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The Upper Devonian Grosmont Formation: Well Log Evaluation and Regional Mapping of a Heavy Oil Carbonate Reservoir in Northeastern Alberta

by

© Eugene A. Dembicki

A thesis submitted to the Faculty of Graduate Studies and Research in partial fulfillment of the requirements for the degree of Master of Science.

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This thesis is dedicated to
Karen
for all her
love, patience, and understanding.

ABSTRACT

The Upper Devonian Grosmont Formation in northeastern Alberta, Canada, is a giant carbonate heavy oil reservoir. Currently, this reservoir is not being exploited for its bitumen content, but it is under investigation for the thermal recovery of bitumen.

Well logs were used to determine elevation, thickness, porosity, net pay, isoporosity (product of net pay and porosity), and hydrocarbon pore volume (product of isoporosity and bitumen saturation) for the Grosmont Formation as well as the overlying Ireton and Nisku Formations. Regional mapping of reservoir characteristics identifies the Upper Grosmont 2 and Nisku Formation as the best reservoirs. The best reservoir rocks are dolostones that have significant primary and various types of secondary porosity. The worst reservoir rocks are limestones because they generally have low primary and no secondary porosity.

One of the most important features associated with these reservoirs is the amount of erosion and dissolution caused by subaerial exposure (karstification) between the Mississippian (?) and Cretaceous periods. Sub-vertical to vertical fractures, collapse breccias, rubble, large vugs, metre size dissolution cavities, or combinations thereof are common in karstified intervals. On well logs, karst features are often related to excursions of the caliper log in clean carbonate sections. In addition, the neutron-density response may show off-scale porosity readings due to lost pad contact, and the sonic curve may display severe cycle skipping. Understanding of well log response in karsted intervals facilitates recognition of karst features on well logs.

The recognition of karst features is important for reservoir evaluation because karst has affected three important reservoir properties: (i) porosity (ii) permeability, and (iii) seal effectiveness. Generally, porosity and permeability are increased and values of 40% and 30,000 md, respectively, are common in strongly karstified intervals. Devonian shaly lithologies, which might be expected to act as seals during steam stimulation, may be breached by karst-

related fractures. Generally, the Devonian seals in the higher stratigraphic units appear to be breached more extensively than the lower seals. Steam stimulation sites should not be located near breached seal(s) because the injected steam would probably escape upwards through fractures in the seal. In the northwest part of the study area, an alternative, and possibly better seal, may be the Cretaceous Clearwater Formation. This formation is a regionally extensive unkarstified marine shale that caps the eroded Devonian strata.

The bitumen that is contained in the Devonian (e.g., Grosmont) and Cretaceous (e.g., Athabasca) reservoirs was originally a free flowing, paraffinic crude oil at the time of migration during the Late Cretaceous. After migration, the oil was transformed into a black viscous bitumen by in-situ biodegradation and water-washing. The western margin of the Cooking Lake Formation probably acted as a conduit for oil from the Duvernay Formation into northeastern Alberta.

Recommendations for the successful recovery of bitumen from the Devonian carbonates, via steam stimulation, is based upon three criteria: (i) high bitumen saturation, (ii) seal effectiveness, and (iii) absence of gas. Most of the promising zones which have a high bitumen saturation and effective seal are found in those parts of the reservoir that currently contain gas. Heavy oil production should not be attempted from the Devonian carbonates until the gas is depleted. The time of gas depletion cannot be estimated because gas is continuously being regenerated by in-situ bacterial activity at a rate that approximately equals production.

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CHAPTER 1

INTRODUCTION

Beneath the Cretaceous Athabasca oil sand deposit, which contains 142 X 10^9 m^3 (893 X 10^9 bbl) of in-situ bitumen (E.R.C.B., 1991), are the bitumen-saturated Devonian Nisku, Upper Ireton, and Grosmont formations. The Nisku Formation is estimated to contain 10 X 10^9 m^3 or 65 X 10^9 bbl of bitumen (E.R.C.B., 1991) and the Upper Ireton may contain 19 X 10^9 m^3 or 120 X 10^9 bbl (Outtrim and Evans, 1977). In-situ bitumen reserves for the Grosmont Formation range from 42 X 10^9 m^3 (264 X 10^9 bbl) as estimated by Outtrim and Evans (1977) to as much as 50 X 10^9 m^3 (317 X 10^9 bbl) as reported by the E.R.C.B. (1991). Although the combined bitumen reserves of the Nisku, Upper Ireton, and Grosmont formations are approximately half the size of the Athabasca deposit, the Grosmont Formation itself is still an immense reserve and can be classified as a giant heavy oil (bitumen) reservoir. A giant oil field is defined as one containing greater than 500 x 10^6 bbl of oil (North, 1984). Currently, the Grosmont Formation is not being exploited for its giant bitumen reserves.

The Grosmont Formation extends over approximately 100,000 km^2 in the subsurface of Alberta and may continue into the Northwest Territories (Figure 1.1) However, the extension of the Grosmont Formation to the north is poorly known due to lack of well control. Towards the south and west, the Grosmont Formation grades into shales and marls of the Ireton Formation. To the northeast, the Grosmont Formation is eroded and subcrops beneath Cretaceous clastics.

1.1 Reservoir Problems

There are several technical difficulties associated with the production of heavy oil or bitumen from the Grosmont Formation. First of all, intense aerobic

Fig. 1.1 Location of study area.

biodegradation combined with water-washing has degraded an original light crude oil into a highly viscous bitumen that is now immobile under present reservoir conditions. Therefore, in order to lower the bitumen's viscosity and enable the bitumen to flow towards the wellbore, the bitumen must be heated by steam injection.

Secondly, erosion and karstified zones associated with the sub-Cretaceous unconformity have resulted in a variety of geological and engineering challenges. For example, the amount of erosion can vary by up to 35 m in as little as 3 km, and can cause difficulties for the geologist in recommending specific depths for steam injection and recovery wells. Also, the shale breaks which may act as seals or vertical permeability barriers for the reservoir engineer, may be present, breached by karst-related fractures, or completely removed by erosion. Where the shale breaks are present, steam stimulation will be successful. However, if steam is injected into regions where a seal is breached or absent, the energy of the injected steam may be lost to overlying strata, and communication problems will exist between injection and recovery wells.

Thirdly, karst has created problems for the drilling engineer. In karsted terrain, the Grosmont Formation is severely fractured and large dissolution cavities are present. As a result, sudden drill bit drops, lost mud circulation, and poor to no core recovery, are common. Furthermore, when attempting to complete such a well, the cement bond between the casing and the formation is frequently of poor quality because of the high cement loss into the highly fractured wall rock (fracture permeability of several darcies). Therefore, in poorly cemented wells, there is the possibility of unwanted vertical communication between the various reservoir units (Vandermeer and Presber, 1980).

Finally, there are several gas fields located along the updip erosional edge of the Grosmont Formation. The presence of gas may interfere with the thermal recovery of bitumen because injected steam may migrate into the gas cap and not heat the targeted bitumen-saturated regions of the reservoir. Thus, until the gas is depleted, large zones of the reservoir are unavailable for heavy oil exploitation.

1.2 Objectives

This study is part of a large project at the University of Alberta sponsored by the Alberta Oil Sands Technology and Research Authority (AOSTRA). This project is entitled "Diagenesis and Reservoir Characteristics of the Heavy Oil Carbonate Trend in Western Canada", and it consists of three broad research categories: facies, diagenesis, and petrophysics. The ultimate purpose of this project is to generate data that will enable prediction of Grosmont reservoir characteristics.

This thesis concentrates on the petrophysical properties of the Grosmont Formation, as well as the juxtaposed Upper Ireton and Nisku Formation. The primary objective is to identify favorable sites for the thermal recovery of bitumen and predict regions where there may be communication problems between injection and recovery wells. This goal is accomplished by generating a suite of maps and cross sections that illustrate various geological and petrophysical properties.

A secondary objective is to investigate Leduc reefs underlying the Grosmont Formation. The Leduc reefs have been examined for two purposes: first, to determine what affect the Leduc reefs have had on Grosmont platform sedimentation; second, to illustrate that some of the bitumen in the Cretaceous (e.g., Athabasca) and Devonian heavy oil reservoirs may have originated from a Devonian source rock.

1.3 Study Area

The study area is nearly 15,000 km^2 large and is located approximately 60 km west of Fort McMurray in northeastern Alberta encompassing Townships 80 to 95, Ranges 16 to 25 west of the fourth meridian (Figure 1.1). There is no permanent road access because of the numerous swamps and muskeg. However, during cold winter months, access can be gained via a seasonal winter road that traverses over the frozen terrain.

Within the study area, three pilot projects have attempted to extract bitumen using steam injection near the limit of the Grosmont. The results of these pilot projects were mixed. Some recovery wells produced commercial amounts of bitumen (80 m^3 or 500 bbl/day) but others did not (Vandermeer and Presber, 1980). The variable success is controlled by complex and heterogeneous reservoir characteristics which are poorly understood.

1.4 Methodology

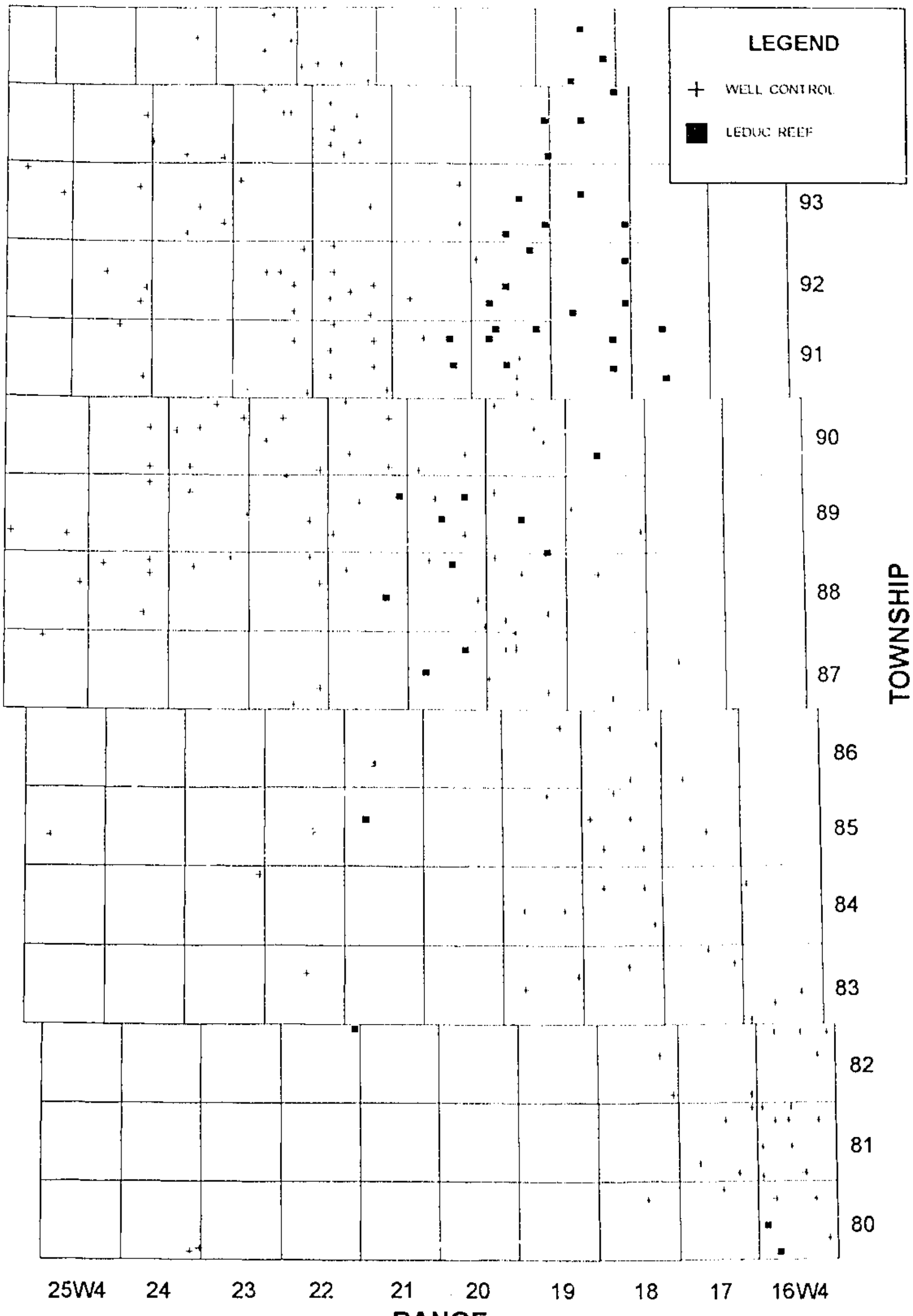
Well logs from 224 wells (Figure 1.2) have been utilized for subsurface mapping and well log analysis. Hard copies of the well logs were obtained from the Alberta Research Council (ARC) in Edmonton. Crosses signify wells that penetrated the Grosmont Formation, and black squares indicate wells which also penetrated underlying Leduc reefs.

1.4.1 Mapping and Correlation Techniques

Formation tops were picked from well logs and entered into a data base (QUATTRO®PRO) to compute subsurface elevations and thicknesses. Resource characteristics of porosity, net pay, isoporosity, and hydrocarbon pore volume (HPV) were determined by computerized well log analysis using programs developed by The Logic Group (LOGDIGI®, LOGAUTO®, LOGPRINT®, and EDITFILE®). The data generated by these methods were mapped on the University of Alberta mainframe computer system using SURFACE II. All of the maps generated by SURFACE II were edited manually, using CorelDRAW®, to correct the contours along the sub-Cretaceous unconformity.

Cross sections were created by exporting a digitized well log as a HPGL file into the LOGPRINT® program. This HPGL file was imported into CorelDRAW®, and the well was enlarged and positioned to scale. Correlations between wells were based upon output files from LOGAUTO®.

Fig. 1.2 Well control map.



1.4.2 Well Log Analysis

Hard copies of well logs obtained from the ARC were converted into digital format using the program LOGDIGI® on a large Summagraphics digitizing tablet (1.0 X 1.25 m). Data was saved every foot for wells in imperial and 0.5 m for wells in metric format. ASCII data files generated by LOGDIGI® were imported into the log interpretation program, LOGAUTO®, to calculate:

V_{sh} = volume of shale,
ϕ = porosity, and
S_w = water saturation at every foot or 0.5 m.

The well log analysis procedure for a complete log suite where:

γ = gamma-ray,
ϕ_n = neutron porosity,
ϕ_d = density porosity, and
R_{id} = resistivity, deep induction is as follows:

1. <u>Determine the resistivity of the formation water (R_w).</u>

   R_w values were obtained from the Formation Water Resistivities of Canada, Map No. 15 (Canadian Well Logging Society, 1987), and entered into LOGAUTO®.

2. <u>Determine the volume of shale (V_{sh}).</u>

   The "older rock method" was utilized to compensate for the high degree of compaction in the Grosmont Formation. GR_{min} and GR_{max} were obtained from the well log, and were entered into LOGAUTO®. The formulas used to calculate V_{sh} are:

$$I_{GR} = \frac{(GR - GR_{min})}{(GR_{max} - GR_{min})}$$

$$V_{sh} = 0.33\,(2^{2(I_{GR})} - 1)$$

where:

I_{GR} = Gamma Ray Index.
GR = Gamma Ray reading from well log.
GR_{min} = Gamma Ray minimum from well log.
GR_{max} = Gamma Ray maximum from well log.
V_{sh} = Volume of shale.

3. Correct ϕ_n and ϕ_d for the presence of shale.

ϕ_{nsh} and ϕ_{dsh} were obtained from the well logs and entered into LOGAUTO®. The formulas used are:

$$\phi_{nc} = \phi_n - (V_{sh})(\phi_{nsh})$$

$$\phi_{dc} = \phi_d - (V_{sh})(\phi_{dsh})$$

where:

ϕ_{nc} = Corrected neutron porosity.
ϕ_n = Neutron porosity reading from well log.
ϕ_{nsh} = Neutron porosity reading in shale.
V_{sh} = Volume of shale.
ϕ_{dc} = Corrected density porosity.
ϕ_d = Density porosity reading from well log.
ϕ_{dsh} = Density porosity reading in shale.

4. Calculate effective porosity (ϕ_e).

For oil,

$$\phi_e = \frac{\phi_{nc} + \phi_{dc}}{2}$$

For gas,

$$\phi_e = \sqrt{\frac{\phi_{nc}^2 + \phi_{dc}^2}{2}}$$

where:

ϕ_e = Effective porosity.
ϕ_{nc} = Corrected neutron porosity.
ϕ_{dc} = Corrected density porosity.

5. <u>Determine water saturation (S_w).</u>

The Archie equation was used to determine S_w.

$$S_w = \left(\frac{a \bullet R_w}{\phi^m \bullet R_t}\right)^{\frac{1}{n}}$$

where:

Sw = Water Saturation.
Rw = Formation water resistivity.
Rt = True formation resistivity, obtained from the deep resistivity tool.
a = 1, tortuosity coefficient.
m = 2, cementation exponent.
n = 2, saturation exponent.

After a well was analyzed, the resultant data file was transferred into the EDITFILE® program. This program calculates the net pay, isoporosity, and hydrocarbon pore volume (HPV) of each reservoir unit. Net pay thicknesses were calculated using a porosity cutoff value of 5%, a shale volume cutoff of 15%, and a water saturation cutoff of 60%. Isoporosity thicknesses (m) were calculated as the product of net pay thickness (m) and porosity (fraction). Isoporosity delineates the porosity distribution (m). Hydrocarbon pore volume (HPV) is the product of net pay thickness (m), porosity (fraction), and bitumen saturation (fraction). HPV delineates the bitumen-rich zones.

Note:

(1) Old electrical logs (prior to the 1970's) were not analyzed because they are inaccurate.

(2) In zones where there was lost pad contact of the porosity tools due to "caves" or rugose boreholes, a porosity between 35 and 40% was assumed.

(3) Sonic logs were not analyzed because of bad cycle skipping.

(4) All the above formulas were obtained from the LOGAN TECHNICAL AND USER MANUAL (1984).

1.4.3 Comparison of Well Log and Core Analyses

Analyzed well logs have been compared to core analysis data to confirm the accuracy of the well log interpretation method. Generally, the two methods obtain similar results. However, porosity discrepancies may result if the formation is vuggy, fractured, or if there is lost core. Results from these two methods is shown below using Well 6-26-89-20 W4M as an example.

UNIT	POROSITY (%)		BITUMEN SATURATION (%)	
	CORE	WELL LOG	CORE	WELL LOG
UGM3	18.8	17.8	91.3	90.5
UGM2	12.7	18.1	79.6	80.6

Except for the UGM2 porosity, the above example clearly shows that there is an excellent correlation between well log and core analyses. The comparatively lower porosity of UGM2 obtained from core analysis can be attributed to a combination of factors. Firstly, core analysis methods cannot accurately measure the porosity of large vugs and fractures (horizontal and vertical) present in the core. Secondly, the core samples are biased towards more consolidated (less porous) parts of the unit because there is poor core recovery and several intervals of lost core in the UGM2 . Well log analysis, unlike core analysis, can measure the porosity of the total interval including fractures and large vugs. Therefore, in this example, the porosity derived from well log analysis should be considered more accurate.

CHAPTER 2

REGIONAL GEOLOGY

2.1 Previous Work

The type well of the Grosmont Formation, Imperial Grosmont No. 1 13-17-67-23 W4M, was drilled in 1949 and 1950 approximately 10 km northeast of the abandoned village of Grosmont. Based upon drill cuttings from this well and core from adjacent wells, Belyea (1952) described the "Grosmont member" as a "widespread biostromal coquinoid limestone and dolomitized limestones and associated reefs" with "coarse vuggy porosity." A descriptive study published by Law (1955) subsequently raised the member name to formation status. In 1956, Belyea correlated and described the Grosmont Formation approximately 200 km northwest of the type well. An outcrop along the northwest bank of the Peace River within the Vermillion Rapids was examined by Norris (1963) and he described the Grosmont Formation as "a pale brownish grey, pale bluish grey to dark grey, fine grained, granular, coarsely vuggy, massive dolomite of probable reef origin. The vugs vary in size up to about an inch in diameter and in places contain black bitumen of tar-like consistency."

There were no more detailed studies published on the Grosmont Formation until 1980 when Vandermeer and Presber of Unocal Canada Ltd. (formerly Union Oil of Canada Ltd.) released the results of technical difficulties from the first two pilot sites at Chipewyan River 14-21-88-19 W4M and Buffalo Creek 14-05-88-19 W4M. They reported that the peak daily production of bitumen per well ranged from 3 m^3 (20 bbl) to 80 m^3 (500 bbl) depending upon the steam stimulation method utilized. "Soak and drive" resulted in the best bitumen production and "soak" produced the least amount of bitumen. The most "irritating technical problem" encountered was unwanted vertical communication between the reservoir units caused by a poor casing-to-formation cement bond. Despite the technical difficulties, Vandermeer and Presber (1980) were confident that billions of barrels of bitumen could be produced from the Grosmont in the future.

Modeling of the thermal recovery of bitumen was based upon core data, observation of well response to temperature changes, and high but erratic bitumen production. Cordell (1982) envisioned the reservoir as high permeability vugular "channels" randomly crosscutting a bitumen-saturated matrix. The "channels" have a dual role as conduits in the steam stimulation process. They rapidly introduce and disperse the steam energy into the reservoir upon steam injection, and upon production they drain the heated bitumen from the matrix.

Geological investigations arising from the pilot site activity was summarized by Harrison and McIntyre (1981) and Harrison (1982, 1984). They published the internal stratigraphy developed by Unocal and the stratigraphic nomenclature. Accordingly, the Grosmont consists of four shallowing-upward carbonate sequences that are separated by argillaceous carbonate/shaly intervals called "shale breaks." It was also noted that diagenetic processes strongly control the porosity distribution, and that the bitumen is concentrated along the updip northeastern erosional edge.

The southern part of the Grosmont Formation (Townships 55-75, Ranges 12W4M-8W5M) was examined by Cutler (1983). Based on detailed core descriptions, Cutler (1983) interpreted that the Grosmont platform evolved in a succession of shallowing-upward lithofacies. Listed in ascending order, an idealized sequence consists of the following lithofacies: 1) green calcareous shales, 2) nodular argillaceous wackestones, 3) coral-stromatoporoid floatstones, 4) *Amphipora* wackestones, 5) peloid packstones, and 6) laminated mudstones. Culter (1983) also recognized that an anhydritic unit, the Hondo Formation, is present in the uppermost part of the Grosmont Formation. In addition, Culter (1982) correlated the evolution of the Grosmont platform to underlying Leduc reefs and found that the reefs were encased by the Grosmont.

As a result of increased interest surrounding the pilot sites, the Alberta Research Council (ARC) consequently produced two open file reports describing the regional stratigraphy and bitumen resources of the Grosmont Formation. Walker (1986) examined an area from Township 66-100 and Range 13W4M-9W5M. Based on gamma-ray logs, Walker (1986) illustrated the stratigraphy through several strike and dip cross-sections as well as structure contour, isopach, and erosional edge maps. Yoon (1986) concentrated on a smaller area (Townships 88-98, Ranges 19W4M-264M) and created hydrocarbon pore volume (HPV) maps by estimating the porosity and bitumen saturation from 140 well logs using a "quick-look" approach.

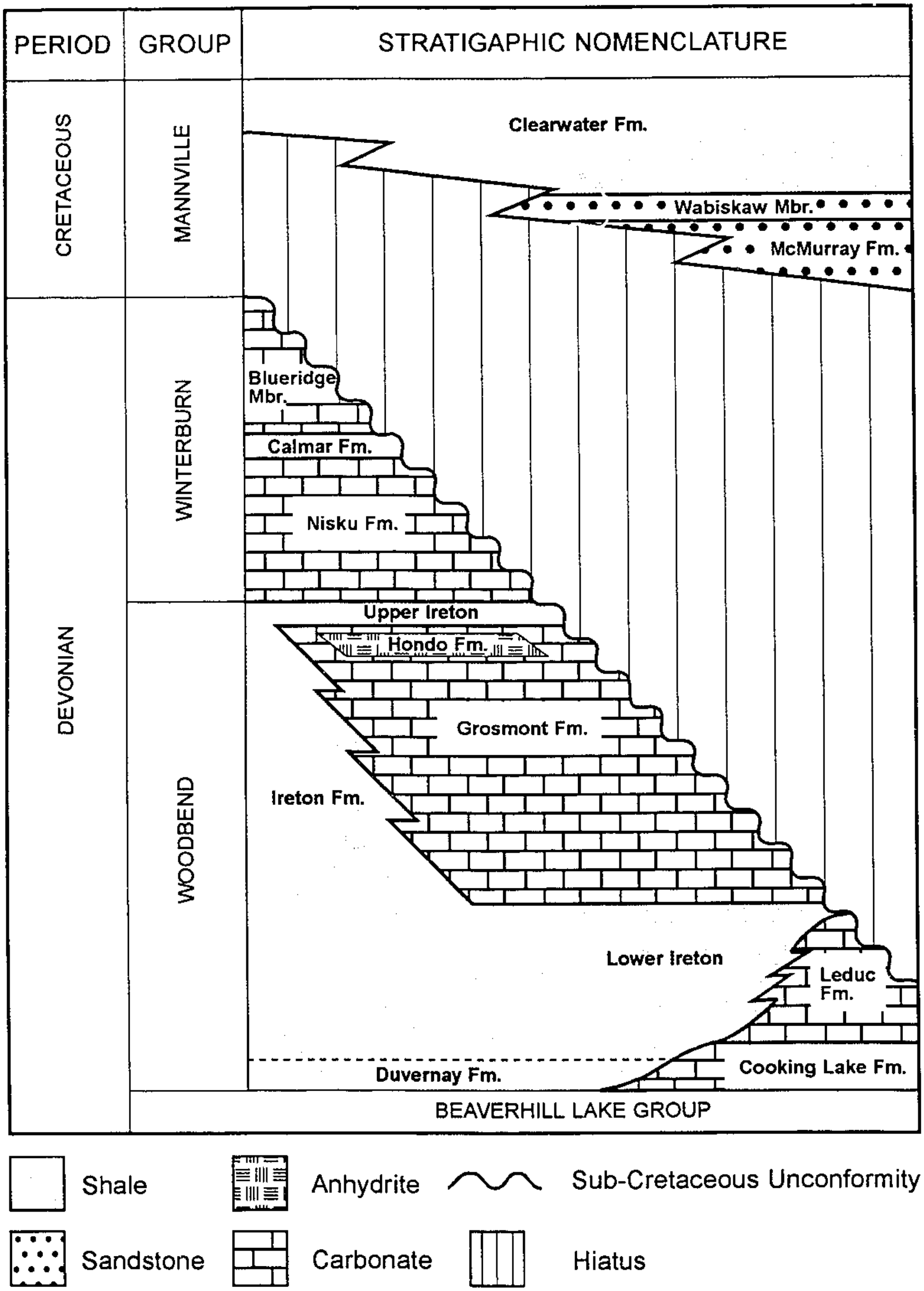
The only published studies concentrating on the diagenesis of the Grosmont Formation are by Theriault and Hutcheon (1987) and Theriault (1988). Theriault and Hutcheon (1987) discussed the dissolution of dolomite and the alteration of dolomite to calcite (dedolomitization). The diagenetic history and the relationships between lithofacies, diagenesis, porosity, and bitumen saturation was examined by Theriault (1988) in an area from Township 86-98, Range 16W4M-25W4M.

Beginning in 1990, additional studies on the Grosmont Formation were undertaken by Dr. H.G. Machel, his graduate students, and postdoctoral fellows at the University of Alberta. Unpublished progress reports submitted to AOSTRA by Machel and Hawlader (1990), Machel and Hawlader (1991), Machel et al. (1991), Hawlader and Machel (1992), Luo et al. (1992), and Luo et al. (1993) have reported results of investigations of the facies, diagenesis, and petrophysical characteristics of the Grosmont Formation. This thesis is an outgrowth of those studies.

2.2 Stratigraphy

The strata examined within the study area range from Devonian carbonates to Cretaceous clastics and encompasses the Beaverhill Lake, Woodbend, Winterburn, and Mannville groups (Figure 2.1). The sub-Cretaceous unconformity has intercepted the Devonian strata from the Leduc Formation of the Woodbend Group to the top of the Winterburn Group. The amount of erosion increases to the northeast. Cretaceous clastic sediments of the Mannville Group overlie the unconformity surface.

Fig. 2.1 Stratigraphic nomenclature of northeastern Alberta (modified after AGAT Laboratories Table of Formations, 1987).



In this study, only the Grosmont and Nisku Formations, and the Upper Ireton have been mapped in detail. The other groups and/or formations have been utilized in some maps and cross sections (discussed in Section 3.2 and Chapter 6).

2.2.1 Beaverhill Lake Group

The Middle Devonian Beaverhill Lake Group is the oldest stratigraphic unit examined in this study. Belyea (1952) described the Beaverhill Lake Formation (now Group) as "an alternating sequence of greenish grey calcareous shales and carbonates." Only the top of the Beaverhill Lake Group (Waterways Formation) is illustrated in the cross-sections. The contact between the Beaverhill Lake Group and the overlying Cooking Lake Formation is placed at an inflection point of the gamma-ray curve as the lithology changes from an argillaceous carbonate to a clean carbonate.

2.2.2 Woodbend Group

The Upper Devonian Woodbend Group consists of shallow marine platform carbonates (Cooking Lake and Grosmont formations) with reefal buildups (Leduc Formation) and basin-filling shales (Ireton Formation). The Cooking Lake platform forms the base of the Woodbend Group. Depending on the geographical location, Leduc reefs or Ireton shale overlie the Cooking Lake Formation. Development of the Grosmont platform was initiated during early Ireton deposition and the Grosmont continued to develop along with the Leduc and Ireton Formations. Eventually the Grosmont platform prograded over the Leduc reefs. Ireton shales and/or marls finally capped the Grosmont and marked the end of Woodbend Group sedimentation.

The Duvernay Formation, which may be present between the Cooking Lake and Ireton Formations, was not recognized in the study area because of the absence of core and the inability to distinguish the Duvernay from the Ireton based solely on well log response. Similarly, the Hondo Formation that is present near the top of the Grosmont Formation farther to the south (Belyea, 1952; Cutler, 1983) was not recognized in this study area. However, in the southwest corner of the study (Township 80, Range 24W4M), two wells penetrated anhydrite in the UGM3 that may be correlatable to the Hondo Formation. The average thickness of the anhydrite in these two wells is 6 m.

