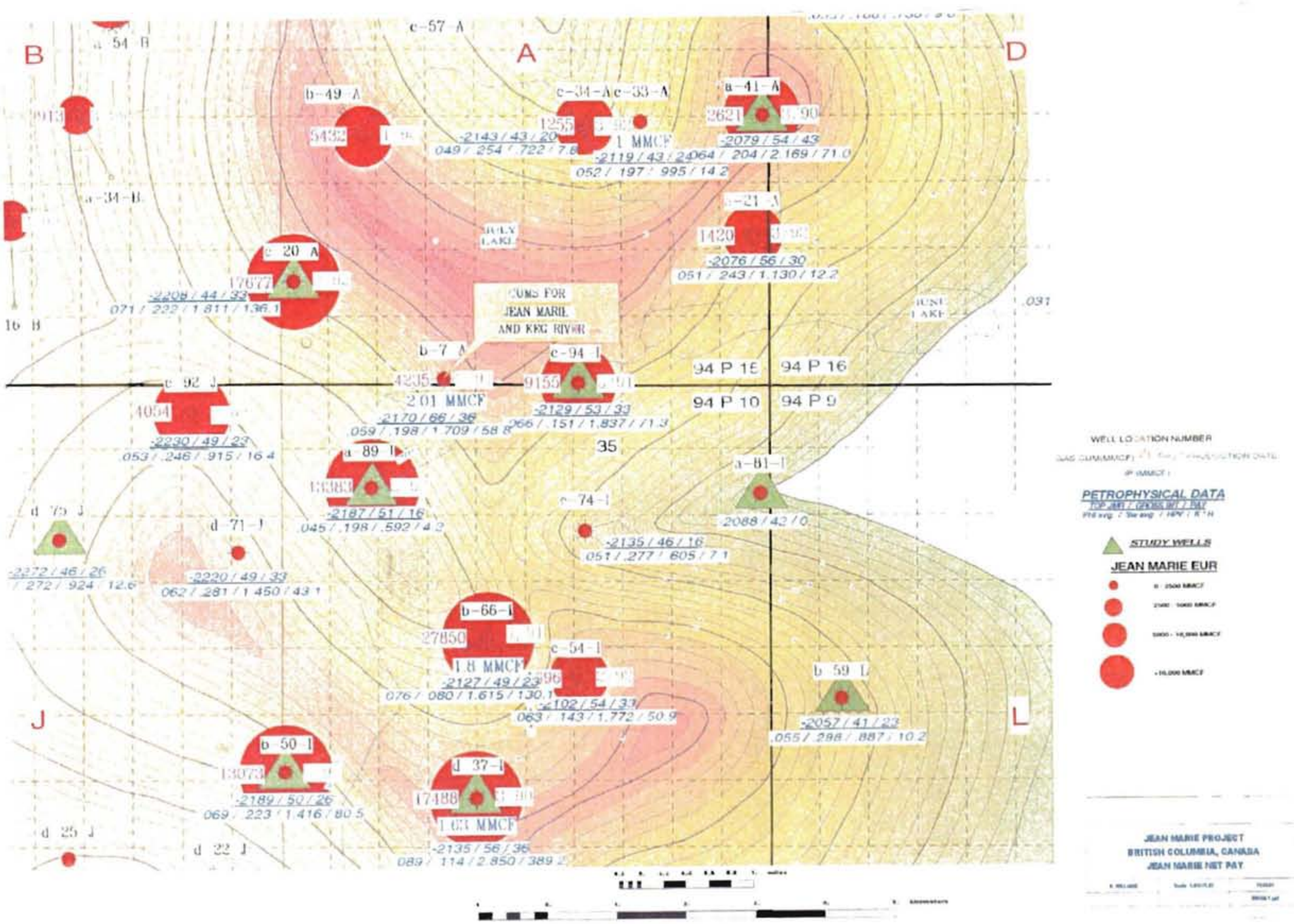


Figure 33. Net thickness map of the northern carbonate buildup.

identifies areas of reservoir that have a low average water saturation in relation to porosity feet and should result in higher productivity wells.

Permeability Feet Map

Permeability feet (K*H), is the product of net pay and average permeability. Permeability is calculated as 10^(((LN(PHI*(1-Sw))/.59)+5) (Heslop, 1996). Values for K*H range from 0 to 389 permeability feet, with contours from 1.3 to 320. The interval was calculated by doubling each successive contour. The K*H map resembles the HPV map (Figure 35; Plate 5). However, as mapping parameters become more defined, the overall area of potential production becomes smaller. This decrease is illustrated by K*H values. The zero line lies significantly closer to the areas of maximum thickness and the area of positive calculated K*H values is much smaller. For example, the area of zero K*H in blocks A, B and H of 94 P 10 covers almost 25% of both block A and H and a larger portion of block B. This is approximately four times the size of the same feature on the HPV map. In addition, there is an area of zero K*H values extending down from the north in the center of block A / 94 P 15 and a zero K*H area cutting across block C / 94 P 10 and continuing through northwestern block K to the center of block J / 94 P 7. As with other parameters, K*H does not always clearly reflect Jean Marie productivity. There are several wells where productivity, as represented by cumulative production, directly correspond to K*H. For instance, the a-81-I/94 P 10 well has a zero K*H value and was unproductive, whereas the d-37-I/94 P 10 well has the highest K*H value of 389

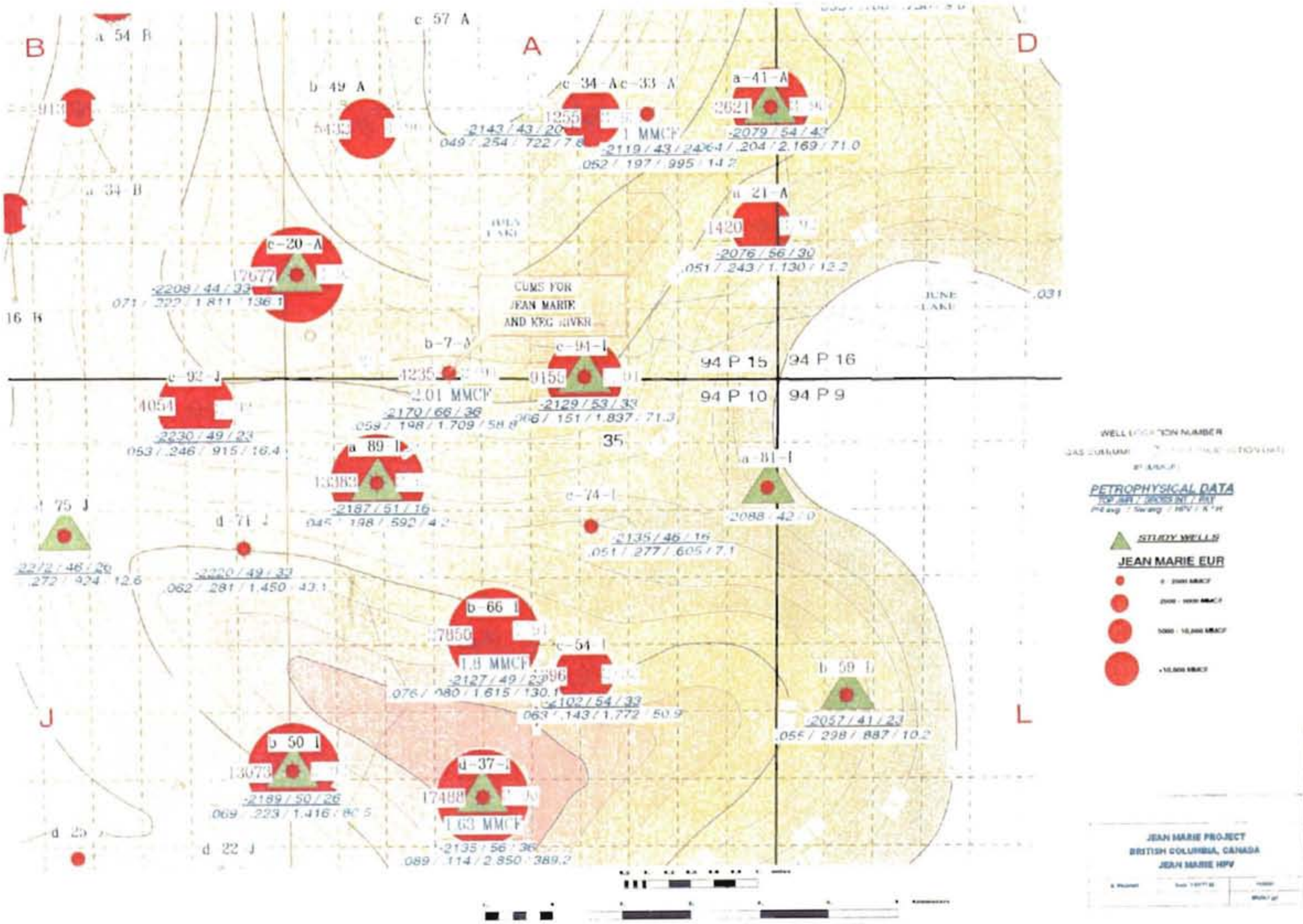


Figure 34. HPV map of the northern carbonate buildup

ft (118.5m) and produced 17.5 BCF. In addition, the c-20-A/94 P 15 well, the largest producer in the northern buildup, has a K*H value of 136 feet and a cumulative production of 17.6 BCF. Once again, the a-89-I/94 P 10 well is anomalous, with a K*H value of only 4.2 feet (1.3 m) but a cumulative production of 13 BCF. In addition, the b-22-B/94 P 10, which has a K*H value of 42 feet (13 m), has no reported production. The well was drilled as a Keg River test in 1976 and the lack of productivity could be attributed to mechanical failure or formation damage. K*H values reflect some production trends, but anomalies persist. When net pay, HPV and K*H are overlain, productivity (in terms of total gas production) is better defined and develops trends that may predict areas of additional productivity.

Structure Map

The structure map demonstrates the regional dip direction and structural features in the area (Figure 36; Plate 6). It is constructed on the top of the Jean Marie, which is also represents the base of the Red Knife Shale. Subsea values were calculated by subtracting the KB or ground elevations at each well from the measured depth at the top of the Jean Marie. The lowest mapped point is –2401 feet (-732 m) and the highest is a subsea depth of -2037 feet (621 m). The regional dip is very gentle to the west at a rate of 0.5 %; strike is generally north south. There are no major faults or sizable structural elements present. There are only a few minor changes in dip within the study area. This supports the premise that a structural trapping mechanism and a strong water drive are not associated with Jean Marie production.

Gas Saturation Map

Gas saturation is much like HPV since it is based on the assumption that pore volume not filled with water must be filled with gas. However, gas saturation does not directly take into consideration average porosity. Instead, averaged values are taken from the pay intervals that have a water saturation of less than 50% and porosity greater than 3%. Gas saturation is simply calculated as (1-Swa). The gas saturation map most closely resembles the K*H an HPV maps (Figure 37; Plate 7). The contour interval is 0.05, and contour values range from 0.55 to 0.90. This map suite comes closest to explaining the productivity of the a-89-A/94 P 10 well, which has 80 % gas saturation. The largest producing well in the study area, the b-66-I/94 P 10 well has the largest gas saturation of 92 %. Gas saturation appears to be the best indicator of productivity, since better wells have relatively high values. However, there are still anomalous wells with high gas saturation, but poor deliverability and total production.

Average Porosity Map

Average porosity defines areas of higher porosity (Figure 38; Plate 8). It is calculated by averaging porosity in pay intervals (greater than 3% porosity and water saturation less than 50%). Average porosity values range from 7 to 9 (0.07 - 0.09) percent with a contour interval of 1 % (0.01). Anomalous wells are evident on the average porosity map. The a-89-I/94 P 10 well has less than 5% porosity. The largest, which is the b-66-I/94 P10 well, has only 7% porosity.

Average Permeability Map

The average permeability map identifies locations of areas with high permeability (Figure 39; Plate 9). Average permeability is calculated using the formula 10^(((LN(PHI*(1-Sw))/.59)+5)(Heslop, 1996). Values of permeability within the net pay intervals are averaged. Values for average permeability range from 0.031 to 16 millidarcies and are mapped similar to K*H, where each successive contour value is 2 times the previous one. Average permeability does a fair job of defining productive trends, with the exception of anomalous wells like the a-89-I/94 P 10 well.

Summary

All maps illustrate the erratic distribution of Jean Marie reservoirs. These maps do not take into consideration porosity types, facies distribution or fracture patterns. There is no effective means to evaluate these from wireline logs alone. However, when used in conjunction with core data, certain log responses can be indicative of reservoir character. One thing that is very evident in log-derived calculations is that any minute change in any of these parameters results in major changes in productivity. The two parameters that are most responsible for generating changes in permeability are water saturation and porosity. For example, Jean Marie limestone with a water saturation of 40% and porosity of 6% has a calculated permeability of 0.232 millidarcies. If the water saturation increases 10 % to 50% Sw, permeability drops to 0.114 millidarcies, or less than half of the value of the first calculation.

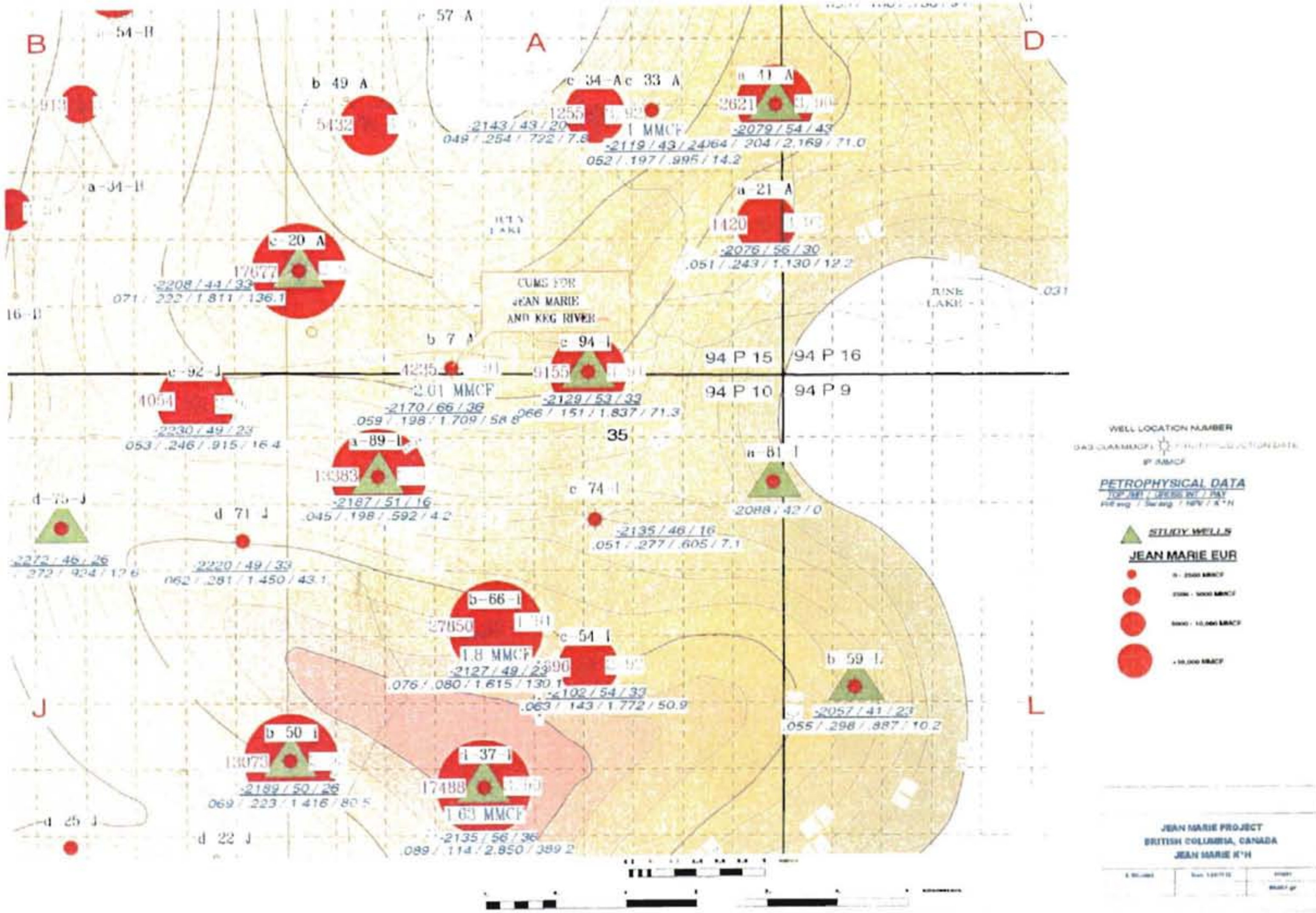


Figure 35. K*H map of the northern carbonate buildup

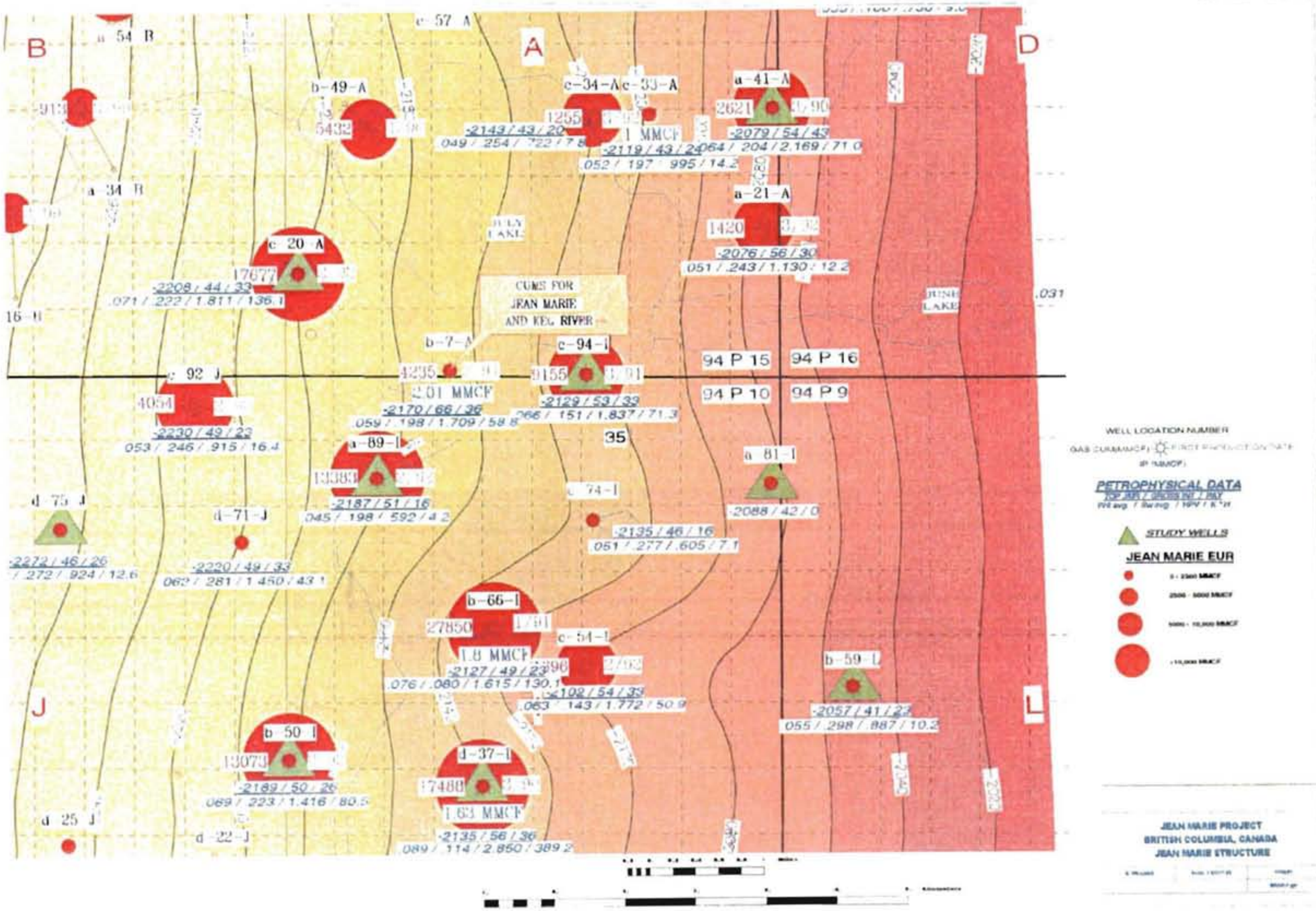


Figure 36. Structure map of the northern carbonate buildup.