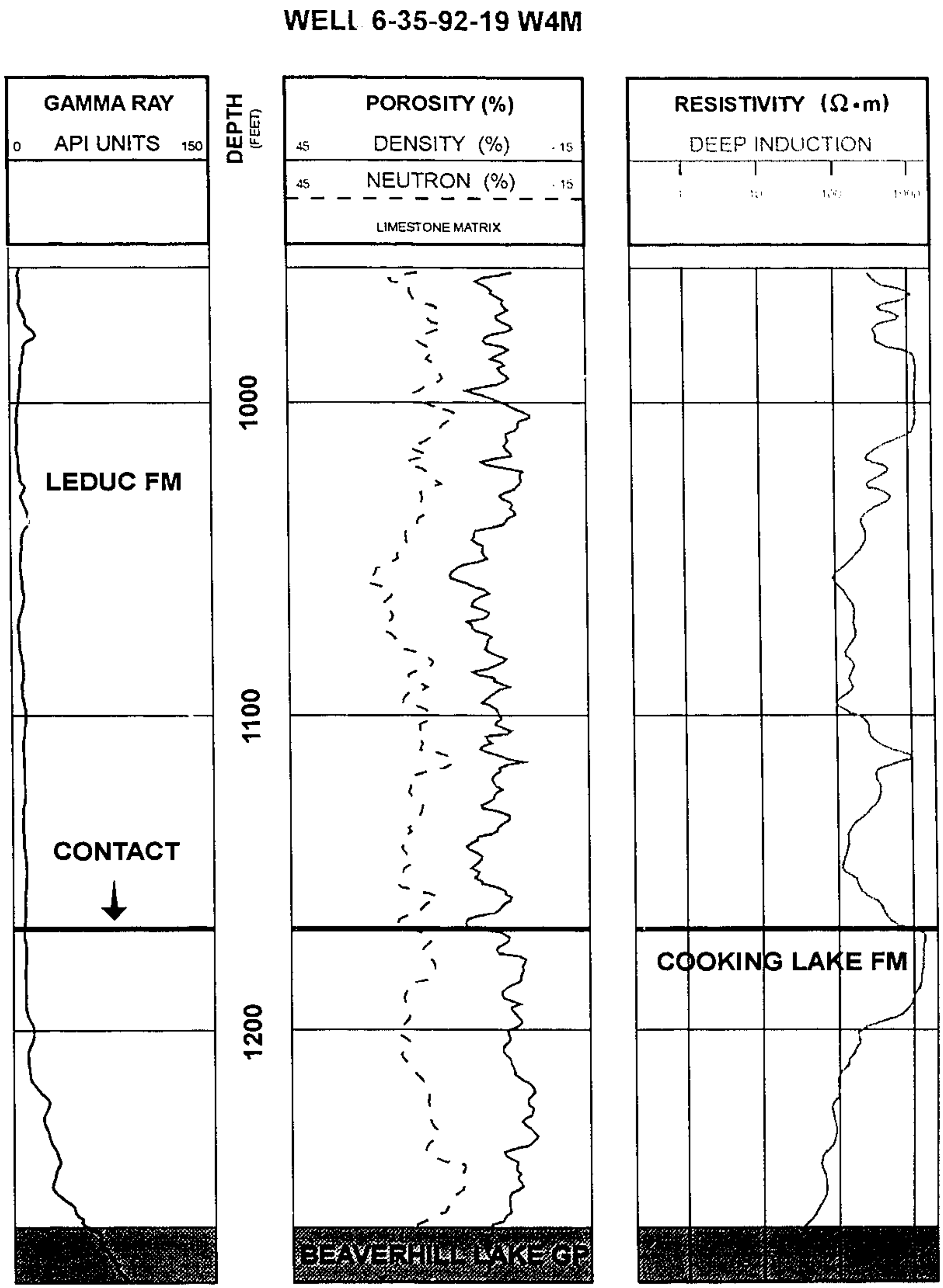
2.2.2-1 Cooking Lake Formation

The Cooking Lake Formation represents deposition on a shallow marine carbonate platform. Typically it consists of buff to light yellow, fine to medium grained, chalky, finely porous limestones. Fossils include small gastropods, ostracods, crinoids, and small stromatoporoids (Belyea, 1952). However, beneath Leduc reefs, the limestone of the Cooking Lake Formation has been altered to crystalline, vuggy dolomite. Dolomitization has destroyed the original sedimentary features (e.g., fossils, pellets, and intraclasts) of both the Cooking Lake and Leduc Formations.

The distinction between the dolomitized Cooking Lake and dolomitized Leduc formations is very difficult (Belyea, 1952; Andrichuk, 1958). Using modern well logs, however, the Cooking Lake Formation can be distinguished from the overlying Leduc Formation in the study area (Figure 2.2). Due to their low shale content, the Cooking Lake and Leduc Formations both have a low gamma-ray response and they can not be separated using the gamma-ray curve. Likewise, the neutron-density porosity response does not distinguish the Cooking Lake Formation from the Leduc Formation. However, the top of the Cooking Lake Formation has a slightly to significantly higher resistivity value caused by a higher bitumen saturation. Hence, the contact between the Cooking Lake and Leduc Formations can be identified on resistivity logs.

In the study area, the thickness of the Cooking Lake Formation varies from 4.5 m to 60 m. The change in thickness is related to the depositional setting. The Cooking Lake Formation is thickest in the platform proper and becomes thinner on the platform slope or ramp towards the west.

Fig. 2.2 Recognition of the Cooking Lake - Leduc contact.



2.2.2-2 Leduc Formation

The Leduc Formation consists of reef complexes that developed on the Cooking Lake platform. Leduc reefs in the study area represent the northern extension of the Rimbey-Meadowbrook reef trend (Figure 2.3). The reefs are preferentially located on the western margin of the underlying Cooking Lake platform because favorable environmental conditions created an ideal ecosystem for reef growth (e.g., well oxygenated, shallow, clear water). A reef located off the main trend in Township 80, Range 16W4M may be analogous to the Redwater reef. Like the Redwater reef, this unnamed reef may have developed on a topographic high (e.g., carbonate shoal) on the underlying Cooking Lake Formation. A lack of deep well control prevents an accurate definition of this reef.

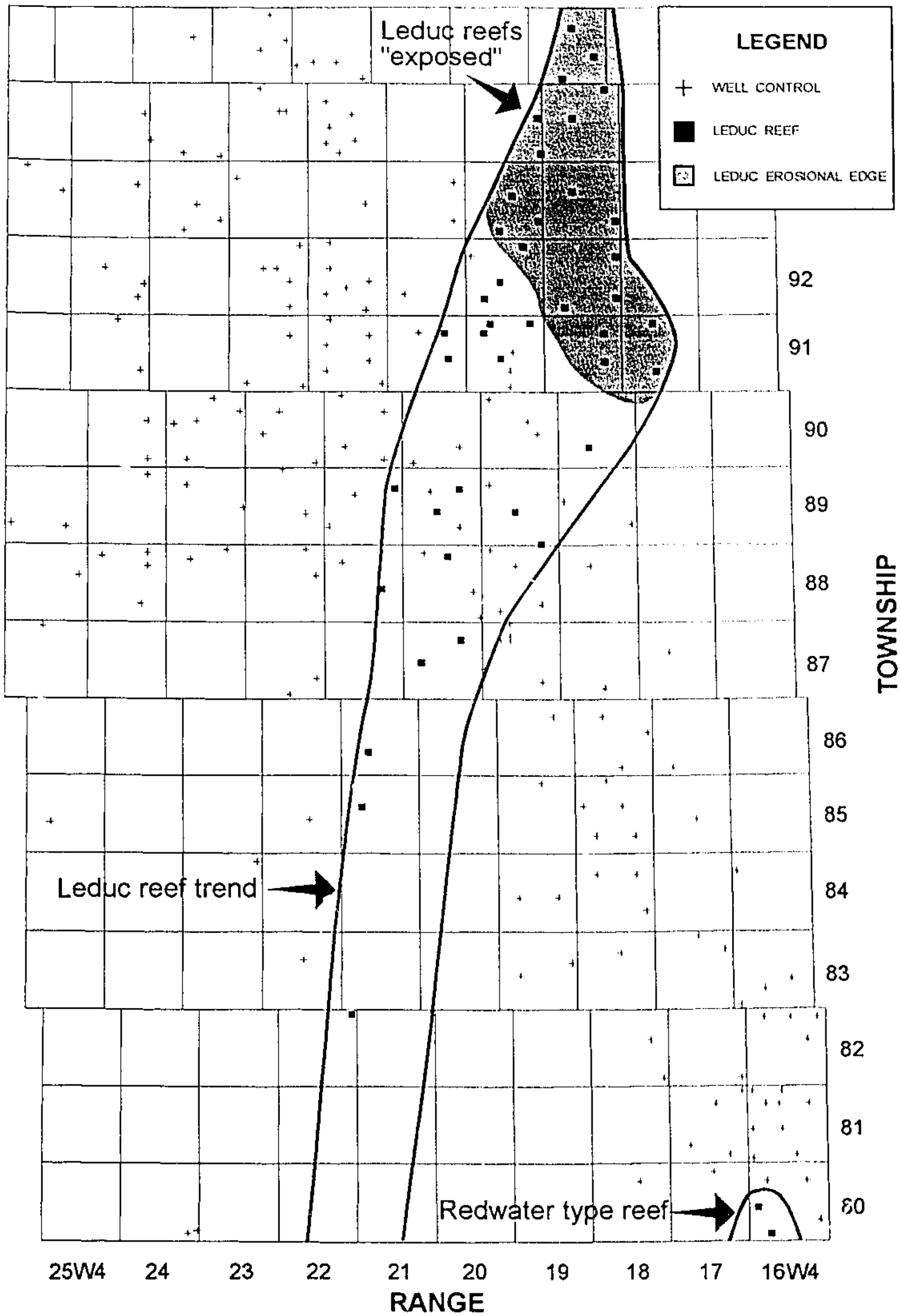
Leduc reefs in the study area are poorly studied. Well 3-34-88-20 W4M has penetrated the Leduc Formation and it is described as a medium to dark grey, coarsely crystalline dolomite with moldic, vuggy, and intercrystalline porosity. Fossils include stromatoporoids, thick-shelled brachiopods, and *Amphipora* (Machel and Hawlader, 1990).

At the northern end of the reef trend (north of Township 90), some of the Leduc reefs have been intercepted by the sub-Cretaceous unconformity (Figure 2.3) The McMurray Formation directly overlies these "exposed" reefs. An "exposed" reef is one that has been truncated by the sub-Cretaceous unconformity. Where they are not eroded, the average thickness of Leduc reefs is approximately 85 m. The relationship between the Leduc and McMurray Formations will be examined further in Chapter 6.

2.2.2-3 Ireton Formation

The Ireton Formation essentially consists of basin-filling shales and marls that interfinger with the Leduc and Grosmont formations. In central Alberta, McCrossan (1961) divided the Ireton Formation into three informal units: the Lower, Middle, and Upper Ireton. In the study area, the Ireton Formation is

Fig. 2.3 Map of the northern extension of the Rimbey - Meadowbrook reef trend.



simply divided into the Lower and Upper Ireton.

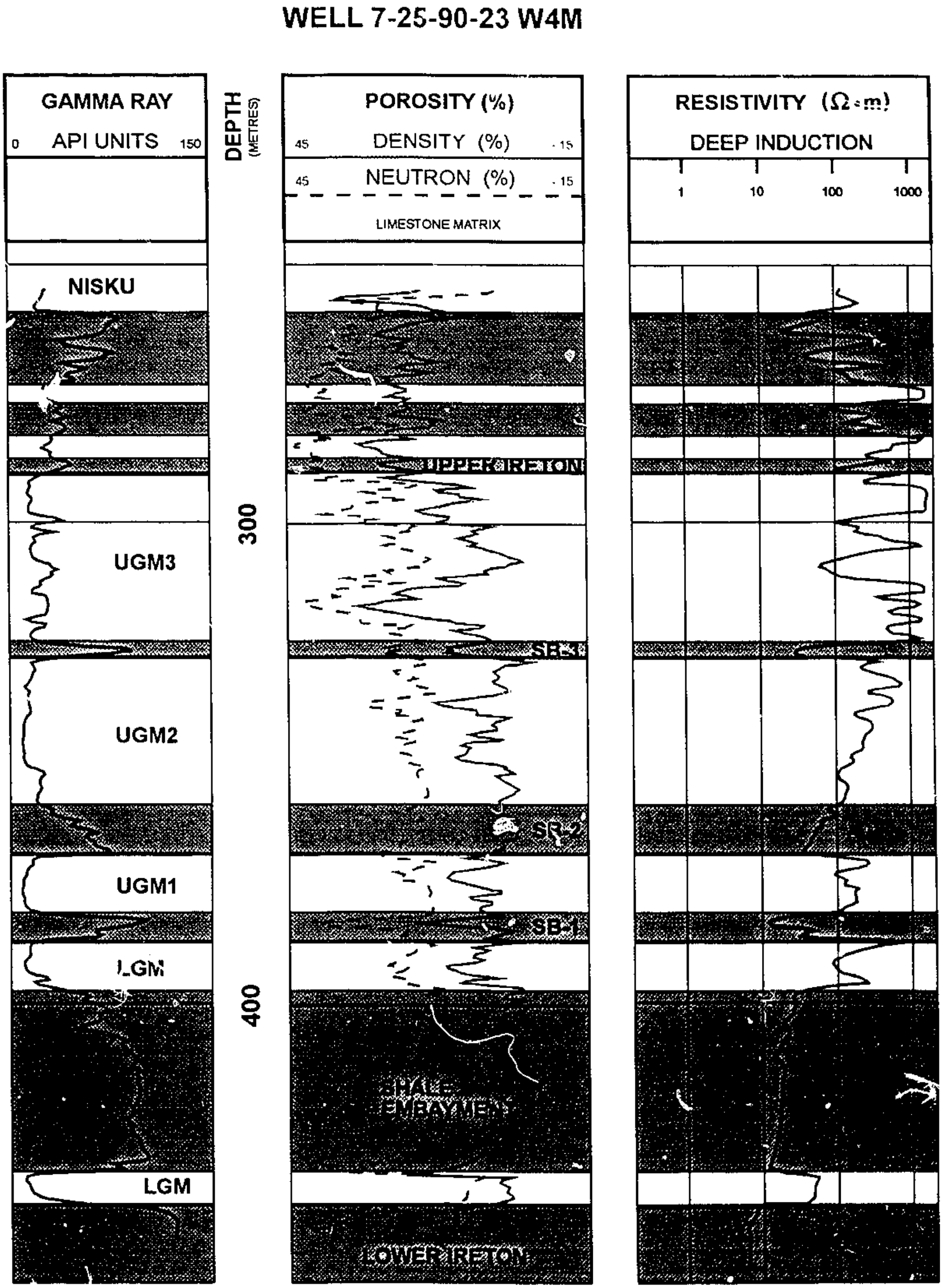
The Lower Ireton conformably overlies the Cooking Lake Formation where Leduc reefs are absent. The contact between the Lower Ireton and the overlying Grosmont is very sharp and it is easily recognized on gamma-ray logs (Figure 2.4). The Lower Ireton in northern Alberta consists of a succession of greenish-grey shales with interbeds of limestones and dolostones. Fossils include *Tentaculites*, crinoids, bryozoa, ostracods, thin-shelled brachiopods, and foraminifera (Belyea, 1952).

The bulk composition of Lower Ireton shales and marls was determined by X-ray Diffraction (XRD) and acid digestion of the carbonate fraction (Luo et al., 1992). The results revealed that the carbonate content is as low as 20% in the shales and increases to 50% in the marls. Quartz is the most abundant non-carbonate mineral, and feldspar is minor. Illite, kaolinite, and chlorite are the most common clay minerals.

Where not eroded, the Upper Ireton conformably overlies the Grosmont Formation and is conformably overlain by the Nisku Formation. Depending on the location, the contact between the Grosmont and Upper Ireton is either sharp or gradational. South of Township 87, the Upper Ireton is dominated by a dolomitic shale and the Grosmont - Upper Ireton contact is sharp. North of Township 87, the Grosmont - Upper Ireton contact is gradational and relatively clean carbonates of the Grosmont grade into 15 - 20 m thick silty to argillaceous dolostone of the Upper Ireton. The gamma-ray response is subtle and changes from 5-15 API units of the underlying Grosmont to 25-35 API units of the Upper Ireton (Figure 2.4). This gradational contact is consistent with industry terminology (as used in GEOBASE by CDPubco of Calgary). The gradational contact Grosmont - Upper Ireton contact is used throughout this study.

Harrison and McIntyre (1981) and Harrison (1982, 1984) prefer to assign the lower silty-argillaceous carbonate subunit of the Upper Ireton as belonging to the Grosmont Formation. They prefer this distinction because of the relatively high carbonate content. This is a valid point because reservoir engineers would treat the UGM3 of the Grosmont Formation and the silty carbonate subunit of the Upper Ireton as one reservoir unit during thermal production of bitumen.

Fig. 2.4 Grosmont well log response.



However, regional stratigraphic correlation of the UGM3 and Upper Ireton does not justify this distinction.

2.2.2-4 Grosmont Formation

The Upper Devonian Grosmont Formation is a shallow marine to peritidal carbonate platform extending over approximately 100,000 km^2 in the subsurface of Alberta and the Northwest Territories (Figure 1.1). The internal stratigraphy of the Grosmont is relatively simple and is divided into four informal units (LGM, UGM1, 2 and 3) based on thin shale intervals (SB-1, 2, and 3) that are easily recognizable on gamma-ray logs (Figure 2.4). The intervening shale breaks probably are Ireton-equivalent sediments (Harrison and McIntyre, 1981). Note, the LGM in Figure 2.4 is not a completely clean carbonate unit because the well was drilled into the shale embayment. The shale embayment is discussed further in Chapter 4.

Most of the Grosmont Formation is dolomitized and dips gently to the southwest and grades into the limestones and marls of the Ireton Formation towards the west and south. To the northeast, the Grosmont Formation is bounded by the sub-Cretaceous unconformity. The extension of the Grosmont Formation to the north is poorly known due to lack of well control (Harrison and McIntyre, 1981).

Within the study area, the Grosmont Formation ranges in thickness from 0 m along the regional unconformity and increases downdip to 140 m in the southwest corner of the study area (Figure 1.1). Depositional thicknesses are of the various units are relatively uniform except where underlying Leduc reefs have locally affected platform sedimentation.

The facies of the Grosmont are relatively simple and each Grosmont unit represents one shallowing-upward cycle (Harrison and McIntyre, 1981; Harrison, 1982, 1984; Culter, 1983; Theriault, 1988; Machel and Hawlader, 1990). In the study area, an idealized shallowing-upward cycle consists of seven lithofacies (Machel and Hawlader, 1990), listed in ascending order: A) shale break (basin),

B) argillaceous, nodular mudstone to wackestone (fore reef), C) stromatoporoid/coral floatstone (reef), D) *Amphipora* floatstone (back reef), E) massive, poorly fossiliferous mudstone to grainstone (subtidal to intertidal) F) laminated mudstone (intertidal), and G) brecciated mudstone (reworked facies F). Generally, the LGM and UGM1 are dominated by the deeper water facies A to C, with some localized reef development (facies D). The UGM2 and UGM3 are dominated by the shallower water facies (D to G).

The diagenesis of the Grosmont Formation is very complex. Theriault (1988) identified 12 diagenetic phases and Machel and Hawlader (1990) listed 17 diagenetic events. The two most important diagenetic factors are dolomitization and karst. Dolomitization of the subtidal sands and muds has resulted in the formation of pervasive sucrosic dolomite that has excellent intercrystalline porosity (approximately 20%). This is the most important type of porosity (Harrison and McIntyre, 1981). The karst has created a very heterogeneous reservoir, and karst-related porosity commonly can reach up to 40%, and locally up to 100% ("caves").

Correlations discussed below are based on log correlation. A complete log suite (γ, ϕ_n, ϕ_d, R_{id}) illustrating the well log response from the top of the Lower Ireton to the base of the Nisku Formation is shown in Figure 2.4. The gamma-ray curve is used to define the internal stratigraphic units of the Grosmont Formation and adjacent formations. The neutron-density and resistivity logs are used to determine the porosity and bitumen saturation respectively. Porosity and resistivity logs show a general trend of decreased porosity and bitumen saturation with depth.

2.2.3 Winterburn Group

2.2.3-1 Nisku Formation

The Nisku Formation conformably overlies the Upper Ireton of the

Woodbend Group. The Nisku Formation may either be conformably overlain by the Calmar Formation or unconformably capped by Cretaceous clastics of the Mannville Group. The Nisku thickens in a westerly direction and may be greater than 100 m where it is not eroded.

Limited core descriptions of the Nisku Formation describe it as a vuggy dolomite with minor limestone (Machel and Hawlader, 1990, 1991). Small interbeds of silt and shale may be present. In most cases the original texture is destroyed by dolomitization. However, some preserved fossils include brachiopods, crinoids, gastropods, and *Amphipora*.

2.2.3-2 Calmar Formation

The Calmar Formation separates the underlying Nisku Formation from the overlying Blueridge Member of the Graminia Formation. The Calmar Formation is relatively thin and averages 5 m in thickness. It ranges in composition from a light green argillaceous siltstone to a light to dark green shale (Belyea, 1952).

2.2.3-3 Blueridge Member

The Blueridge Member of the Graminia Formation conformably overlies the Calmar Formation and is unconformably overlain by the Cretaceous Mannville Group. There is little information on the Blueridge Member in the study area. Belyea (1952) briefly describes it as "thick dolomite sections interbedded with siltstone beds."

2.2.4 Mannville Group

The Lower Cretaceous clastics of the Mannville Group unconformably overlie the Devonian Winterburn and Woodbend Groups. The Mannville Group (listed in ascending order) consists of the McMurray Formation, Wabiskaw Member of the Clearwater Formation, and Grand Rapids Formation. The Grand Rapids Formation is not utilized in this study.

2.2.4-1 McMurray Formation

The McMurray Formation are fine to very coarse grained commonly unconsolidated sands with interbeds of light brown-grey silty clays. It was deposited unconformably on the underlying Devonian strata and grades into the Wabiskaw Member of the Clearwater Formation. The thickness of the McMurray is controlled by structural relief of the eroded Devonian strata. The McMurray is thickest in valleys and is thinner on Paleozoic ridges or highs. Most of the McMurray Formation was deposited in a north-south trending depression or trough that was caused by the dissolution of underlying Middle Devonian evaporites of the Elk Point Formation (Flach and Mossop, 1985)

The McMurray Formation is informally divided into lower, middle, and upper members (Flach and Mossop, 1985). The lower member is fluvial in nature and was deposited in a northwestward-flowing drainage system that formed in response to the underlying salt collapse. The base of the lower member consists of subrounded to angular quartzite pebbles, angular pebbles of vein quartz, and cleavage fragments of feldspar (Conybeare, 1966). The coarse basal lag rapidly grades upwards into a sequence of angular cross-bedded fine to medium grained sand. The source of the sand is believed to originate from the metamorphic quartzite of the Athabasca Formation located to the northeast in Saskatchewan (Carrigy, 1959; Conybeare, 1966; Gallup, 1974; and Jardine, 1974). Thin coal streaks and root zones are common at the top of the lower member (Flach and Mossop, 1985).

The middle member is dominated by fine to medium grained sands. Sedimentary structures include trough cross-beds, angular cross-beds, and shale clast breccias. Shale clast breccias are light brown angular silt-shale clasts (0.5 - 5.0 cm) suspended in a sandy matrix, and are created by the collapse of the channel bank. Extensive burrowed shaly sequences are also present. Coal and rooted zones are rare. Flach and Mossop (1985) interpret the middle member to be dominantly fluvial with minor marine influences. Wightman and Pemberton (1993) interpreted the middle member to be deposited in an estuarine setting.

The upper member consists of bioturbated shaly sands which are slightly glauconitic. They form laterally extensive tabular sheets (e.g., beach). Coal streaks and rooted zones are common locally (Flach and Mossop, 1985). The upper member is interpreted as an estuarine setting influenced by marine processes (Wightman and Pemberton, 1993).

2.2.4-2 Wabiskaw Member

The Wabiskaw Member is a glauconitic sand at the base of the Clearwater Formation. It overlies the McMurray Formation, and in places, unconformably overlies Devonian strata. In the study area, the Wabiskaw is deposited as a longitudinal sand body (e.g., beach, offshore bar) along the emergent Grosmont strata.

2.2.4-3 Clearwater Formation

The Clearwater Formation is a dark grey silty shale that was deposited in a marine setting. It conformably overlies the Wabiskaw Member and it unconformably caps the remaining Devonian strata where they were not covered by the Wabiskaw or McMurray sediments.

CHAPTER 3

SUB-CRETACEOUS UNCONFORMITY

3.1 Topography of the Sub-Cretaceous Unconformity

The sub-Cretaceous unconformity marks a major erosional event and represents a time difference of approximately 241 million years between the Devonian carbonates and the Cretaceous clastics. The structure contour map of the sub-Cretaceous unconformity illustrates the unconformity surface (Figure 3.1), and the data base for the unconformity map is summarized in **Appendix 1**. Although the present westerly dip of the sub-Cretaceous unconformity was not removed, the paleotopography of the Devonian erosional surface is readily apparent. Shaded in red and orange are Paleozoic erosional highs and they represent part of the northwest-southeast trending ridge which is informally called the Grosmont High (Ranger, personal comm.) Incised into the Grosmont High are the tributaries of three McMurray channels (labeled with solid arrows) that drain in a northeasterly direction into the main McMurray channel that is located east of the study area in Ranges 6 to 13 W4M. In addition, a significant sinkhole is present in Township 89, Range 20 W4M.

The topography of the sub-Cretaceous unconformity is also shown in 3-D perspective diagrams from four directions (Figure 3.2). In all four directional viewpoints, the vertical scale is greatly exaggerated to emphasize the erosional features. Thus, the small erosional highs which only have between 40 and 100 m of relief look like mountains. The maximum relief of the sub-Cretaceous unconformity over the entire study area is approximately 240 m.

LEGEND

+ WELL CONTROL

■ LEDUC REEF

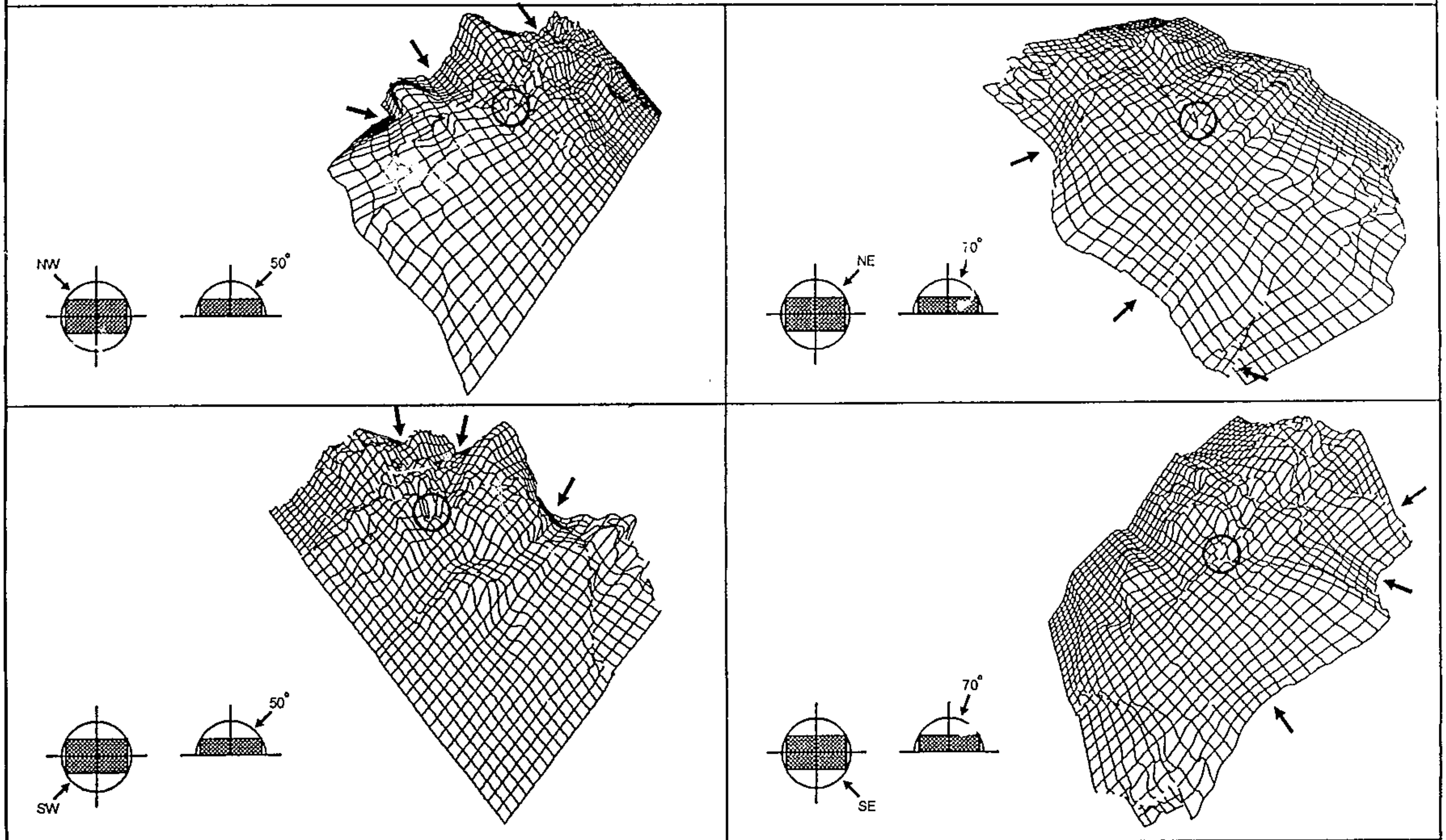
↗ McMURRAY CHANNEL

Unconformity Elevation (metres above sea level)

> 320	180 - 200
300 - 320	160 - 180
280 - 300	140 - 160
260 - 280	120 - 140
240 - 260	100 - 120
220 - 240	80 - 100
200 - 220	< 80

Fig. 3.1 Sub-Cretaceous unconformity structure contour map (C.I. = 20 m)

Fig. 3.2 3-D perspective diagram of the sub-Cretaceous unconformity viewed from various viewpoints. Solid arrows signify McMurray channels incised into the Grosmont High and the hollow circle marks the sinkhole in Township 89, Range 20 W4M. The symbols in the bottom left corner for each perspective diagram indicate the directional viewpoint in terms of the azimuth and angle from horizontal.



3.2 Devonian Erosion and Cretaceous Deposition

The Devonian strata have been eroded to variable degrees during and/or prior to the Cretaceous. The erosional edges (or intervals intercepted by the sub-Cretaceous unconformity) of the Nisku, Upper Ireton, four Grosmont units (UGM3, UGM2, UGM1, and LGM), Lower Ireton, and Leduc are superimposed on the structure contour map of the sub-Cretaceous unconformity (Figure 3.3). Figure 3.3 reveals that the amount of erosion systematically increases in a northeasterly direction, as reflected by the ages of the erosional edges intercepted by the sub-Cretaceous unconformity. The erosional edges of the Nisku, Upper Ireton, UGM3, UGM2, UGM1, LGM, and Leduc were obtained from Figures 4.2, 4.9, 4.16, 4.23, 4.30, 4.37, and 2.3 respectively (to be discussed in Chapter 4). Due to the lack of well control northeast of the Grosmont Formation in this study, the erosional edge of the Lower Ireton was estimated parallel to erosional edge of the LGM. In addition, the Devonian strata above the Nisku Formation (e.g., Calmar Formation, Blueridge Member) was not examined in detail; therefore, the erosional edges southwest of the Nisku Formation are not mapped.

The first Cretaceous unit deposited on the emergent Grosmont High was the upper member of the McMurray Formation (Conybeare, 1966). The spatial distribution of the McMurray reveals that it wraps around the Grosmont High (Figure 3.4). The next unit to be deposited on the emergent Devonian strata was the Wabiskaw Member of the Clearwater Formation. Lastly, deep water marine shales of the Clearwater Formation capped the remaining emergent Devonian strata as the Boreal Sea transgressed over the Grosmont High.

Fig. 3.3 Location of Devonian strata truncated by the sub-Cretaceous unconformity (C.I. = 20 m).