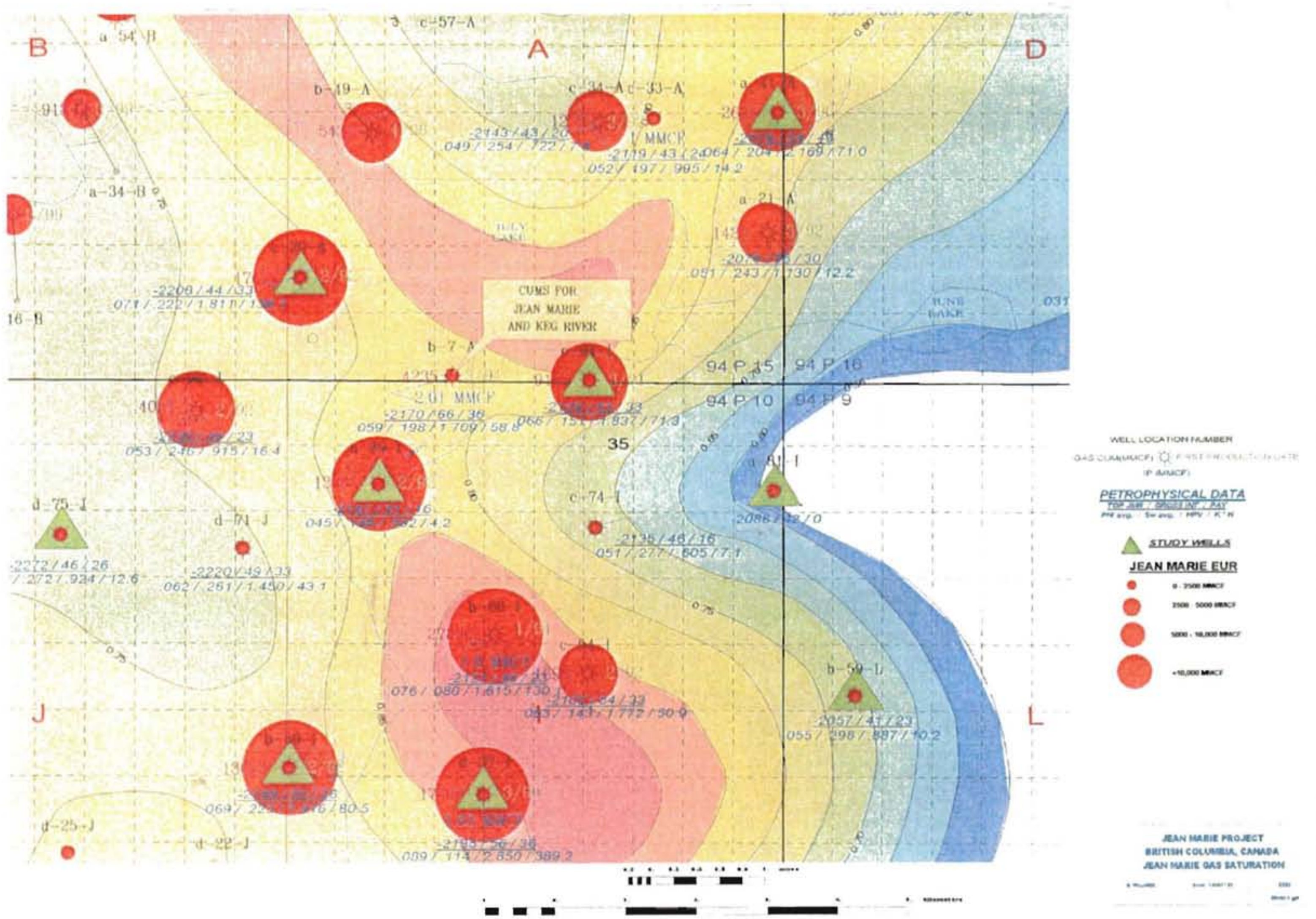


Figure 37. Gas saturation map of the northern carbonate buildup.

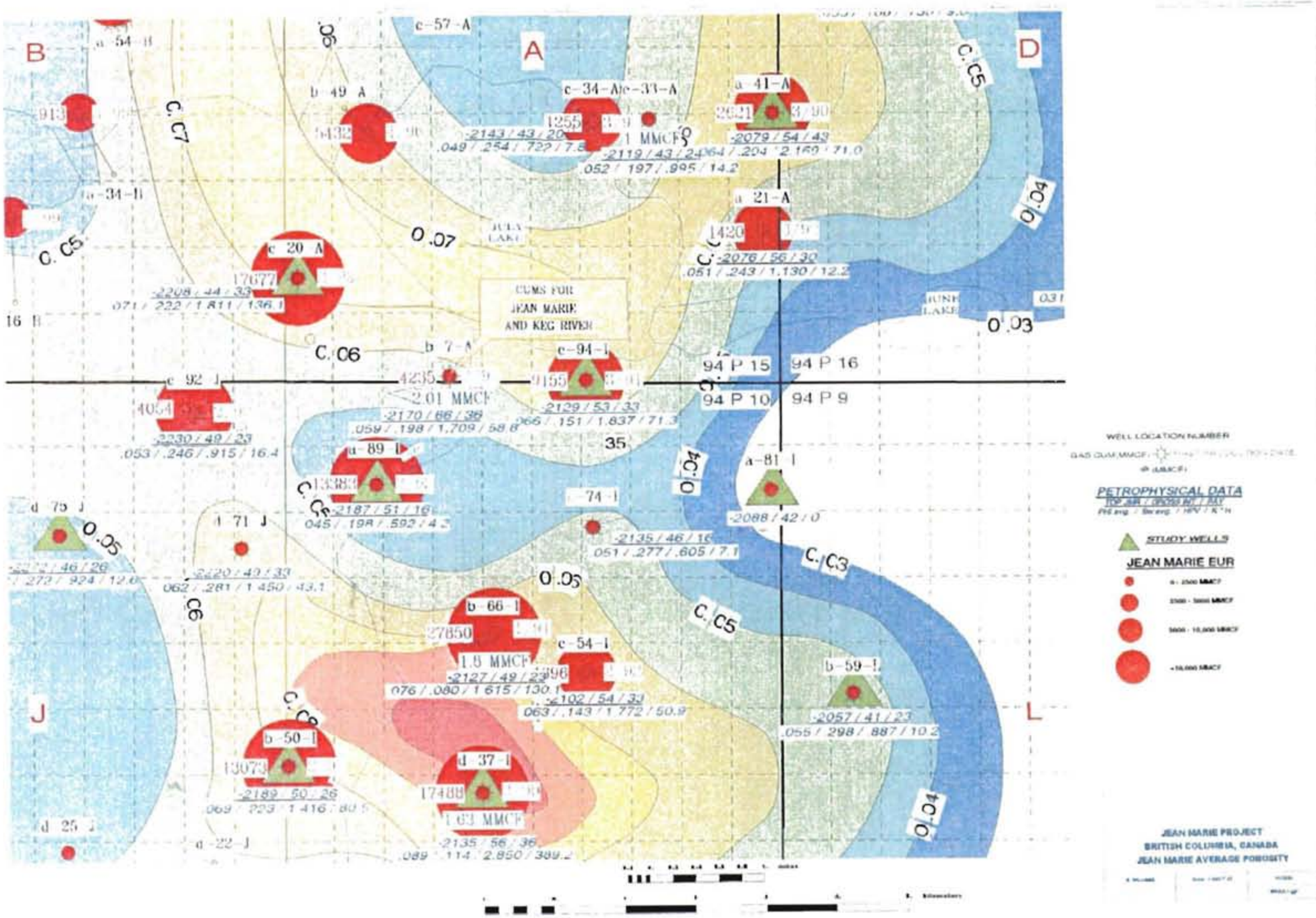


Figure 38. Average porosity map of the northern carbonate buildup.

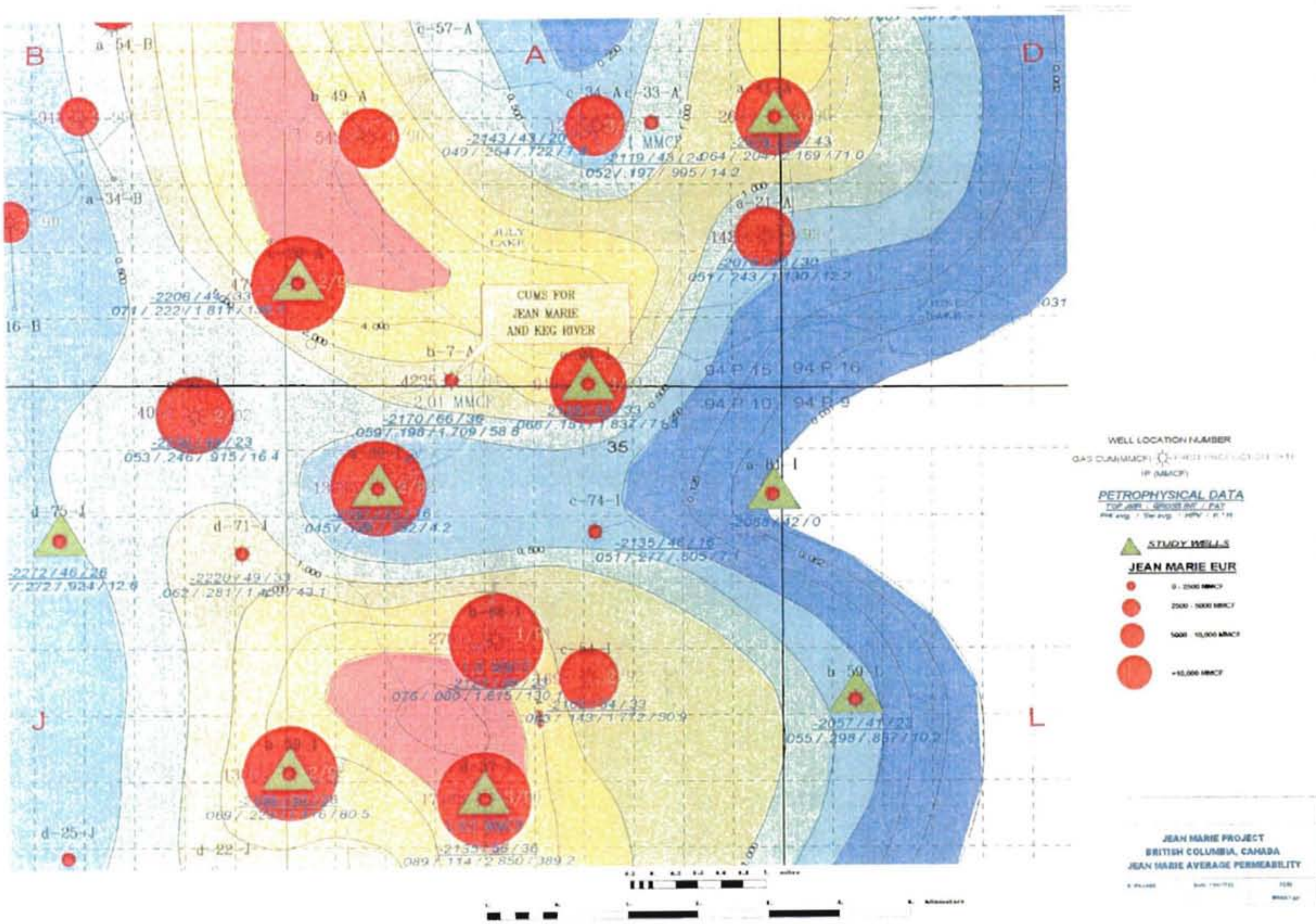


Figure 39. Average permeability map of the northern carbonate buildup.

Cross Sections

Four stratigraphic cross sections (Plate 10,11, 12, 13 and 14) were constructed for the study area to illustrate changes in thickness at various locations in the carbonate buildups. The interval included in these cross sections extends from the limestone marker just above the Red Knife Shale to a point below the top of the Ft. Simpson Shale. The limestone marker is shown in blue, the Red Knife Shale in red, the Jean Marie in green and the Ft. Simpson Shale in tan. The datum is the shale marker that occurs in the lower portion of the Jean Marie (Plates 11, 12, 13 and 14). Pay intervals are shown in yellow (Sw <50% and porosity greater than 3%). Also shown on the cross sections are cored intervals, drill stem tests and perforations. Cored intervals are illustrated as dark green rectangles, DST's are blue triangles and perforations are shown with red rectangles. Cored wells that were examined for this study are indicated by red well symbols. Excel spreadsheets containing log, DST recoveries and production data are posted below the log for each well. Cross section A-A' (Plate 11) contains 17 wells, 9 of which are study wells. A-A' runs from north to south, from the c-74-A/94 P 15 well to the b-90-I/94 P 7 well. B-B' (Plate 12) is located on the northern end of the study area and extends east to west. It contains six wells, including one study well and extends from the d-84-C/94 P 15 well to the b-68-D/94 P 16 well. The middle, east-west cross section (C-C') (Plate 13). contains five wells, including three study wells. It begins at the c-89-G/94 P 10 well and terminates at the b-62-H/94 P10. The southernmost cross section (D-D') (Plate 14) is an east west cross section. Cross section D-D' contains five wells, including two study wells. D-D' starts with the d-53-C/94 P 10 and ends at the d-11-A/94 P 10.

Separate from the cross sections are diagrams of individual study wells that relate facies, completion information and production (Figure 40). Representative data that compare a poor producing well with a high-volume well are shown in Figure (41). Diagrams for most study wells are in Appendix I.

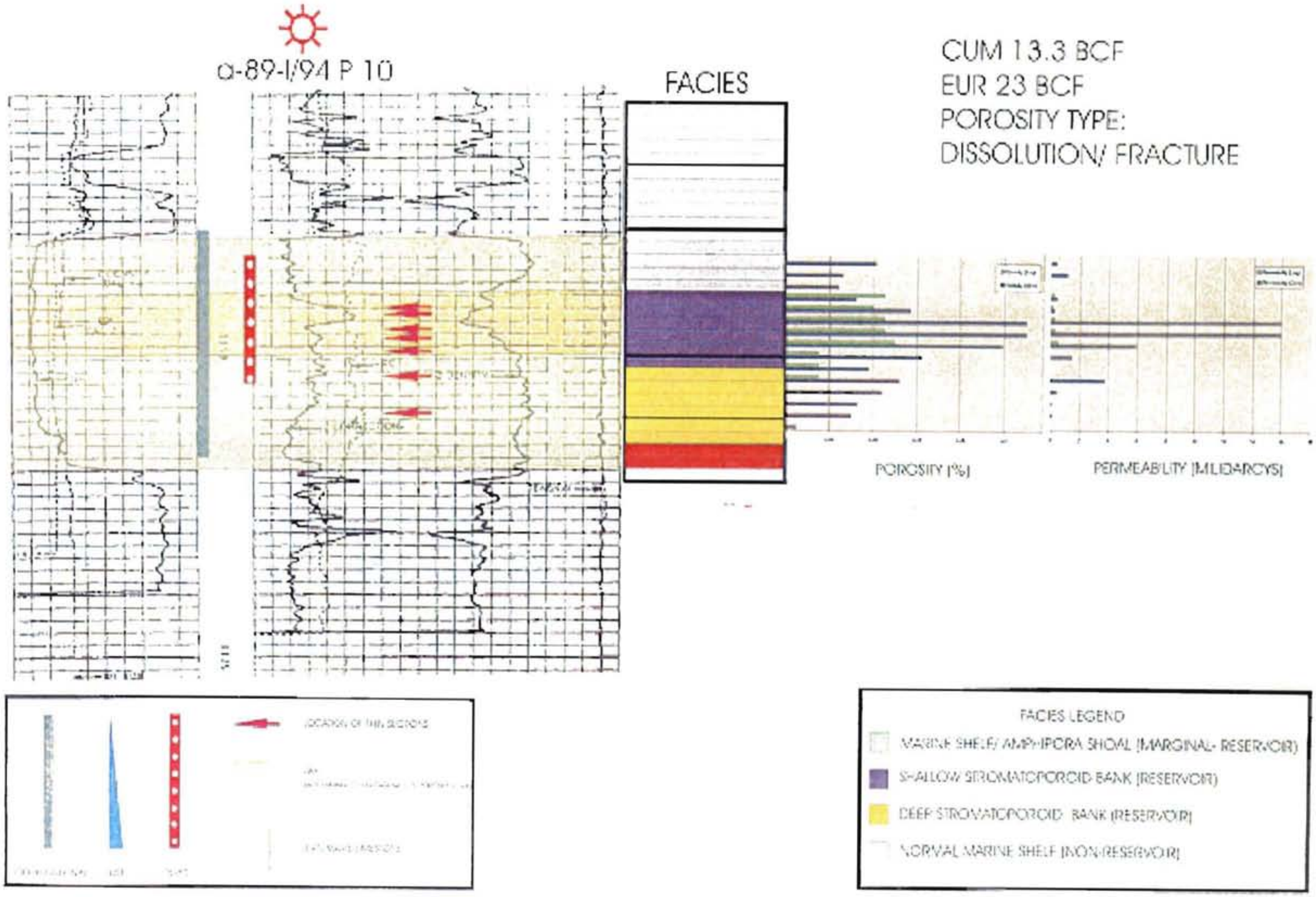


Figure 40. Diagram comparing wireline log data, core data and facies distribution, porosity type and cumulative production. Note that core porosity (blue) exceeds log porosity (green) in most cases. A correlation between SSB and porosity and permeability is readily evident in this figure.

WELL	GROSS INTERVAL THICKNESS (m)	PAY (m)	LOG AVE POROSITY (%)	CORE AVE POROSITY (%)	POROSITY TYPE	LOG AVE PERMEABILITY (millidarcys)	CORE AVE PERMEABILITY (millidarcys)	AVE WATER SATURATION %	PHI*H (ft)	HPV (ft)	K*H (ft)	MSASF (m)	SSBF (m)	DSBF (m)	NMSF (m)	CUMULATIVE GAS (BCF)	EUR (BCF)
Canadian Natural Resources d-19-G/94 P10	14	5	0.051	0.044	Fracture/Dissolution	0.769	14.53	0.141	0.843	0.725	12.6	4	0	6	7.5	2.5	4.9
Canadian Hunter d-37-I/94 P 10	17	11	0.089	0.082	Dissolution	10.784	84	0.114	3.215	2.85	389.2	4.5	1	9	2	17	23

Figure 41. Comparision of data from a high cumulative production well vs. a lower cumulative production well. Note that the highly productive d-37-I/94 P 10 contains more SSB, DSB and slightly more MSAS biofacies than the d-19-G/94 P 10

CHAPTER V

CONCLUSIONS

In the Jean Marie Member of the Red Knife Formation, reservoir quality and resultant gas production are primarily controlled by biofacies and resultant lithofacies, fracturing and dissolution. Specific conclusions include:

1. Jean Marie facies appear to be the dominant control of productivity. Four generalized facies are recognized. They are the normal marine shelf (NMS), deep stromatoporoid bank (DSB), shallow stromatoporoid bank (SSB) and the marine shelf/amphipora shoal (MSAS).
2. The deep stromatoporoid (DSB), shallow stromatoporoid bank (SSB) and marine shelf/amphipora shoal (MSAS) biofacies contain the most solution-enlarged pores and fractures. The brittle nature of these facies is believed to have facilitated their fracturing.
3. Locating and delineating biofacies and lithofacies is key to finding productive Jean Marie reservoirs. Shallow stromatoporoid bank facies are grain rich and develop into good reservoirs. Shallow stromatoporoid bank biofacies are commonly found near the crest of the buildups. Porosity is best developed where stromatoporoid sheltering on the seeward side, prevented the winnowing out of *renalcis*. Where the deep stromatoporoid bank and the normal marine

shelf/amphipora shoal biofacies are more evenly distributed throughout the buildups, porosity is enhanced by solution enlarged fractures.

4. Mud-rich normal marine shelf (NMS) lithofacies did not develop into reservoirs
5. The Cordova Embayment developed as a result of differential compaction of thicker Ft. Simpson shale between highs on the Keg River. Drape over these deeper highs is also believed to be a primary mechanism for the generation of fractures in the Jean Marie. Post-fracturing fluid migration and dissolution was responsible for enlarging the Jean Marie porosity network. Evidence for both meteoric and hydrothermal fluid migration exists.
6. Structure maps of the Jean Marie shelf area show very little evidence of folding and faulting. Gas accumulation in the Jean Marie is entirely stratigraphically controlled.
7. Jean Marie reservoirs are underpressured with respect to hydrostatic pressure. Generation of this low pressure is not well understood, but may relate to expansion of porosity by dissolution or cooling of the reservoir following oil migration and gas generation.
8. Mapping provided a methodology to improve predictability of Jean Marie reservoir trends. The best correlations between cumulative gas production and wireline log parameters were provided by the gas saturation, average permeability and K*H maps. They all relate directly to reservoir quality and rock properties. Therefore it is believed an approach that uses available rock, wireline and production data can improve predictability of Jean Marie reservoir trends.

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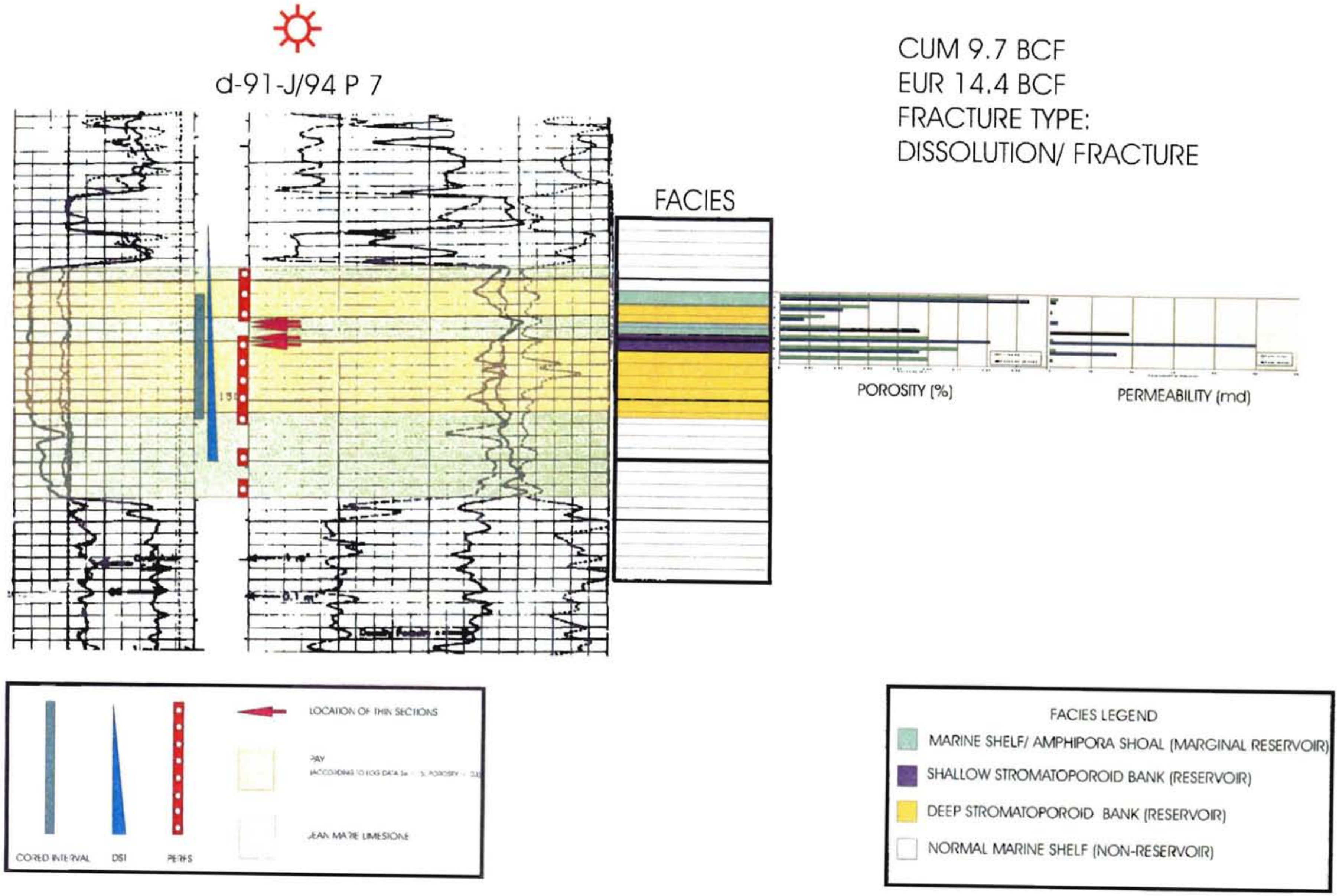
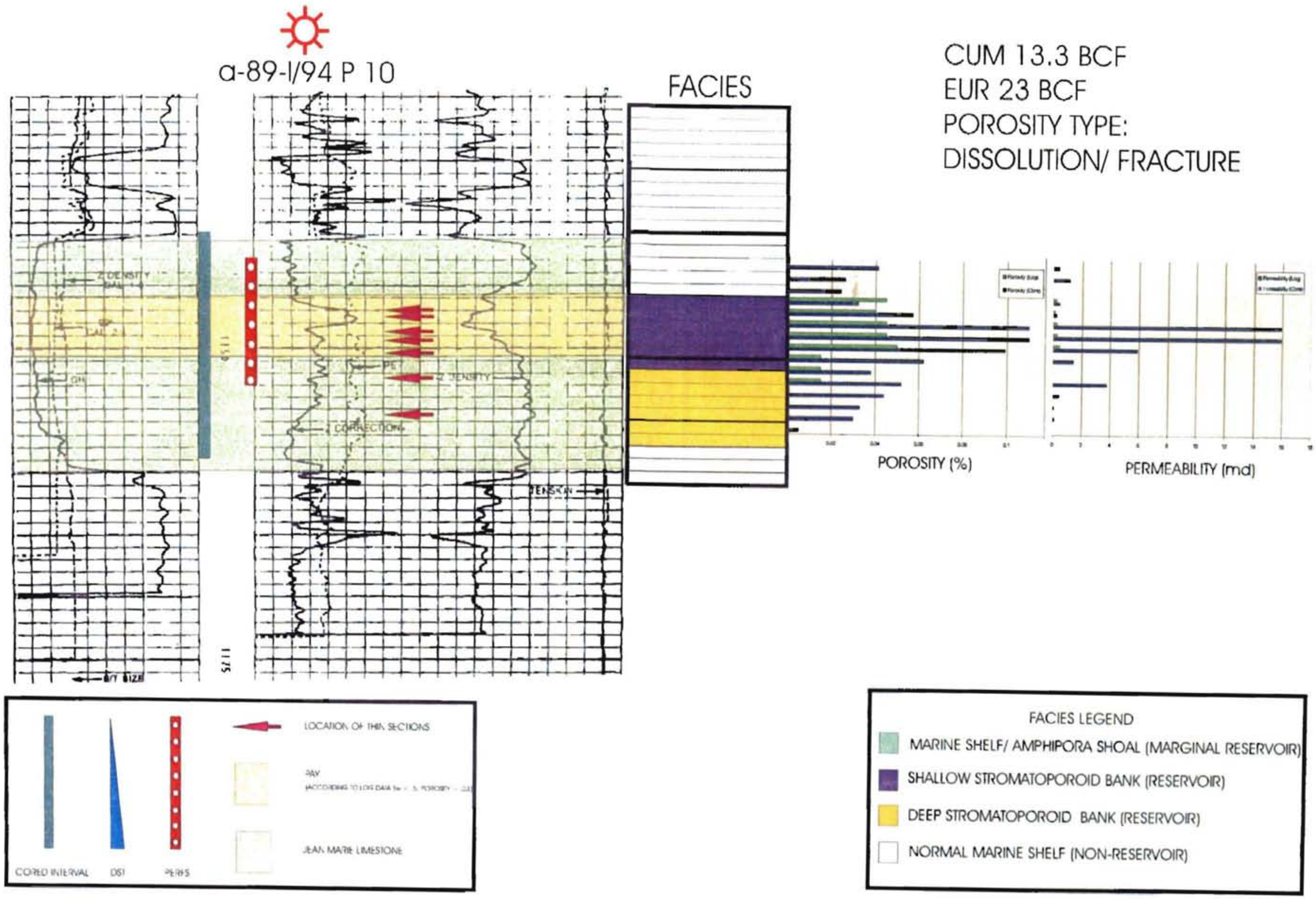
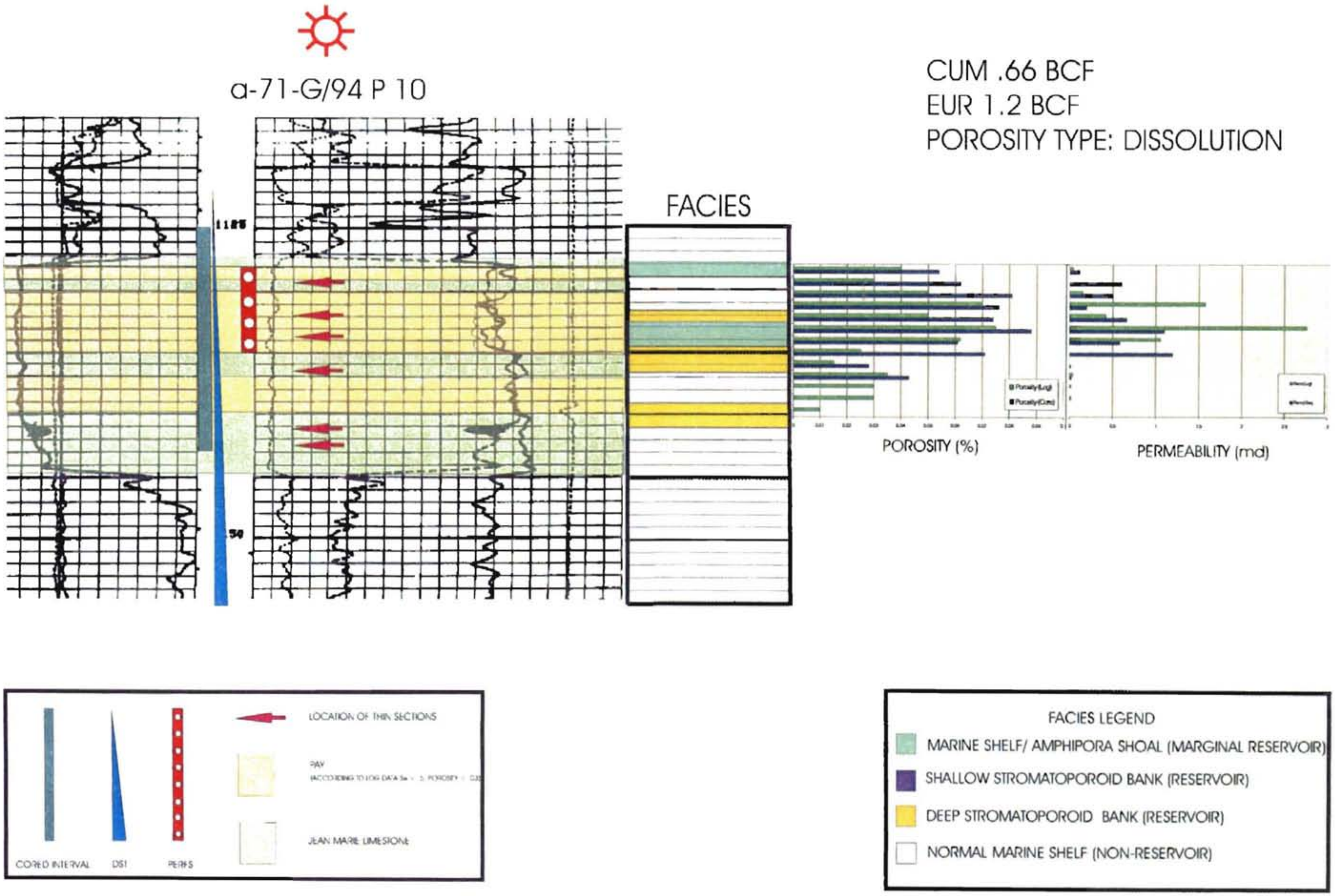
APPENDIX A

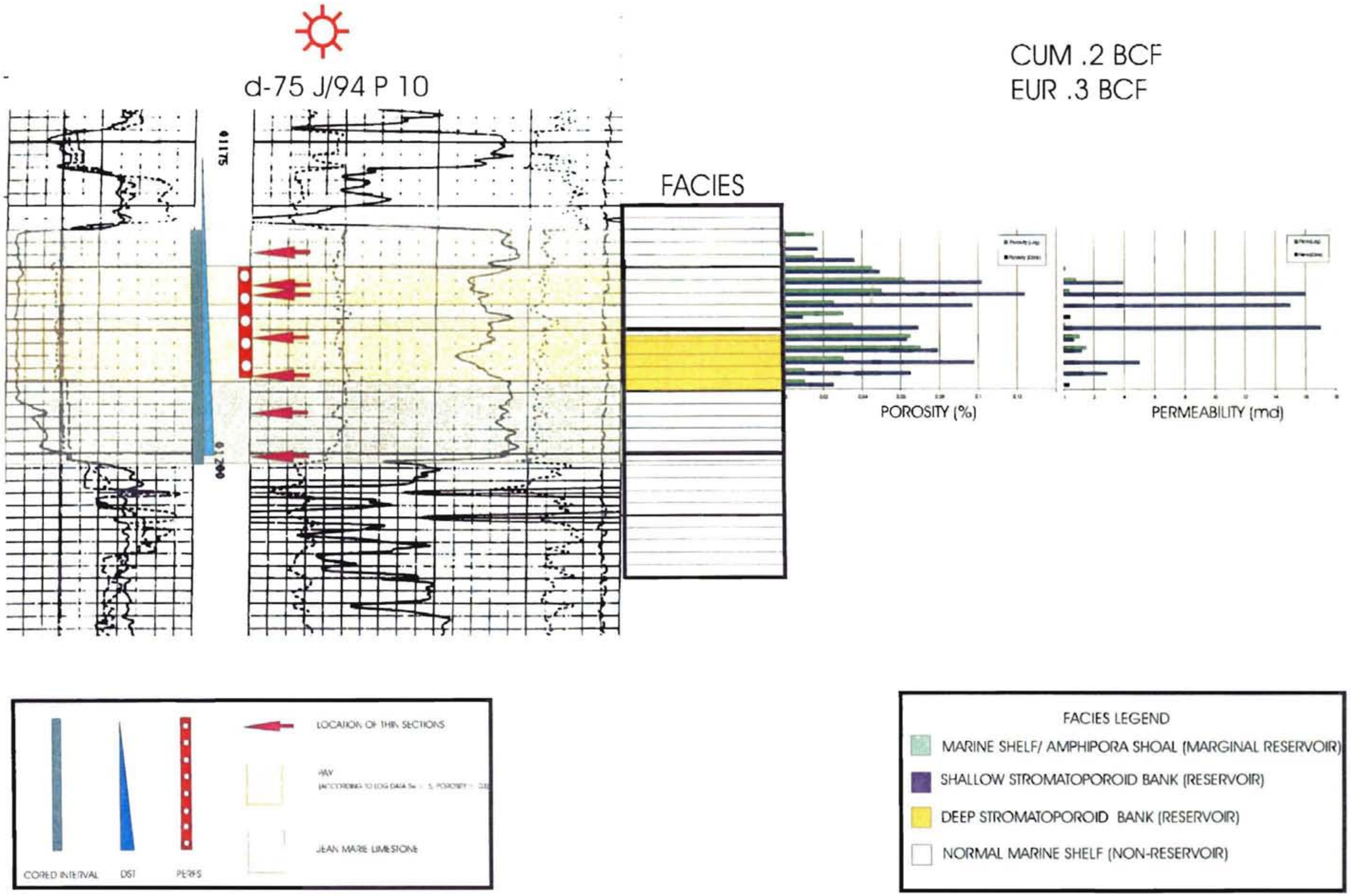
WIRELINE LOG DATA SUMMARY

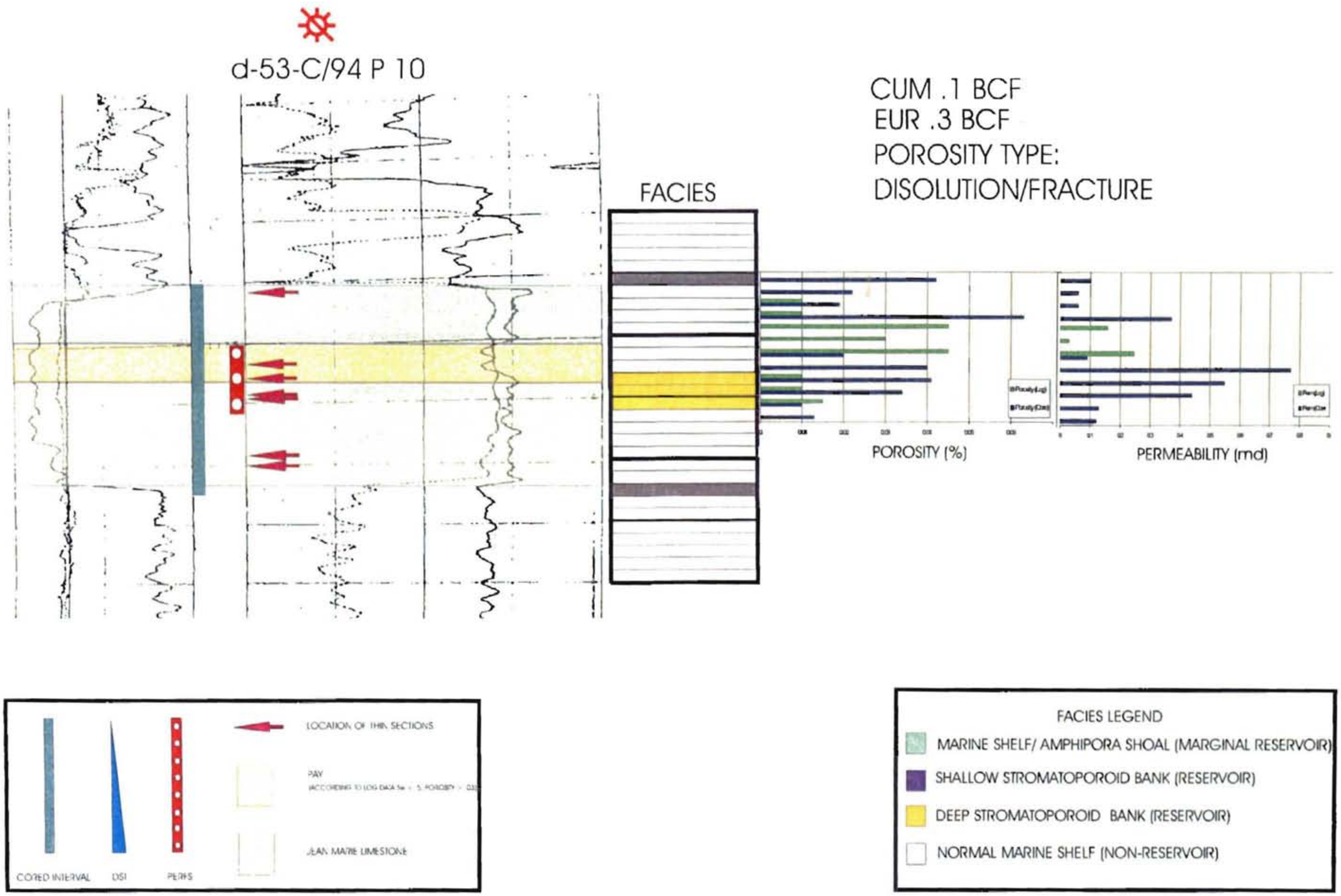

d-91-J/94 P 7
CUM 9.7 BCF
EUR 14.4 BCF
FRACTURE TYPE:
DISSOLUTION/ FRACTURE
FACIES
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DSI
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