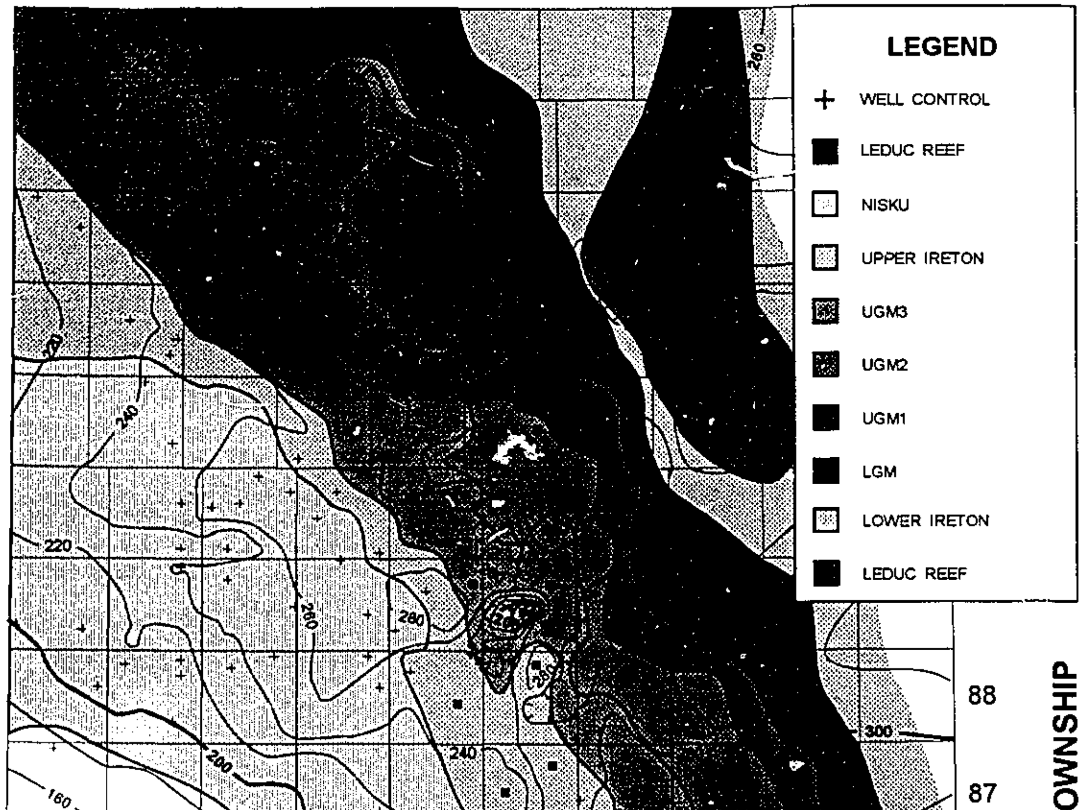
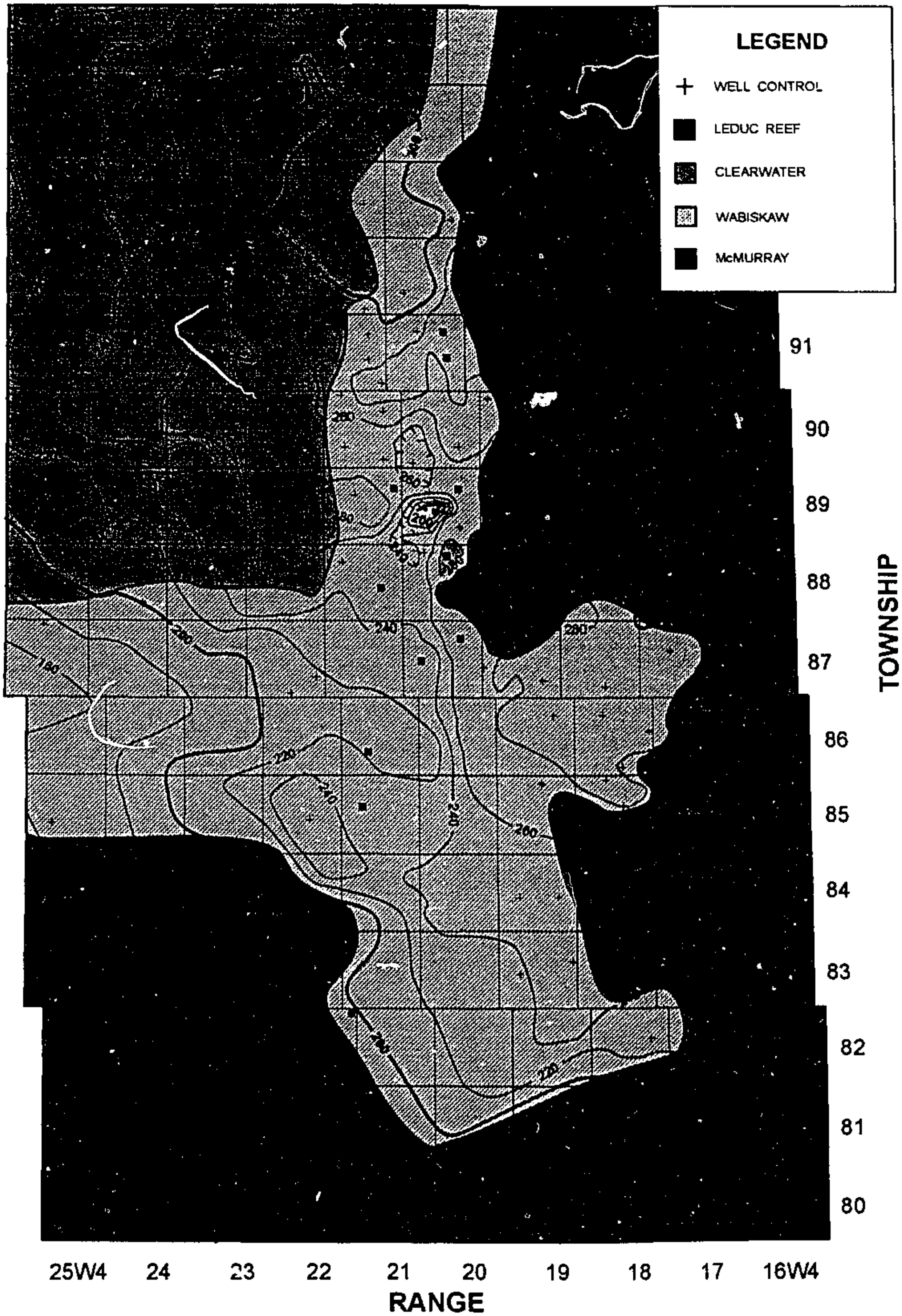


Fig. 3.4 Distribution of Cretaceous clastics in contact with the sub-Cretaceous unconformity (C.I. = 20 m).



3.3 Recognition, Spatial Distribution, and Timing of "Cave" Development

In order to more accurately predict poor communication problems between wells, the recognition of karst features such as "caves" is necessary. Most "caves" probably represent fractures, vugs, collapse breccias, large dissolution cavities, or combinations thereof. On well logs, "caves" are recognized by excursions of the caliper log as well as off scale neutron-density porosity readings in clean carbonate intervals (Figures 3.5 and 3.6). The sonic log, if run, also skips badly in "caves". The average "cave" height is 23.5 m, but most "caves" (60%) are less than 15 m in height. Core descriptions reveal that "caves" are associated with karst-related fractures or breccias and the core recovered ranges from poor to none (Machel et al., 1991).

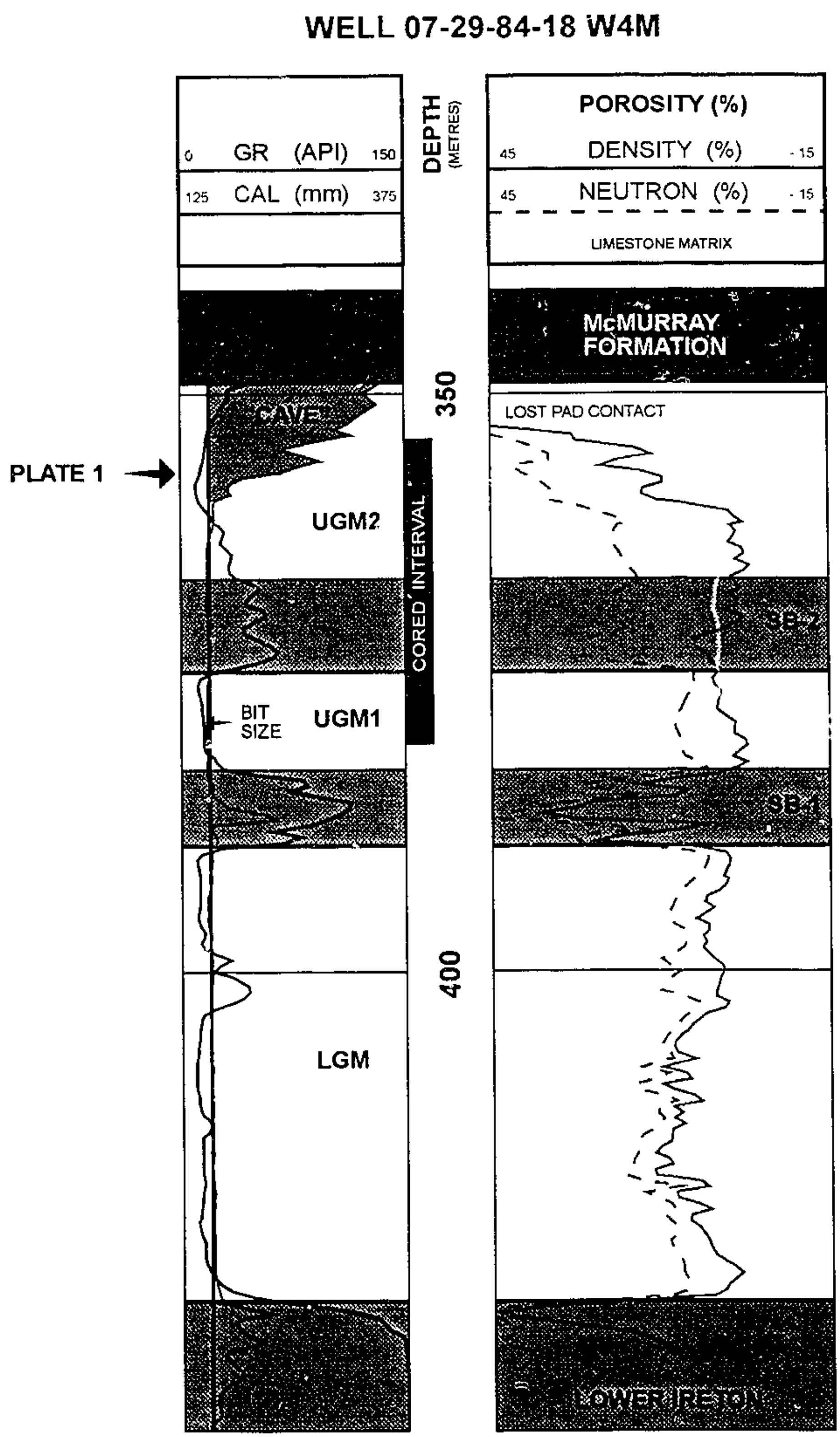
"Caves" may also arise from the wash-out of sucrosic dolomite (unconsolidated silt to sand sized grains of dolomite cemented by bitumen) during drilling. However, in much of the study area, the sucrosic dolomite has a thickness of less than one metre, and zones with such a narrow thickness often go unrecognized in caliper logs.

Two examples of "caves" are illustrated by log suites (Figures 3.5, 3.6) and core photographs (Plates 1,2). The porosity and bitumen saturation values cited in the photographs were determined by computerized well log analysis. The first example, well 07-29-84-18 W4M, is located in the upper tributary of the southernmost McMurray channel. The caliper log reveals that the "cave" (shaded in orange) is present at the top of the UGM2 and it is approximately 10 m in height (Figure 3.5). Towards the top of the "cave", the porosity tools go off scale because of lost pad contact. Core recovered from the "cave" shows that it is comprised of intervals of competent rock with vuggy porosity and incompetent rock composed of dolomite powder and dolomite fragments (Plate 1). The second example, well 14-17-87-20 W4M, is located slightly off the crest of the Grosmont High. The Wabiskaw Member covers the Devonian strata. The caliper log reveals that there are two "caves" (Figure 3.6). The first "cave", which is approximately 22 m in height, starts from the Upper Ireton and extends into the top of the UGM3. Lost pad contact of the porosity tools occurs in the "cave" in the Upper Ireton shale. Core recovered immediately below the "cave" consists of karst breccia (Plate 2). The second "cave" begins in the UGM3 and extends into the UGM2. It is approximately 30 m in height. There are no core photographs for the second "cave".

The spatial distribution of "caves" shows that they are ubiquitous and there is no regionally predictable pattern (Figure 3.7). Therefore, during drilling and completion, karst-related problems (e.g., lost mud circulation, sudden drill bit drops, poor cement bonds, etc.) should be expected in all parts of the study area. However, there is an overall decrease in "cave" abundance with depth, as discussed in later Chapters. The data base for the mapping of "caves" is summarized in **Appendix 2.**

The degree of dissolution probably varied throughout geological time as the Devonian strata were subaerially exposed. However, the intensity of karst-related processes (e.g., dissolution, fracturing, dedolomitization, etc.) was probably at its peak during the Jurassic and early Cretaceous. During this time interval, any strata exposed to the atmosphere was probably extremely prone to karst development because the climate was warm and humid.

Fig. 3.5 Recognition of "caves" from well logs (1).



A. Vuggy porosity in "cave". Some bitumen staining remains after washing. *Well 07-29-84-18 W4M, UGM2, 355.0 m, porosity = 34.4 %, bitumen saturation = 97 %.*

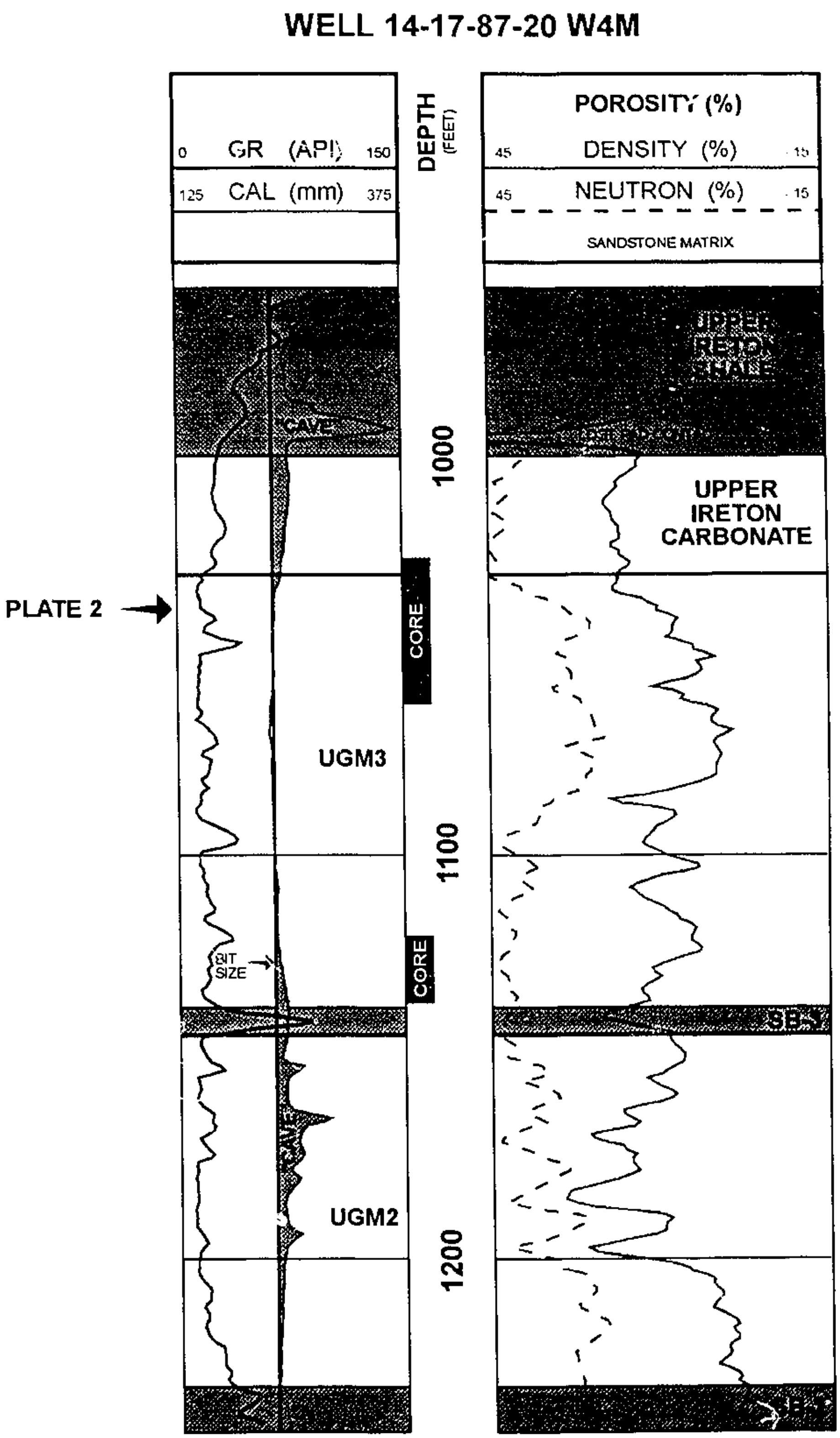
B. Washed sample of sucrosic dolomite powder and weathered dolomite fragments in "cave". *Well 07-29-84-18 W4M, UGM2, 356.0 m, porosity = 27.7%, bitumen saturation = 94.7%.*

Plate 1

A

B

Fig. 3.6 Recognition of "caves" from well logs (2).



A. Karst breccia located below the "cave". *Well 14-17-87-20 W4M, UGM3, 1039', porosity = 23.2%, bitumen saturation = 81.9%.*

B. Top view of **A** illustrating the angular fragments cemented by bitumen.

Plate 2

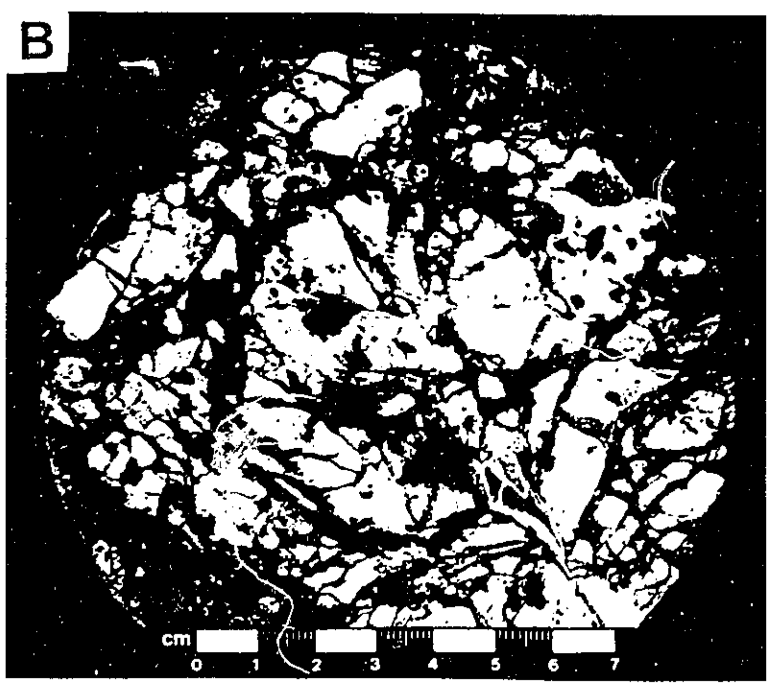
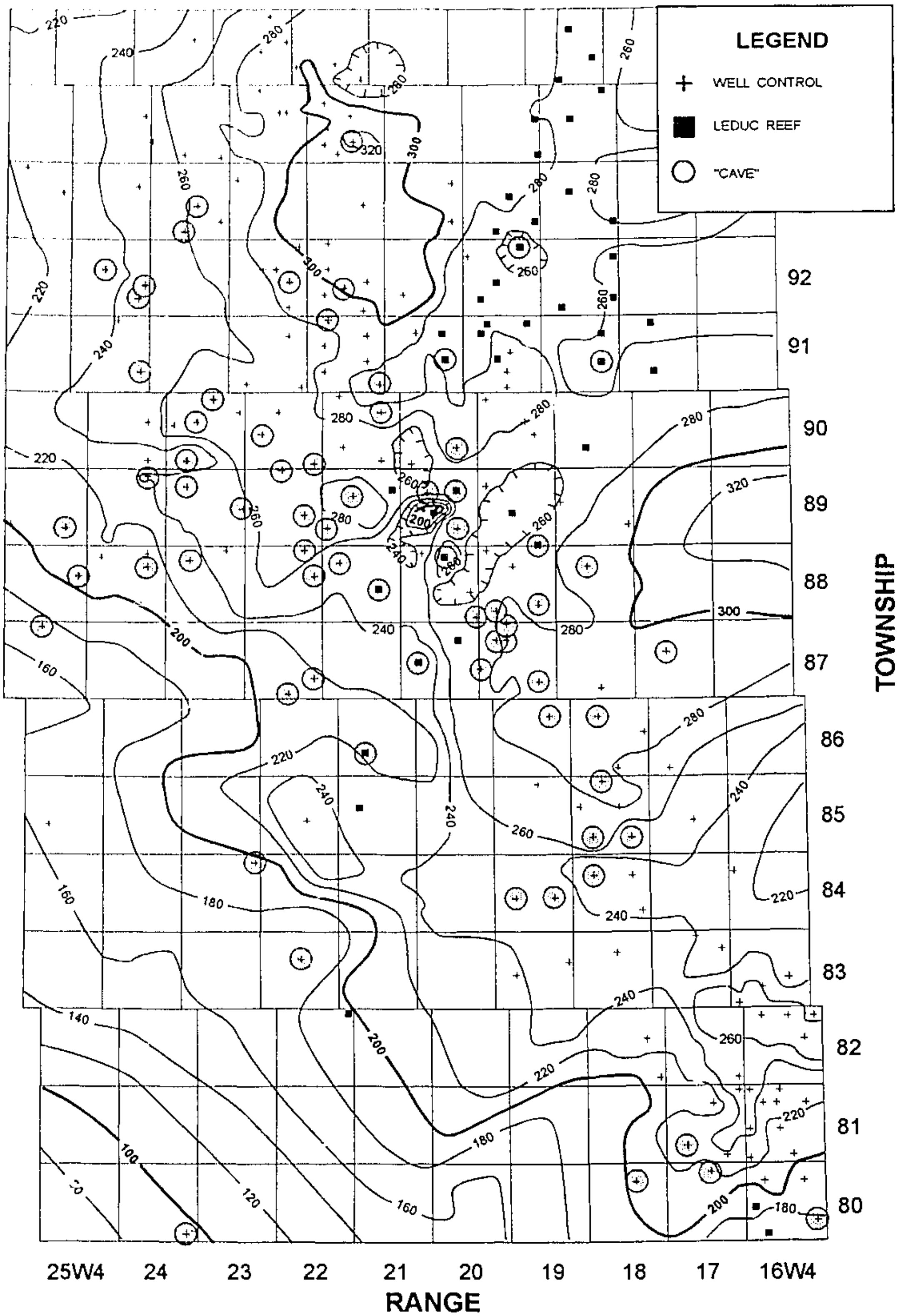


Fig. 3.7 Sub-Cretaceous unconformity structure contour map with "caves" (C.I. = 20 m).



CHAPTER 4

RESERVOIR CHARACTERISTICS FROM WELL LOG DATA

The reservoir characteristics determined by computerized well log analysis are illustrated by a suite of maps (Figures 4.1 to 4.44) that encompasses Townships 80 to 95 and Ranges 16 to 25 W4M. The computer-generated maps consist of structure contour, isopach, "cave" location, porosity, net pay, and hydrocarbon pore volume (HPV) maps. The potential carbonate reservoirs examined are the Nisku, Upper Ireton, and the four informal carbonate sequences within the Grosmont (UGM3, UGM2, UGM1, and LGM). In total, there are 44 maps illustrating the reservoir properties and in all maps, C.I. denotes the contour interval. The data for the "cave" location, reservoir characteristics, and shale embayment are summarized in **Appendices 2**, **3**, and **4** respectively.

4.1 Nisku Formation

The Nisku Formation displays a regional strike of 150^{0} (Figure 4.1) and dips to the southwest at 0.2^{0} (approximately 3.4 m/km). The elevation for the top of the Nisku ranges from 50 m above sea level in the southwest to nearly 275 m above sea level in Township 89. The strike and dip deviate from the regional trend where the Nisku is partially eroded and it is shaded in grey (Figure 4.1). This zone represents the Nisku erosional edge. An erosional edge is defined as a Devonian interval which is truncated by the sub-Cretaceous unconformity. For the Nisku Formation, the erosional edge is outlined by the estimated subcrop limit of the overlying Calmar Formation to the southwest and by the subcrop limit of the Nisku to the northeast (obtained from Figure 4.2).

The isopach map (Figure 4.2) shows that the Nisku thickens in a westerly direction. The maximum thickness may be greater than 100 m where it is not eroded. Within the Nisku erosional edge, the thickness is highly variable and it can vary by up to 40 m in a single Township.

Utilizing well logs, 25 "caves" have been recognized in the Nisku. The "cave" location map (Figure 4.3) shows that the "caves" appear to be concentrated in the erosional edge north of Township 87, but this is a misconception caused by a greater well density. The ubiquitous nature of the "caves" suggests that the karst is extensive and well developed.

The porosity map of the Nisku (Figure 4.4) shows that the average porosity is greater than 16% over much of the study area. Locally, the average porosity may exceed 32%. The high porosity 'pockets' are associated with "caves".

The net pay map (Figure 4.5), isoporosity map (Figure 4.6), and HPV map (Figure 4.7) all show similar trends. Net pay, isoporosity, and HPV have their highest values centred in the erosional edge in Township 89 and they decrease parallel to the subcrop limit and towards the southeast. The decrease parallel to the subcrop limit is caused by erosion and the decrease towards the southeast reflects a decrease in bitumen saturation.

Fig. 4.1 Nisku structure contour map (C.I. = 25 m).

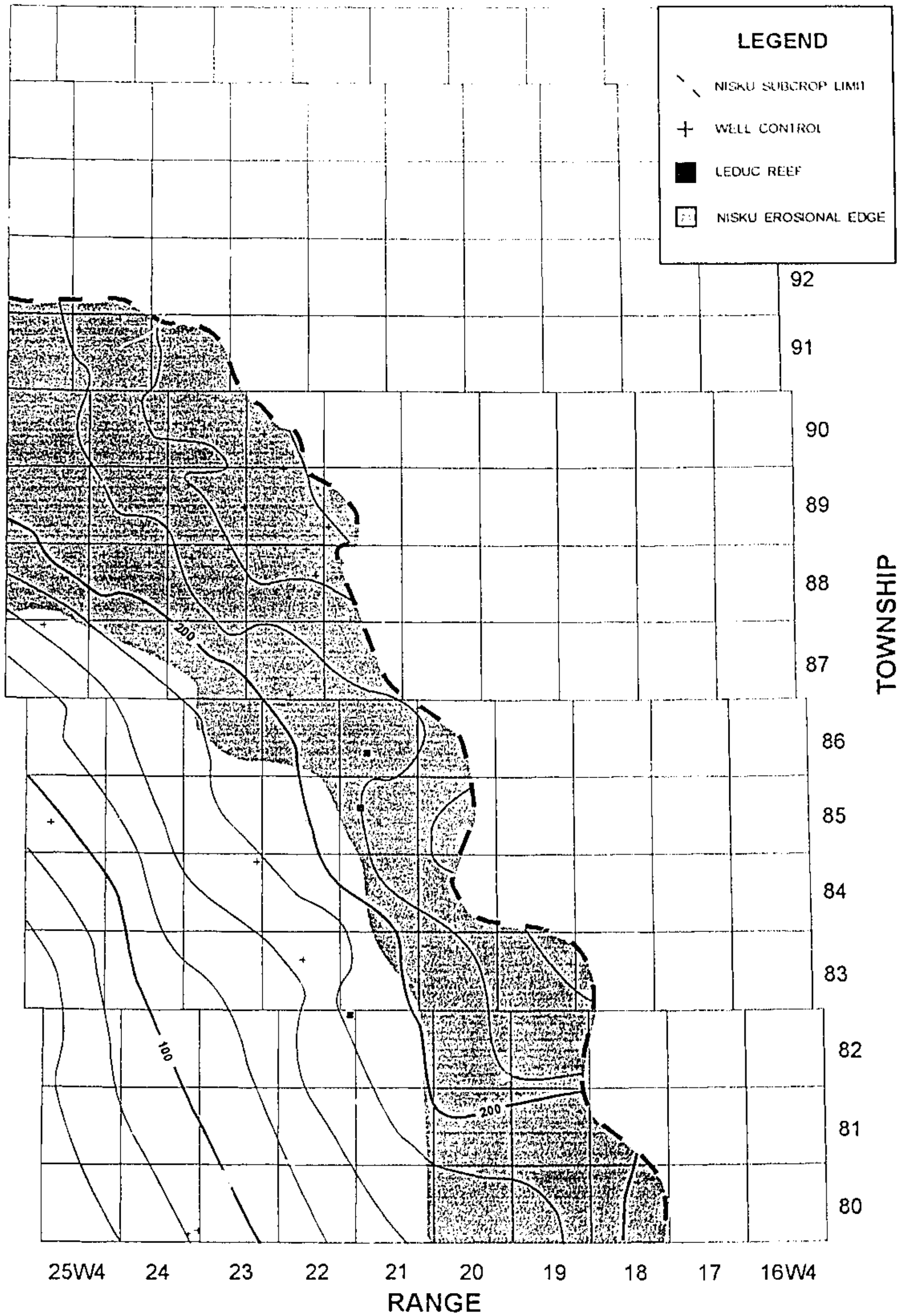


Fig. 4.2 Nisku isopach map (C.I. = 10 m)

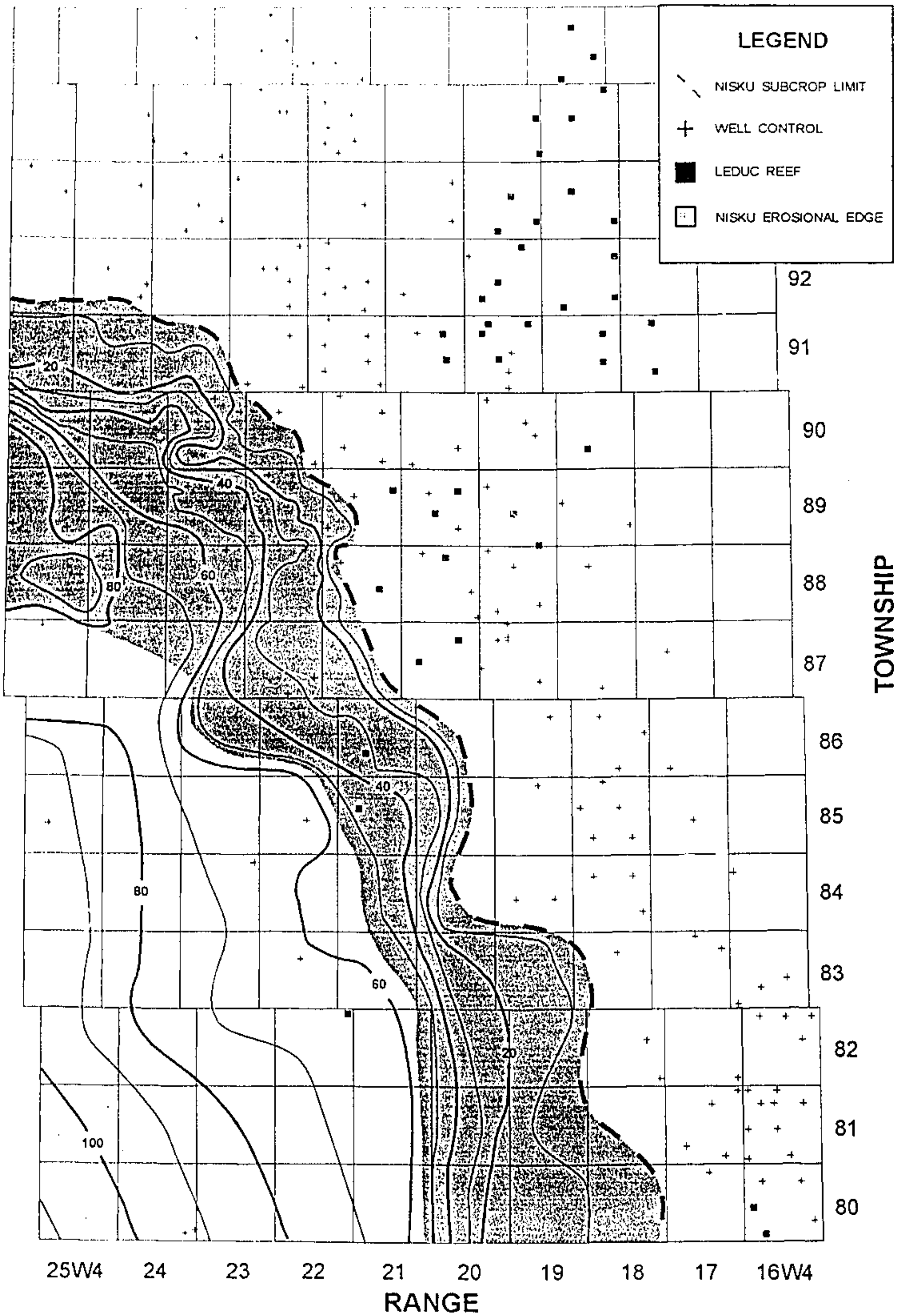


Fig. 4.3 Location of Nisku "caves".