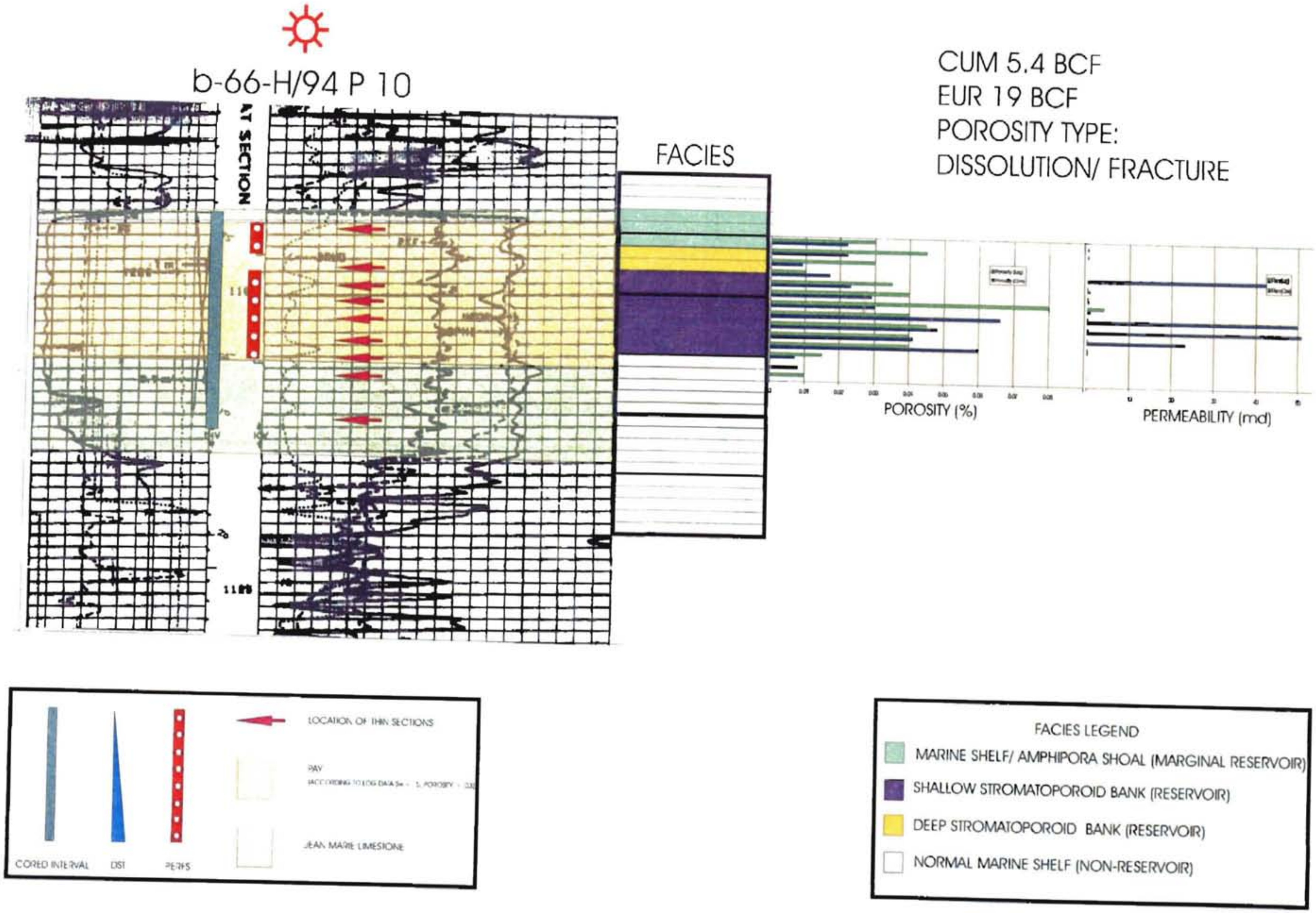


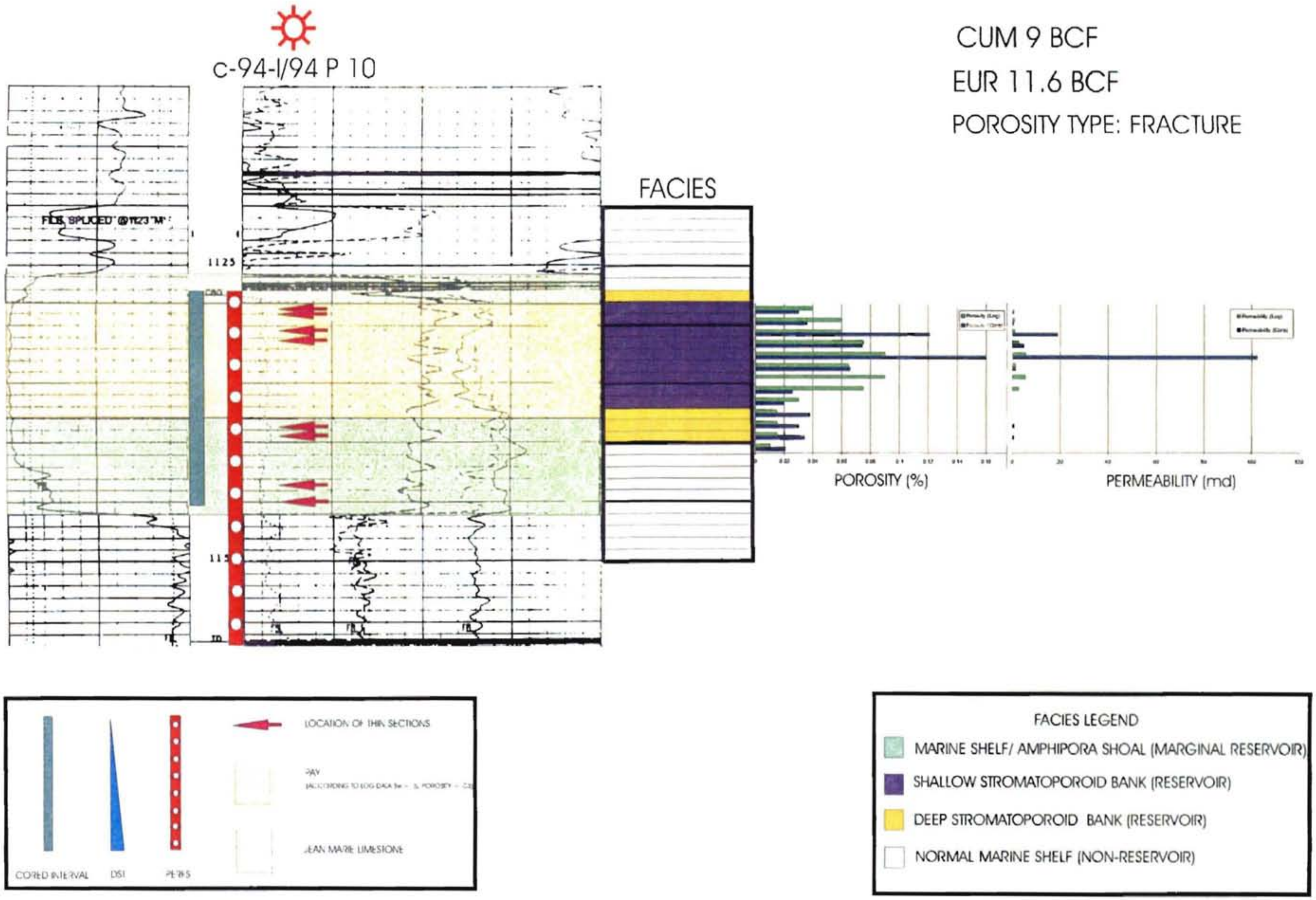
a-89-I/94 P 10
FACIES
CUM 13.3 BCF
EUR 23 BCF
POROSITY TYPE:
DISSOLUTION/ FRACTURE
Z DENSITY
CAL
GR
PE
Z CORRECTION
DENSITY
BIT SIZE
POROSITY (%)
PERMEABILITY (md)
CORED INTERVAL
DST
PERFS
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

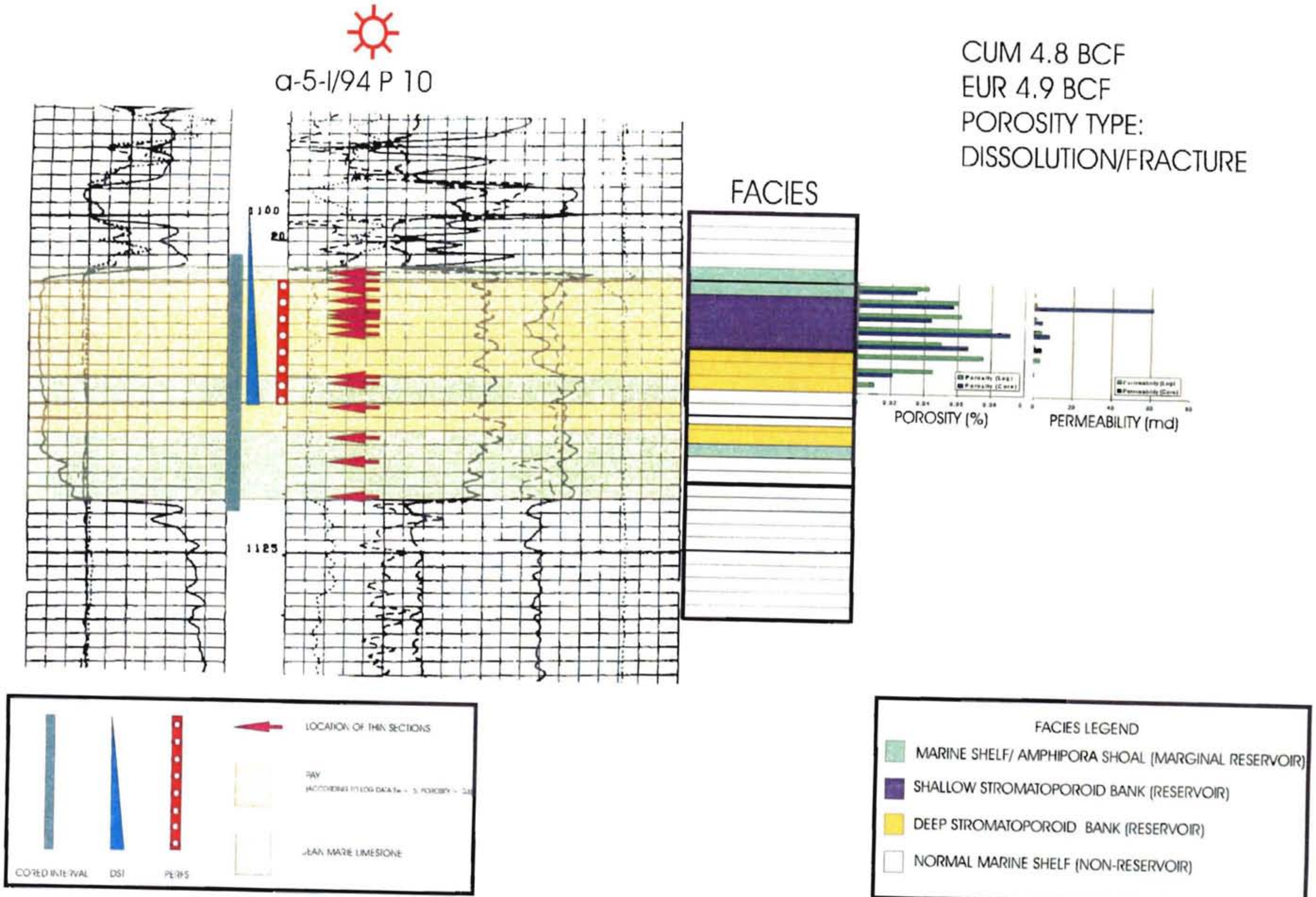

a-71-G/94 P 10
CUM .66 BCF
EUR 1.2 BCF
POROSITY TYPE: DISSOLUTION
FACIES
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DST
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

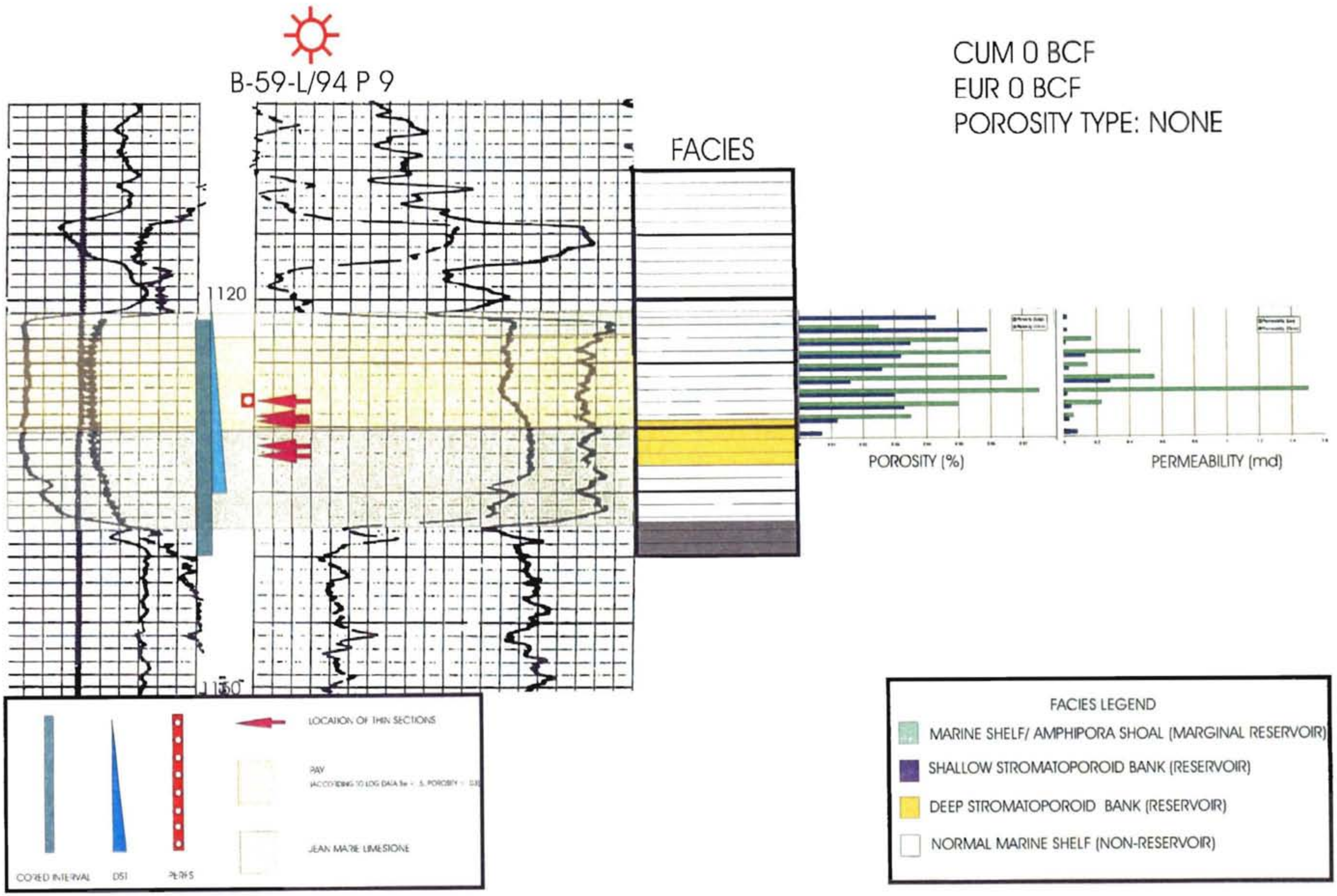

d-75 J/94 P 10
CUM .2 BCF
EUR .3 BCF
FACIES
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DST
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)


d-53-C/94 P 10
CUM .1 BCF
EUR .3 BCF
POROSITY TYPE:
DISOLUTION/FRACTURE
FACIES
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DSI
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)


b-66-H/94 P 10
FACIES
CUM 5.4 BCF
EUR 19 BCF
POROSITY TYPE:
DISSOLUTION/ FRACTURE
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DST
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

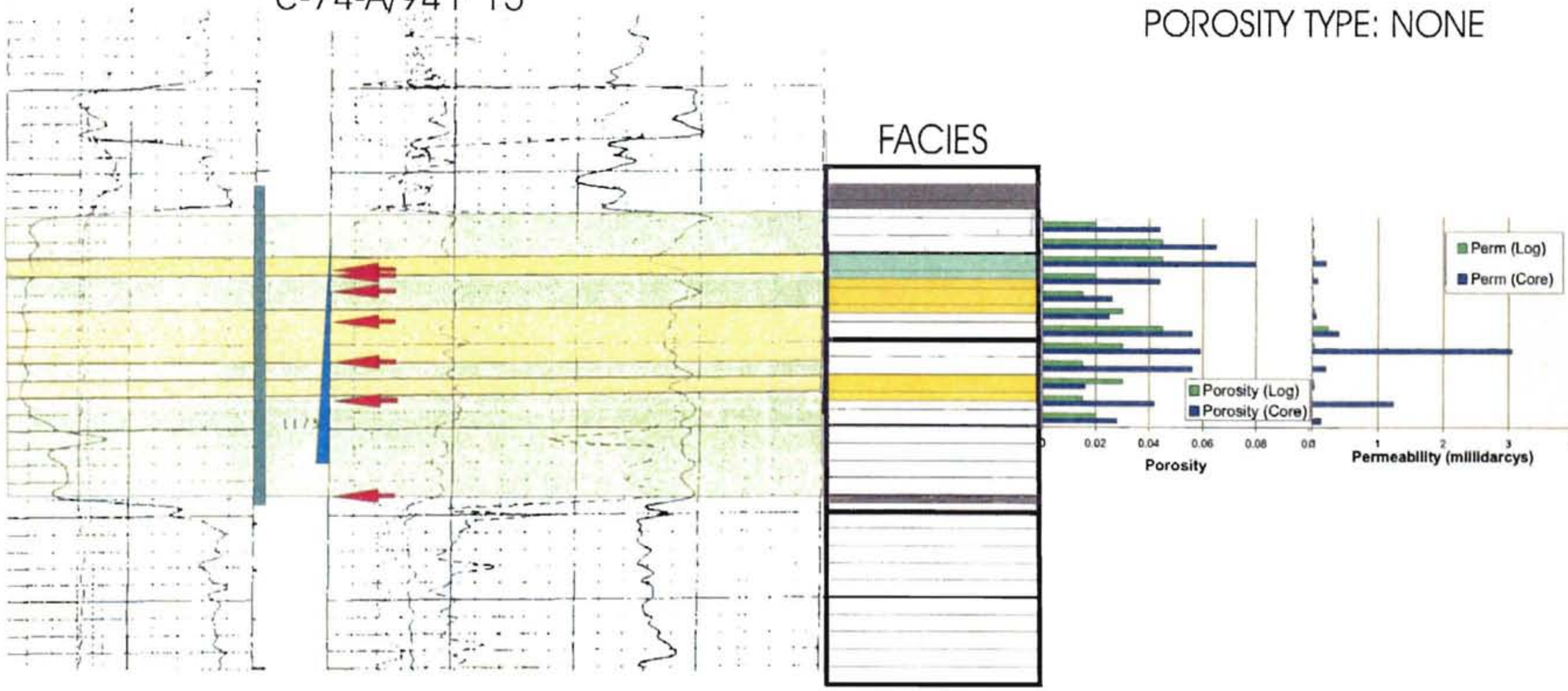

c-94-I/94 P 10
CUM 9 BCF
EUR 11.6 BCF
POROSITY TYPE: FRACTURE
FACIES
FILE SPLICED @1123 "M"
1125
POROSITY (%)
PERMEABILITY (md)
CORED INTERVAL
DSI
PERFS
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

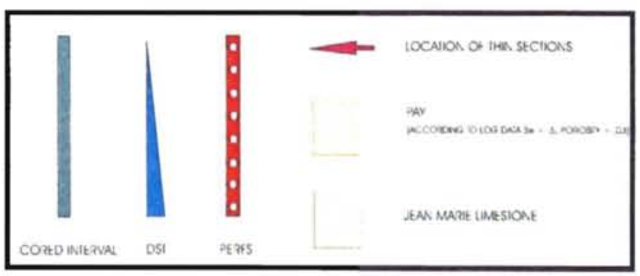

a-5-I/94 P 10
CUM 4.8 BCF
EUR 4.9 BCF
POROSITY TYPE:
DISSOLUTION/FRACTURE
FACIES
1100
1125
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DST
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

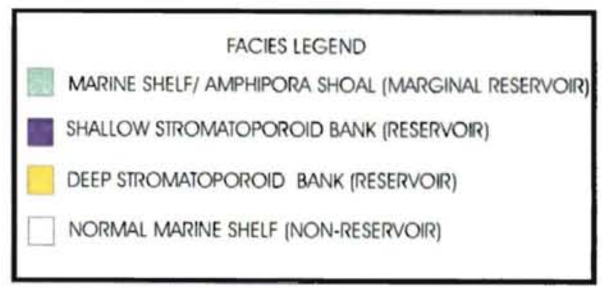

B-59-L/94 P 9
CUM 0 BCF
EUR 0 BCF
POROSITY TYPE: NONE
FACIES
1120
1150
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DST
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

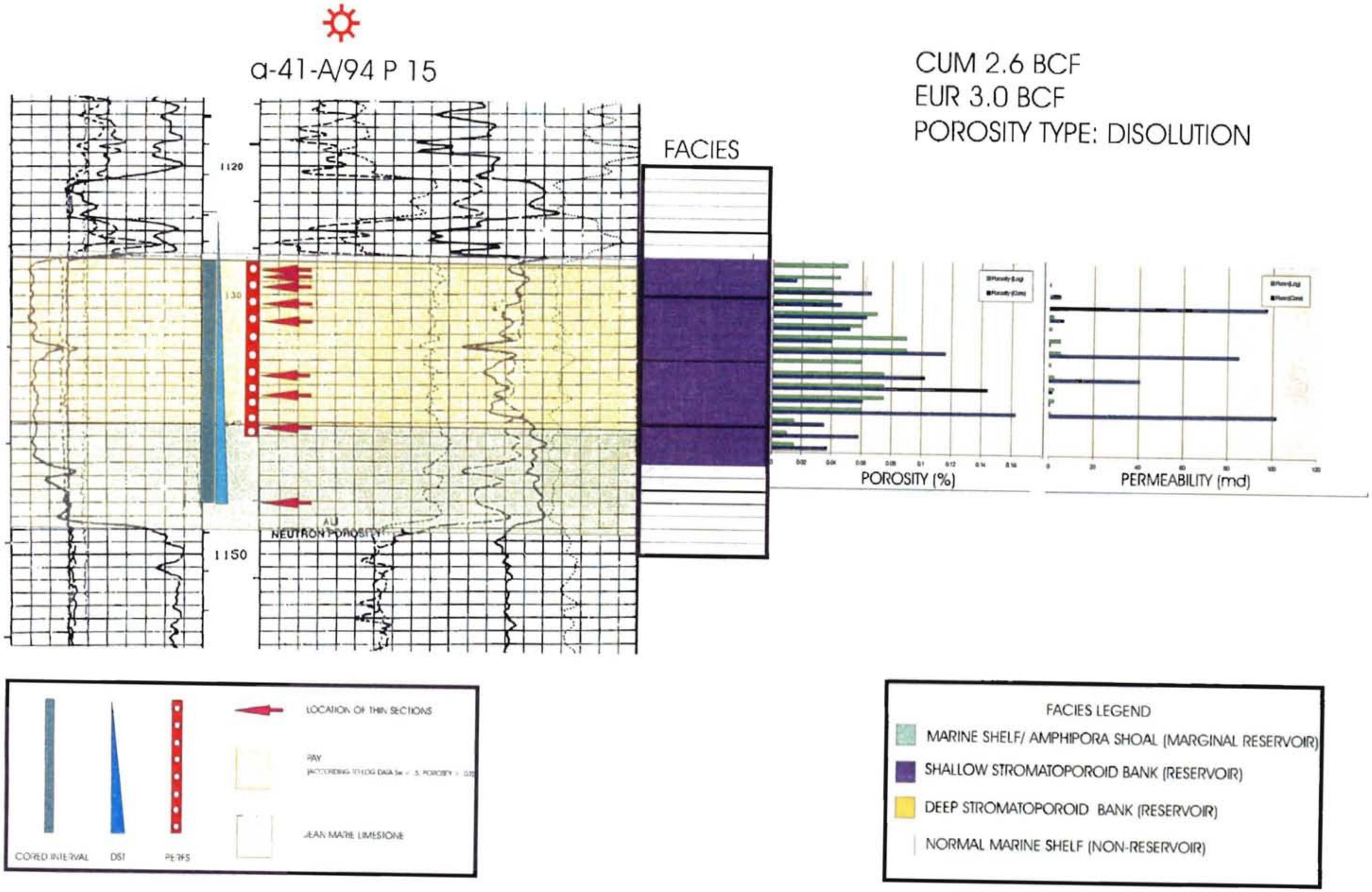
c-74-A/94 P 15

CUM 0 BCF
EUR 0 BCF
POROSITY TYPE: NONE








a-41-A/94 P 15
CUM 2.6 BCF
EUR 3.0 BCF
POROSITY TYPE: DISOLUTION
FACIES
1120
1150
NEUTRON POROSITY
POROSITY (%)
PERMEABILITY (md)
LOCATION OF THIN SECTIONS
PAY
JEAN MARIE LIMESTONE
CORED INTERVAL
DST
PERFS
FACIES LEGEND
MARINE SHELF/ AMPHIPORA SHOAL (MARGINAL RESERVOIR)
SHALLOW STROMATOPOROID BANK (RESERVOIR)
DEEP STROMATOPOROID BANK (RESERVOIR)
NORMAL MARINE SHELF (NON-RESERVOIR)