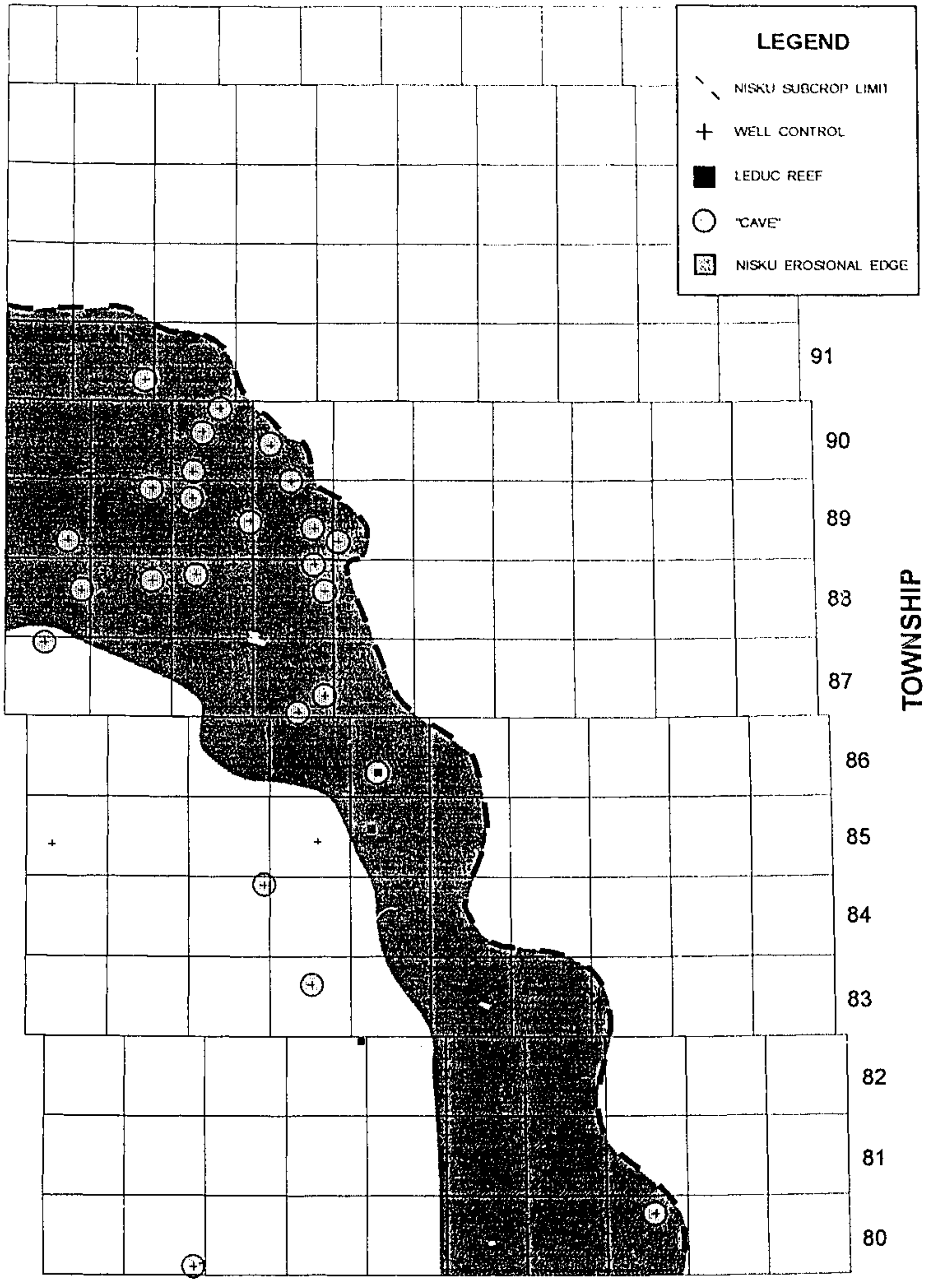


Fig. 4.4 Nisku porosity map (C.I. = 4%).

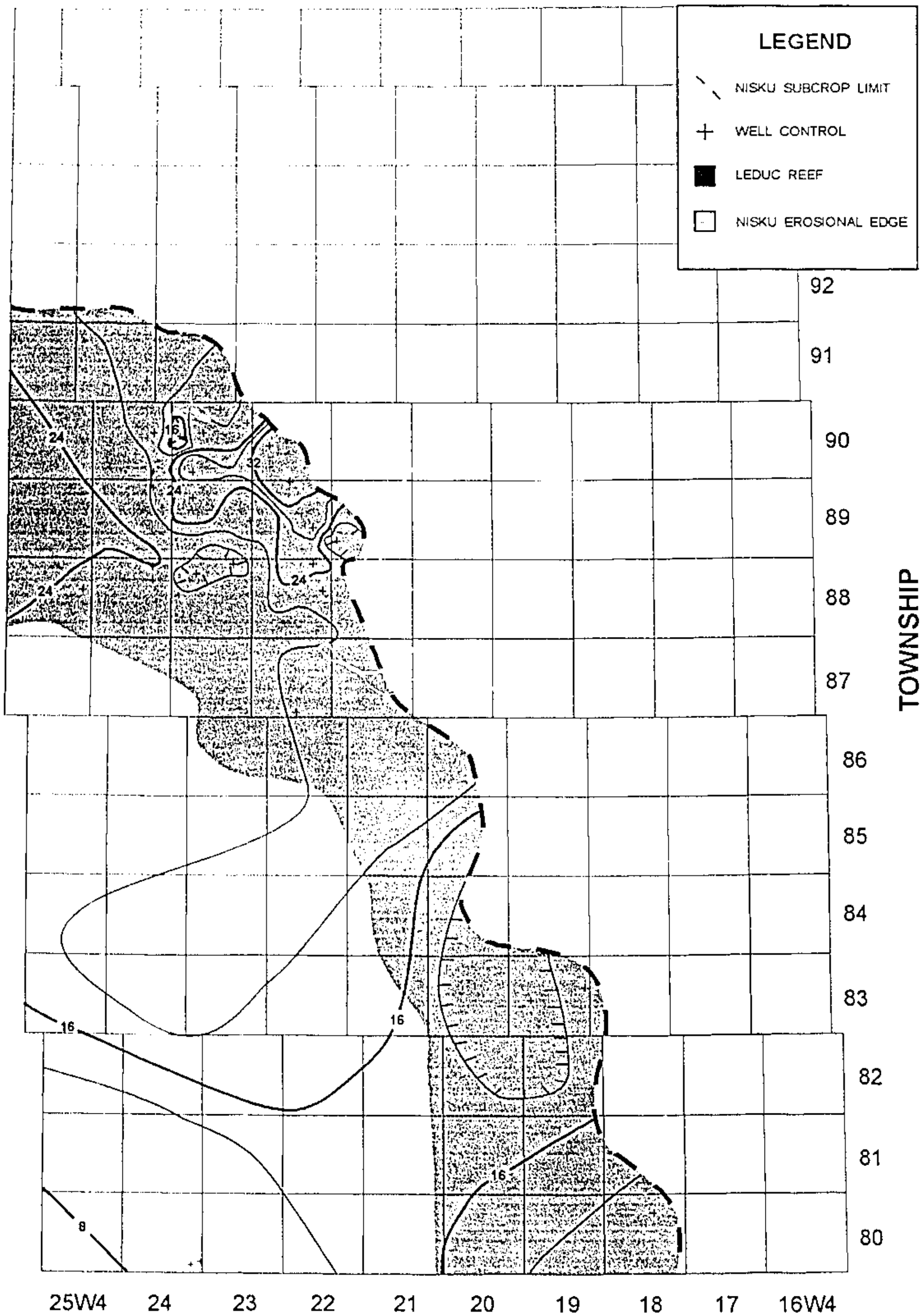


Fig. 4.5 Nisku net pay map (C.I. = 10 m).

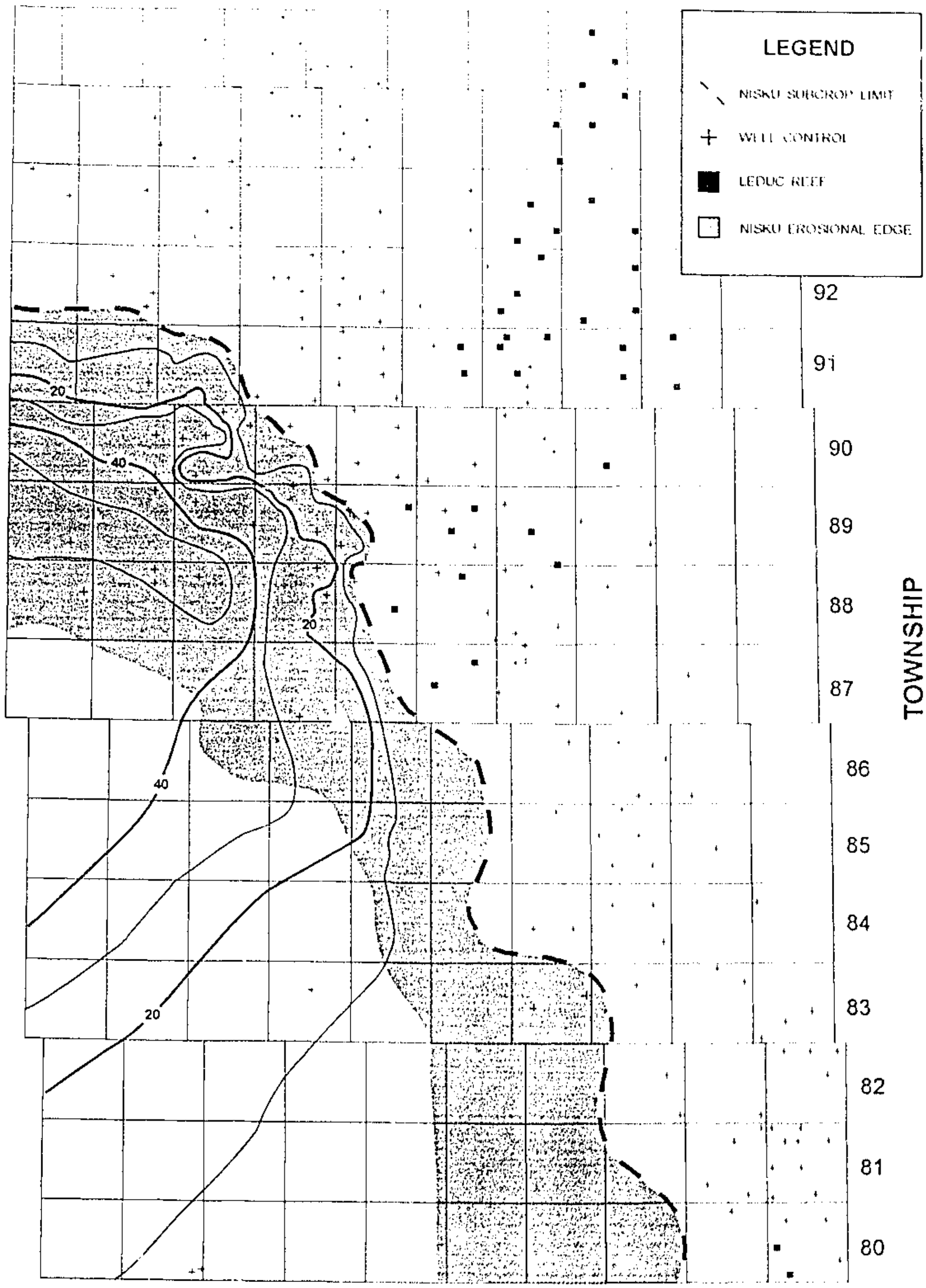


Fig. 4.6 Nisku isoporosity map (C.I. = 2 m).

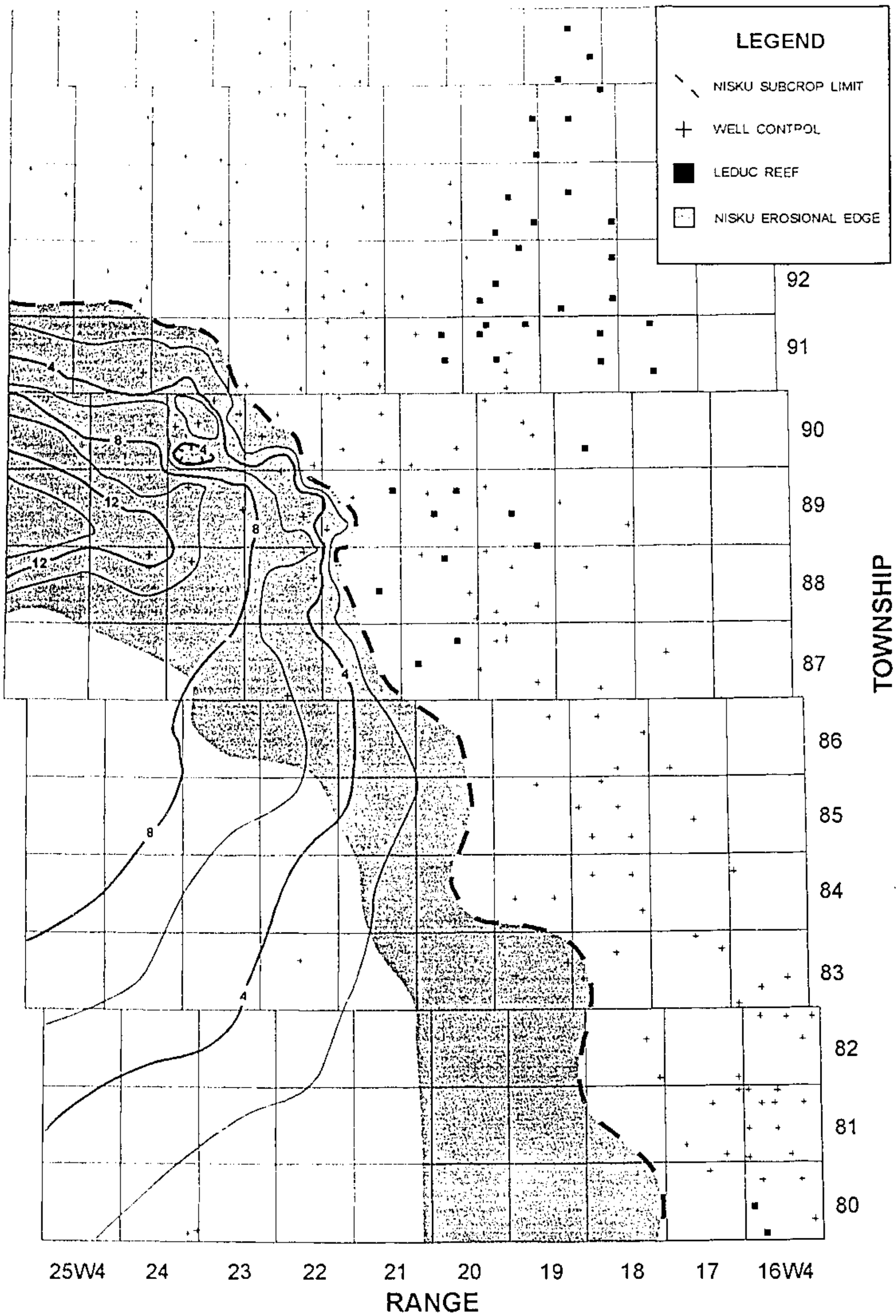
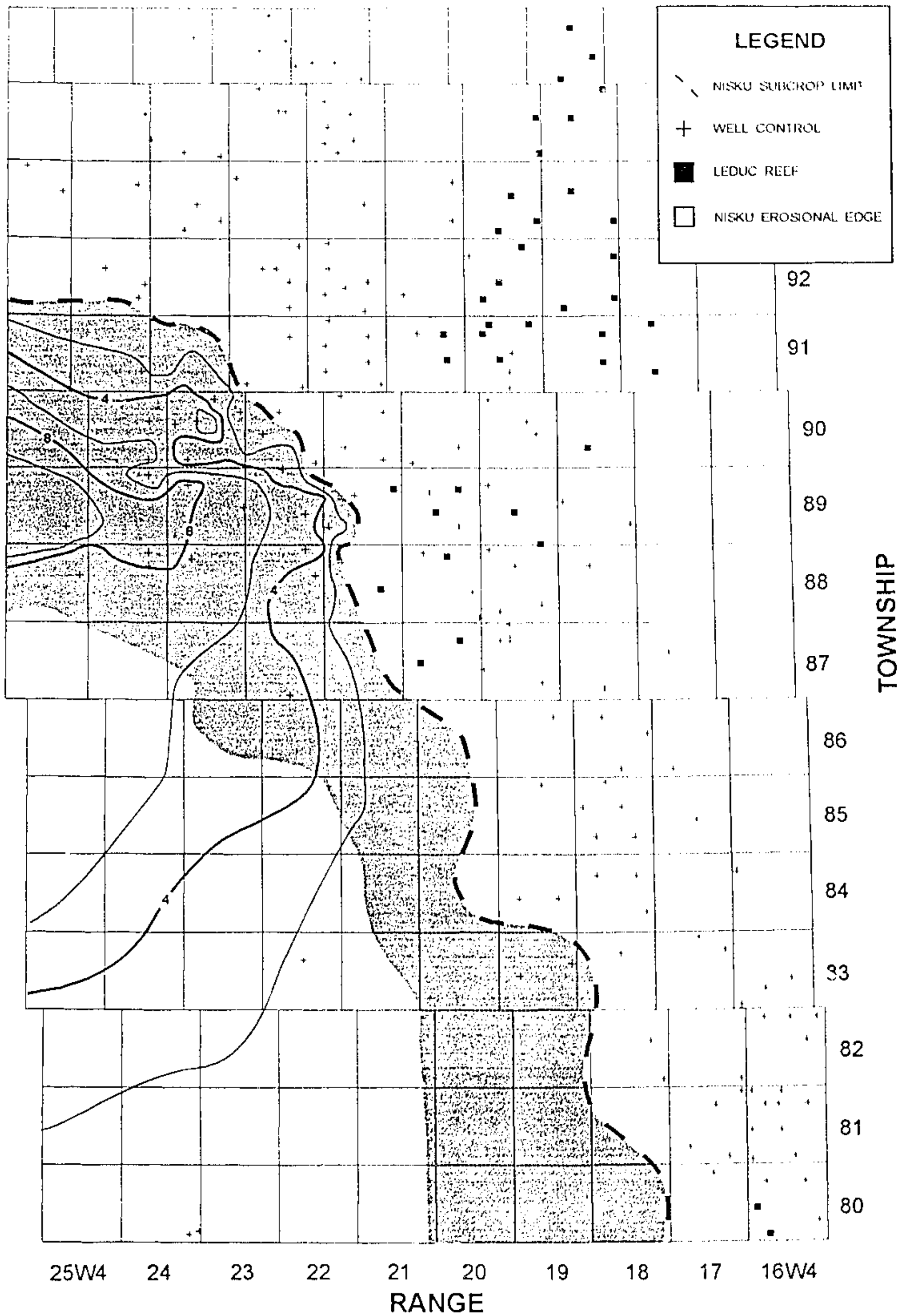


Fig. 4.7 Nisku hydrocarbon pore volume map (C.I. = 2 m).



4.2 Upper Ireton

Due to its mixed clastic-carbonate lithology, the Upper Ireton acts both as a reservoir and as a seal. South of Township 87, the Upper Ireton is dominated by a dolomitic shale that has poor reservoir characteristics. North of Township 87, the base of the Upper Ireton is composed of a silty to argillaceous dolomite which has some reservoir potential. In this chapter, the reservoir properties of the silty-argillaceous carbonate subunit will be examined. The ability of the Upper Ireton to behave as a seal is examined in Chapter 5.

The structure contour map for the Upper Ireton (Figure 4.8) shows that this unit has a slightly variable northwest-southeast strike. Locally, the strike varies from 135^0 north of Township 87, and changes to 160^0 in the southwest corner of the study area. The dip is to the southwest at about 0.25^0 (approximately 4.3 m/km). The elevation of the top of the Upper Ireton ranges from 75 m below sea level in the southwest corner of the study area to slightly over 275 m above sea level near the subcrop limit. The Upper Ireton erosional edge (shaded grey) is bounded by the subcrop limit of the Upper Ireton (obtained from Figure 4.9) and the subcrop limit of the Nisku (obtained from Figure 4.2).

The isopach map of the Upper Ireton (Figure 4.9) shows that this unit has a relatively uniform thickness. Where it is not eroded, the thickness generally ranges from 20 to 30 m with a localized thickness greater than 30 m in the northwest corner of the study area. Within the Upper Ireton erosional edge, the thickness is highly variable, reflecting topography on this surface.

There are 25 "caves" randomly distributed in the Upper Ireton (Figure 4.10). The spatial distribution of "caves" is not restricted to the Upper Ireton erosional edge. Thus, karst-related fluids have penetrated both the Nisku and Upper Ireton and karst-related dissolution in the Upper Ireton, as in the Nisku, is extensive.

The porosity map of the Upper Ireton (Figure 4.11) shows that south of Township 87, the Upper Ireton is dominated by dolomitic shale. In this area, porosity values are not applicable because of the high shale content. North of

Township 87, the average porosity is quite high and may exceed 44%. The high porosity 'pockets' tend to coincide with "caves".

The resource maps of net pay (Figure 4.12), isoporosity (Figure 4.13), and HPV (Figure 4.14) all display similar trends. The resource values are nil south of Township 87. North of Township 87, the highest values are roughly parallel to the erosional edge. Within the erosional edge, the resource values decrease parallel to the subcrop limit as a result of erosion. Also, they decrease towards the southwest because of a decreasing bitumen saturation.

Fig. 4.8 Upper Ireton structure contour map (C.I. = 25 m).

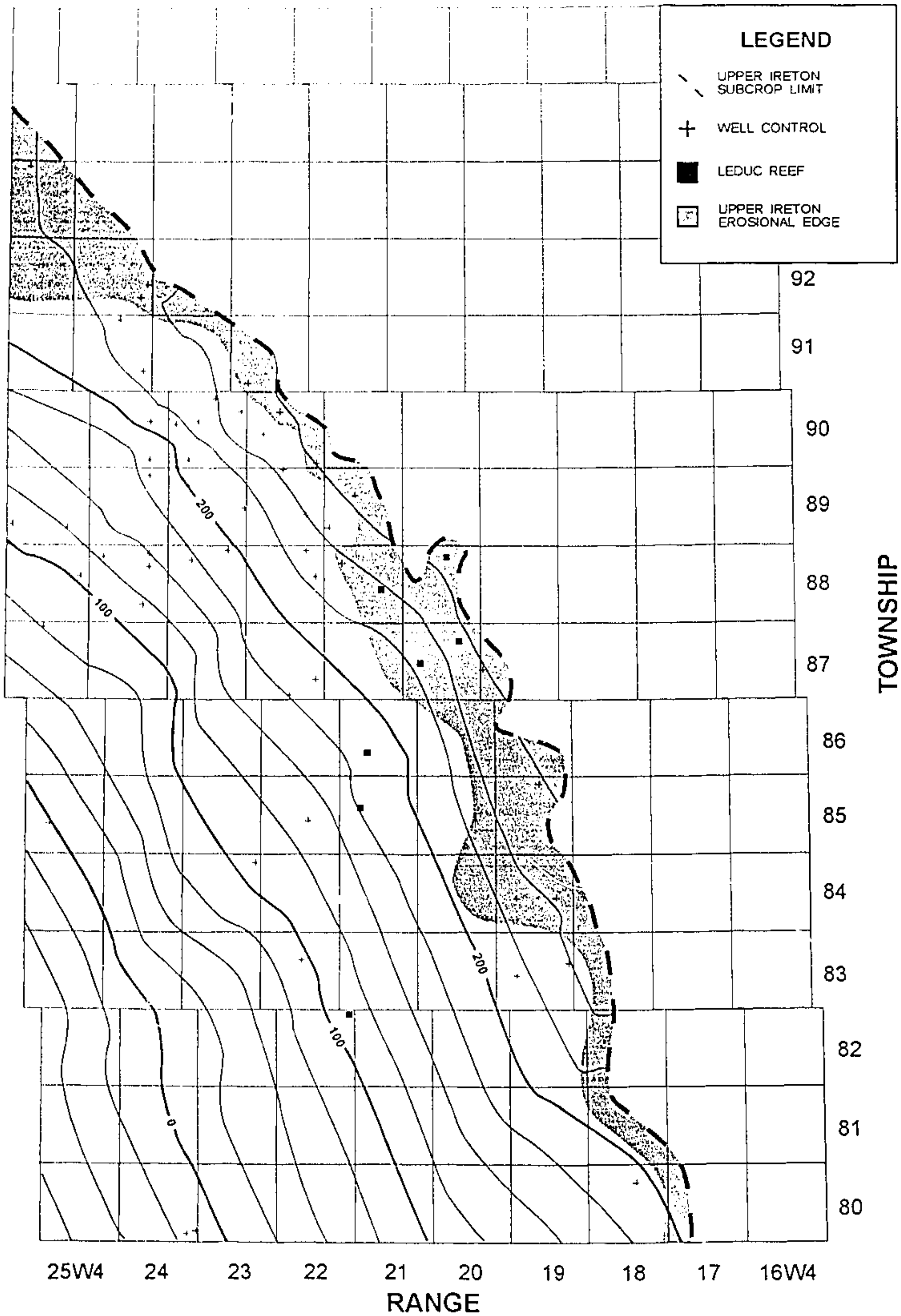


Fig. 4.9 Upper Ireton isopach map (C.I. = 10 m).

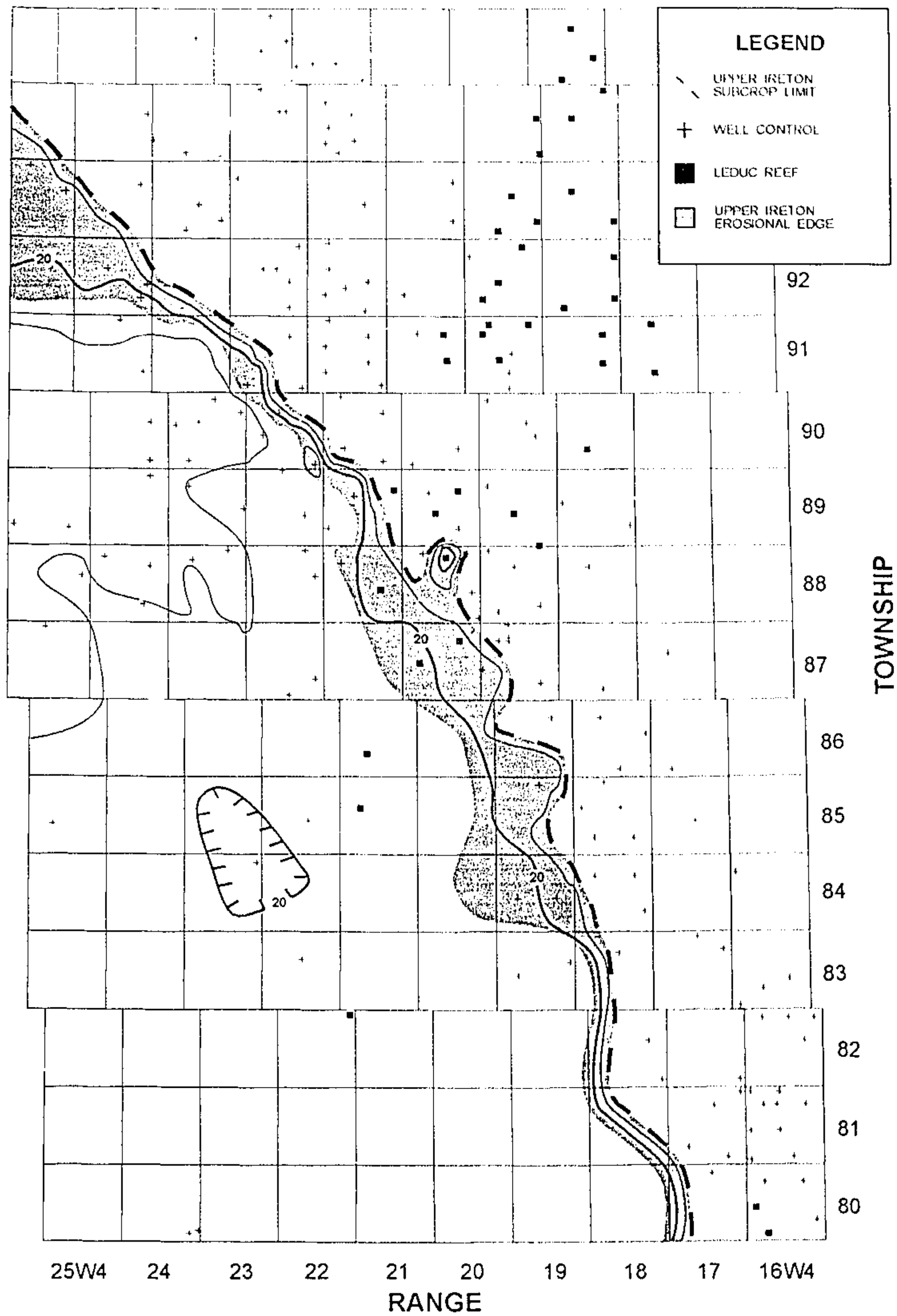


Fig. 4.10 Location of Upper Ireton "caves".

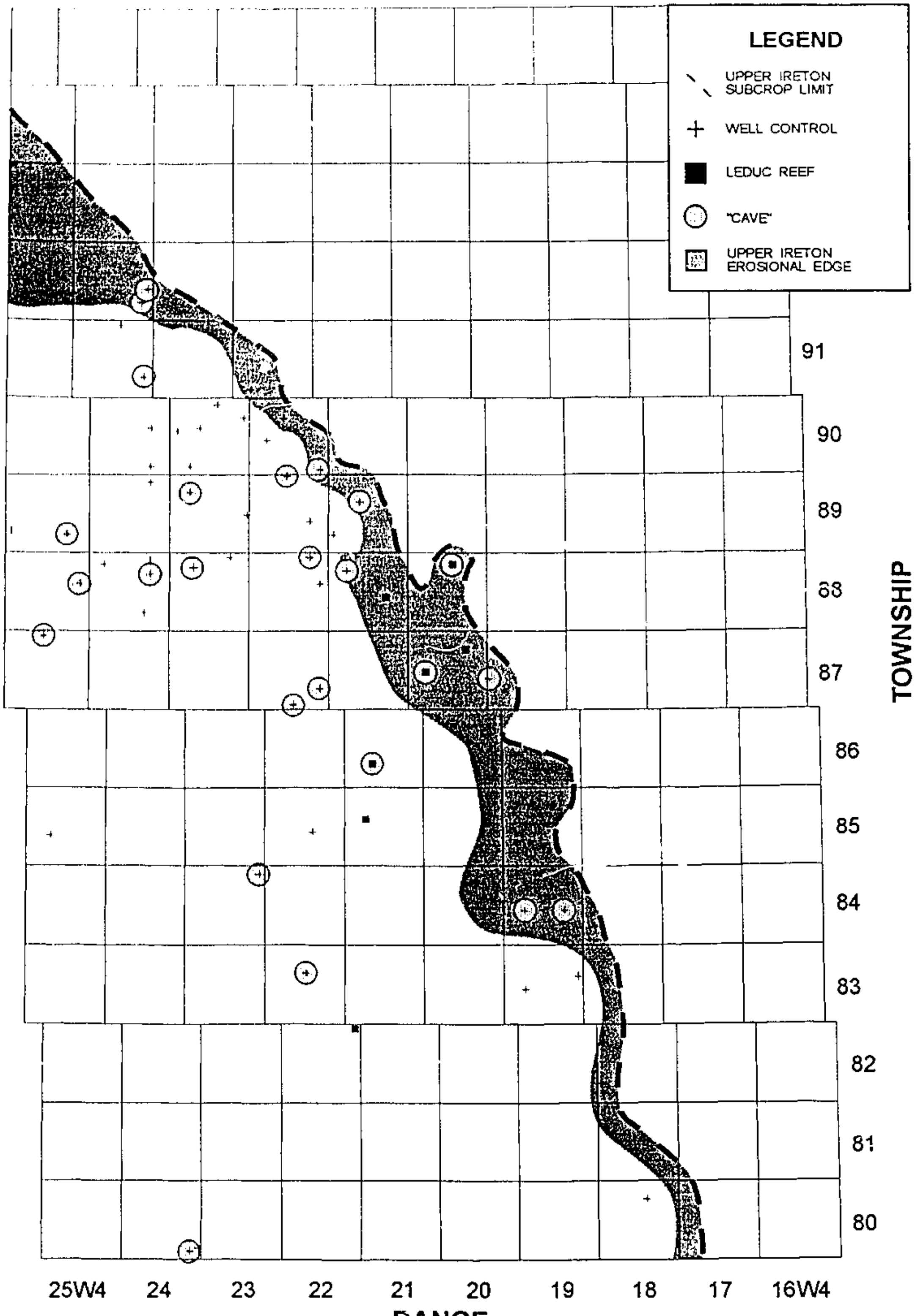


Fig. 4.11 Upper Ireton porosity map (C.I. = 4%).