Plates 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13 and 14

PLATE 1
FENCE DIAGRAM SHOWING DISTRIBUTION OF DEPOSITIONAL FACIES


94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
JULY LAKE
KIMEA LAKE
CUMS FOR JEAN MARIE AND KEG RIVER
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
PLATE 2
HELMET NORTH-JULY LAKE
BRITISH COLUMBIA, CANADA
JMR GROSS INTERVAL ISOPACH
B. WILLIAMS
Scale 1:28000.
4/24/02
BWGI.gpf


94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
JULY LAKE
JUNE LAKE
KIMEA LAKE
CUMS FOR
JEAN MARIE
AND KEG RIVER
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
PLATE 3
HELMET NORTH-JULY LAKE
BRITISH COLUMBIA, CANADA
JMR NET PAY
B. WILLIAMS
Scale 1:28000.
4/24/02

Scale 1:28000.

miles

kilometers

JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF) FIRST PRODUCTION DATE
IP (MMCF)

PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H

STUDY WELLS

JEAN MARIE EUR

0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF

PLATE 4		
HELMET NORTH-JULY LAKE BRITISH COLUMBIA, CANADA JMR HPV		
B. WILLIAMS	Scale 1:28000.	4/24/92


94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
JULY LAKE
JUNE LAKE
KIMEA LAKE
CUMS FOR JEAN MARIE AND KEG RIVER
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K*H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
PLATE 5
HELMET NORTH-JULY LAKE
BRITISH COLUMBIA, CANADA
JMR K*H
S. WILLIAMS
Scale 1:28000.
6/3/02


94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
CUMS FOR
JEAN MARIE
AND KEG RIVER
JULY LAKE
JUNE LAKE
KIMEA LAKE
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K*H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
PLATE 6
HELMET NORTH-JULY LAKE FIELDS
BRITISH COLUMBIA, CANADA
JMR STRUCTURE


94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
JULY LAKE
JUNE LAKE
KIMEA LAKE
CUMS FOR JEAN MARIE AND KEG RIVER
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
PLATE 7
HELMET NORTH-JULY LAKE FIELDS
BRITISH COLUMBIA, CANADA
JMR GAS SATURATION
B. WILLIAMS
Scale 1:28000.
4/24/02


94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
JULY LAKE
JUNE LAKE
KIMEA LAKE
CUMS FOR JEAN MARIE AND KEG RIVER
2.01 MMCF
1.8 MMCF
1.63 MMCF
2.93 MMCF
1.05 MMCF
1.145 MMCF
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
PLATE 8
HELMET NORTH-JULY LAKE
BRITISH COLUMBIA, CANADA
JMR AVERAGE POROSITY
B. WILLIAMS
Scale 1:28000.

JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF) FIRST PRODUCTION DATE
IP (MMCF)

PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H

STUDY WELLS

JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF

PLATE 9

HELMET NORTH-JULY LAKE
BRITISH COLUMBIA, CANADA
JMR AVERAGE PERMEABILITY

B. WILLIAMS | Scale 1:25000. | 4/24/92

PLATE 10
HELMET NORTH-JULY LAKE FIELDS
BRITISH COLUMBIA, CANADA
CROSS SECTION INDEX MAP
B. WILLIAMS
Scale 1:28000.
JEAN MARIE WELLS
WELL LOCATION NUMBER
GAS CUM (MMCF)
FIRST PRODUCTION DATE
IP (MMCF)
PETROPHYSICAL DATA
TOP JMR / GROSS INT / PAY
PHI avg. / Sw avg. / HPV / K * H
STUDY WELLS
JEAN MARIE EUR
0 - 2500 MMCF
2500 - 5000 MMCF
5000 - 10,000 MMCF
+10,000 MMCF
CUMS FOR
JEAN MARIE
AND KEG RIVER
94P 10
94 P 15
94 P 16
94 P 10
94 P 9
94 P 7
94 P 8
JULY LAKE
JUNE LAKE
KIMEA LAKE
A
A'
B
B'
C
C'
D
D'

LOG DATA

WELL : c-74-A/94-P-15

	m	ft.	SS
KB :	507.3	1664	
LS MKR. :	1155.0	3789	
JMR :	1162.4	3814	-2149
SH. MKR. :	1175.0	3855	
LS MKR. - JMR		24	
JMR - SH. MKR.		41	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1163	-	1164		0.020	18	0.007	1.179	TITE	######
1164	-	1165		0.045	16	0.032	0.556	TITE	0.023
1165	-	1166		0.045	20	0.041	0.497	PAY	0.038
1166	-	1167		0.020	150	0.060	0.408	TITE	0.003
1167	-	1168		0.015	250	0.056	0.422	TITE	0.001
1168	-	1169		0.030	125	0.113	0.298	PAY	0.029
1169	-	1170		0.045	125	0.253	0.199	PAY	0.234
1170	-	1171		0.030	150	0.135	0.272	PAY	0.033
1171	-	1172		0.015	100	0.023	0.667	TITE	0.000
1172	-	1173		0.030	70	0.063	0.398	PAY	0.016
1173	-	1174		0.015	70	0.016	0.797	TITE	0.000
1174	-	1175		0.020	45	0.018	0.745	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1165	-	1166		0.045	20	0.041	0.497	PAY	0.038
1168	-	1169		0.030	125	0.113	0.298	PAY	0.029
1169	-	1170		0.045	125	0.253	0.199	PAY	0.234
1170	-	1171		0.030	150	0.135	0.272	PAY	0.033
1172	-	1173		0.030	70	0.063	0.398	PAY	0.016
PAY (FT.)			16	0.036		0.121	0.333		0.070
			PHI*H	0.591	HPV		0.394	k*h	1.1

COMMENTS:
Core 1162 - 1180.4
DST 1164 - 1177.2; Rec. 49' mud

WELL : c-34-A/94-P-15

	m	ft.	SS
KB :	479.6	1573	
JMR :	1132.9	3717	-2143
SH. MKR. :	1145.9	3759	
JMR - SH. MKR.		43	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1133	-	1134		0.030	30	0.027	0.609	TITE	0.003
1134	-	1135		0.030	50	0.045	0.471	PAY	0.009
1135	-	1136		-0.020	70	0.028	0.598	TITE	#####
1136	-	1137		0.015	90	0.020	0.703	TITE	0.000
1137	-	1138		0.045	90	0.182	0.234	PAY	0.196
1138	-	1139		0.050	80	0.200	0.224	PAY	0.312
1139	-	1140		0.050	70	0.175	0.239	PAY	0.288
1140	-	1141		0.060	85	0.306	0.181	PAY	0.783
1141	-	1142		0.060	90	0.324	0.176	PAY	0.802
1142	-	1143		0.020	50	0.020	0.707	TITE	0.000
1143	-	1144		0.000	60	0.000	#####	TITE	#####
1144	-	1145		0.000	40	0.000	#####	TITE	#####

COMMENTS:
Core 1131 - 1149.2
DST 1131 - 1148; GTS @ 89 MCF/D

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1134	-	1135		0.030	50	0.045	0.471	PAY	0.009
1137	-	1138		0.045	90	0.182	0.234	PAY	0.196
1138	-	1139		0.050	80	0.200	0.224	PAY	0.312
1139	-	1140		0.050	70	0.175	0.239	PAY	0.288
1140	-	1141		0.060	85	0.306	0.181	PAY	0.783
1141	-	1142		0.060	90	0.324	0.176	PAY	0.802
PAY (FT.)			20	0.049		0.205	0.254		0.398
			PHI*H	0.968	HPV		0.722	k*h	7.8

COMMENTS:
Pf. 1133 - 1144; Acid
1st prod. 3/92; produced 1 month
Continuous production since 3/97; maximum rate 1200 MCF/D
C - 570 MMCF to 7/31/98

WELL : c-20-A/94-P-15

	m	ft.	SS
KB :	483.9	1588	
LS MKR. :	1149.5	3771	
JMR :	1157.0	3796	-2208
SH. MKR. :	1170.5	3840	
LS MKR. - JMR		25	
JMR - SH. MKR.		44	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1157	-	1158		0.000	33	0.000	#####	TITE	#DIV/0!
1158	-	1159		0.045	30	0.061	0.406	PAY	0.073
1159	-	1160		0.070	25	0.123	0.286	PAY	0.837
1160	-	1161		0.050	80	0.200	0.224	PAY	0.312
1161	-	1162		0.080	110	0.704	0.119	PAY	3.192
1162	-	1163		0.120	80	1.152	0.093	PAY	17.401
1163	-	1164		0.105	70	0.772	0.114	PAY	9.445
1164	-	1165		0.105	65	0.717	0.118	PAY	9.267
1165	-	1166		0.060	80	0.288	0.186	PAY	0.762
1166	-	1167		0.045	80	0.162	0.248	PAY	0.182
1167	-	1168		0.030	60	0.054	0.430	PAY	0.013
1168	-	1169		0.015	60	0.014	0.861	TITE	0.000
1169	-	1170		0.010	50	0.005	1.414	TITE	#NUM!

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1158	-	1159		0.045	30	0.061	0.406	PAY	0.073
1159	-	1160		0.070	25	0.123	0.286	PAY	0.837
1160	-	1161		0.050	80	0.200	0.224	PAY	0.312
1161	-	1162		0.080	110	0.704	0.119	PAY	3.192
1162	-	1163		0.120	80	1.152	0.093	PAY	17.401
1163	-	1164		0.105	70	0.772	0.114	PAY	9.445
1164	-	1165		0.105	65	0.717	0.118	PAY	9.267
1165	-	1166		0.060	80	0.288	0.186	PAY	0.762
1166	-	1167		0.045	80	0.162	0.248	PAY	0.182
1167	-	1168		0.030	60	0.054	0.430	PAY	0.013
PAY (FT.)			33	0.071		0.423	0.222		4.148
			PHI*H	2.329	HPV		1.811	k*h	136.1

COMMENTS:
Core 1157 - 1174.2
DST 1151 - 1172.7; F/ 559 MCF/D
Pf. 1158 - 1169; Acid; FP 2/92 @ 10000 MCF/D;
C - 14927 MMCF thru 9/30/98
BHP 625# in 3/95

WELL : b-7-A/94-P-15

	m	ft.	SS
KB :		1542	
LS MKR. :		3695	
JMR :		3712	-2170
SH. MKR. :		3778	
LS MKR. - JMR		17	
JMR - SH. MKR.		66	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
3714	-	3716		0.045	150	0.304	0.181	PAY	0.254
3716	-	3718		0.060	60	0.216	0.215	PAY	0.662
3718	-	3720		0.045	70	0.142	0.266	PAY	0.166
3720	-	3722		0.015	70	0.016	0.797	TITE	0.000
3722	-	3724		0.015	80	0.018	0.745	TITE	0.000
3724	-	3726		0.045	80	0.162	0.248	PAY	0.182
3726	-	3728		0.030	100	0.090	0.333	PAY	0.023
3728	-	3730		0.075	110	0.619	0.127	PAY	2.395
3730	-	3732		0.075	150	0.844	0.109	PAY	2.596
3732	-	3734		0.060	150	0.540	0.136	PAY	0.963
3734	-	3736		0.060	100	0.360	0.167	PAY	0.837
3736	-	3738		0.075	90	0.506	0.141	PAY	2.254
3738	-	3740		0.090	100	0.810	0.111	PAY	5.237
3740	-	3742		0.095	105	0.948	0.103	PAY	6.709
3742	-	3744		0.090	120	0.972	0.101	PAY	5.463
3744	-	3746		0.060	120	0.432	0.152	PAY	0.895
3746	-	3748		0.045	110	0.223	0.212	PAY	0.219
3748	-	3750		0.015	110	0.025	0.636	TITE	0.000
3750	-	3752		0.030	100	0.090	0.333	PAY	0.023
3752	-	3754		0.010	90	0.009	1.054	TITE	######
3754	-	3756		0.010	90	0.009	1.054	TITE	######
3756	-	3758		0.055	90	0.272	0.192	PAY	0.529
3758	-	3760		0.015	90	0.020	0.703	TITE	0.000
3760	-	3762		0.010	70	0.007	1.195	TITE	######
3762	-	3764		0.030	60	0.054	0.430	PAY	0.013
3764	-	3766		-0.010	60	0.006	1.291	TITE	0.000
3766	-	3768		-0.010	60	0.006	1.291	TITE	0.000
3768	-	3770		-0.015	40	0.009	1.054	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
3714	-	3716		0.045	150	0.304	0.181	PAY	0.254
3716	-	3718		0.060	60	0.216	0.215	PAY	0.662
3718	-	3720		0.045	70	0.142	0.266	PAY	0.166
3724	-	3726		0.045	80	0.162	0.248	PAY	0.182
3726	-	3728		0.030	100	0.090	0.333	PAY	0.023
3728	-	3730		0.075	110	0.619	0.127	PAY	2.395
3730	-	3732		0.075	150	0.844	0.109	PAY	2.596
3732	-	3734		0.060	150	0.540	0.136	PAY	0.963
3734	-	3736		0.060	100	0.360	0.167	PAY	0.837
3736	-	3738		0.075	90	0.506	0.141	PAY	2.254
3738	-	3740		0.090	100	0.810	0.111	PAY	5.237
3740	-	3742		0.095	105	0.948	0.103	PAY	6.709
3742	-	3744		0.090	120	0.972	0.101	PAY	5.463
3744	-	3746		0.060	120	0.432	0.152	PAY	0.895
3746	-	3748		0.045	110	0.223	0.212	PAY	0.219
3750	-	3752		0.030	100	0.090	0.333	PAY	0.023
3756	-	3758		0.055	90	0.272	0.192	PAY	0.529
3762	-	3764		0.030	60	0.054	0.430	PAY	0.013
PAY (FT.)			36	0.059		0.421	0.198		1.634
			PHI*H	2.130	HPV		1.709	k*h	58.84

COMMENTS:
DST 3725 - 3755; F/ 2165 MCF/D
DST Keg River 6535 - 6605; F/ 4349 MCF/D; Rec. 729' SW
Pf. 6600 - 6606; 6582 - 6586; 3715 - 3742; Acid
JMR, KEGR gas well; FP 2/94 @ 2333 MCF/D; C - 3077 MMCF

WELL : a-89-I/94-P-10

	m	ft.	SS
KB :	477.7	1567	
LS MKR. :	1134.5	3722	
JMR :	1141.5	3745	-2178
SH. MKR. :	1157.0	3796	
LS MKR. - JMR		23	
JMR - SH. MKR.		51	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1142	-	1143		-0.015	35	0.008	1.127	TITE	0.000
1143	-	1144		-0.015	60	0.014	0.861	TITE	######
1144	-	1145		-0.015	90	0.020	0.703	TITE	######
1145	-	1146		0.045	100	0.203	0.222	PAY	0.208
1146	-	1147		0.040	100	0.160	0.250	PAY	0.114
1147	-	1148		0.045	125	0.253	0.199	PAY	0.234
1148	-	1149		0.045	160	0.324	0.176	PAY	0.261
1149	-	1150		0.050	190	0.475	0.145	PAY	0.454
1150	-	1151		0.015	175	0.039	0.504	TITE	0.000
1151	-	1152		0.015	100	0.023	0.667	TITE	0.000
1152	-	1153		0.015	100	0.023	0.667	TITE	0.000
1153	-	1154		-0.015	90	0.020	0.703	TITE	######
1154	-	1155		-0.015	70	0.016	0.797	TITE	######
1155	-	1156		-0.020	60	0.024	0.645	TITE	######
1156	-	1157		0.000	35	0.000	######	TITE	######

COMMENTS:
Broken ML 1145 - 1149

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1145	-	1146		0.045	100	0.203	0.222	PAY	0.208
1146	-	1147		0.040	100	0.160	0.250	PAY	0.114
1147	-	1148		0.045	125	0.253	0.199	PAY	0.234
1148	-	1149		0.045	160	0.324	0.176	PAY	0.261
1149	-	1150		0.050	190	0.475	0.145	PAY	0.454
PAY (FT.)			16	0.045		0.283	0.198		0.254
			PHI*H	0.738	HPV		0.592	k*h	4.2

COMMENTS:
Core 1141 - 1159
Pf. 1143 - 1153; Acid
FP 1/94 @ 8333 MCF/D; C - 10.3 BCF thru 10/31/96; EUR - 16.1 BCF

WELL : b-66-I/94-P-10

	m	ft.	SS
KB :	482.0	1581	
LS MKR. :	1124.0	3688	
JMR :	1130.3	3708	-2127
SH. MKR. :	1145.3	3758	
LS MKR. - JMR		21	
JMR - SH. MKR.		49	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1131	-	1132		-0.030	40	0.036	0.527	TITE	#NUM!
1132	-	1133		0.015	100	0.023	0.667	TITE	0.000
1133	-	1134		0.045	250	0.506	0.141	PAY	0.307
1134	-	1135		0.050	375	0.938	0.103	PAY	0.547
1135	-	1136		0.055	350	1.059	0.097	PAY	0.814
1136	-	1137		0.105	325	3.583	0.053	PAY	12.247
1137	-	1138		0.105	400	4.410	0.048	PAY	12.512
1138	-	1139		0.075	420	2.363	0.065	PAY	3.131
1139	-	1140		0.100	350	3.500	0.053	PAY	10.097
1140	-	1141		0.015	100	0.023	0.667	TITE	0.000
1141	-	1142		0.010	90	0.009	1.054	TITE	#NUM!
1142	-	1143		0.010	80	0.008	1.118	TITE	#NUM!
1143	-	1144		0.000	70	0.000	#####	TITE	#DIV/0!
1144	-	1145		0.010	60	0.006	1.291	TITE	#NUM!

COMMENTS:
ML 1134 - 1141

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1133	-	1134		0.045	250	0.506	0.141	PAY	0.307
1134	-	1135		0.050	375	0.938	0.103	PAY	0.547
1135	-	1136		0.055	350	1.059	0.097	PAY	0.814
1136	-	1137		0.105	325	3.583	0.053	PAY	12.247
1137	-	1138		0.105	400	4.410	0.048	PAY	12.512
1138	-	1139		0.075	420	2.363	0.065	PAY	3.131
1139	-	1140		0.100	350	3.500	0.053	PAY	10.097
PAY (FT.)			23	0.076		2.337	0.080		5.665
			PHI*H	1.755	HPV		1.615	k*h	130.1

COMMENTS:
Core 1131.4 - 1149.4
DST 1132 - 1147; FP 448 - 543; F/ 1848 MCF/D
Pf. 1132.5 - 1140; Acid
FP 1/91 @ 16.7 MM/D; C - 24.2 BCF; EUR - 41.1 BCF

WELL : d-37-I/94-P-10

	m	ft.	SS
KB :	476.8	1564	
LS MKR. :	1120.1	3675	
JMR :	1127.5	3699	-2135
SH. MKR. :	1144.5	3755	
LS MKR. - JMR		24	
JMR - SH. MKR.		56	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1128	-	1129		0.075	30	0.169	0.243	PAY	1.371
1129	-	1130		0.075	60	0.338	0.172	PAY	1.948
1130	-	1131		0.090	125	1.013	0.099	PAY	5.512
1131	-	1132		0.120	150	2.160	0.068	PAY	19.360
1132	-	1133		0.105	225	2.481	0.063	PAY	11.717
1133	-	1134		0.135	200	3.645	0.052	PAY	32.717
1134	-	1135		0.135	200	3.645	0.052	PAY	32.717
1135	-	1136		0.105	250	2.756	0.060	PAY	11.877
1136	-	1137		0.060	200	0.720	0.118	PAY	1.045
1137	-	1138		0.040	300	0.480	0.144	PAY	0.191
1138	-	1139		0.040	200	0.320	0.177	PAY	0.164
1139	-	1140		-0.010	60	0.006	1.291	TITE	0.000
1140	-	1141		0.015	70	0.016	0.797	TITE	0.000
1141	-	1142		0.010	70	0.007	1.195	TITE	#NUM!
1142	-	1143		0.010	70	0.007	1.195	TITE	#NUM!
1143	-	1144		0.010	55	0.006	1.348	TITE	#NUM!