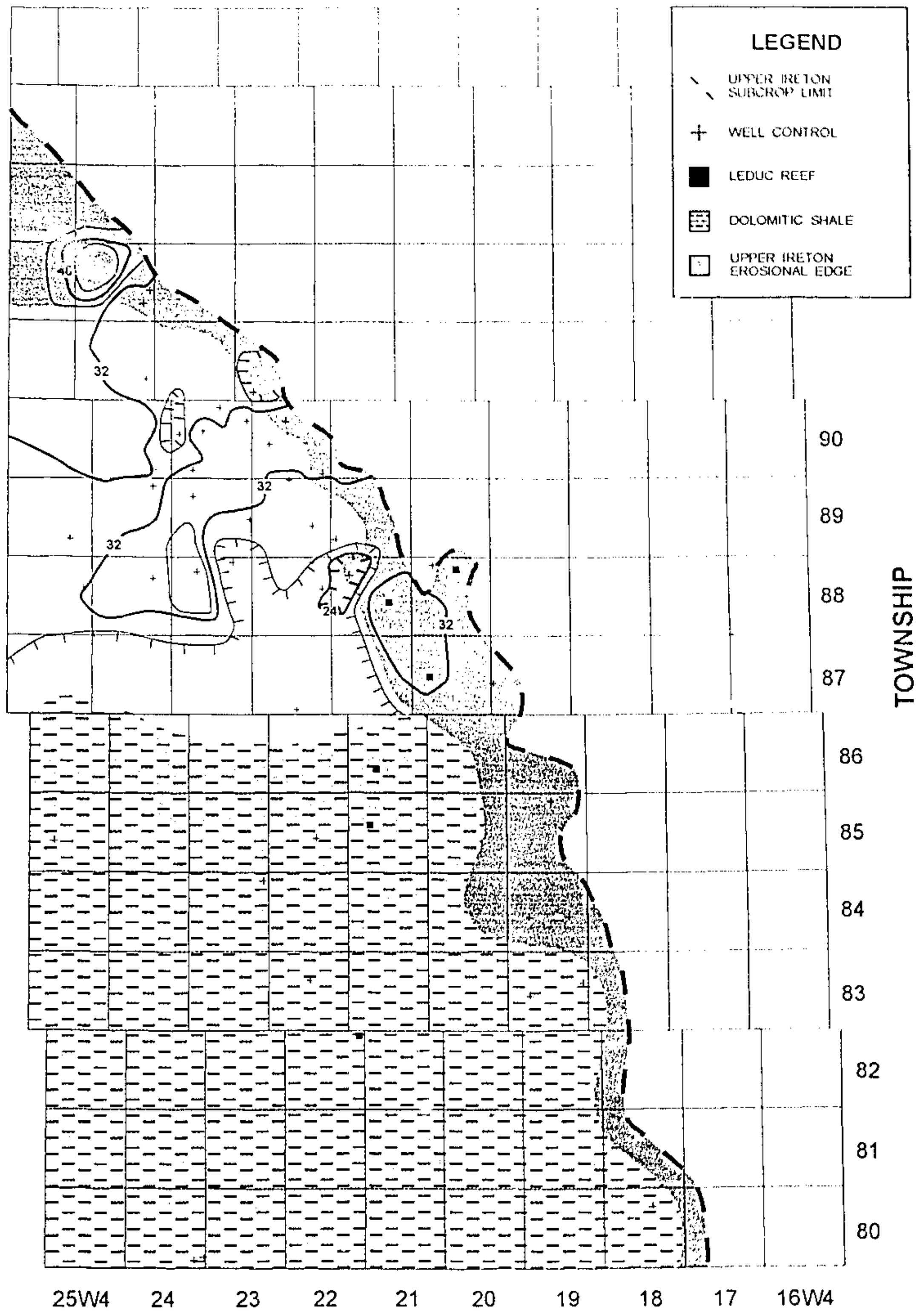


Fig. 4.12 Upper Ireton net pay map (C.I. = 10 m).

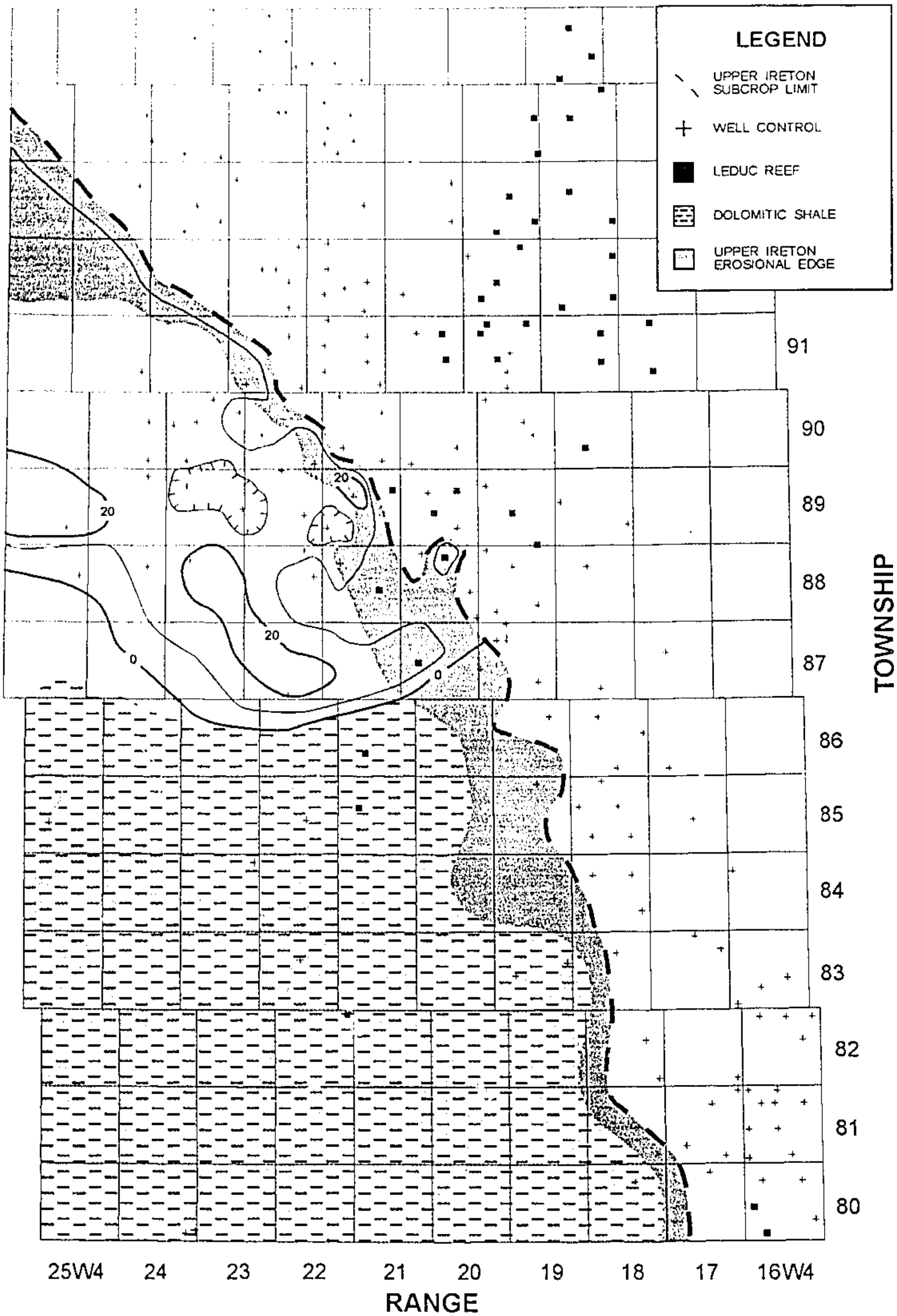


Fig. 4.13 Upper Ireton isoporosity map (C.I. = 2 m).

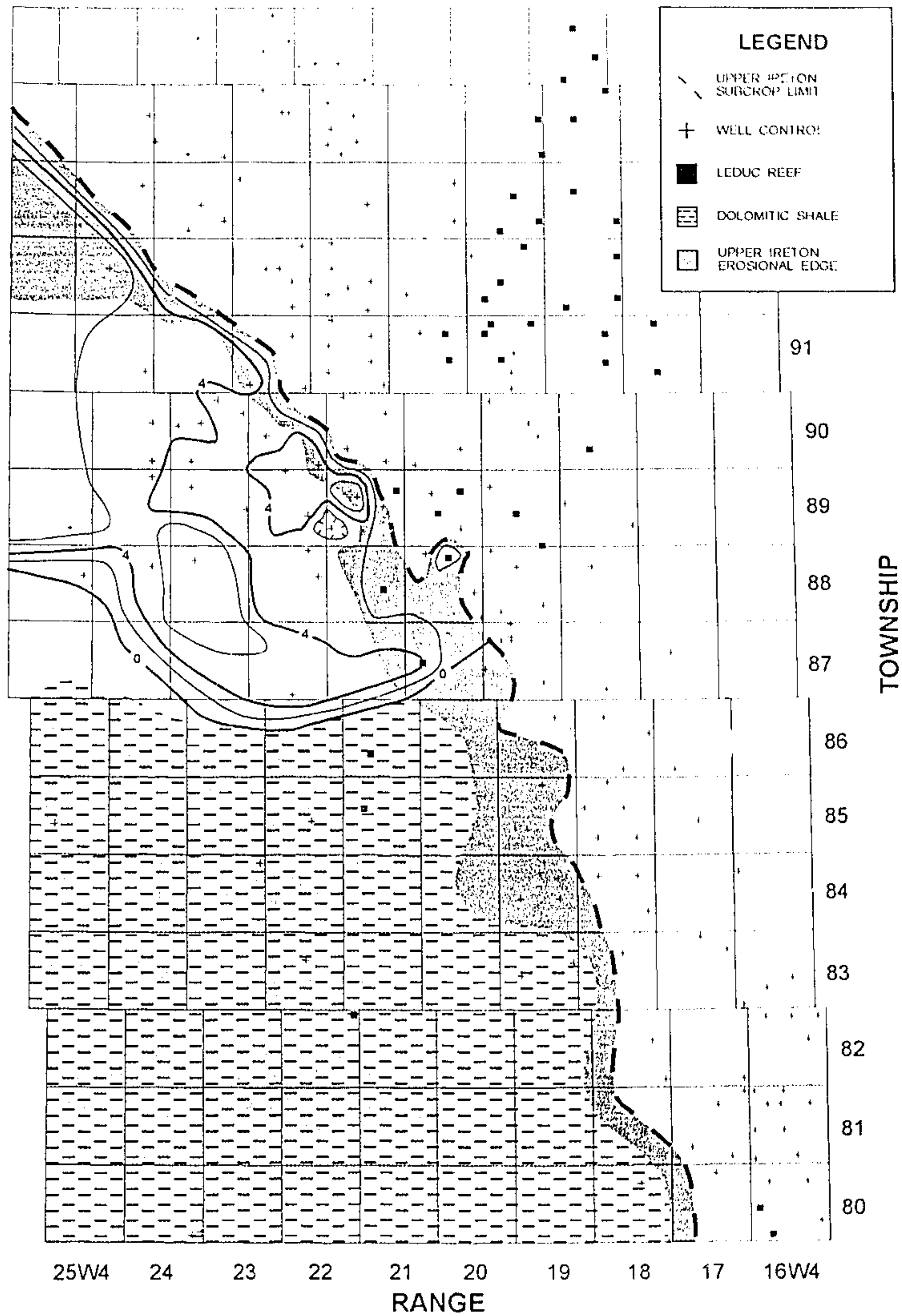
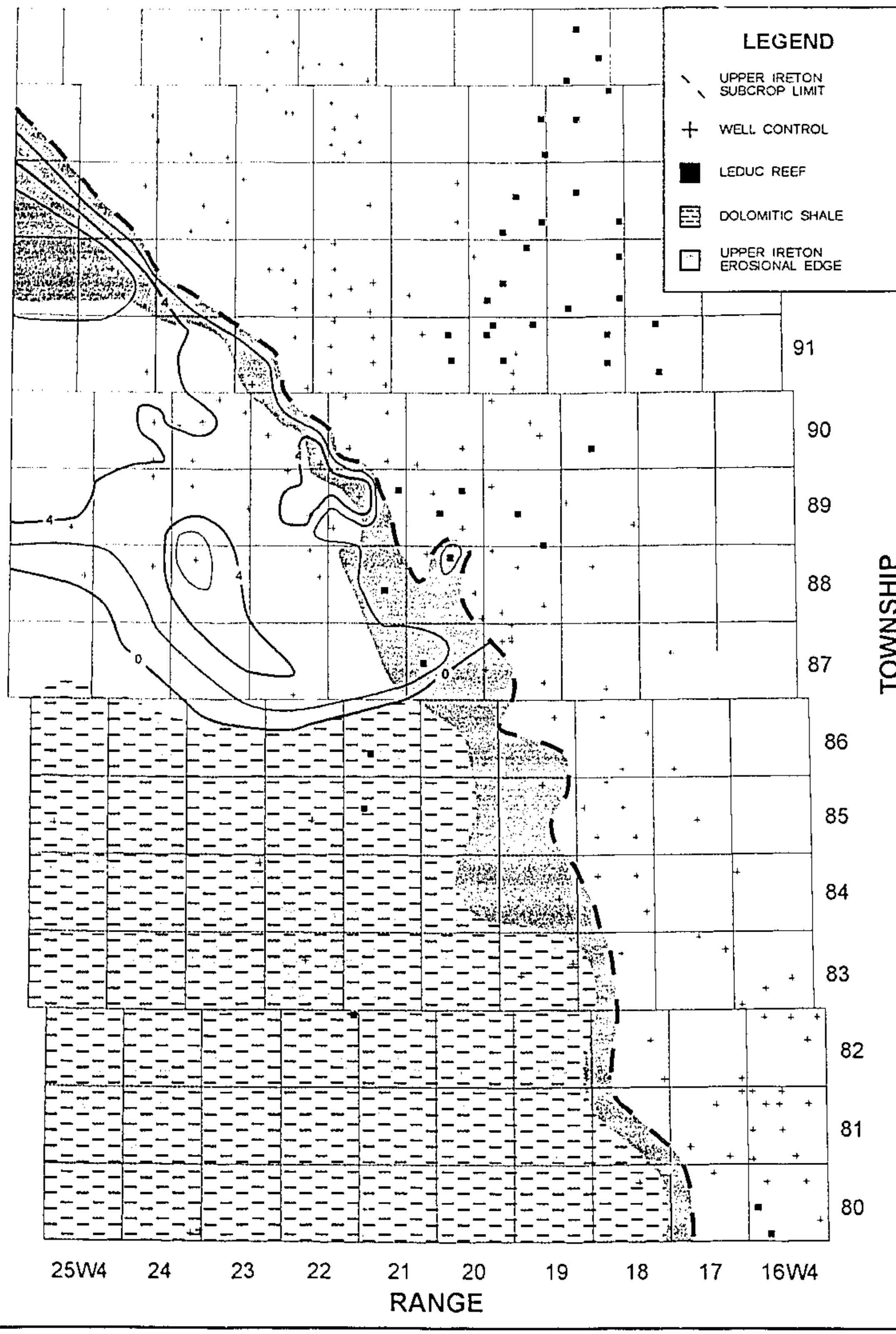


Fig. 4.14 Upper Ireton hydrocarbon pore volume map (C.i. = 2 m).



4.3 UGM3

The structure contour map of the UGM3 (Figure 4.15) shows that this unit has a regional strike of 150^0 and a dip of about 0.3^0 to the southwest (approximately 5.2 m/km). The elevation of the top of the UGM3 increases from 100 m below sea level in the southwest to over 300 m near the subcrop limit in Township 92. However, strike and elevation become irregular within the UGM3 erosional edge (zone shaded in grey) especially in Township 89, Range 20 W4M where a sinkhole is present. The zone shaded in grey represents the erosional edge of the UGM3 whose limit has been determined by the subcrop limits of the UGM3 (obtained from Figure 4.16) and the Upper Ireton (obtained from Figure 4.9).

Figure 4.16 further reveals that the UGM3 has a uniform thickness of 30 to slightly over 40 m across the study area, except within the erosional edge where the thickness can vary by up to 40 m. The thickness is especially variable in Township 89, Range 20 W4M because of a large sinkhole (Well 10-16-89-20 W4M).

There are 41 "caves" that have been identified from log data. The "caves" appear to be randomly distributed throughout the UGM3 (Figure 4.17). The wide distribution of "caves" implies that the karst is extensive and well developed.

The porosity map of the UGM3 (Figure 4.18) shows that the UGM3 is very porous. Over much of the study area, the average porosity is greater than 20% with localized areas exceeding 30%. Most of the high porosity areas are associated with "caves".

The net pay map (Figure 4.19), isoporosity map (Figure 4.20), and HPV map (Figure 4.21) all show similar trends. Net pay, isoporosity, and HPV have their highest values just southwest of the erosional edge and they decrease towards the northeast and the southwest. The decrease towards the northeast is caused by erosion whereas the decrease towards the southwest reflects a decreasing bitumen saturation.

Fig. 4.15 UGM3 structure contour map (C.I. = 25 m).

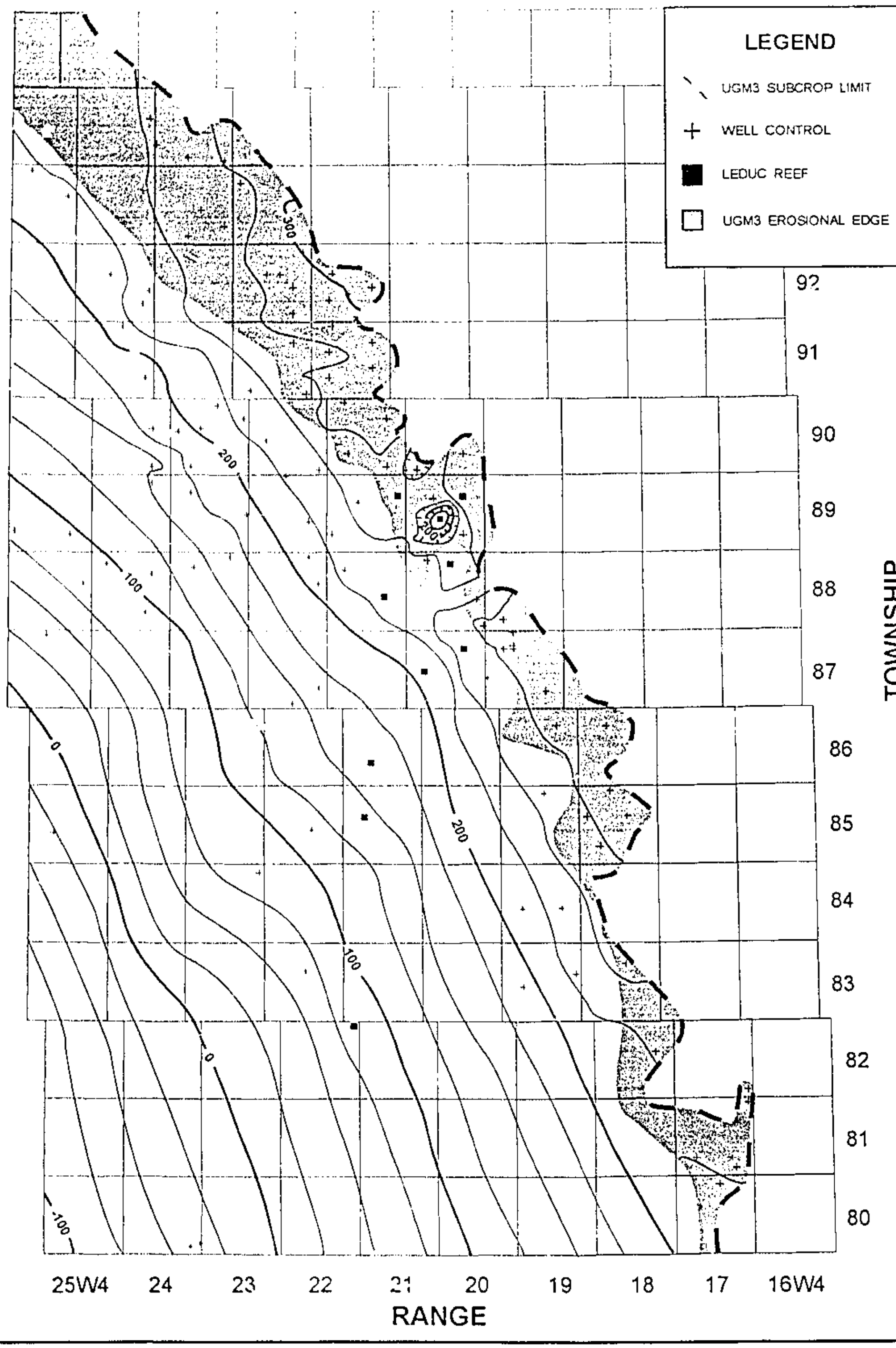


Fig. 4.16 UGM3 isopach map (C.I. = 10 m).

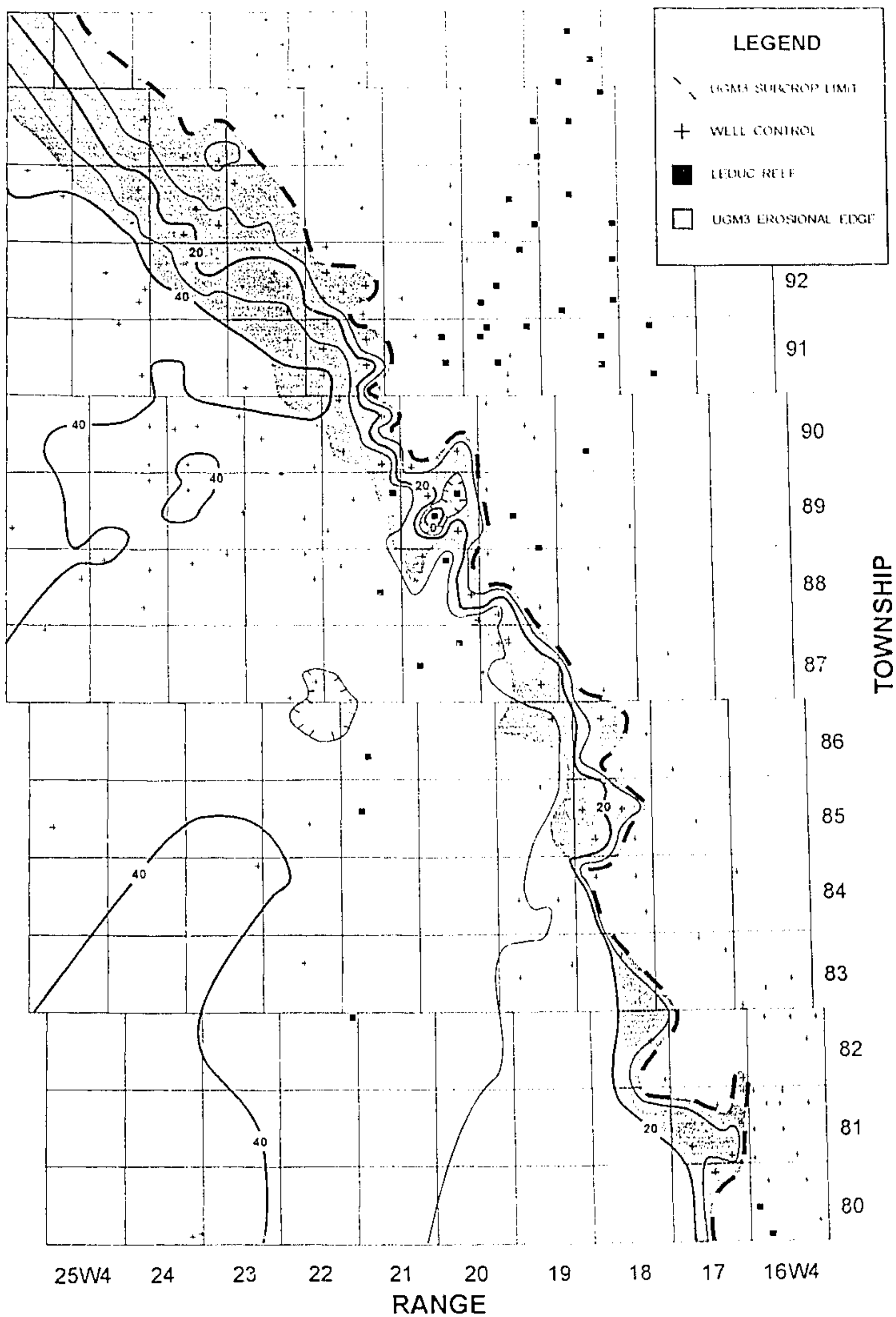


Fig. 4.17 Location of UGM3 "caves".

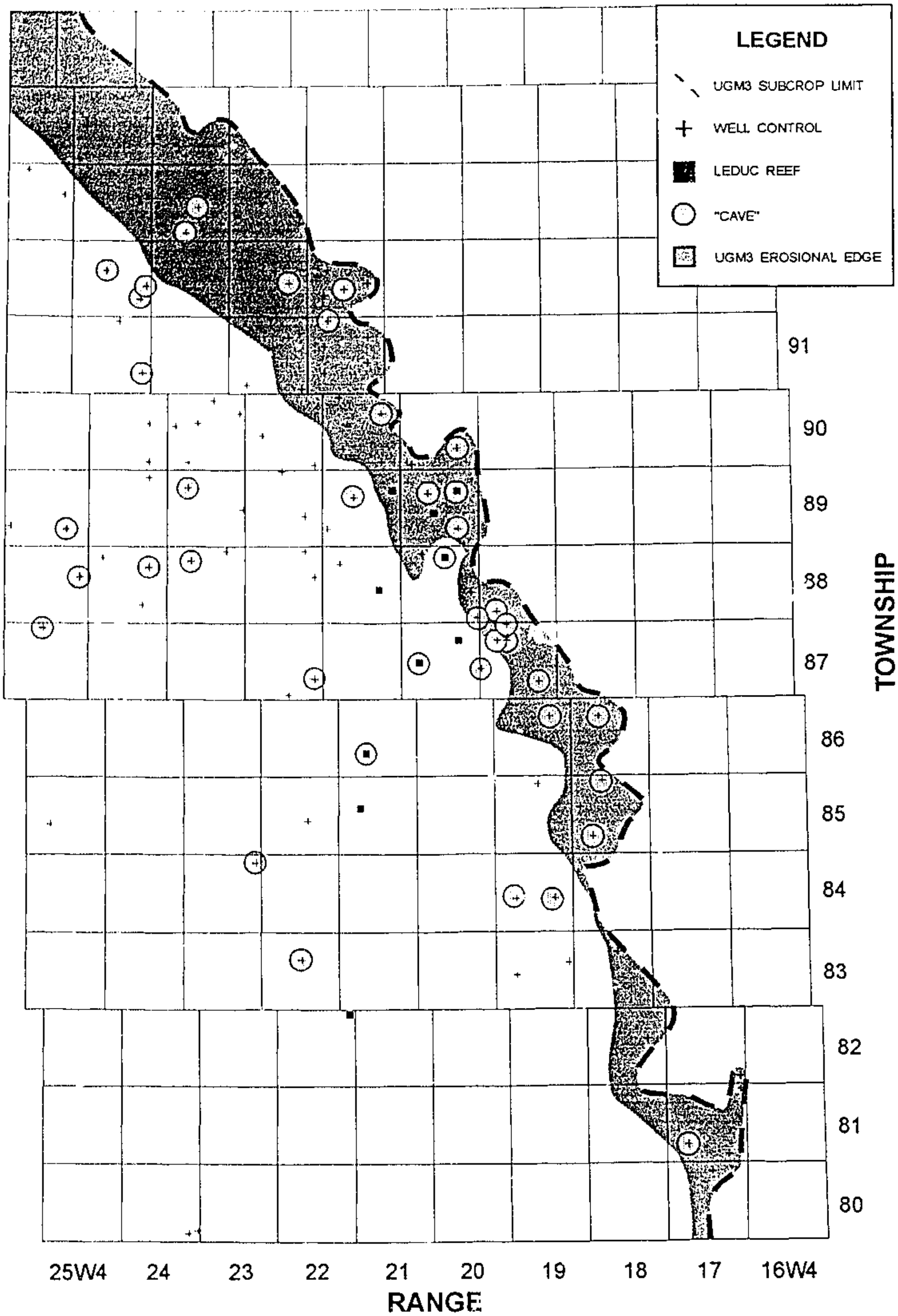


Fig. 4.18 UGM3 porosity map (C.I. = 4%).