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1128	-	1129		0.075	30	0.169	0.243	PAY	1.371
1129	-	1130		0.075	60	0.338	0.172	PAY	1.948
1130	-	1131		0.090	125	1.013	0.099	PAY	5.512
1131	-	1132		0.120	150	2.160	0.068	PAY	19.360
1132	-	1133		0.105	225	2.481	0.063	PAY	11.717
1133	-	1134		0.135	200	3.645	0.052	PAY	32.717
1134	-	1135		0.135	200	3.645	0.052	PAY	32.717
1135	-	1136		0.105	250	2.756	0.060	PAY	11.877
1136	-	1137		0.060	200	0.720	0.118	PAY	1.045
1137	-	1138		0.040	300	0.480	0.144	PAY	0.191
1138	-	1139		0.040	200	0.320	0.177	PAY	0.164
PAY (FT.)			36	0.089		1.611	0.114		10.784
			PHI*H	3.215	HPV		2.850	k*h	389.2

COMMENTS:
Core 1126 - 1143
DST 1121 - 1143; FP 375 - 505; F/ 1638 MCF/D
Pf. 1128.5 - 1139; Acid
FP 3/90 @ 7500 MCF/D; C - 14.9 BCF thru 10/31/98

WELL : a-25-I/94-P-10

	m	ft.	SS
KB :	470.2	1543	
LS MKR. :	1106.9	3632	
JMR :	1113.7	3654	-2111
SH. MKR. :	1128.3	3702	
LS MKR. - JMR		22	
JMR - SH. MKR.		48	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1114	-	1115		0.045	100	0.203	0.222	PAY	0.208
1115	-	1116		0.060	1000	3.600	0.053	PAY	1.380
1116	-	1117		0.060	1000	3.600	0.053	PAY	1.380
1117	-	1118		0.070	1000	4.900	0.045	PAY	2.597
1118	-	1119		0.060	450	1.620	0.079	PAY	1.238
1119	-	1120		0.095	900	8.123	0.035	PAY	8.909
1120	-	1121		0.095	1000	9.025	0.033	PAY	8.974
1121	-	1122		0.045	500	1.013	0.099	PAY	0.369
1122	-	1123		0.018	80	0.026	0.621	TITE	0.000
1123	-	1124		0.015	50	0.011	0.943	TITE	0.000
1124	-	1125		0.020	60	0.024	0.645	TITE	0.000
1125	-	1126		0.020	80	0.032	0.559	TITE	0.001
1126	-	1127		0.030	80	0.072	0.373	PAY	0.018
1127	-	1128		0.015	90	0.020	0.703	TITE	0.000

COMMENTS:
ML 1114 - 1122

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1114	-	1115		0.045	100	0.203	0.222	PAY	0.208
1115	-	1116		0.060	1000	3.600	0.053	PAY	1.380
1116	-	1117		0.060	1000	3.600	0.053	PAY	1.380
1117	-	1118		0.070	1000	4.900	0.045	PAY	2.597
1118	-	1119		0.060	450	1.620	0.079	PAY	1.238
1119	-	1120		0.095	900	8.123	0.035	PAY	8.909
1120	-	1121		0.095	1000	9.025	0.033	PAY	8.974
1121	-	1122		0.045	500	1.013	0.099	PAY	0.369
1126	-	1127		0.030	80	0.072	0.373	PAY	0.018
PAY (FT.)			30	0.062		3.573	0.110		2.786
			PHI*H	1.837	HPV		1.635	k*h	82.3

COMMENTS:
Core 1114 - 1128
Pf. 1114 - 1122; Acid; FP 3/98 @ 1167 MCF/D
C - 235 MMCF thru 10/31/98

WELL : a-5-I/94-P-10

	m	ft.	SS
KB :	466.8	1531	
LS. MKR. :	1097.7	3601	
JMR :	1104.3	3623	-2092
SH. MKR. :	1118.0	3668	
LS. MKR. - JMR		22	
JMR - SH. MKR.		45	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1105	-	1106		0.042	100	0.176	0.238	PAY	0.147
1106	-	1107		0.060	350	1.260	0.089	PAY	1.184
1107	-	1108		0.062	400	1.538	0.081	PAY	1.395
1108	-	1109		0.080	375	2.400	0.065	PAY	4.037
1109	-	1110		0.050	400	1.000	0.100	PAY	0.555
1110	-	1111		0.075	400	2.250	0.067	PAY	3.110
1111	-	1112		0.045	300	0.608	0.128	PAY	0.324
1112	-	1113		0.010	150	0.015	0.816	TITE	0.000
1113	-	1114		0.025	100	0.063	0.400	TITE	0.008
1114	-	1115		0.030	90	0.081	0.351	PAY	0.021
1115	-	1116		0.030	90	0.081	0.351	PAY	0.021
1116	-	1117		0.025	90	0.056	0.422	TITE	0.007
1117	-	1118		0.010	90	0.009	1.054	TITE	######

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1105	-	1106		0.042	100	0.176	0.238	PAY	0.147
1106	-	1107		0.060	350	1.260	0.089	PAY	1.184
1107	-	1108		0.062	400	1.538	0.081	PAY	1.395
1108	-	1109		0.080	375	2.400	0.065	PAY	4.037
1109	-	1110		0.050	400	1.000	0.100	PAY	0.555
1110	-	1111		0.075	400	2.250	0.067	PAY	3.110
1111	-	1112		0.045	300	0.608	0.128	PAY	0.324
1114	-	1115		0.030	90	0.081	0.351	PAY	0.021
1115	-	1116		0.030	90	0.081	0.351	PAY	0.021
PAY (FT.)			30	0.053		1.044	0.163		1.199
			PHI*H	1.555	HPV		1.301	k*h	35.4

COMMENTS:
Core 1103 - 1121.8
DST 1099 - 1114.1; F/ 193 MCF/D
Pf. 1105 - 1112; Acid; FP 3/90 @ 3000 MCF/D; C - 4530 MMCF thru 9/30/98
BHP 453# 6/97

WELL : b-85-H/94-P-10

	m	ft.	SS
KB :	458.6	1505	
LS MKR. :	1082.1	3550	
JMR :	1088.0	3570	-2065
SH. MKR. :	1106.5	3630	
LS MKR. - JMR		19	
JMR - SH. MKR.		61	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1088	-	1089		0.015	1000	0.225	0.211	TITE	0.003
1089	-	1090		0.032	100	0.102	0.313	PAY	0.034
1090	-	1091		-0.015	90	0.020	0.703	TITE	######
1091	-	1092		0.015	125	0.028	0.596	TITE	0.000
1092	-	1093		0.050	140	0.350	0.169	PAY	0.406
1093	-	1094		0.045	300	0.608	0.128	PAY	0.324
1094	-	1095		0.030	400	0.360	0.167	PAY	0.056
1095	-	1096		0.045	450	0.911	0.105	PAY	0.360
1096	-	1097		0.030	450	0.405	0.157	PAY	0.058
1097	-	1098		0.020	800	0.320	0.177	PAY	0.011
1098	-	1099		0.032	500	0.512	0.140	PAY	0.081
1099	-	1100		0.025	500	0.313	0.179	TITE	0.026
1100	-	1101		0.015	400	0.090	0.333	TITE	0.002
1101	-	1102		0.000	400	0.000	######	TITE	######
1102	-	1103		0.045	325	0.658	0.123	PAY	0.332
1103	-	1104		-0.035	225	0.276	0.190	TITE	######
1104	-	1105		0.000	200	0.000	######	TITE	######
1105	-	1106		-0.015	125	0.028	0.596	TITE	######

COMMENTS:
ML 1088 - 1099; 1101.5 - 1104.5

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1089	-	1090		0.032	100	0.102	0.313	PAY	0.034
1092	-	1093		0.050	140	0.350	0.169	PAY	0.406
1093	-	1094		0.045	300	0.608	0.128	PAY	0.324
1094	-	1095		0.030	400	0.360	0.167	PAY	0.056
1095	-	1096		0.045	450	0.911	0.105	PAY	0.360
1096	-	1097		0.030	450	0.405	0.157	PAY	0.058
1097	-	1098		0.020	800	0.320	0.177	PAY	0.011
1098	-	1099		0.032	500	0.512	0.140	PAY	0.081
1102	-	1103		0.045	325	0.658	0.123	PAY	0.332
PAY (FT.)			30	0.037		0.470	0.164		0.186
			PHI*H	1.079	HPV		0.902	k*h	5.5

COMMENTS:
DST 1089 - 1097; F/ 141 MCF/D
Pf. 1088 - 1099.5; 1101.5 - 1104.5; Acid
FP 3/90 @ 2000 MCF/D; C - 3827 MMCF; U - 9000 MMCF

WELL : b-66-H/94-P-10

	m	ft.	SS
KB :	452.4	1484	
JMR :	1093.2	3587	-2102
SH. MKR. :	1108.4	3636	
JMR - SH. MKR.		50	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1094	-	1095		0.030	1000	0.900	0.105	PAY	0.074
1095	-	1096		0.045	650	1.316	0.087	PAY	0.388
1096	-	1097		0.030	1000	0.900	0.105	PAY	0.074
1097	-	1098		0.010	1000	0.100	0.316	TITE	0.000
1098	-	1099		0.035	200	0.245	0.202	PAY	0.086
1099	-	1100		0.040	300	0.480	0.144	PAY	0.191
1100	-	1101		0.080	325	2.080	0.069	PAY	3.956
1101	-	1102		0.040	600	0.960	0.102	PAY	0.230
1102	-	1103		0.045	500	1.013	0.099	PAY	0.369
1103	-	1104		0.040	425	0.680	0.121	PAY	0.211
1104	-	1105		0.040	500	0.800	0.112	PAY	0.220
1105	-	1106		0.015	350	0.079	0.356	TITE	0.001
1106	-	1107		-0.020	175	0.070	0.378	TITE	#####
1107	-	1108		0.010	140	0.014	0.845	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1094	-	1095		0.030	1000	0.900	0.105	PAY	0.074
1095	-	1096		0.045	650	1.316	0.087	PAY	0.388
1096	-	1097		0.030	1000	0.900	0.105	PAY	0.074
1098	-	1099		0.035	200	0.245	0.202	PAY	0.086
1099	-	1100		0.040	300	0.480	0.144	PAY	0.191
1100	-	1101		0.080	325	2.080	0.069	PAY	3.956
1101	-	1102		0.040	600	0.960	0.102	PAY	0.230
1102	-	1103		0.045	500	1.013	0.099	PAY	0.369
1103	-	1104		0.040	425	0.680	0.121	PAY	0.211
1104	-	1105		0.040	500	0.800	0.112	PAY	0.220
PAY (FT.)			33	0.043		0.937	0.115		0.580
			PHI*H	1.394	HPV		1.234	k*h	19.0

COMMENTS:
Core 1093 - 1111
Pf. 1094 - 1096.5; 1098 - 1105.5; Acid
1st prod. 3/90 @ 1917 MCF/D
C - 4289 MMCF to 7/31/98

WELL : d-6-H/94-P-10

	m	ft.	SS
KB :		1521	
LS MKR. :		3624	
JMR :		3644	-2123
SH. MKR. :		3684	
LS MKR. - JMR		20	
JMR - SH. MKR.		40	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
3646	-	3648		0.010	45	0.005	1.491	TITE	#####
3648	-	3650		0.015	40	0.009	1.054	TITE	#####
3650	-	3652		0.045	45	0.091	0.331	PAY	0.115
3652	-	3654		0.045	50	0.101	0.314	PAY	0.127
3654	-	3656		0.030	60	0.054	0.430	PAY	0.013
3656	-	3658		0.015	60	0.014	0.861	TITE	0.000
3658	-	3660		0.025	70	0.044	0.478	TITE	0.004
3660	-	3662		0.010	85	0.009	1.085	TITE	#####
3662	-	3664		0.000	90	0.000	#####	TITE	#####
3664	-	3666		0.020	75	0.030	0.577	TITE	0.001
3666	-	3668		0.030	50	0.045	0.471	PAY	0.009
3668	-	3670		0.015	40	0.009	1.054	TITE	#####
3670	-	3672		0.025	40	0.025	0.632	TITE	0.001
3672	-	3674		0.010	40	0.004	1.581	TITE	#####
3674	-	3676		0.025	40	0.025	0.632	TITE	0.001
3676	-	3678		0.010	45	0.005	1.491	TITE	#####
3678	-	3680		0.020	50	0.020	0.707	TITE	0.000
3680	-	3682		-0.015	40	0.009	1.054	TITE	0.000
3682	-	3684		0.000	20	0.000	#####	TITE	#####

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
3650	-	3652		0.045	45	0.091	0.331	PAY	0.115
3652	-	3654		0.045	50	0.101	0.314	PAY	0.127
3654	-	3656		0.030	60	0.054	0.430	PAY	0.013
3666	-	3668		0.030	50	0.045	0.471	PAY	0.009
PAY (FT.)			8	0.038		0.073	0.387		0.066
			PHI*H	0.300	HPV		0.184	k*h	0.5

COMMENTS:
No JMR tests rpt.; Abnd. KEGR test 2/76

WELL : d-76-A/94-P-10

	m	ft.	SS
KB :	459.8	1509	
JMR :	1106.0	3629	-2120
SH. MKR. :	1124.0	3688	
JMR - SH. MKR.		59	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1106	-	1107		0.015	160	0.036	0.527	TITE	0.000
1107	-	1108		-0.020	200	0.080	0.354	TITE	######
1108	-	1109		0.015	175	0.039	0.504	TITE	0.000
1109	-	1110		0.030	200	0.180	0.236	PAY	0.040
1110	-	1111		0.030	175	0.158	0.252	PAY	0.037
1111	-	1112		0.015	200	0.045	0.471	TITE	0.001
1112	-	1113		0.030	200	0.180	0.236	PAY	0.040
1113	-	1114		0.025	225	0.141	0.267	TITE	0.017
1114	-	1115		0.030	150	0.135	0.272	PAY	0.033
1115	-	1116		0.020	200	0.080	0.354	TITE	0.004
1116	-	1117		0.020	200	0.080	0.354	TITE	0.004
1117	-	1118		0.015	200	0.045	0.471	TITE	0.001
1118	-	1119		0.032	175	0.179	0.236	PAY	0.051
1119	-	1120		0.015	300	0.068	0.385	TITE	0.001
1120	-	1121		0.010	200	0.020	0.707	TITE	0.000
1121	-	1122		0.020	250	0.100	0.316	TITE	0.005
1122	-	1123		0.025	200	0.125	0.283	TITE	0.015
1123	-	1124		0.000	180	0.000	######	TITE	######

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1109	-	1110		0.030	200	0.180	0.236	PAY	0.040
1110	-	1111		0.030	175	0.158	0.252	PAY	0.037
1112	-	1113		0.030	200	0.180	0.236	PAY	0.040
1114	-	1115		0.030	150	0.135	0.272	PAY	0.033
1118	-	1119		0.032	175	0.179	0.236	PAY	0.051
PAY (FT.)			16	0.030		0.166	0.246		0.040
			PHI*H	0.499	HPV		0.376	k*h	0.7

COMMENTS:
Core 1105 - 1117.2
DST 1109 - 1125; Rec. 46' mud
Pf. 1108 - 1123; Acid; F/ 23 MCF/D, BHP 344# in 3/80

WELL : d-35-A/94-P-10

	m	ft.	SS
KB :	468.5	1537	
JMR :	1115.8	3661	-2124
SH. MKR. :	1130.0	3707	
JMR - SH. MKR.		47	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1116	-	1117		0.040	70	0.112	0.299	PAY	0.088
1117	-	1118		0.040	80	0.128	0.280	PAY	0.097
1118	-	1119		0.040	85	0.136	0.271	PAY	0.102
1119	-	1120		0.030	125	0.113	0.298	PAY	0.029
1120	-	1121		0.090	175	1.418	0.084	PAY	5.889
1121	-	1122		0.075	200	1.125	0.094	PAY	2.766
1122	-	1123		0.085	225	1.626	0.078	PAY	4.824
1123	-	1124		0.085	250	1.806	0.074	PAY	4.907
1124	-	1125		0.100	250	2.500	0.063	PAY	9.696
1125	-	1126		0.075	225	1.266	0.089	PAY	2.831
1126	-	1127		0.075	225	1.266	0.089	PAY	2.831
1127	-	1128		0.030	200	0.180	0.236	PAY	0.040
1128	-	1129		0.015	180	0.041	0.497	TITE	0.001
1129	-	1130		0.015	90	0.020	0.703	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1116	-	1117		0.040	70	0.112	0.299	PAY	0.088
1117	-	1118		0.040	80	0.128	0.280	PAY	0.097
1118	-	1119		0.040	85	0.136	0.271	PAY	0.102
1119	-	1120		0.030	125	0.113	0.298	PAY	0.029
1120	-	1121		0.090	175	1.418	0.084	PAY	5.889
1121	-	1122		0.075	200	1.125	0.094	PAY	2.766
1122	-	1123		0.085	225	1.626	0.078	PAY	4.824
1123	-	1124		0.085	250	1.806	0.074	PAY	4.907
1124	-	1125		0.100	250	2.500	0.063	PAY	9.696
1125	-	1126		0.075	225	1.266	0.089	PAY	2.831
1126	-	1127		0.075	225	1.266	0.089	PAY	2.831
1127	-	1128		0.030	200	0.180	0.236	PAY	0.040
PAY (FT.)			39	0.064		0.973	0.163		2.842
			PHI*H	2.510	HPV		2.101	k*h	111.9

COMMENTS:
CORE 1109-1127
DST 1111.0-1132 REC 240' MUD
Pf 1115.5-1117.5, 1118.5-1127, 1128-1129, IP1.05 MMCF; C 16959 MMCF

WELL : c-18-A/94-P-10

	m	ft.	SS
KB :	473.3	1553	
JMR :	1127.0	3697	-2145
SH. MKR. :	1144.6	3755	
JMR - SH. MKR.		58	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHIs	Rd	Rwa	Sw	COMMENTS	k
1128	-	1129	51	0.040	110	0.176	0.238	PAY	0.121
1129	-	1130	50	0.030	110	0.099	0.318	PAY	0.026
1130	-	1131	48	0.020	200	0.080	0.354	TITE	0.004
1131	-	1132	50	0.030	300	0.270	0.192	PAY	0.049
1132	-	1133	52	0.045	350	0.709	0.119	PAY	0.339
1133	-	1134	55	0.065	300	1.268	0.089	PAY	1.620
1134	-	1135	53	0.050	225	0.563	0.133	PAY	0.479
1135	-	1136	56	0.070	200	0.980	0.101	PAY	2.053
1136	-	1137	52	0.045	250	0.506	0.141	PAY	0.307
1137	-	1138	52	0.045	450	0.911	0.105	PAY	0.360
1138	-	1139	50	0.030	700	0.630	0.126	PAY	0.067
1139	-	1140	52	0.045	500	1.013	0.099	PAY	0.369
1140	-	1141	50	0.030	400	0.360	0.167	PAY	0.056
1141	-	1142	50	0.030	300	0.270	0.192	PAY	0.049
1142	-	1143	50	0.030	200	0.180	0.236	PAY	0.040
1143	-	1144	51	0.040	100	0.160	0.250	PAY	0.114

COMMENTS:
Used 22,000'/sec. to calculate PHIs

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHIs	Rd	Rwa	Sw	COMMENTS	k
1128	-	1129	51	0.040	110	0.176	0.238	PAY	0.121
1129	-	1130	50	0.030	110	0.099	0.318	PAY	0.026
1131	-	1132	50	0.030	300	0.270	0.192	PAY	0.049
1132	-	1133	52	0.045	350	0.709	0.119	PAY	0.339
1133	-	1134	55	0.065	300	1.268	0.089	PAY	1.620
1134	-	1135	53	0.050	225	0.563	0.133	PAY	0.479
1135	-	1136	56	0.070	200	0.980	0.101	PAY	2.053
1136	-	1137	52	0.045	250	0.506	0.141	PAY	0.307
1137	-	1138	52	0.045	450	0.911	0.105	PAY	0.360
1138	-	1139	50	0.030	700	0.630	0.126	PAY	0.067
1139	-	1140	52	0.045	500	1.013	0.099	PAY	0.369
1140	-	1141	50	0.030	400	0.360	0.167	PAY	0.056
1141	-	1142	50	0.030	300	0.270	0.192	PAY	0.049
1142	-	1143	50	0.030	200	0.180	0.236	PAY	0.040
1143	-	1144	51	0.040	100	0.160	0.250	PAY	0.114
PAY (FT.)			49	0.042		0.540	0.167		0.403
			PHI*H	2.051	HPV		1.708	k*h	19.8

COMMENTS:
Core 1120.5 - 1137
DST 1132 - 1172; F/ 471 MCF/D
Pf. 1127.5 - 1144; Acid; FP 4/80 @ 2000 MCF/D; C - 3888 MMCF

WELL : d-91-J/94-P-7

	m	ft.	SS
KB :	479.5	1573	
JMR :	1138.5	3735	-2162
SH. MKR. :	1152.1	3780	
JMR - SH. MKR.		45	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1139	-	1140		0.015	95	0.021	0.684	TITE	0.000
1140	-	1141		0.045	100	0.203	0.222	PAY	0.208
1141	-	1142		0.070	100	0.490	0.143	PAY	1.704
1142	-	1143		0.030	175	0.158	0.252	PAY	0.037
1143	-	1144		0.015	350	0.079	0.356	TITE	0.001
1144	-	1145		0.020	400	0.160	0.250	TITE	0.008
1145	-	1146		0.050	425	1.063	0.097	PAY	0.562
1146	-	1147		0.060	400	1.440	0.083	PAY	1.213
1147	-	1148		0.050	275	0.688	0.121	PAY	0.507
1148	-	1149		0.065	200	0.845	0.109	PAY	1.486
1149	-	1150		0.085	175	1.264	0.089	PAY	4.613
1150	-	1151		0.060	200	0.720	0.118	PAY	1.045
1151	-	1152		0.015	250	0.056	0.422	TITE	0.001

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1140	-	1141		0.045	100	0.203	0.222	PAY	0.208
1141	-	1142		0.070	100	0.490	0.143	PAY	1.704
1142	-	1143		0.030	175	0.158	0.252	PAY	0.037
1145	-	1146		0.050	425	1.063	0.097	PAY	0.562
1146	-	1147		0.060	400	1.440	0.083	PAY	1.213
1147	-	1148		0.050	275	0.688	0.121	PAY	0.507
1148	-	1149		0.065	200	0.845	0.109	PAY	1.486
1149	-	1150		0.085	175	1.264	0.089	PAY	4.613
1150	-	1151		0.060	200	0.720	0.118	PAY	1.045
PAY (FT.)			30	0.057		0.763	0.137		1.264
			PHI*H	1.690	HPV		1.458	k*h	37.3

COMMENTS:
Core 1141 - 1151.6
DST 1135 - 1155; F/ 1145 MCF/D
Pf. 1144.5 - 52; 1154 - 1155.5; 1156.5 - 1158; 1139 - 1143.5; Acid
FP 3/88 @ 5000 MCF/D; C - 8662 MMCF

WELL : b-90-I/94-P-7

	m	ft.	SS
KB :	501.5	1645	
JMR :	1172.5	3847	-2201
SH. MKR. :	1185.0	3888	
JMR - SH. MKR.		41	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1173	-	1174		0.045	50	0.101	0.314	PAY	0.127
1174	-	1175		0.070	80	0.392	0.160	PAY	1.577
1175	-	1176		0.060	150	0.540	0.136	PAY	0.963
1176	-	1177		0.015	150	0.034	0.544	TITE	0.000
1177	-	1178		0.035	200	0.245	0.202	PAY	0.086
1178	-	1179		0.090	250	2.025	0.070	PAY	6.241
1179	-	1180		0.085	350	2.529	0.063	PAY	5.150
1180	-	1181		0.060	350	1.260	0.089	PAY	1.184
1181	-	1182		0.055	300	0.908	0.105	PAY	0.787
1182	-	1183		0.050	150	0.375	0.163	PAY	0.417
1183	-	1184		0.075	150	0.844	0.109	PAY	2.596
1184	-	1185		0.010	25	0.003	2.000	TITE	#####

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1173	-	1174		0.045	50	0.101	0.314	PAY	0.127
1174	-	1175		0.070	80	0.392	0.160	PAY	1.577
1175	-	1176		0.060	150	0.540	0.136	PAY	0.963
1177	-	1178		0.035	200	0.245	0.202	PAY	0.086
1178	-	1179		0.090	250	2.025	0.070	PAY	6.241
1179	-	1180		0.085	350	2.529	0.063	PAY	5.150
1180	-	1181		0.060	350	1.260	0.089	PAY	1.184
1181	-	1182		0.055	300	0.908	0.105	PAY	0.787
1182	-	1183		0.050	150	0.375	0.163	PAY	0.417
1183	-	1184		0.075	150	0.844	0.109	PAY	2.596
PAY (FT.)			33	0.063		0.922	0.141		1.913
			PHI*H	2.051	HPV		1.761	k*h	62.8

COMMENTS:
Pf. 1173 - 76; 1177.5 - 1183.5; Acid
FP 3/81 @ 4300 MCF/D; C - 7785 MMCF

LOG DATA

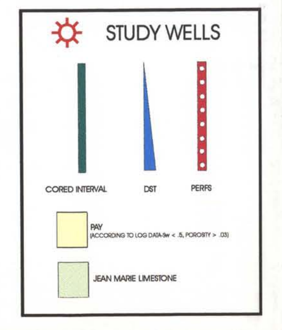


PLATE 11
STRATIGRAPHIC CROSS SECTION A-A'
DATUM- JEAN MARIE SHALE MARKER

CROSS SECTION B - B'

LOG DATA

WELL :	d-84-C/94-P-15		
	m	ft.	SS
KB :	517.5	1698	
LS MKR. :	1243.3	4079	
JMR :	1252.3	4109	-2411
SH. MKR. :	1265.0	4150	
LS MKR. - JMR		30	
JMR - SH. MKR.		42	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1253 - 1254		-0.010	60	0.006	1.291	TITE	0.000
1254 - 1255		0.015	60	0.014	0.861	TITE	0.000
1255 - 1256		-0.010	70	0.007	1.195	TITE	0.000
1256 - 1257		0.045	110	0.223	0.212	PAY	0.219
1257 - 1258		0.040	110	0.176	0.238	PAY	0.121
1258 - 1259		0.065	100	0.423	0.154	PAY	1.213
1259 - 1260		0.030	125	0.113	0.298	PAY	0.029
1260 - 1261		0.000	175	0.000	#####	TITE	#####
1261 - 1262		0.000	100	0.000	#####	TITE	#####
1262 - 1263		0.010	90	0.009	1.054	TITE	#####
1263 - 1264		0.010	65	0.007	1.240	TITE	#####
1264 - 1265		0.010	40	0.004	1.581	TITE	#####

COMMENTS:

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1256 - 1257		0.045	110	0.223	0.212	PAY	0.219
1257 - 1258		0.040	110	0.176	0.238	PAY	0.121
1258 - 1259		0.065	100	0.423	0.154	PAY	1.213
1259 - 1260		0.030	125	0.113	0.298	PAY	0.029
PAY (FT.)	13	0.045		0.233	0.226		0.396
	PHI*H	0.591	HPV		0.457	k*h	5.2

COMMENTS:
Core 1254 - 1272
Pf. 1241 - 1298 (open hole); Acid
FP 4/96 @ 433 MCF/D; C - 323 MMCF thru 9/30/98
BHP 870# in 2/95

WELL :	d-79-B/94-P-15		
	m	ft.	SS
KB :	509.0	1670	
JMR :	1221.0	4006	-2336
SH. MKR. :	1234.6	4050	
JMR - SH. MKR.		45	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1221 - 1222		-0.015	40	0.009	1.054	TITE	0.000
1222 - 1223		0.015	40	0.009	1.054	TITE	#NUM!
1223 - 1224		0.030	25	0.023	0.667	TITE	0.002
1224 - 1225		0.020	25	0.010	1.000	TITE	#NUM!
1225 - 1226		0.050	60	0.150	0.258	PAY	0.261
1226 - 1227		0.075	90	0.506	0.141	PAY	2.254
1227 - 1228		0.050	125	0.313	0.179	PAY	0.388
1228 - 1229		0.080	100	0.640	0.125	PAY	3.110
1229 - 1230		0.075	100	0.563	0.133	PAY	2.329
1230 - 1231		0.080	80	0.512	0.140	PAY	2.910
1231 - 1232		0.030	70	0.063	0.398	PAY	0.016
1232 - 1233		-0.015	80	0.018	0.745	TITE	#NUM!
1233 - 1234		0.010	60	0.006	1.291	TITE	#NUM!

COMMENTS:
Core 1222 - 1240.5

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1225 - 1226		0.050	60	0.150	0.258	PAY	0.261
1226 - 1227		0.075	90	0.506	0.141	PAY	2.254
1227 - 1228		0.050	125	0.313	0.179	PAY	0.388
1228 - 1229		0.080	100	0.640	0.125	PAY	3.110
1229 - 1230		0.075	100	0.563	0.133	PAY	2.329
1230 - 1231		0.080	80	0.512	0.140	PAY	2.910
1231 - 1232		0.030	70	0.063	0.398	PAY	0.016
PAY (FT.)	23	0.063		0.392	0.196		1.610
	PHI*H	1.444	HPV		1.160	HPV	37.0

COMMENTS:
Pf 1213-1340; 1271-1340
CORES 1220-1240.5 CUM 29523 MMCF

WELL :	d-85-B/94-P-15		
	m	ft.	SS
KB :	518.3	1700	
JMR :	1218.3	3997	-2297
SH. MKR. :	1232.5	4044	
JMR - SH. MKR.		47	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1219 - 1220		0.010	30	0.003	1.826	TITE	#####
1220 - 1221		0.000	30	0.000	#####	TITE	#####
1221 - 1222		0.030	90	0.081	0.351	PAY	0.021
1222 - 1223		0.045	95	0.192	0.228	PAY	0.202
1223 - 1224		0.070	90	0.441	0.151	PAY	1.645
1224 - 1225		0.080	80	0.512	0.140	PAY	2.910
1225 - 1226		0.060	80	0.288	0.186	PAY	0.762
1226 - 1227		0.045	90	0.182	0.234	PAY	0.196
1227 - 1228		0.035	100	0.123	0.286	PAY	0.056
1228 - 1229		0.035	100	0.123	0.286	PAY	0.056
1229 - 1230		0.025	70	0.044	0.478	TITE	0.004
1230 - 1231		-0.010	100	0.010	1.000	TITE	#####
1231 - 1232		0.000	35	0.000	#####	TITE	#####

COMMENTS:

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1221 - 1222		0.030	90	0.081	0.351	PAY	0.021
1222 - 1223		0.045	95	0.192	0.228	PAY	0.202
1223 - 1224		0.070	90	0.441	0.151	PAY	1.645
1224 - 1225		0.080	80	0.512	0.140	PAY	2.910
1225 - 1226		0.060	80	0.288	0.186	PAY	0.762
1226 - 1227		0.045	90	0.182	0.234	PAY	0.196
1227 - 1228		0.035	100	0.123	0.286	PAY	0.056
1228 - 1229		0.035	100	0.123	0.286	PAY	0.056
PAY (FT.)	26	0.050		0.243	0.233		0.731
	PHI*H	1.312	HPV		1.007	k*h	19.2

COMMENTS:
Core 1219.2 - 1237.4
Pf. 1221 - 1230; Frac.
1st prod. 4/96 @ 917 MCF/D
C - 481 MMCF thru 7/31/98

WELL :	c-57-A/94-P-15		
	m	ft.	SS
KB :	488.9	1604	
LS MKR. :	1142.0	3747	
JMR :	1149.4	3771	-2167
SH. MKR. :	1162.0	3812	
LS MKR. - JMR		24	
JMR - SH. MKR.		41	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1150 - 1151		0.010	15	0.002	2.582	TITE	#####
1151 - 1152		0.010	30	0.003	1.826	TITE	#####
1152 - 1153		0.030	25	0.023	0.667	TITE	0.002
1153 - 1154		0.075	55	0.309	0.180	PAY	1.878
1154 - 1155		0.060	80	0.288	0.186	PAY	0.762
1155 - 1156		0.030	85	0.077	0.362	PAY	0.020
1156 - 1157		0.065	90	0.380	0.162	PAY	1.168
1157 - 1158		0.015	95	0.021	0.684	TITE	0.000
1158 - 1159		0.015	90	0.020	0.703	TITE	0.000
1159 - 1160		0.000	70	0.000	#####	TITE	#####
1160 - 1161		0.030	80	0.072	0.373	PAY	0.018
1161 - 1162		0.030	55	0.050	0.449	PAY	0.011

COMMENTS:

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1153 - 1154		0.075	55	0.309	0.180	PAY	1.878
1154 - 1155		0.060	80	0.288	0.186	PAY	0.762
1155 - 1156		0.030	85	0.077	0.362	PAY	0.020
1156 - 1157		0.065	90	0.380	0.162	PAY	1.168
1160 - 1161		0.030	80	0.072	0.373	PAY	0.018
1161 - 1162		0.030	55	0.050	0.449	PAY	0.011
PAY (FT.)	20	0.048		0.196	0.285		0.643
	PHI*H	0.951	HPV		0.680	k*h	12.7

COMMENTS:
Core 1148 - 1166.4
DST 1146 - 66; F/ 86 MCF/D
DST Keg River 2010 - 2020; F/ 15252 MCF/D
Pf. Keg River 2014 - 2018; Pf. JMR 1153 - 1159, Frac. JMR pfs.
Results n. rpt.

WELL :	c-74-A/94-P-15		
	m	ft.	SS
KB :	507.3	1664	
LS MKR. :	1155.0	3789	
JMR :	1162.4	3814	-2149
SH. MKR. :	1175.0	3855	
LS MKR. - JMR		24	
JMR - SH. MKR.		41	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1163 - 1164		0.020	18	0.007	1.179	TITE	#####
1164 - 1165		0.045	16	0.032	0.556	TITE	0.023
1165 - 1166		0.045	20	0.041	0.497	PAY	0.038
1166 - 1167		0.020	150	0.060	0.408	TITE	0.003
1167 - 1168		0.015	250	0.056	0.422	TITE	0.001
1168 - 1169		0.030	125	0.113	0.298	PAY	0.029
1169 - 1170		0.045	125	0.253	0.199	PAY	0.234
1170 - 1171		0.030	150	0.135	0.272	PAY	0.033
1171 - 1172		0.015	100	0.023	0.667	TITE	0.000
1172 - 1173		0.030	70	0.063	0.398	PAY	0.016
1173 - 1174		0.015	70	0.016	0.797	TITE	0.000
1174 - 1175		0.020	45	0.018	0.745	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1165 - 1166		0.045	20	0.041	0.497	PAY	0.038
1168 - 1169		0.030	125	0.113	0.298	PAY	0.029
1169 - 1170		0.045	125	0.253	0.199	PAY	0.234
1170 - 1171		0.030	150	0.135	0.272	PAY	0.033
1172 - 1173		0.030	70	0.063	0.398	PAY	0.016
PAY (FT.)	16	0.036		0.121	0.333		0.070
	PHI*H	0.591	HPV		0.394	k*h	1.1

COMMENTS:
Core 1162 - 1180.4
DST 1164 - 1177.2; Rec. 49' mud

WELL :	b-68-D/94-P-16		
	m	ft.	SS
KB :	505.8	1659	
LS MKR. :	1123.2	3685	
JMR :	1130.2	3708	-2049
SH. MKR. :	1144.0	3753	
LS MKR. - JMR		23	
JMR - SH. MKR.		45	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1130 - 1131		-0.030	20	0.018	0.745	TITE	#####
1131 - 1132		-0.020	42	0.017	0.772	TITE	#####
1132 - 1133		0.025	60	0.038	0.516	TITE	0.003
1133 - 1134		0.025	70	0.044	0.478	TITE	0.004
1134 - 1135		0.060	90	0.324	0.176	PAY	0.802
1135 - 1136		0.050	90	0.225	0.211	PAY	0.332
1136 - 1137		0.025	100	0.063	0.400	TITE	0.008
1137 - 1138		0.050	100	0.250	0.200	PAY	0.350
1138 - 1139		0.062	100	0.384	0.161	PAY	0.975
1139 - 1140		0.055	90	0.272	0.192	PAY	0.529
1140 - 1141		0.000	70	0.000	#####	TITE	#####
1141 - 1142		0.000	60	0.000	#####	TITE	#####
1142 - 1143		-0.010	50	0.005	1.414	TITE	0.000
1143 - 1144		0.000	30	0.000	#####	TITE	#####

COMMENTS:
Broken ML 1132 - 1140

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1134 - 1135		0.060	90	0.324	0.176	PAY	0.802
1135 - 1136		0.050	90	0.225	0.211	PAY	0.332
1137 - 1138		0.050	100	0.250	0.200	PAY	0.350
1138 - 1139		0.062	100	0.384	0.161	PAY	0.975
1139 - 1140		0.055	90	0.272	0.192	PAY	0.529
PAY (FT.)	16	0.055		0.291	0.188		0.598
	PHI*H	0.909	HPV		0.738	k*h	9.8

COMMENTS:
DST JMR 1125-1145; F/ 312 MCF/D
Pf. JMR 1125-1140.5; Acid; FP 3/98 @ 1400 MCF/D; C -1289 MMCF thru 2/01
CORE 1132-1150.3

LOG DATA

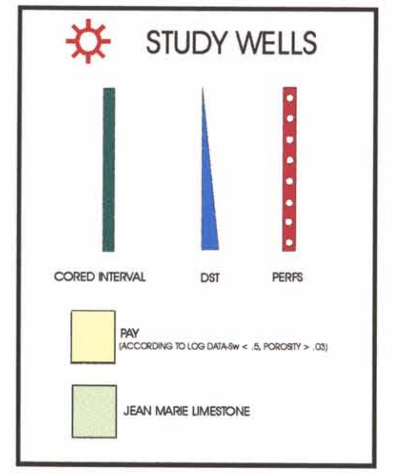


PLATE 12
STRATIGRAPHIC CROSS SECTION B-B'
DATUM- JEAN MARIE SHALE MARKER

CROSS SECTION C - C'

C
WEST

C'
EAST

LOG DATA

WELL : c-89-G/94-P-10

	m	ft.	SS
KB :	454.7	1492	
LS MKR. :	1146.0	3760	
JMR :	1153.9	3786	-2294
SH. MKR. :	1167.3	3830	
LS MKR. - JMR		26	
JMR - SH. MKR.		44	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1154 - 1155		0.000	40	0.000	#####	TITE	#####
1155 - 1156		-0.010	35	0.004	1.690	TITE	0.000
1156 - 1157		-0.010	55	0.006	1.348	TITE	0.000
1157 - 1158		0.010	60	0.006	1.291	TITE	#####
1158 - 1159		**0.050**	**125**	**0.313**	**0.179**	**PAY**	**0.388**
1159 - 1160		**0.032**	**175**	**0.179**	**0.236**	**PAY**	**0.051**
1160 - 1161		**0.055**	**175**	**0.529**	**0.137**	**PAY**	**0.681**
1161 - 1162		0.015	175	0.039	0.504	TITE	0.000
1162 - 1163		-0.010	150	0.015	0.816	TITE	#####
1163 - 1164		0.010	175	0.018	0.756	TITE	0.000
1164 - 1165		0.000	175	0.000	#####	TITE	#####
1165 - 1166		0.015	125	0.028	0.596	TITE	0.000
1166 - 1167		-0.010	80	0.008	1.118	TITE	0.000

COMMENTS:
ML 1157.7 - 1161 ; Mudcake 1157 - 1165

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1158 - 1159		0.050	125	0.313	0.179	PAY	0.388
1159 - 1160		0.032	175	0.179	0.236	PAY	0.051
1160 - 1161		0.055	175	0.529	0.137	PAY	0.681
PAY (FT.)	10	0.046		0.340	0.184		0.373
	PHI*H	0.449	HPV		0.367	HPV	3.7

COMMENTS:
Core 1147 - 1165.2
DST 1149 - 1175; FP 156 - 447; F/ 45 MCF/D
DST KEGR 2020 - 2039; FP 2183 - 2277; F/ 7543 MCF/D
Suspended Gas Well 3/82

WELL : d-96-G/94-P-10

	m	ft.	SS
KB :	445.2	1461	
LS MKR. :	1121.9	3681	
JMR :	1130.1	3708	-2247
SH. MKR. :	1143.8	3753	
LS MKR. - JMR		27	
JMR - SH. MKR.		45	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1146 - 1147		0.010	30	0.003	1.826	TITE	#####
1147 - 1148		0.010	50	0.005	1.414	TITE	#####
1148 - 1149		0.000	50	0.000	#####	TITE	#####
1149 - 1150		0.010	55	0.006	1.348	TITE	#####
1150 - 1151		**0.062**	**100**	**0.384**	**0.161**	**PAY**	**0.975**
1151 - 1152		**0.060**	**125**	**0.450**	**0.149**	**PAY**	**0.908**
1152 - 1153		**0.055**	**150**	**0.454**	**0.148**	**PAY**	**0.648**
1153 - 1154		**0.045**	**125**	**0.253**	**0.199**	**PAY**	**0.234**
1154 - 1155		0.010	90	0.009	1.054	TITE	#####
1155 - 1156		0.000	100	0.000	#####	TITE	#####
1156 - 1157		0.010	100	0.010	1.000	TITE	#####
1157 - 1158		0.010	95	0.010	1.026	TITE	#####
1158 - 1159		0.010	75	0.008	1.155	TITE	#####

COMMENTS:
Deviated wellbore; PHI & Rd in MD (used for log analysis)
ML in TVD (used for tops)
ML 1134.5 - 1138.1 TVD