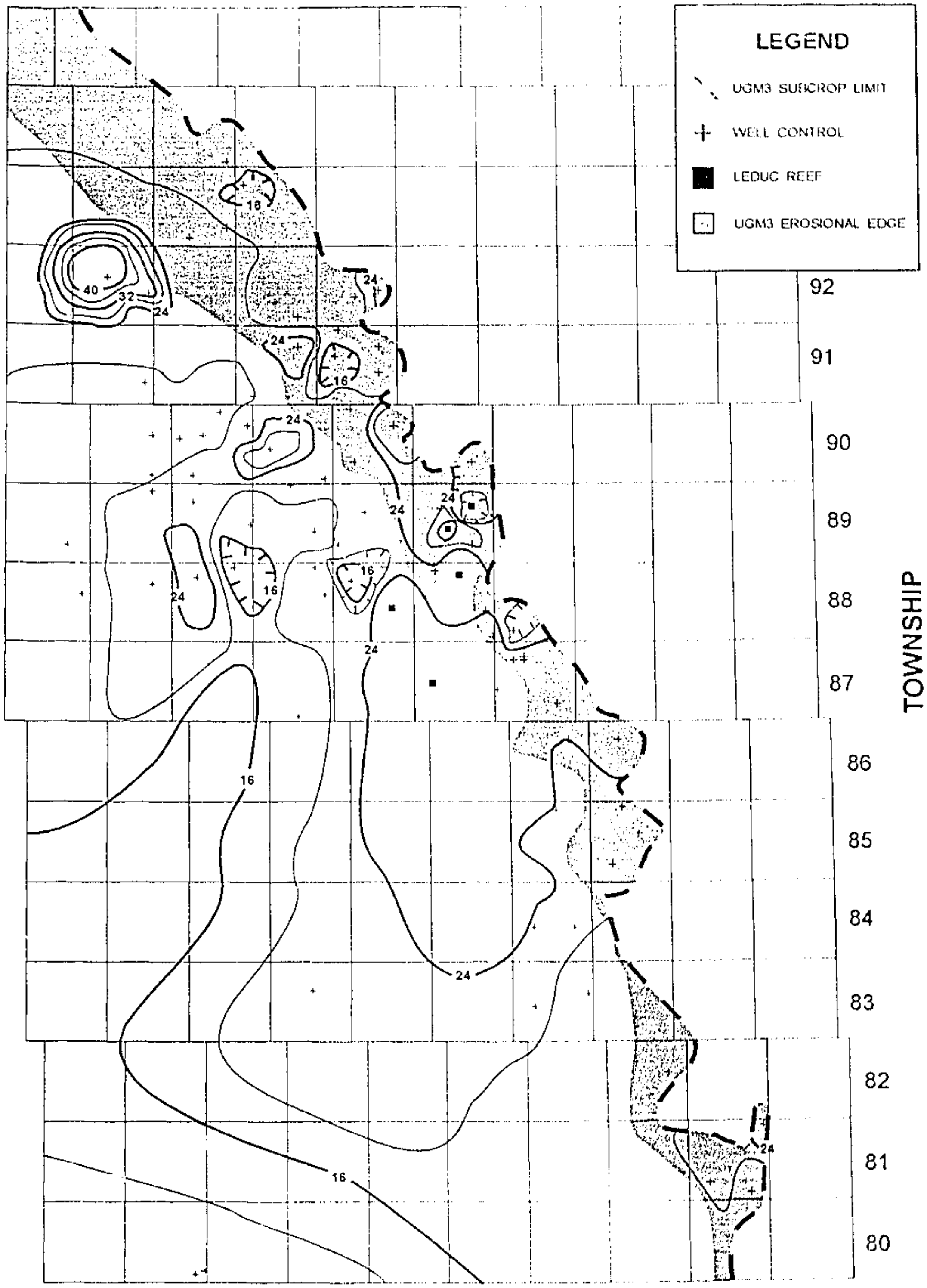


Fig. 4.19 UGM3 net pay map (C.I. = 10 m).

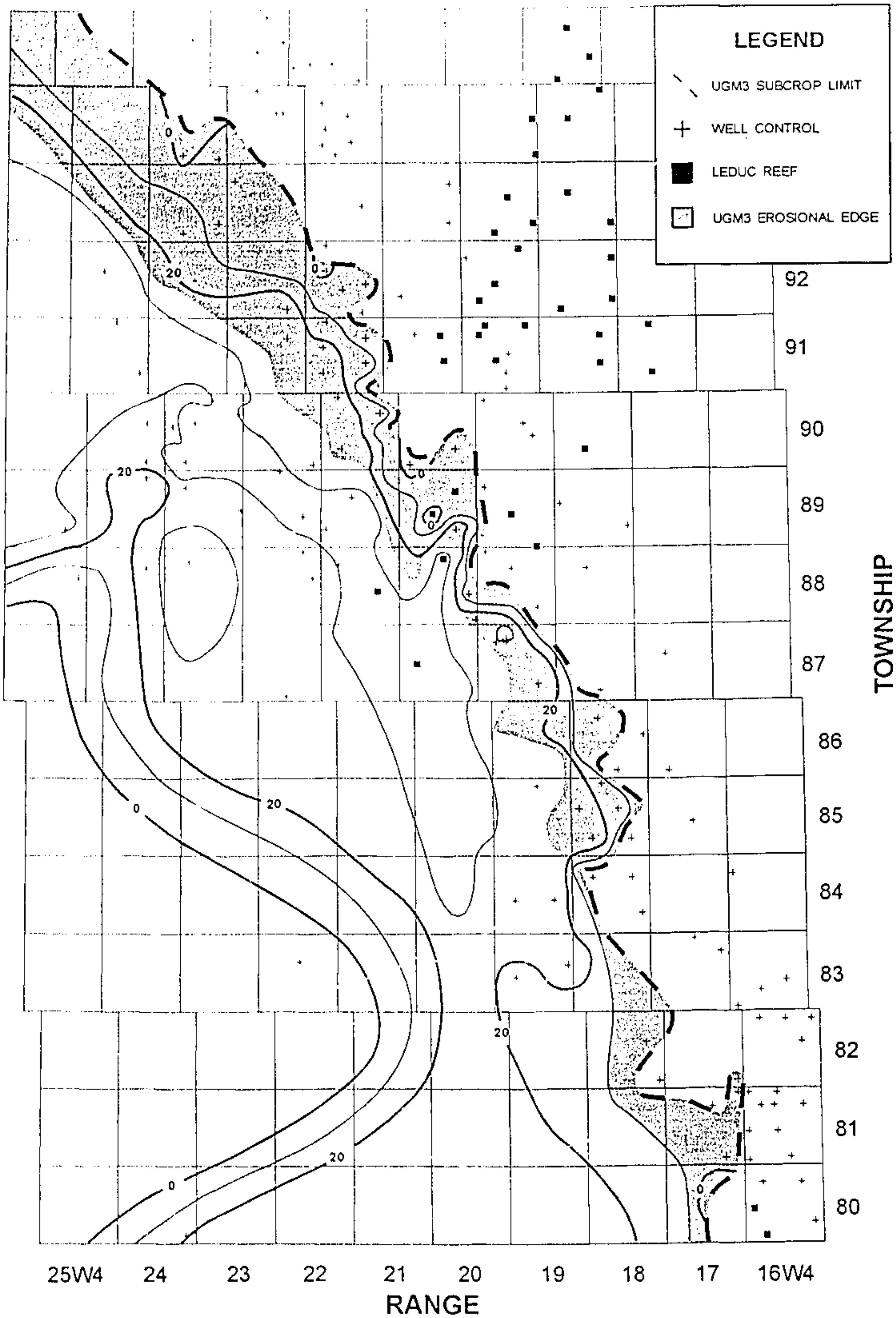


Fig. 4.20 UGM3 isoporosity map (C.I. = 2 m).

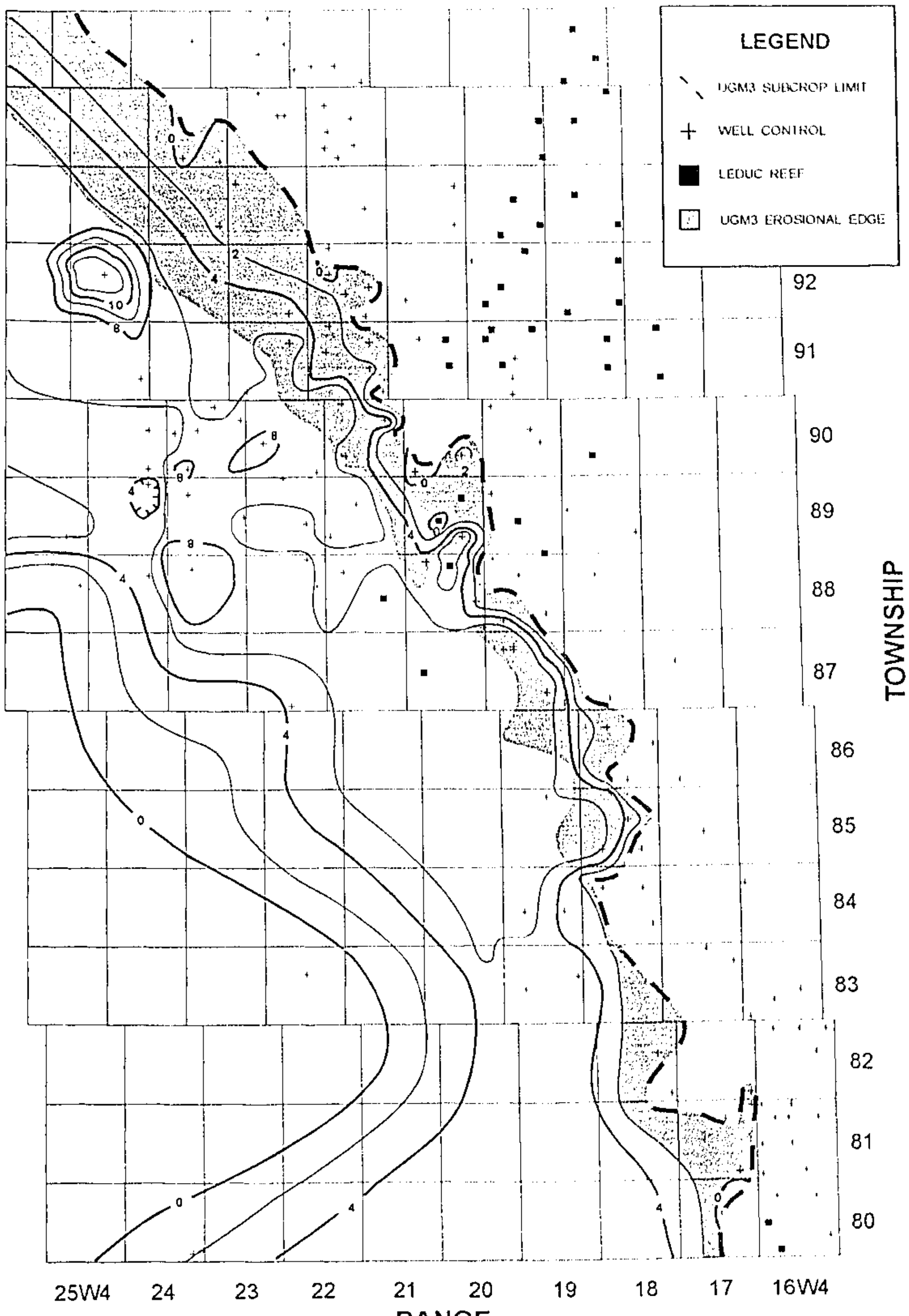
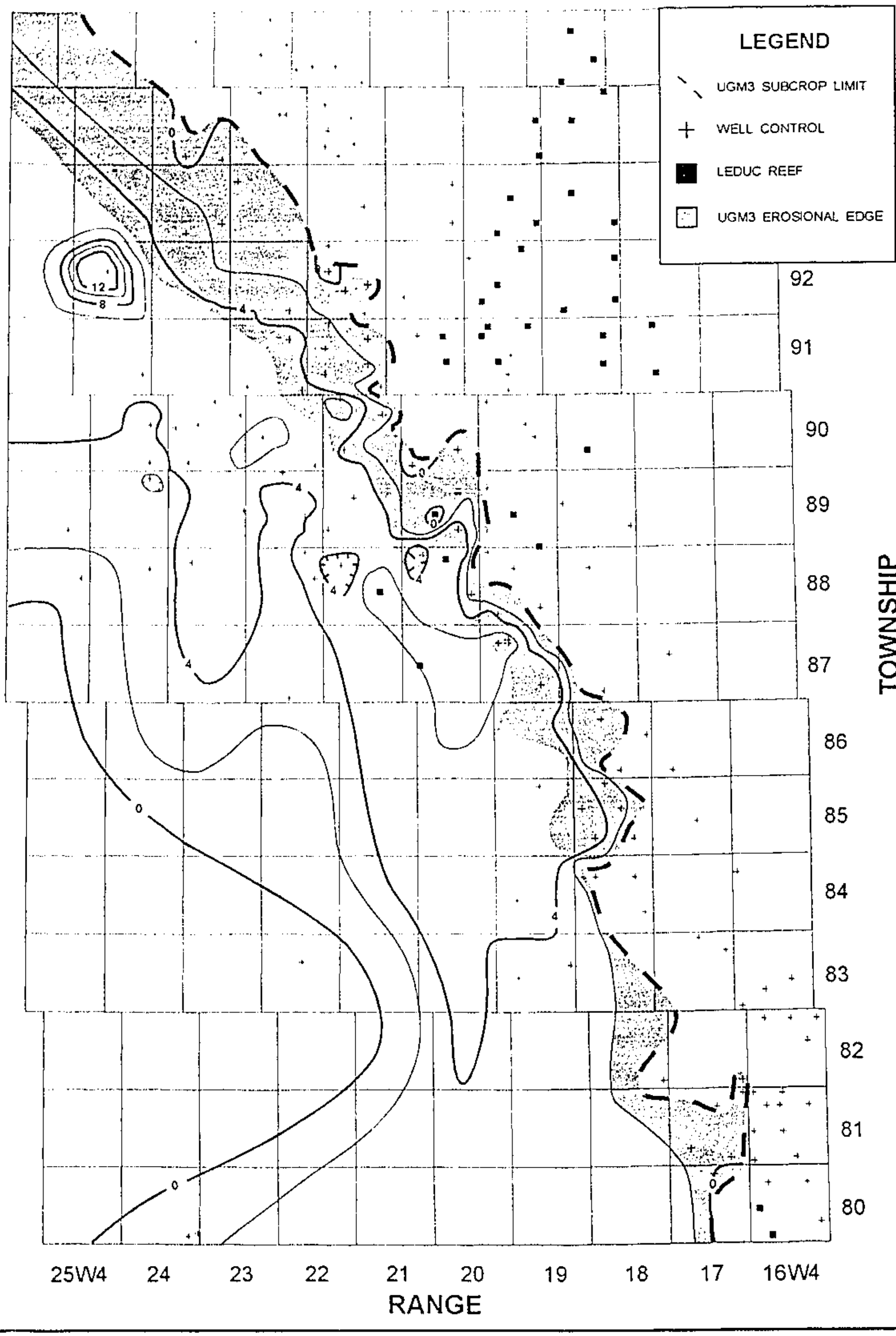


Fig. 4.21 UGM3 hydrocarbon pore volume map (C.I. = 2 m).



4.4 UGM2

The structure contour map of the UGM2 (Figure 4.22) reveals a regional strike of about 150^{0} and a dip to the southwest of about 0.3^{0} (approximately 5.2 m/km). The elevation of the top of the UGM2 ranges from 150 m below sea level in the southwest and increases up-dip in a northeasterly direction to 320 m above sea level in Township 94. Locally, strike and dip deviate from the above values where the UGM2 is partially eroded along the sub-Cretaceous unconformity (zone shaded in grey) and near the sinkhole in Township 89, Range 20 W4M. The zone shaded in grey represents the erosional edge of the UGM2 which is defined as the area between the subcrop limit of the UGM3 (obtained from Figure 4.16) and the subcrop limit of the UGM2 (obtained from Figure 4.23).

Comparison of Figures 4.16 and 4.23 shows that the UGM3 and UGM2 generally have similar thicknesses in the study area, i.e., between 30 and 40 m, whereby the higher values are located in the western half of the study area. However, near the sinkhole in Township 89, Range 20 W4M and within the UGM2 erosional edge, the thickness is very irregular and it can vary by up to 35 m in a single township.

There are 28 "caves" recognized in the UGM2 (Figure 4.24). They tend to be located near the erosional edge in the central part of the study area. The distribution of the "caves" suggest that the karst is not as extensive as in the overlying carbonate units (e.g., Nisku, Upper Ireton, and UGM3).

The porosity map of the UGM2 (Figure 4.25) illustrates that the porosity is greater than 12% over much of the study area. Locally, there are 'pockets' with greater than 20% or less than 12%. The high porosity 'pockets' tend to coincide with the "caves" that are shown on Figure 4.24.

The net pay (Figure 4.26), isoporosity (Figure 4.27), and HPV (Figure 4.28) maps reveal the same overall trends that are developed in the UGM3. The highest values occur near the erosional edge of the UGM2, and the values decrease towards the northeast and southwest.

Fig. 4.22 UGM2 structure contour map (C.I. = 25 m).

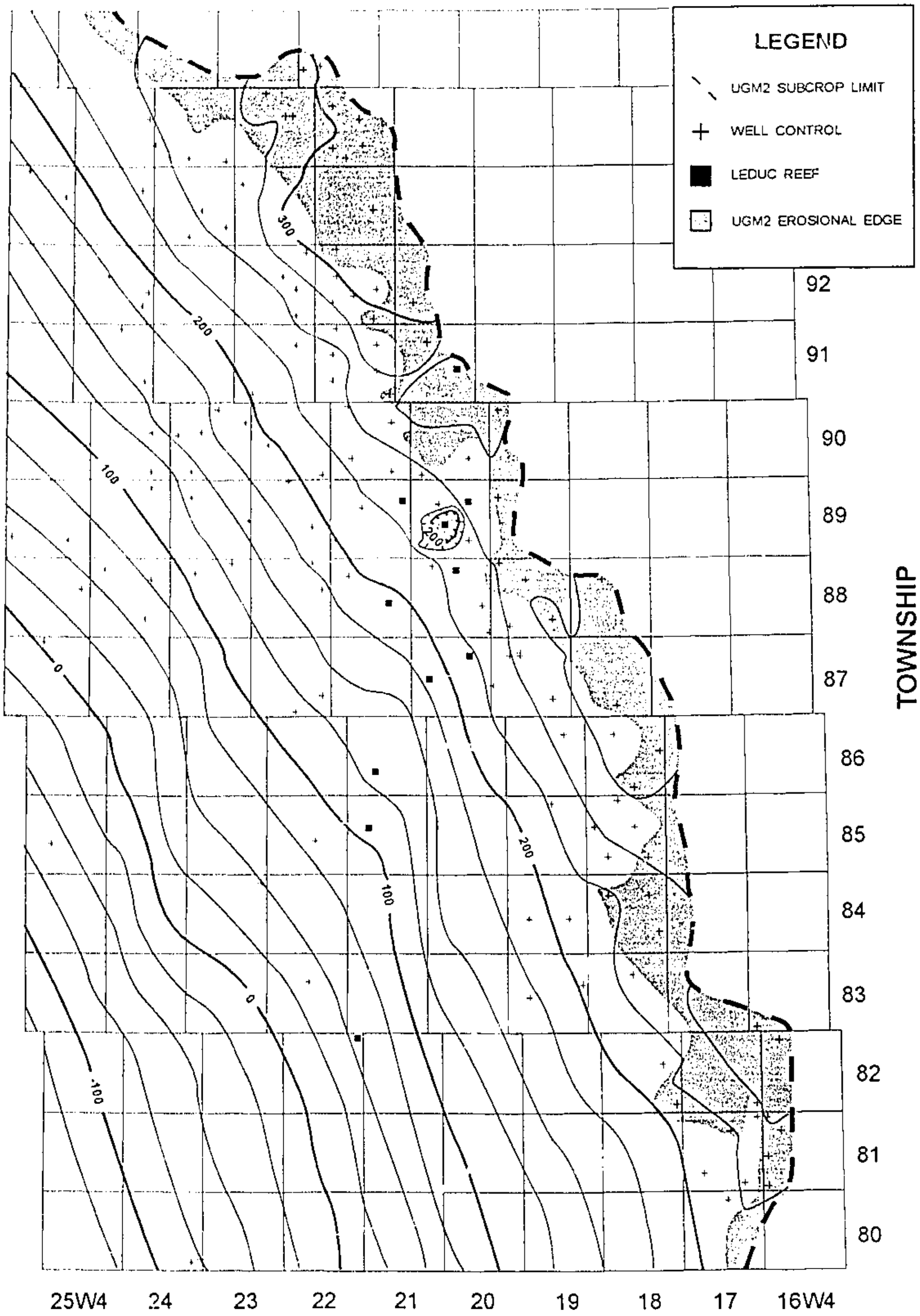


Fig. 4.23 UGM2 isopach map (C.I. = 10 m).

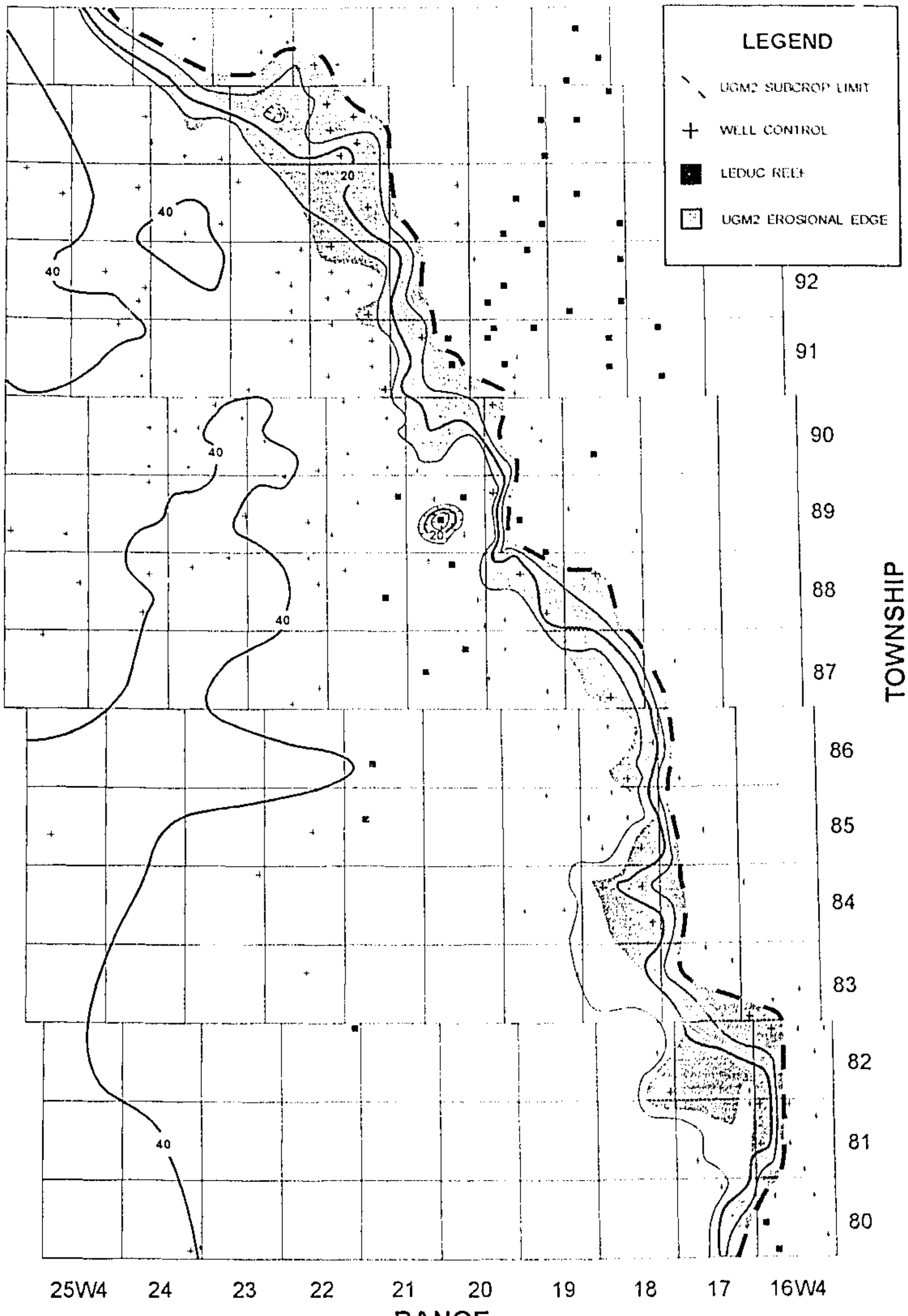


Fig. 4.24 Location of UGM2 "caves".

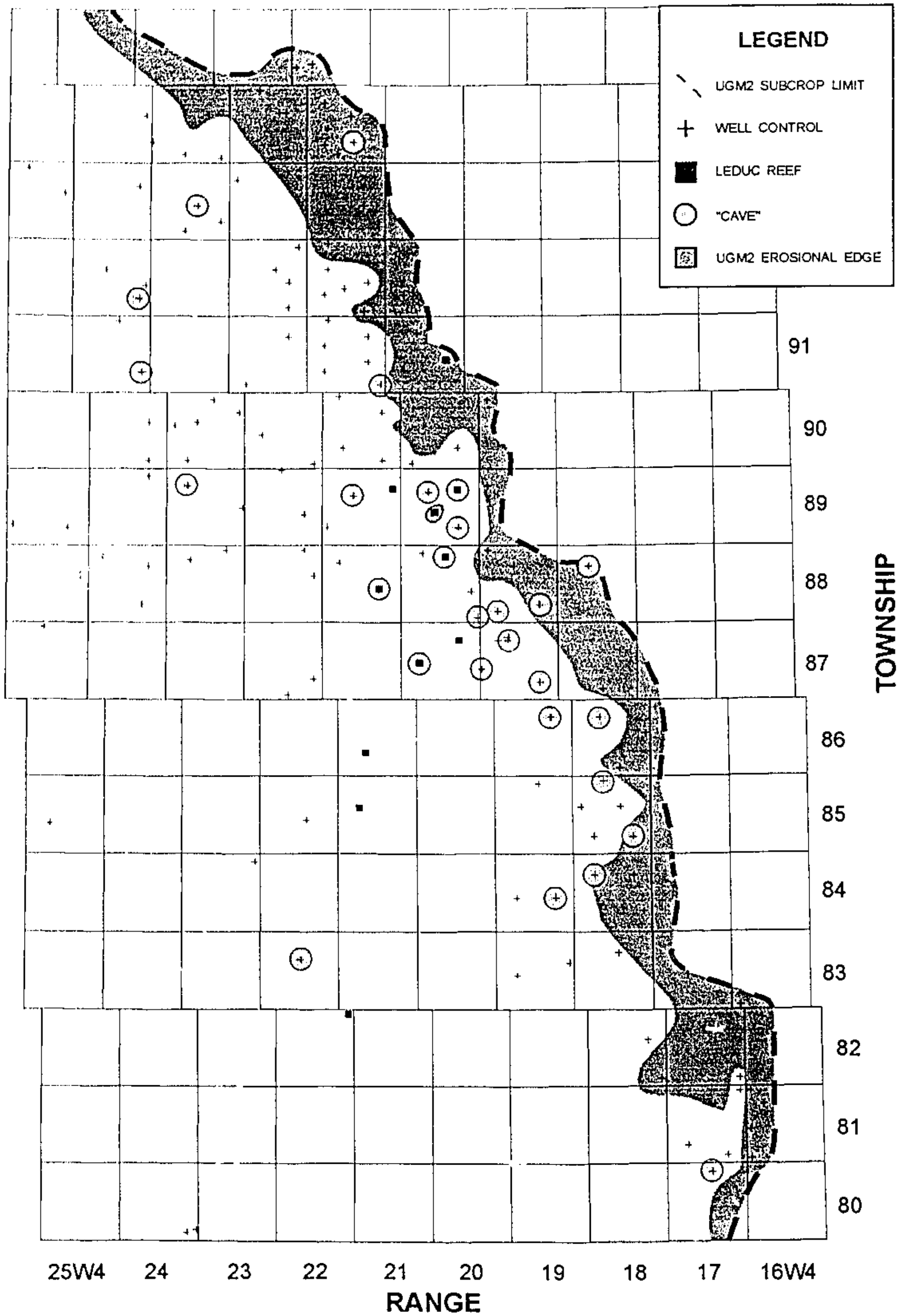


Fig. 4.25 UGM2 porosity map (C.I. = 4%).

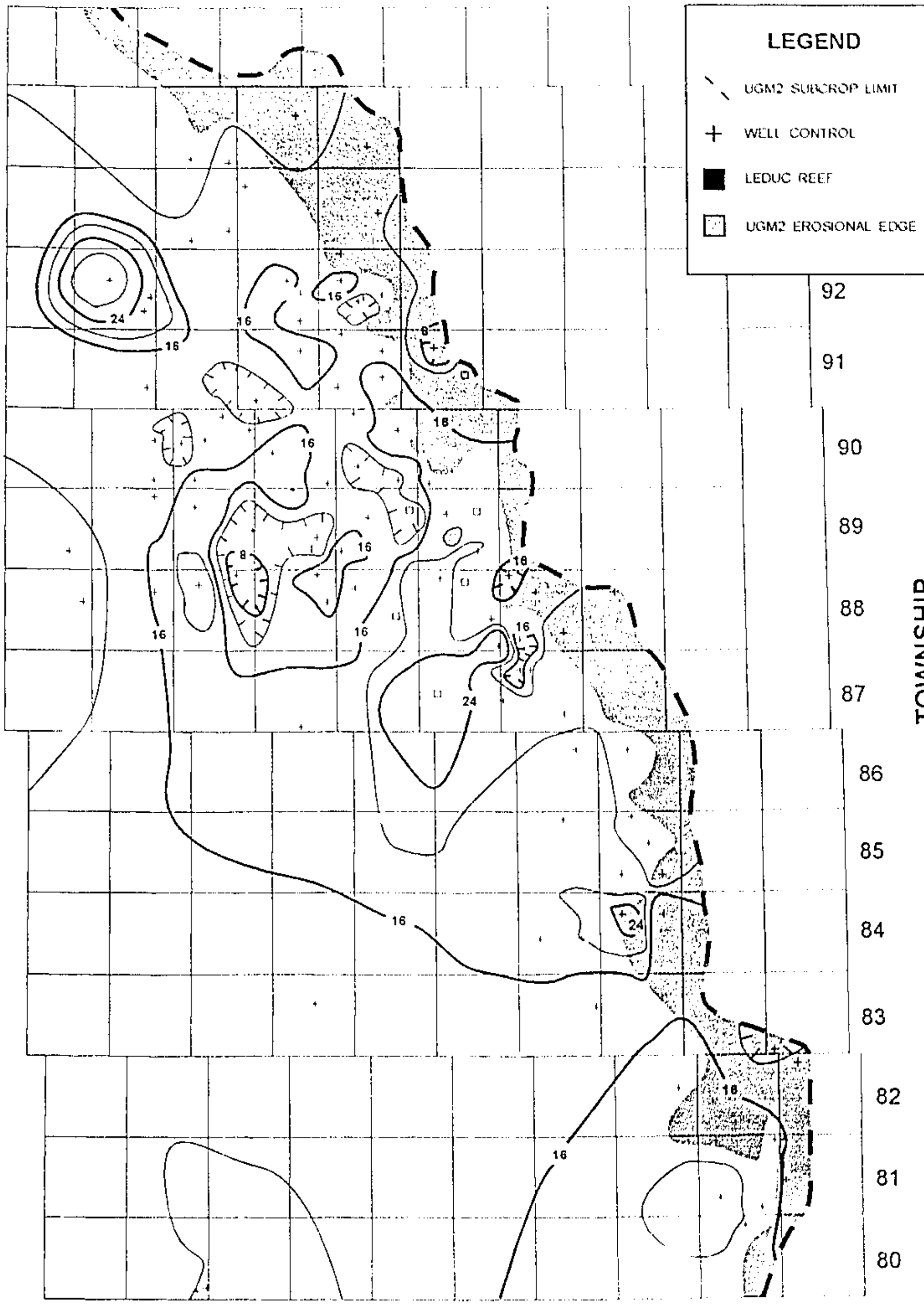


Fig. 4.26 UGM2 net pay map (C.I. = 10 m).

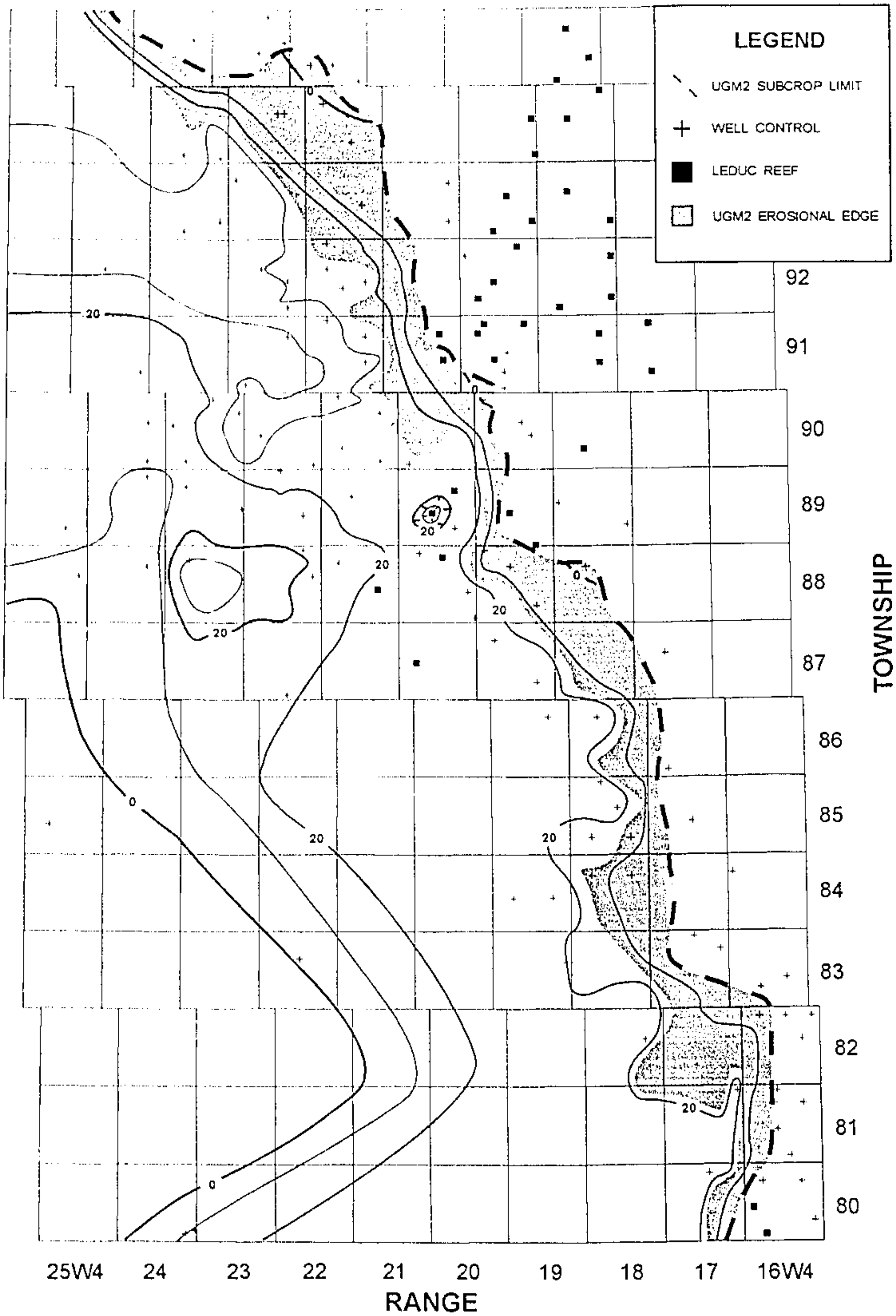


Fig. 4.27 UGM2 isoporosity map (C.I. = 2 m).

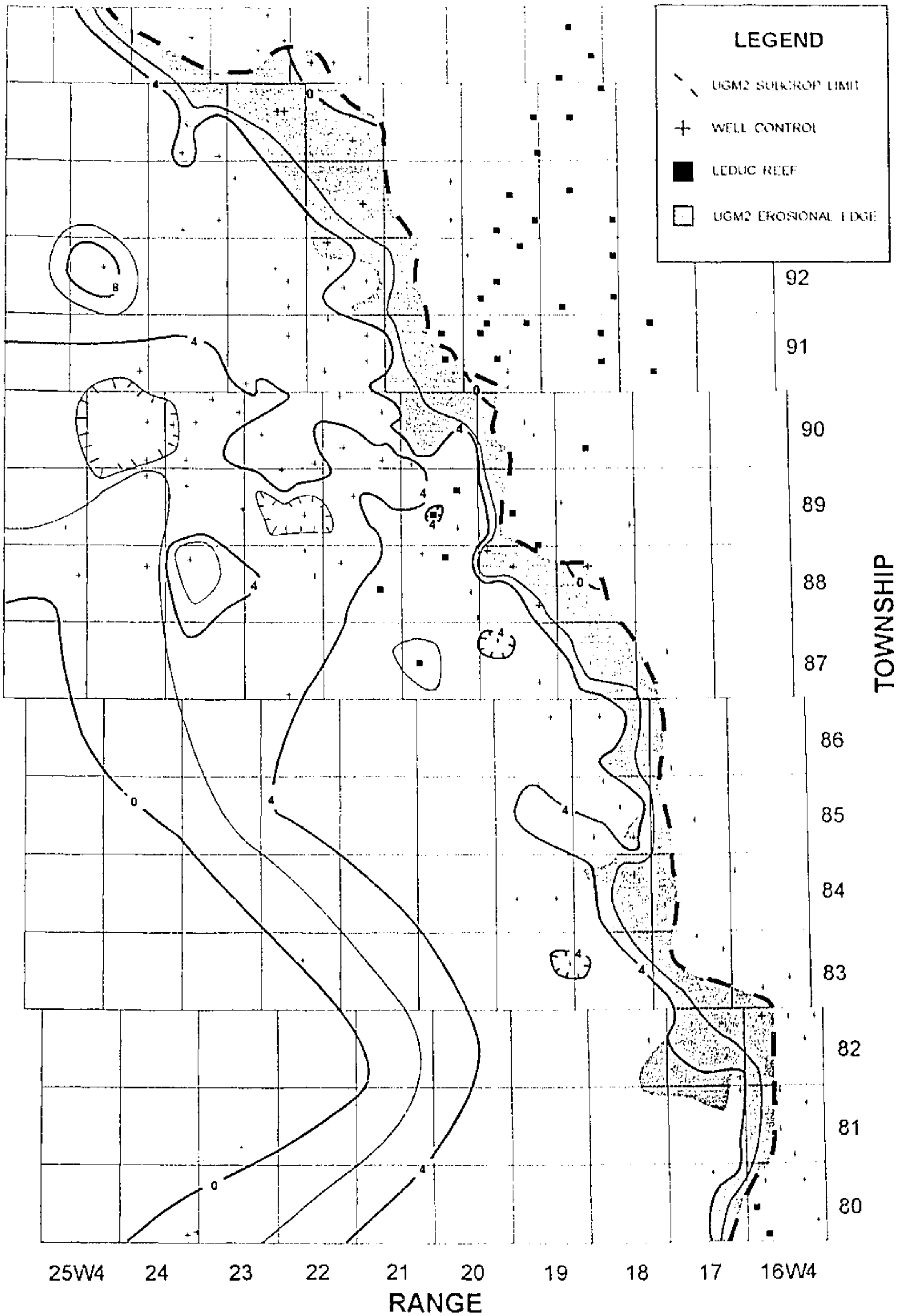
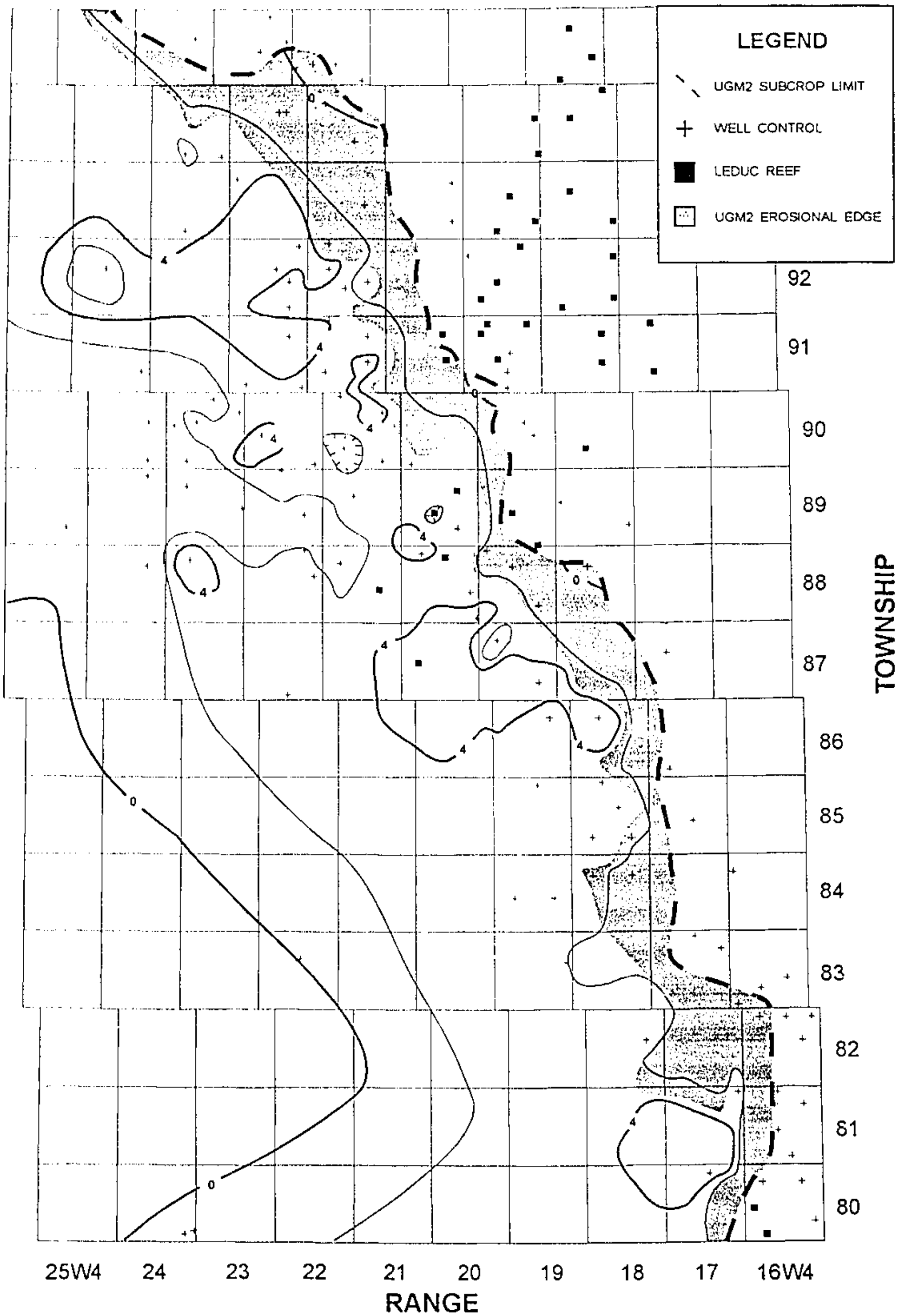


Fig. 4.28 UGM2 hydrocarbon pore volume map (C.I. = 2 m).



4.5 UGM1

The structure contour map of the UGM1 (Figure 4.29) indicates a regional strike of about 150^{0} and a dip to the southwest of about 0.3^{0} (approximately 5.2 m/km). The elevation of the top of the UGM2 ranges from approximately 175 m below sea level in the southwest to slightly more than 300 m in the northeast. Within the erosional edge (shaded grey) of the UGM1, which is much narrower than those of the UGM2 and UGM3, strike and dip can vary dramatically (e.g., Township 91). In addition, the strike and dip deviate above Leduc reefs in Township 89. Analogous to the erosional edges of the overlying units, the erosional edge of the UGM1 is determined by the subcrop limit of the UGM2 (obtained from Figure 4.23) and the subcrop limit of the UGM1 (obtained from Figure 4.30).

The isopach map (Figure 4.30) reveals that the UGM1 is the thinnest reservoir unit of the Grosmont Formation. Generally, the thickness is relatively uniform and ranges between 15 and 22.5 m. There is, however, an isolated low in the northwestern part of the study area where thicknesses are less than 10 m.

The UGM1 only has 9 "caves" (Figure 4.31). Most "caves" are close to the erosional edge or are near the sinkhole in Township 89, Range 20 W4M. The spatial distribution of the "caves" suggest that the karst is localized and that it is not as intense as the overlying units.

The porosity map of the UGM1 (Figure 4.32) displays a highly variable porosity distribution that ranges from less than 8% to as much as 32%. The variability of porosity in the UGM1 is probably controlled by its variability in lithology (Hawlader and Machel, 1992). Generally, the lower overall porosity values in the southern part of the study area correlate with a predominance of limestones, and larger average porosity values in the northern part of the study area correlate with a predominance of dolostones.

The resource maps of net pay (Figure 4.33), isoporosity (4.34), and HPV (Figure 4.35) display decreasing values within the erosional edge because of erosion. In most of the southern half of the study area, the resource values are poor as a result of low bitumen saturation.

Fig. 4.29 UGM1 structure contour map (C.I. = 25 m).

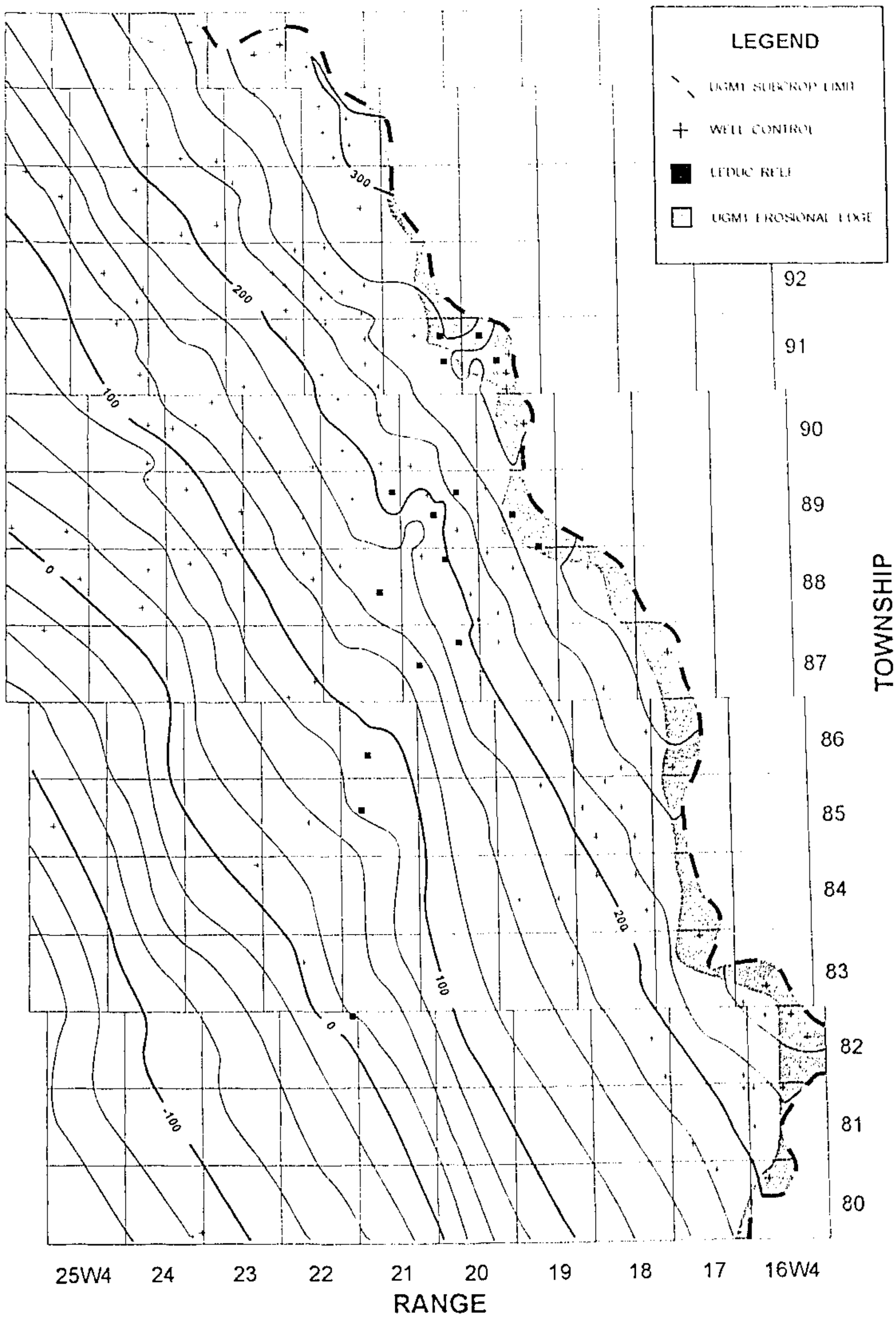


Fig. 4.30 UGM1 isopach map (C.I. = 5 m).

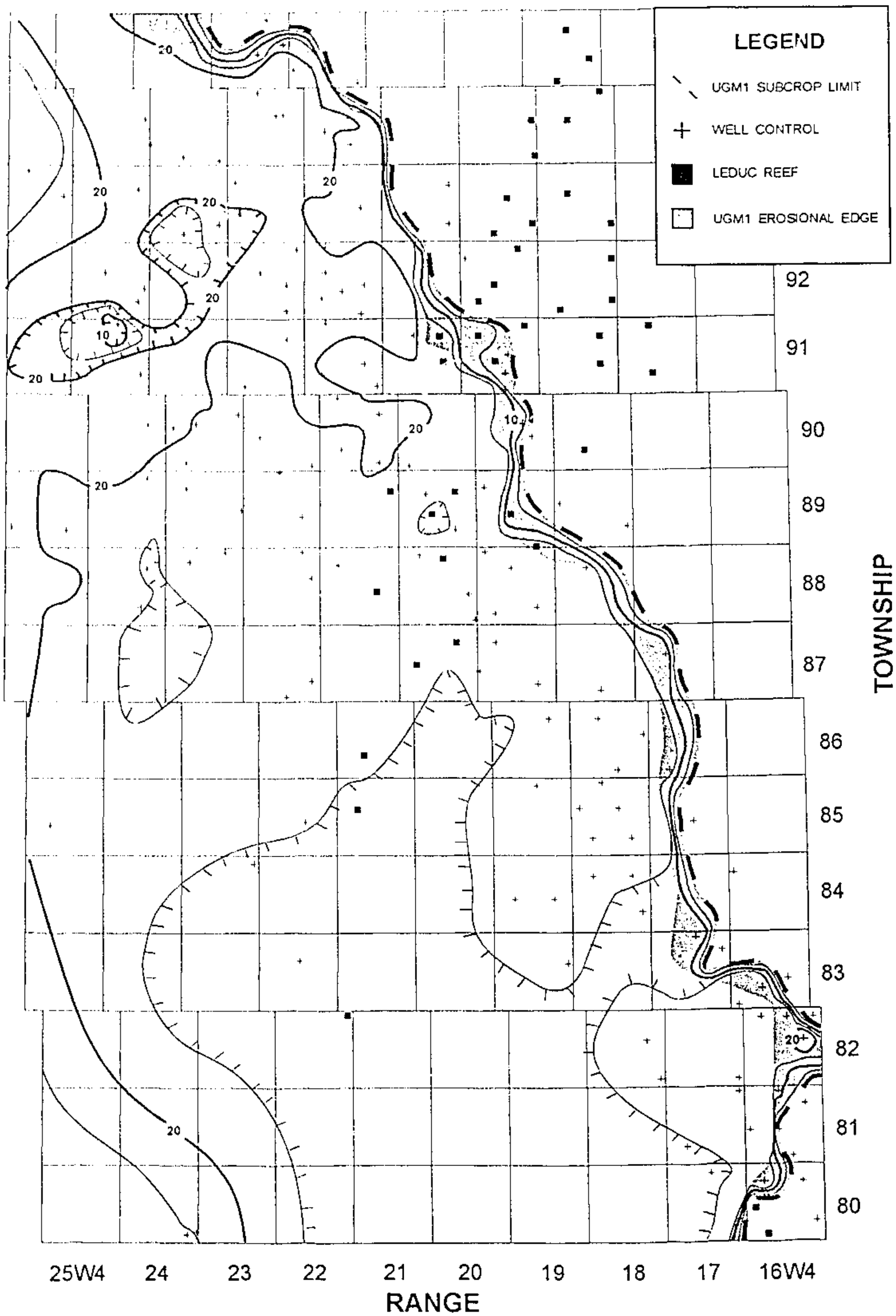


Fig. 4.31 Location of UGM1 "caves".

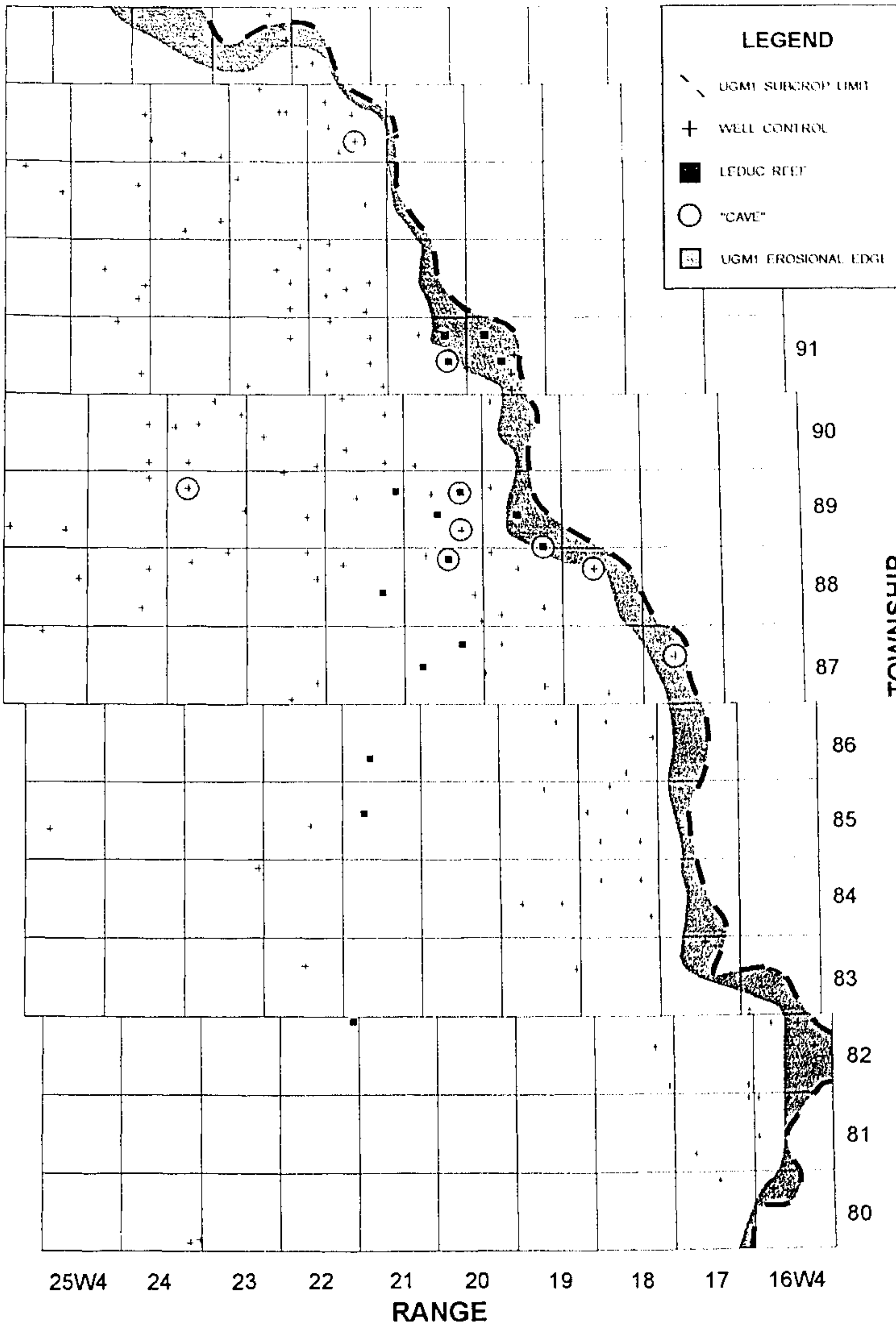


Fig. 4.32 UGM1 porosity map (C.I. = 4%).

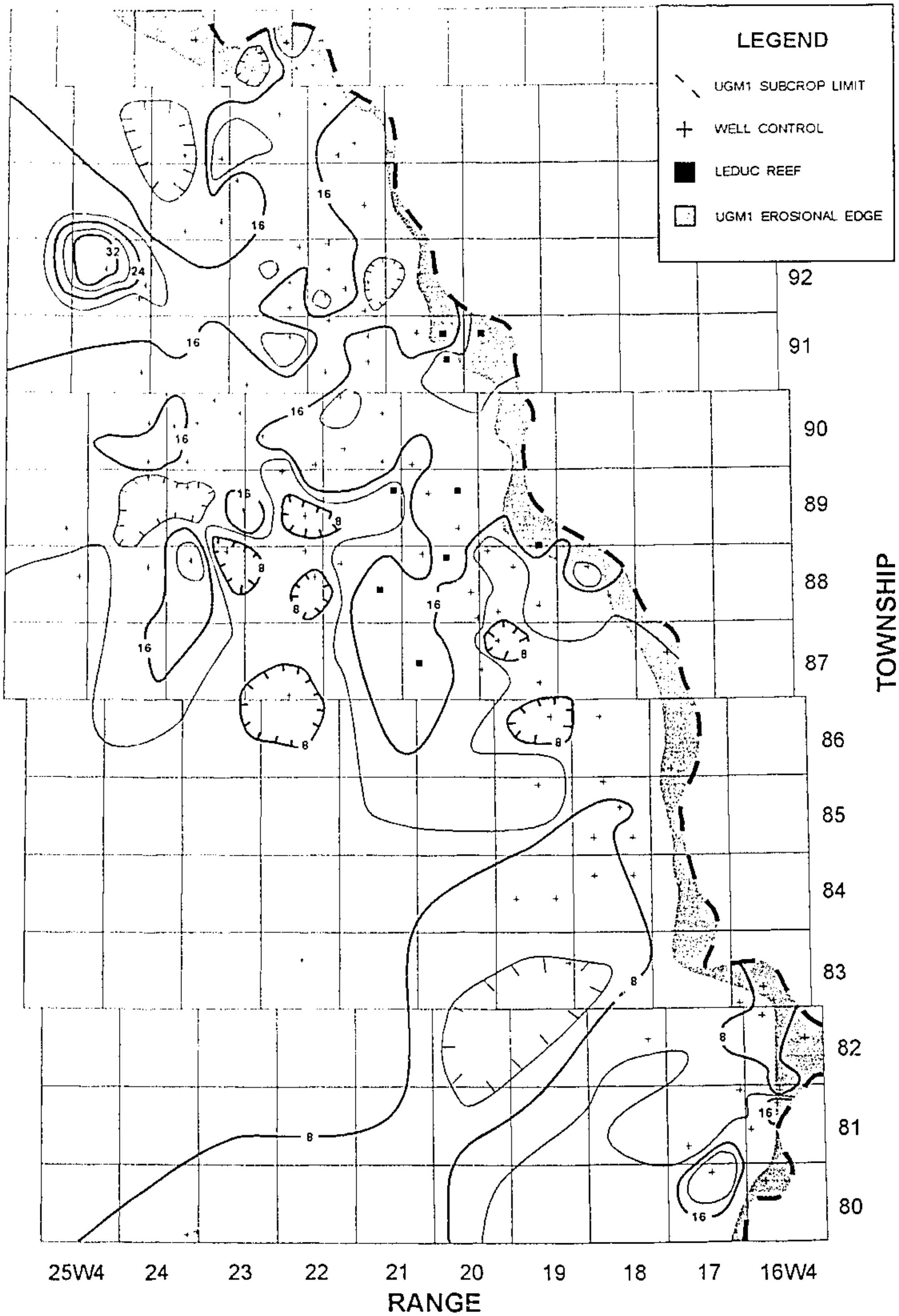


Fig. 4.33 UGM1 net pay map (C.I. = 5 m).

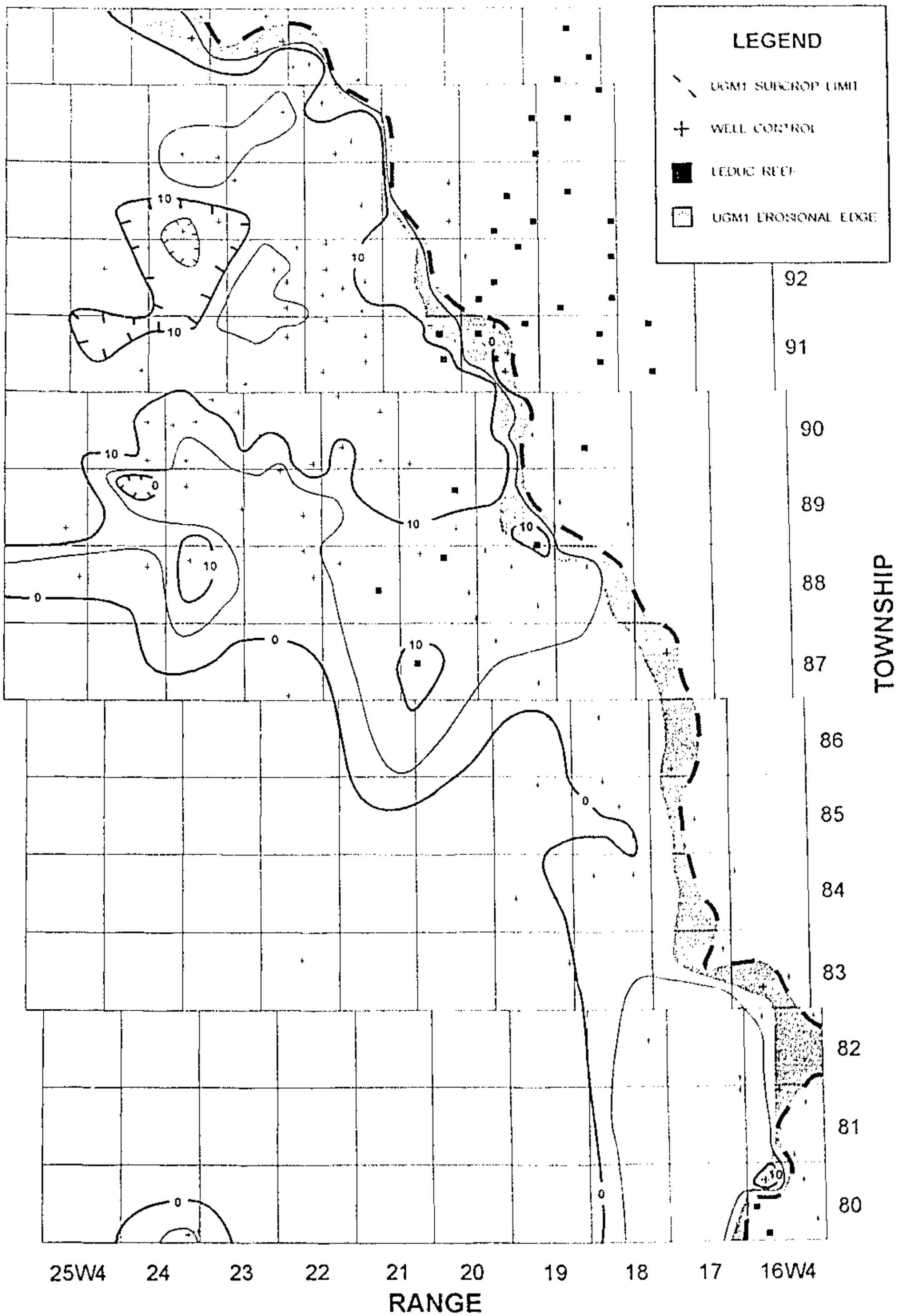


Fig. 4.34 UGM1 isoporosity map (C.I. = 1 m).