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1150 - 1151		0.062	100	0.384	0.161	PAY	0.975
1151 - 1152		0.060	125	0.450	0.149	PAY	0.908
1152 - 1153		0.055	150	0.454	0.148	PAY	0.648
1153 - 1154		0.045	125	0.253	0.199	PAY	0.234
PAY (FT.)	13	0.056		0.385	0.164		0.691
	PHI*H	0.728	HPV		0.609	k*h	9.1

COMMENTS:
Core 1154 - 1166.8
Pf. 1149 - 1154; Acid
FP 3/92 @ 1000 MCF/D; C - 809 MMCF thru 10/31/98; U - 3393 MMCF

WELL : a-71-G/94-P-10

	m	ft.	SS
KB :	452.2	1484	
LS MKR. :	1120.0	3674	
JMR :	1127.7	3700	-2216
SH. MKR. :	1141.0	3743	
LS MKR. - JMR		25	
JMR - SH. MKR.		44	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1128 - 1129		**0.040**	**33**	**0.053**	**0.435**	**PAY**	**0.038**
1129 - 1130		0.030	30	0.027	0.609	TITE	0.003
1130 - 1131		**0.050**	**30**	**0.075**	**0.365**	**PAY**	**0.142**
1131 - 1132		**0.070**	**80**	**0.392**	**0.160**	**PAY**	**1.577**
1132 - 1133		**0.050**	**150**	**0.375**	**0.163**	**PAY**	**0.417**
1133 - 1134		**0.075**	**200**	**1.125**	**0.094**	**PAY**	**2.766**
1134 - 1135		**0.062**	**125**	**0.481**	**0.144**	**PAY**	**1.054**
1135 - 1136		0.025	70	0.044	0.478	TITE	0.004
1136 - 1137		0.015	60	0.014	0.861	TITE	0.000
1137 - 1138		**0.035**	**65**	**0.080**	**0.354**	**PAY**	**0.038**
1138 - 1139		**0.030**	**70**	**0.063**	**0.398**	**PAY**	**0.016**
1139 - 1140		**0.030**	**70**	**0.063**	**0.398**	**PAY**	**0.016**
1140 - 1141		0.010	50	0.005	1.414	TITE	#####

COMMENTS:
ML 1128.1 - 1128.9; 1130.4 - 1139.5

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1128 - 1129		0.040	33	0.053	0.435	PAY	0.038
1130 - 1131		0.050	30	0.075	0.365	PAY	0.142
1131 - 1132		0.070	80	0.392	0.160	PAY	1.577
1132 - 1133		0.050	150	0.375	0.163	PAY	0.417
1133 - 1134		0.075	200	1.125	0.094	PAY	2.766
1134 - 1135		0.062	125	0.481	0.144	PAY	1.054
1137 - 1138		0.035	65	0.080	0.354	PAY	0.038
1138 - 1139		0.030	70	0.063	0.398	PAY	0.016
1139 - 1140		0.030	70	0.063	0.398	PAY	0.016
PAY (FT.)	30	0.049		0.301	0.279		0.674
	PHI*H	1.450	HPV		1.045	k*h	19.9

COMMENTS:
Core 1126 - 1144
DST 1122 - 1175; FP 85 - 106; F/ 52 MCF/D
Pf. 1128 - 1135; Acid
FP 3/90 @ 667 MCF/d; C - 661 MMCF thru 1/94; U - 1146 MMCF

WELL : b-66-H/94-P-10

	m	ft.	SS
KB :	452.4	1484	
JMR :	1093.2	3587	-2102
SH. MKR. :	1108.4	3636	
JMR - SH. MKR.		50	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1094 - 1095		**0.030**	**1000**	**0.900**	**0.105**	**PAY**	**0.074**
1095 - 1096		**0.045**	**650**	**1.316**	**0.087**	**PAY**	**0.388**
1096 - 1097		**0.030**	**1000**	**0.900**	**0.105**	**PAY**	**0.074**
1097 - 1098		0.010	1000	0.100	0.316	TITE	0.000
1098 - 1099		**0.035**	**200**	**0.245**	**0.202**	**PAY**	**0.086**
1099 - 1100		**0.040**	**300**	**0.480**	**0.144**	**PAY**	**0.191**
1100 - 1101		**0.080**	**325**	**2.080**	**0.069**	**PAY**	**3.956**
1101 - 1102		**0.040**	**600**	**0.960**	**0.102**	**PAY**	**0.230**
1102 - 1103		**0.045**	**500**	**1.013**	**0.099**	**PAY**	**0.369**
1103 - 1104		**0.040**	**425**	**0.680**	**0.121**	**PAY**	**0.211**
1104 - 1105		**0.040**	**500**	**0.800**	**0.112**	**PAY**	**0.220**
1105 - 1106		0.015	350	0.079	0.356	TITE	0.001
1106 - 1107		-0.020	175	0.070	0.378	TITE	#####
1107 - 1108		0.010	140	0.014	0.845	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1094 - 1095		0.030	1000	0.900	0.105	PAY	0.074
1095 - 1096		0.045	650	1.316	0.087	PAY	0.388
1096 - 1097		0.030	1000	0.900	0.105	PAY	0.074
1098 - 1099		0.035	200	0.245	0.202	PAY	0.086
1099 - 1100		0.040	300	0.480	0.144	PAY	0.191
1100 - 1101		0.080	325	2.080	0.069	PAY	3.956
1101 - 1102		0.040	600	0.960	0.102	PAY	0.230
1102 - 1103		0.045	500	1.013	0.099	PAY	0.369
1103 - 1104		0.040	425	0.680	0.121	PAY	0.211
1104 - 1105		0.040	500	0.800	0.112	PAY	0.220
PAY (FT.)	33	0.043		0.937	0.115		0.580
	PHI*H	1.394	HPV		1.234	k*h	19.0

COMMENTS:
Core 1093 - 1111
Pf. 1094 - 1096.5; 1098 - 1105.5; Acid
1st prod. 3/90 @ 1917 MCF/D
C - 4289 MMCF to 7/31/98

WELL : b-62-H/94-P-10

	m	ft.	SS
KB :	452.0	1483	
JMR :	1081.0	3547	-2064
SH. MKR. :	1094.0	3589	
JMR - SH. MKR.		43	

GROSS INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1082 - 1083		0.000	30	0.000	#####	TITE	#####
1083 - 1084		-0.015	70	0.016	0.797	TITE	#####
1084 - 1085		0.000	125	0.000	#####	TITE	#####
1085 - 1086		0.000	150	0.000	#####	TITE	#####
1086 - 1087		0.015	200	0.045	0.471	TITE	0.001
1087 - 1088		0.015	275	0.062	0.402	TITE	0.001
1088 - 1089		**0.030**	**325**	**0.293**	**0.185**	**PAY**	**0.051**
1089 - 1090		**0.040**	**325**	**0.520**	**0.139**	**PAY**	**0.196**
1090 - 1091		0.015	300	0.068	0.385	TITE	0.001
1091 - 1092		0.000	225	0.000	#####	TITE	#####
1092 - 1093		0.000	175	0.000	#####	TITE	#####
1093 - 1094		-0.015	150	0.034	0.544	TITE	#####

COMMENTS:

PAY INTERVAL:

INTERVAL	MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1088 - 1089		0.030	325	0.293	0.185	PAY	0.051
1089 - 1090		0.040	325	0.520	0.139	PAY	0.196
PAY (FT.)	7	0.035		0.406	0.162		0.123
	PHI*H	0.230	HPV		0.193	k*h	0.8

COMMENTS:
DST 1083 - 1122; GTS TSTM; Rec. 36' mud

LOG DATA

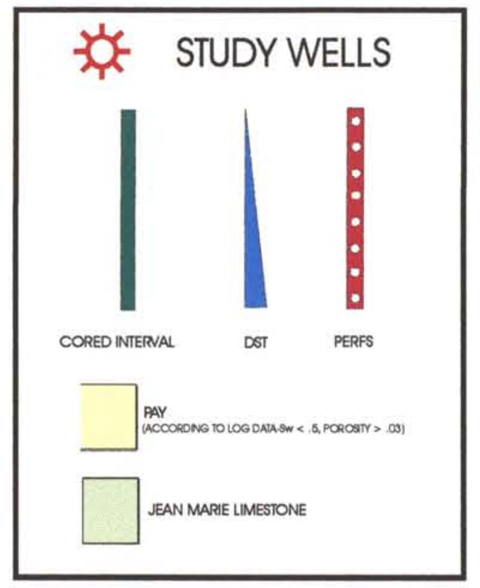


PLATE 13
STRATIGRAPHIC CROSS SECTION C-C'
DATUM- JEAN MARIE SHALE MARKER

CROSS SECTION D - D'

LOG DATA

WELL : d-53-C/94-P-10

		m	ft.	SS
KB	:	460.0	1509	
LS MKR.	:	1165.0	3822	
JMR	:	1171.0	3842	-2333
SH. MKR.	:	1183.0	3881	
LS MKR. - JMR			20	
JMR - SH. MKR.			39	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1171	-	1172		-0.030	15	0.014	0.861	TITE	#####
1172	-	1173		0.000	25	0.000	#####	TITE	#####
1173	-	1174		0.010	30	0.003	1.826	TITE	#####
1174	-	1175		0.010	25	0.003	2.000	TITE	#####
1175	-	1176		0.045	65	0.132	0.276	PAY	0.158
1176	-	1177		0.030	125	0.113	0.298	PAY	0.029
1177	-	1178		0.045	140	0.284	0.188	PAY	0.246
1178	-	1179		-0.010	150	0.015	0.816	TITE	#####
1179	-	1180		0.010	150	0.015	0.816	TITE	0.000
1180	-	1181		0.010	150	0.015	0.816	TITE	0.000
1181	-	1182		0.015	100	0.023	0.667	TITE	0.000
1182	-	1183		-0.010	70	0.007	1.195	TITE	0.000

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1175	-	1176		0.045	65	0.132	0.276	PAY	0.158
1176	-	1177		0.030	125	0.113	0.298	PAY	0.029
1177	-	1178		0.045	140	0.284	0.188	PAY	0.246
PAY (FT.)			10	0.040		0.176	0.254		0.144
			PHI*H	0.394	HPV		0.294	k*h	1.4

COMMENTS:
Core 1170 - 1188
Pf. 1175 - 81; Acid; Results n. rpt.

WELL : a-47-B/94-P-10

		m	ft.	SS
KB	:	469.3	1540	
LS MKR.	:	1148.3	3767	
JMR	:	1154.0	3786	-2246
SH. MKR.	:	1166.8	3828	
LS MKR. - JMR			19	
JMR - SH. MKR.			42	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1154	-	1155		0.010	20	0.002	2.236	TITE	#####
1155	-	1156		0.010	30	0.003	1.826	TITE	#####
1156	-	1157		0.032	80	0.082	0.349	PAY	0.027
1157	-	1158		0.055	150	0.454	0.148	PAY	0.648
1158	-	1159		0.010	250	0.025	0.632	TITE	0.000
1159	-	1160		0.010	300	0.030	0.577	TITE	0.000
1160	-	1161		0.000	300	0.000	#####	TITE	#####
1161	-	1162		0.015	275	0.062	0.402	TITE	0.001
1162	-	1163		0.025	150	0.094	0.327	TITE	0.012
1163	-	1164		-0.010	175	0.018	0.756	TITE	#####

COMMENTS:

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1156	-	1157		0.032	80	0.082	0.349	PAY	0.027
1157	-	1158		0.055	150	0.454	0.148	PAY	0.648
PAY (FT.)			7	0.044		0.268	0.249		0.338
			PHI*H	0.285	HPV		0.214	K*h	2.2

COMMENTS:
DST 1151.5 - 1194; Rec. 128' mud
Pf. 1156 - 1159; 1162 - 1165; Acid; F/ 465 MCF/D 2/81
BHP = 740# in 6/95

WELL : b-22-B/94-P-10

		m	ft.	SS
KB	:		1561	
LS MKR.	:		3720	
JMR	:		3736	-2175
SH. MKR.	:		3778	
LS MKR. - JMR			16	
JMR - SH. MKR.			42	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
3738	-	3740		0.015	85	0.019	0.723	TITE	0.000
3740	-	3742		0.015	80	0.018	0.745	TITE	0.000
3742	-	3744		0.000	80	0.000	#####	TITE	#####
3744	-	3746		-0.010	95	0.010	1.026	TITE	0.000
3746	-	3748		-0.015	120	0.027	0.609	TITE	#####
3748	-	3750		0.000	125	0.000	#####	TITE	#####
3750	-	3752		0.015	120	0.027	0.609	TITE	0.000
3752	-	3754		0.020	110	0.044	0.477	TITE	0.002
3754	-	3756		0.030	120	0.108	0.304	PAY	0.028
3756	-	3758		0.045	120	0.243	0.203	PAY	0.229
3758	-	3760		0.045	120	0.243	0.203	PAY	0.229
3760	-	3762		0.085	120	0.867	0.107	PAY	4.259
3762	-	3764		0.062	120	0.461	0.147	PAY	1.040
3764	-	3766		0.035	120	0.147	0.261	PAY	0.064
3766	-	3768		0.085	100	0.723	0.118	PAY	4.071
3768	-	3770		0.070	110	0.539	0.136	PAY	1.756
3770	-	3772		0.070	120	0.588	0.130	PAY	1.803
3772	-	3774		0.090	120	0.972	0.101	PAY	5.463
3774	-	3776		0.075	80	0.450	0.149	PAY	2.168
3776	-	3778		-0.015	25	0.006	1.333	TITE	0.000

COMMENTS:
Mudcake 3754 - 3776

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
3754	-	3756		0.030	120	0.108	0.304	PAY	0.028
3756	-	3758		0.045	120	0.243	0.203	PAY	0.229
3758	-	3760		0.045	120	0.243	0.203	PAY	0.229
3760	-	3762		0.085	120	0.867	0.107	PAY	4.259
3762	-	3764		0.062	120	0.461	0.147	PAY	1.040
3764	-	3766		0.035	120	0.147	0.261	PAY	0.064
3766	-	3768		0.085	100	0.723	0.118	PAY	4.071
3768	-	3770		0.070	110	0.539	0.136	PAY	1.756
3770	-	3772		0.070	120	0.588	0.130	PAY	1.803
3772	-	3774		0.090	120	0.972	0.101	PAY	5.463
3774	-	3776		0.075	80	0.450	0.149	PAY	2.168
PAY (FT.)			22	0.063		0.486	0.169		1.919
			PHI*H	1.384	HPV		1.150	HPV	42.2

COMMENTS:
DST 3750 - 3775; F/ 411 MCF/D
Pf. 3754 - 3764; 3766 - 3776; Acid; Results n. rpt.; SIGW 3/76
BHP 409# 1/95

WELL : c-18-A/94-P-10

		m	ft.	SS
KB	:	473.3	1553	
JMR	:	1127.0	3697	-2145
SH. MKR.	:	1144.6	3755	
JMR - SH. MKR.			58	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHIs	Rd	Rwa	Sw	COMMENTS	k
1128	-	1129	51	0.040	110	0.176	0.238	PAY	0.121
1129	-	1130	50	0.030	110	0.099	0.318	PAY	0.026
1130	-	1131	48	0.020	200	0.080	0.354	TITE	0.004
1131	-	1132	50	0.030	300	0.270	0.192	PAY	0.049
1132	-	1133	52	0.045	350	0.709	0.119	PAY	0.339
1133	-	1134	55	0.065	300	1.268	0.089	PAY	1.620
1134	-	1135	53	0.050	225	0.563	0.133	PAY	0.479
1135	-	1136	56	0.070	200	0.980	0.101	PAY	2.053
1136	-	1137	52	0.045	250	0.506	0.141	PAY	0.307
1137	-	1138	52	0.045	450	0.911	0.105	PAY	0.360
1138	-	1139	50	0.030	700	0.630	0.126	PAY	0.067
1139	-	1140	52	0.045	500	1.013	0.099	PAY	0.369
1140	-	1141	50	0.030	400	0.360	0.167	PAY	0.056
1141	-	1142	50	0.030	300	0.270	0.192	PAY	0.049
1142	-	1143	50	0.030	200	0.180	0.236	PAY	0.040
1143	-	1144	51	0.040	100	0.160	0.250	PAY	0.114

COMMENTS:
Used 22,000'/sec. to calculate PHIs

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHIs	Rd	Rwa	Sw	COMMENTS	k
1128	-	1129	51	0.040	110	0.176	0.238	PAY	0.121
1129	-	1130	50	0.030	110	0.099	0.318	PAY	0.026
1131	-	1132	50	0.030	300	0.270	0.192	PAY	0.049
1132	-	1133	52	0.045	350	0.709	0.119	PAY	0.339
1133	-	1134	55	0.065	300	1.268	0.089	PAY	1.620
1134	-	1135	53	0.050	225	0.563	0.133	PAY	0.479
1135	-	1136	56	0.070	200	0.980	0.101	PAY	2.053
1136	-	1137	52	0.045	250	0.506	0.141	PAY	0.307
1137	-	1138	52	0.045	450	0.911	0.105	PAY	0.360
1138	-	1139	50	0.030	700	0.630	0.126	PAY	0.067
1139	-	1140	52	0.045	500	1.013	0.099	PAY	0.369
1140	-	1141	50	0.030	400	0.360	0.167	PAY	0.056
1141	-	1142	50	0.030	300	0.270	0.192	PAY	0.049
1142	-	1143	50	0.030	200	0.180	0.236	PAY	0.040
1143	-	1144	51	0.040	100	0.160	0.250	PAY	0.114
PAY (FT.)			49	0.042		0.540	0.167		0.403
			PHI*H	2.051	HPV		1.708	k*h	19.8

COMMENTS:
Core 1120.5 - 1137
DST 1132 - 1172; F/ 471 MCF/D
Pf. 1127.5 - 1144; Acid; FP 4/80 @ 2000 MCF/D; C - 4073 MMCF

LOG DATA

WELL : d-11-A/94-P-10

		m	ft.	SS
KB	:	465.4	1527	
JMR	:	1100.3	3610	-2083
SH. MKR.	:	1111.6	3647	
JMR - SH. MKR.			37	

GROSS INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1101	-	1102		0.040	35	0.056	0.423	PAY	0.041
1102	-	1103		0.015	45	0.010	0.994	TITE	0.000
1103	-	1104		0.030	45	0.041	0.497	PAY	0.008
1104	-	1105		0.030	30	0.027	0.609	TITE	0.003
1105	-	1106		0.030	25	0.023	0.667	TITE	0.002
1106	-	1107		0.015	30	0.007	1.217	TITE	#####
1107	-	1108		0.020	80	0.032	0.559	TITE	0.001
1108	-	1109		0.020	110	0.044	0.477	TITE	0.002
1109	-	1110		0.020	100	0.040	0.500	TITE	0.002
1110	-	1111		0.030	100	0.090	0.333	PAY	0.023

COMMENTS:
DST 1095 - 1115; Rec. 10' mud

PAY INTERVAL:

INTERVAL			MSEC./FT.	PHId	Rd	Rwa	Sw	COMMENTS	k
1101	-	1102		0.040	35	0.056	0.423	PAY	0.041
1103	-	1104		0.030	45	0.041	0.497	PAY	0.008
1110	-	1111		0.030	100	0.090	0.333	PAY	0.023
PAY (FT.)			10	0.033		0.062	0.418		0.024
			PHI*H	0.328	HPV		0.191	k*h	0.2

COMMENTS:
Abnd. 3/80

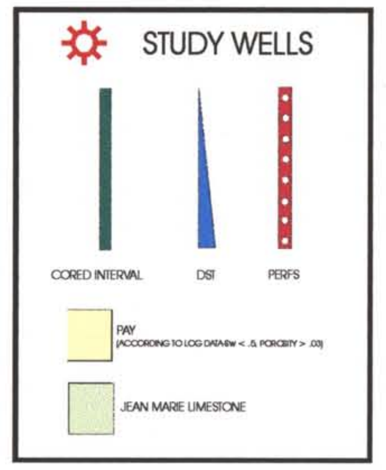


PLATE 14
STRATIGRAPHIC CROSS SECTION D-D'
DATUM- JEAN MARIE SHALE MARKER

VITA

Dwayne Brent Williams 2

Candidate for the Degree of

Masters of Science

Thesis: RESERVOIR CHARACTERIZATION AND PRODUCIBILITY OF THE JEAN MARIE LIMESTONE, NORTHEAST BRITISH COLUMBIA, CANADA

Major Field: Geology

Biographical:

Personal Data: Born in Pauls Valley, Oklahoma, on November 18,1975, the son of Kent and Janet Williams.

Education: Graduated from Lindsay High School, Lindsay, Oklahoma in May 1994; received Associates Degree in Agronomy from Eastern Oklahoma State College, Wilburton, Oklahoma in May 1997 and a Bachelor Degree in Geology from Oklahoma State University, Stillwater, Oklahoma in 2001. Completed the requirements for the Masters of Science degree with a major in Geology at the Oklahoma State University in May 2002.

Experience: Raised on a farm near Lindsay, Oklahoma; Employed as an oilfield and farm laborer during summers as well as intern for Louis Dreyfus Natural Gas and associate geologist for Chesapeake Energy Corp, 2000 to present.

Professional Memberships: American Association of Petroleum Geologists, Oklahoma City Geological Society and Oklahoma State Geological Society.