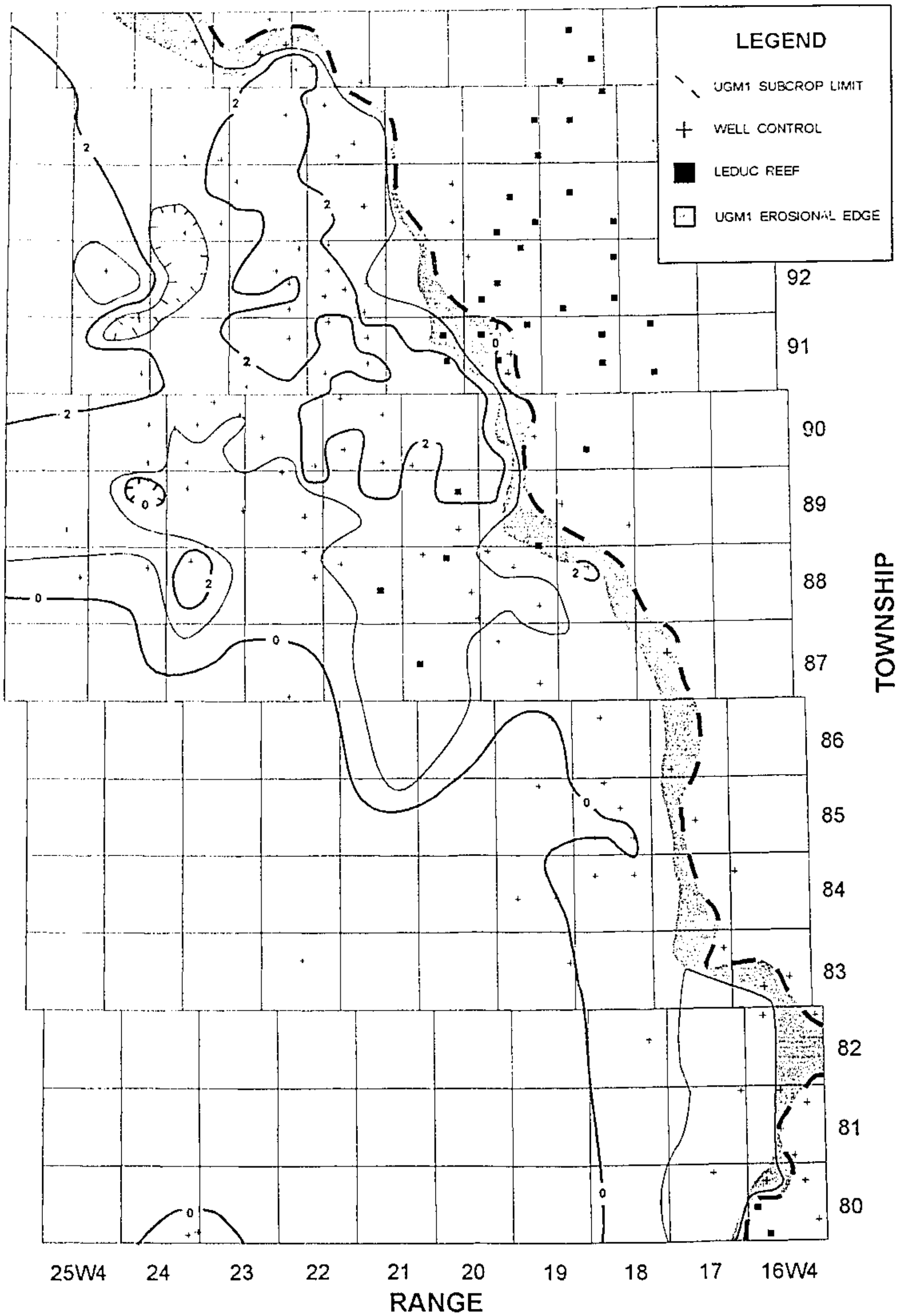
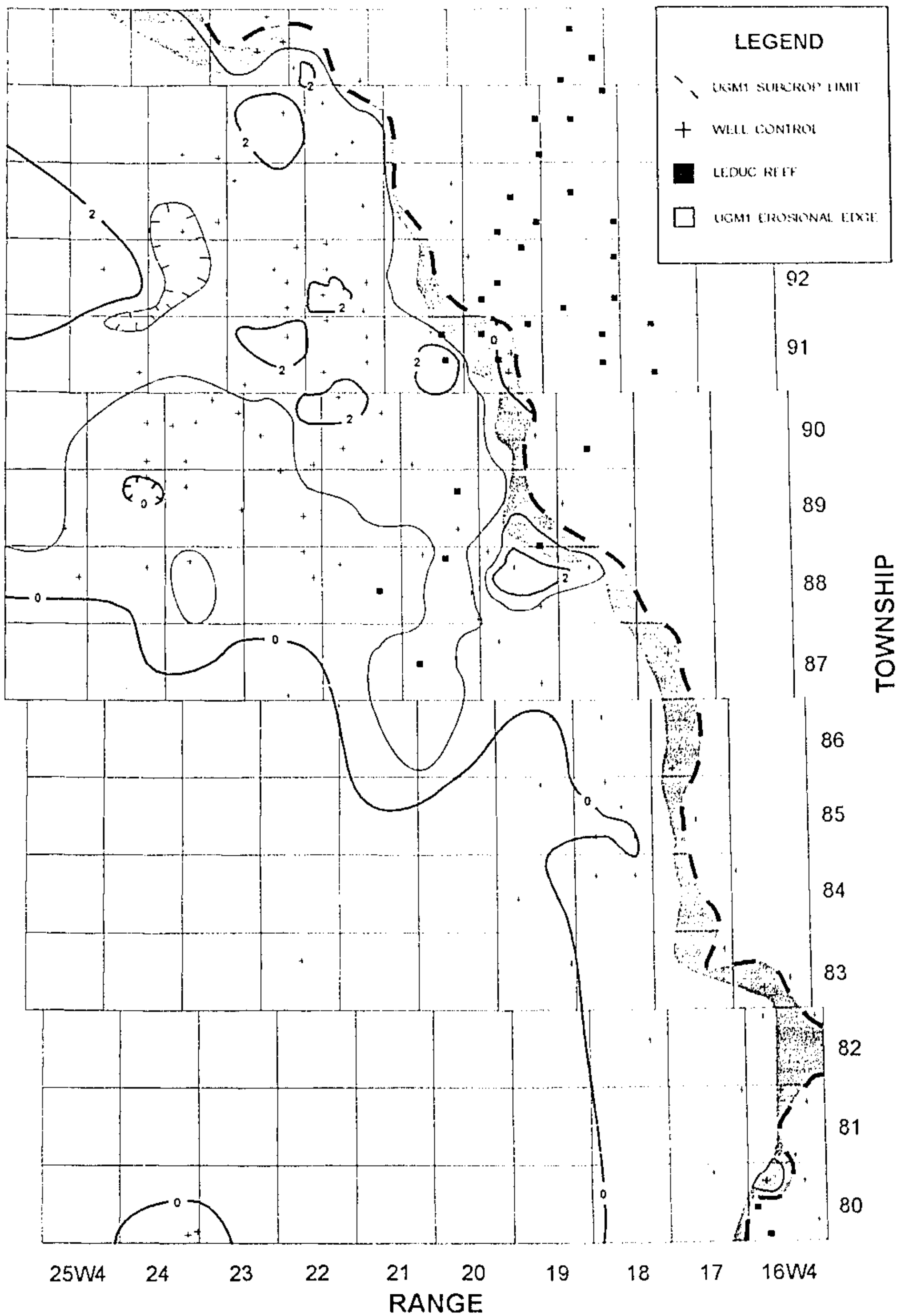


Fig. 4.35 UGM1 hydrocarbon pore volume map (C.I. = 1 m).



4.6 LGM

The structure contour map of the LGM (Figure 4.36) shows that this unit has a regional strike of 150^0 and gradually dips to the southwest at approximately 0.3^0 (5.2 m/km). The elevation of the top of the LGM ranges from approximately 175 m below sea level in the southwest to slightly over 300 m in the northeast. Locally, the strike and dip deviate from the regional trends above Leduc reefs in Township 89 and within the erosional edge (shaded grey). The LGM erosional edge is defined by the subcrop limit of the UGM1 (obtained from Figure 4.30) and the subcrop limit of the LGM (obtained from Figure 4.36).

The isopach map (Figure 4.37) reveals that the LGM is the thickest Grosmont reservoir unit. Generally, thicknesses range from 40 to 50 m. However, the LGM is not as thick within the erosional edge, over underlying Leduc reefs (north of Township 86), and in the southwest corner of the study area where the LGM carbonate platform progrades into the Ireton shale basin.

Within the LGM, there is a thick shale present north of Township 87 which is informally called the "shale embayment" (Theriault, 1988). The gamma-ray signature of the shale embayment is illustrated in Figure 2.4. The structure contour map of the shale embayment (Figure 4.38) shows that the top ranges in elevation from 50 m below sea level in the southwest and increases up-dip to slightly over 300 m. The regional strike is 150^0 and the dip is 0.3^0 to the southwest.

The isopach map of the shale embayment (Figure 4.39) shows that Leduc reefs appear to subdivide the shale embayment into two lobes. The shale embayment is thickest in the northwest part of the study area. The southern limit of the shale embayment is depositional and the northeastern edge is bounded by the sub-Cretaceous unconformity.

There are only 5 "caves" recognized in the LGM (Figure 4.40). One is isolated in Township 89, Range 23 W4M, one occurs within the erosional edge in Township 80, and three are located near the sinkhole in Township 89, Range 20 W4M. The sparse distribution of "caves" indicates that the karst is localized and is very weak as compared to the upper carbonate units (e.g., Nisku or UGM3).

Compared to the overlying three Grosmont reservoir units, the LGM has the lowest average porosity values. Over much of the study area, the porosity ranges between 8 and 12% (Figure 4.41). Locally, there are 'pockets' of less than 8% and greater than 16%. The porosity distribution in the LGM is a function of lithology (Hawlader and Machel, 1992). Most of the high porosity areas consist predominantly of dolostones, and the low porosity areas generally consist of limestones. The effects of karst-related dissolution is minimal because only 5 "caves" are recognized.

The LGM resource values of net pay (Figure 4.42), isoporosity (Figure 4.43), and HPV (Figure 4.44) all show the same overall trend. Most of the southern half of the study area is uneconomic because of low bitumen saturation. The low resource values north of Township 87 are caused by the shale embayment.

Fig. 4.36 LGM structure contour map (C.I. = 25 m).

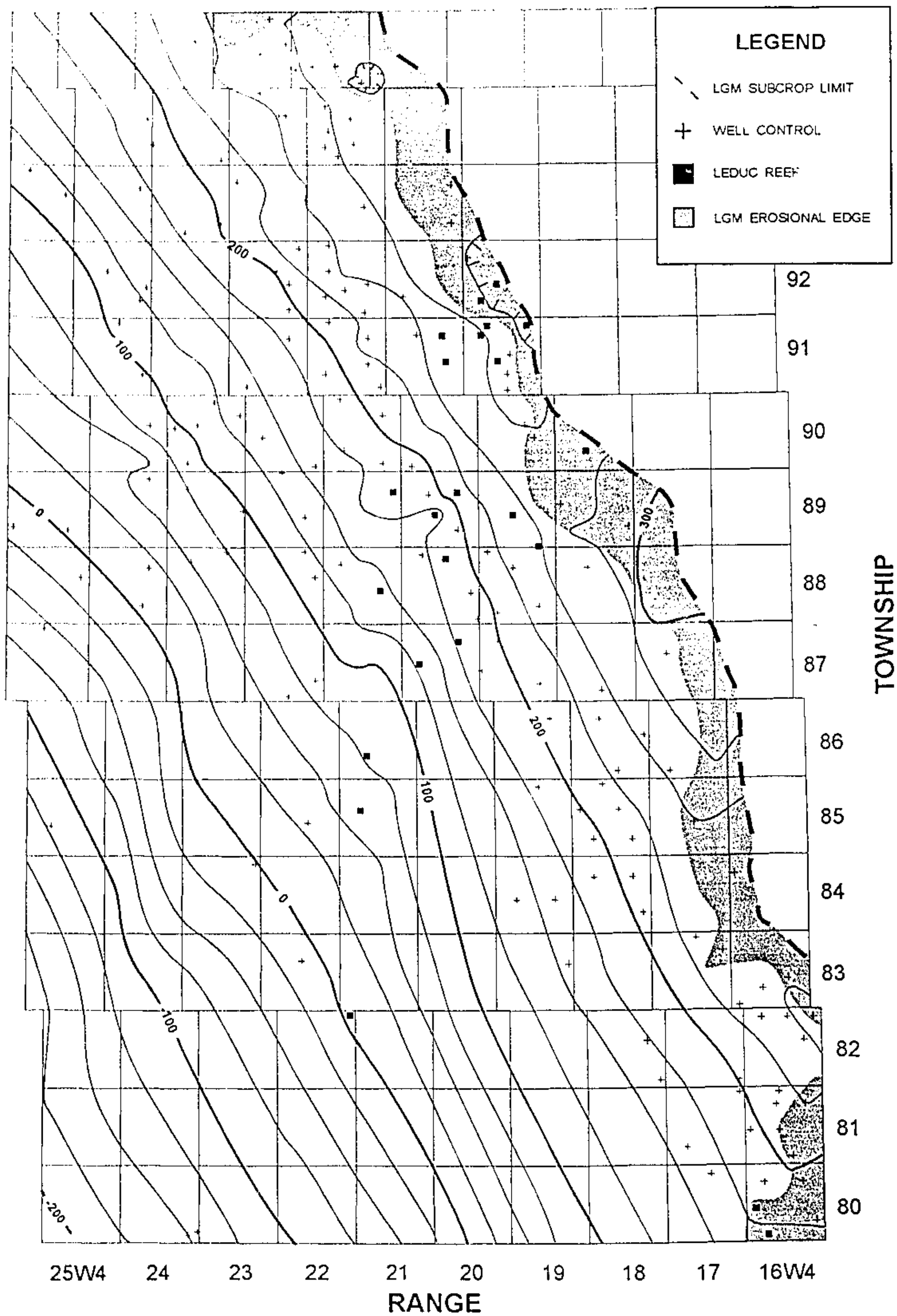


Fig. 4.37 LGM isopach map (C.I. = 10 m).

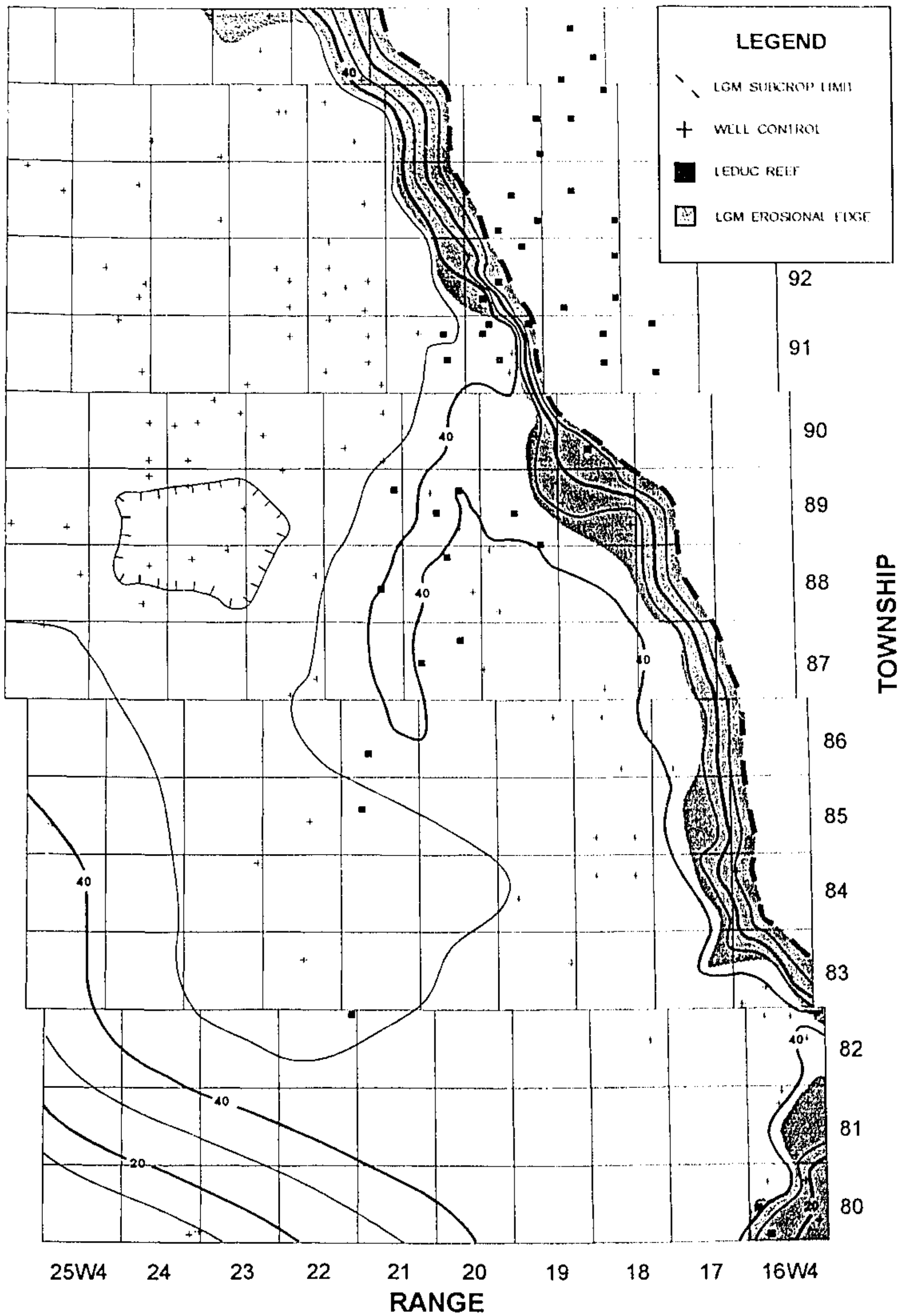


Fig. 4.38 Shale Embayment structure contour map (C.I. = 25 m).

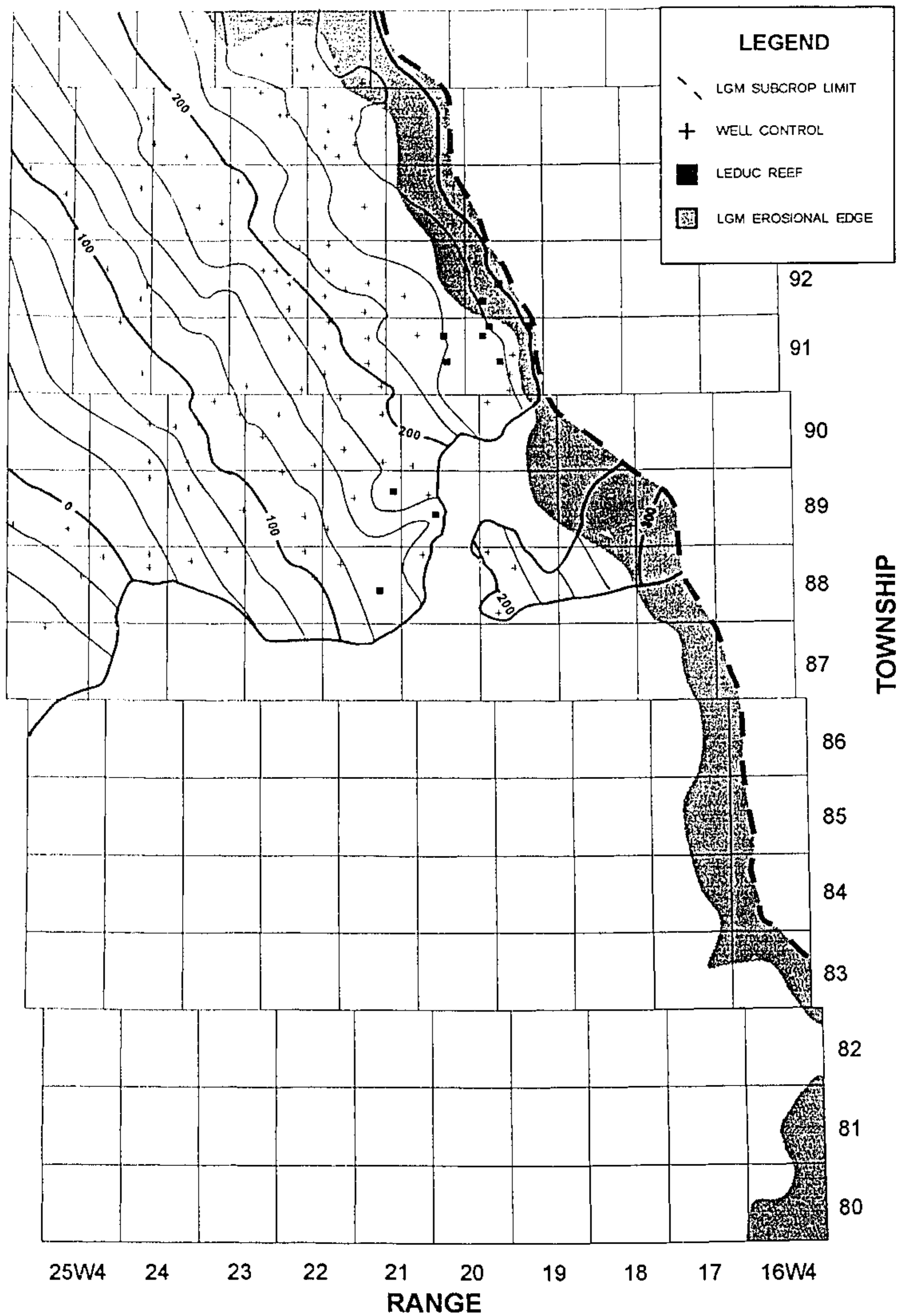


Fig. 4.39 Shale Embayment isopach map (C.I. = 10 m).

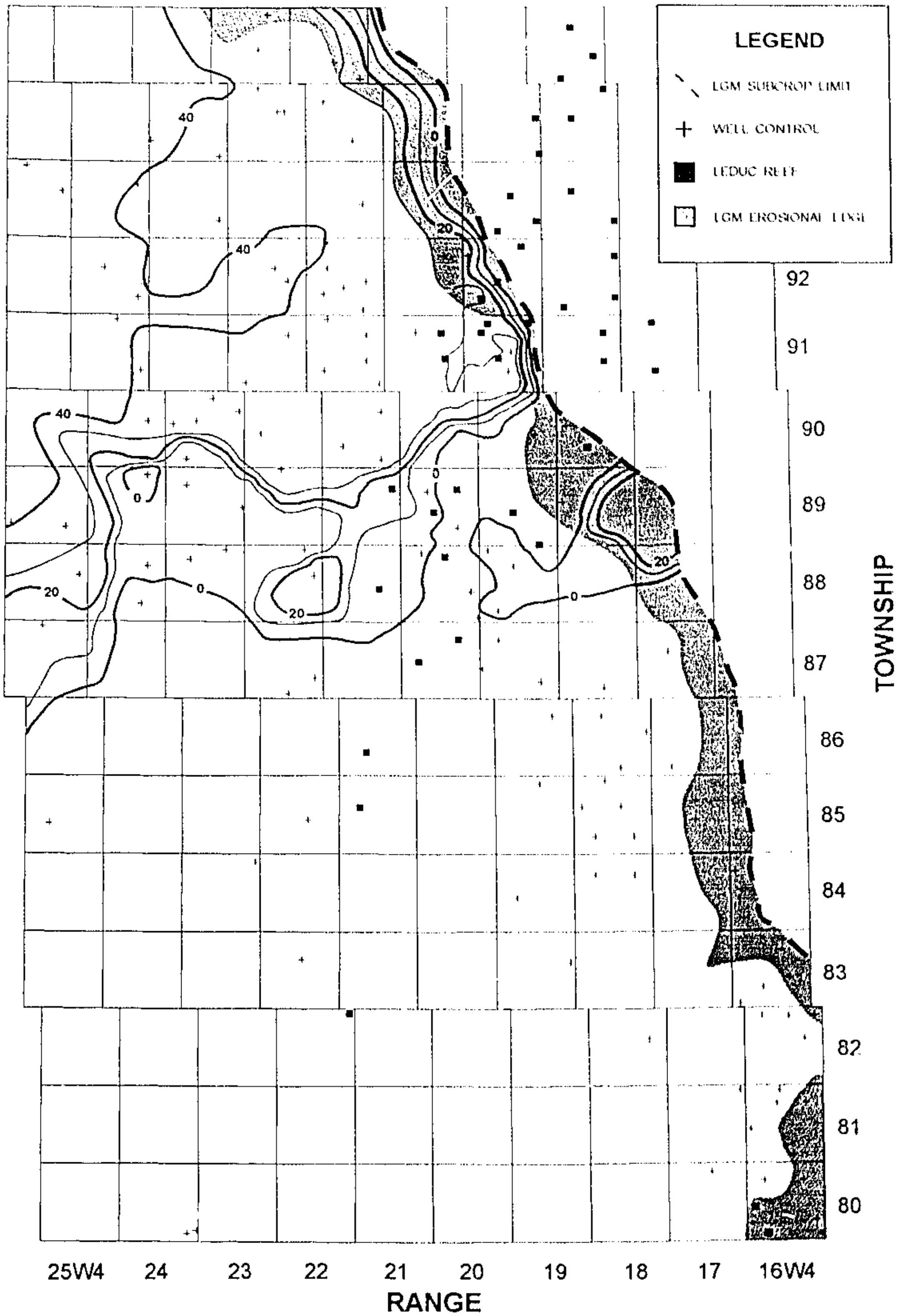


Fig. 4.40 Location of LGM "caves".

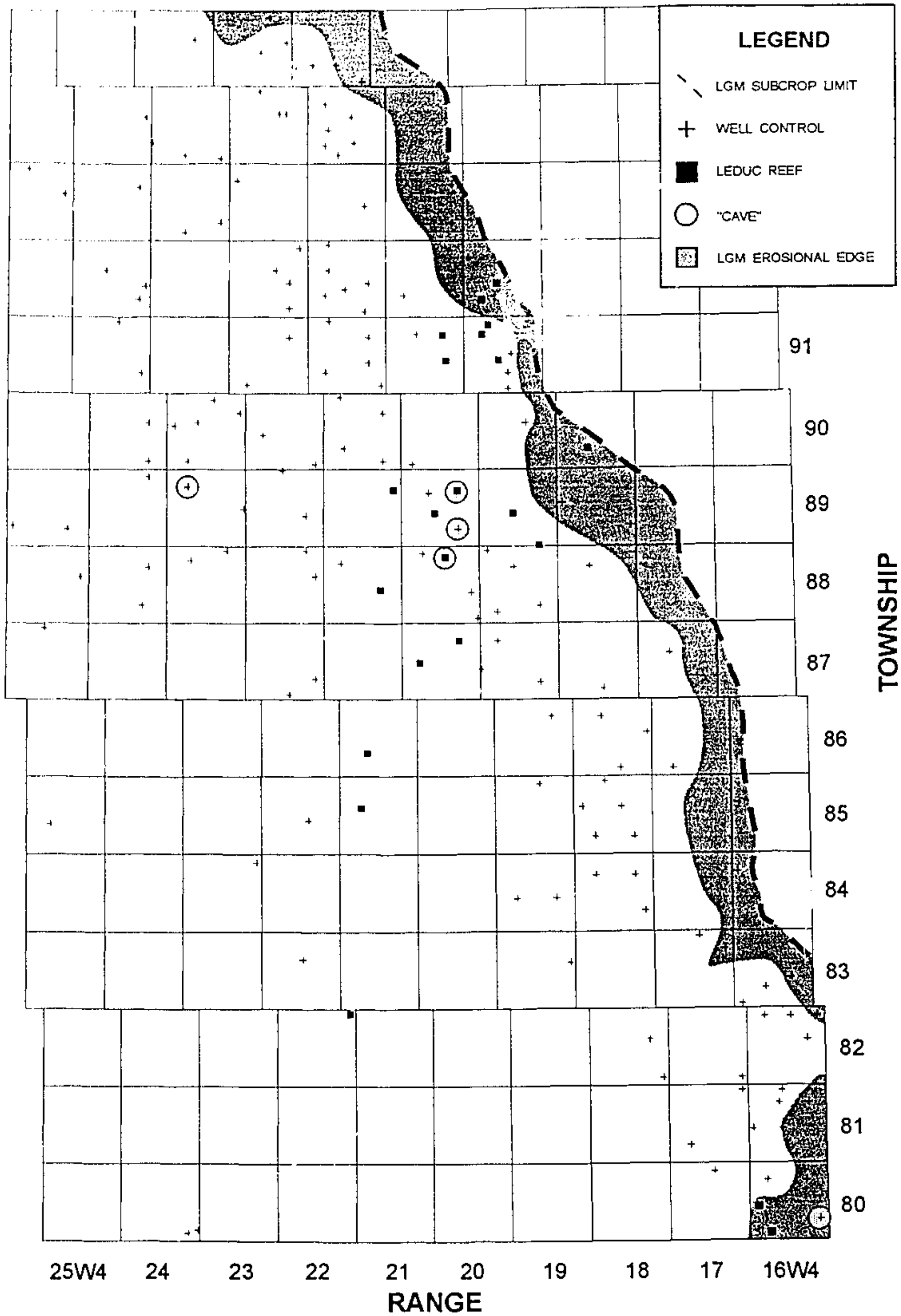


Fig. 4.41 LGM porosity map (C.I. = 4%).

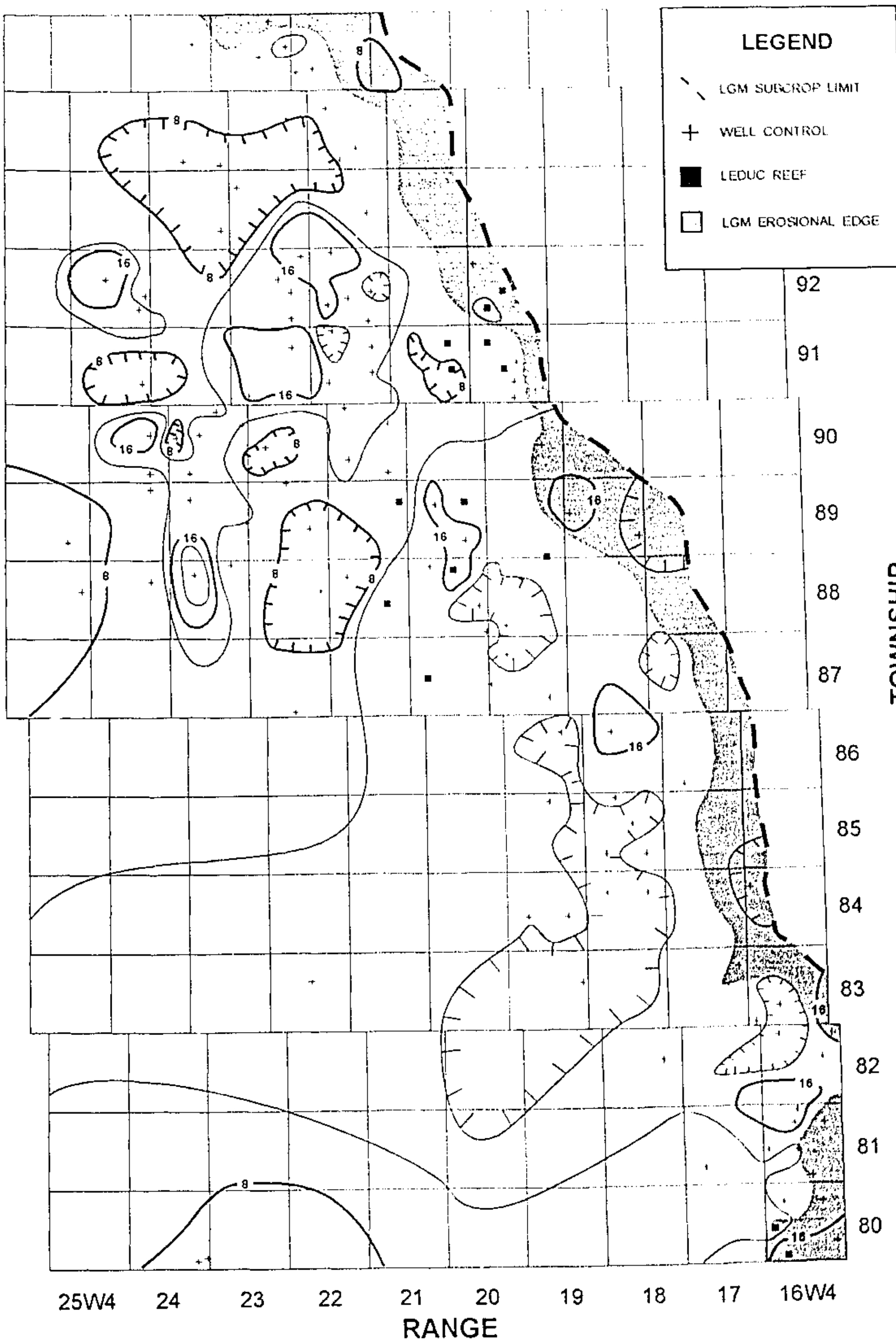


Fig. 4.42 LGM net pay map (C.I. = 10 m).

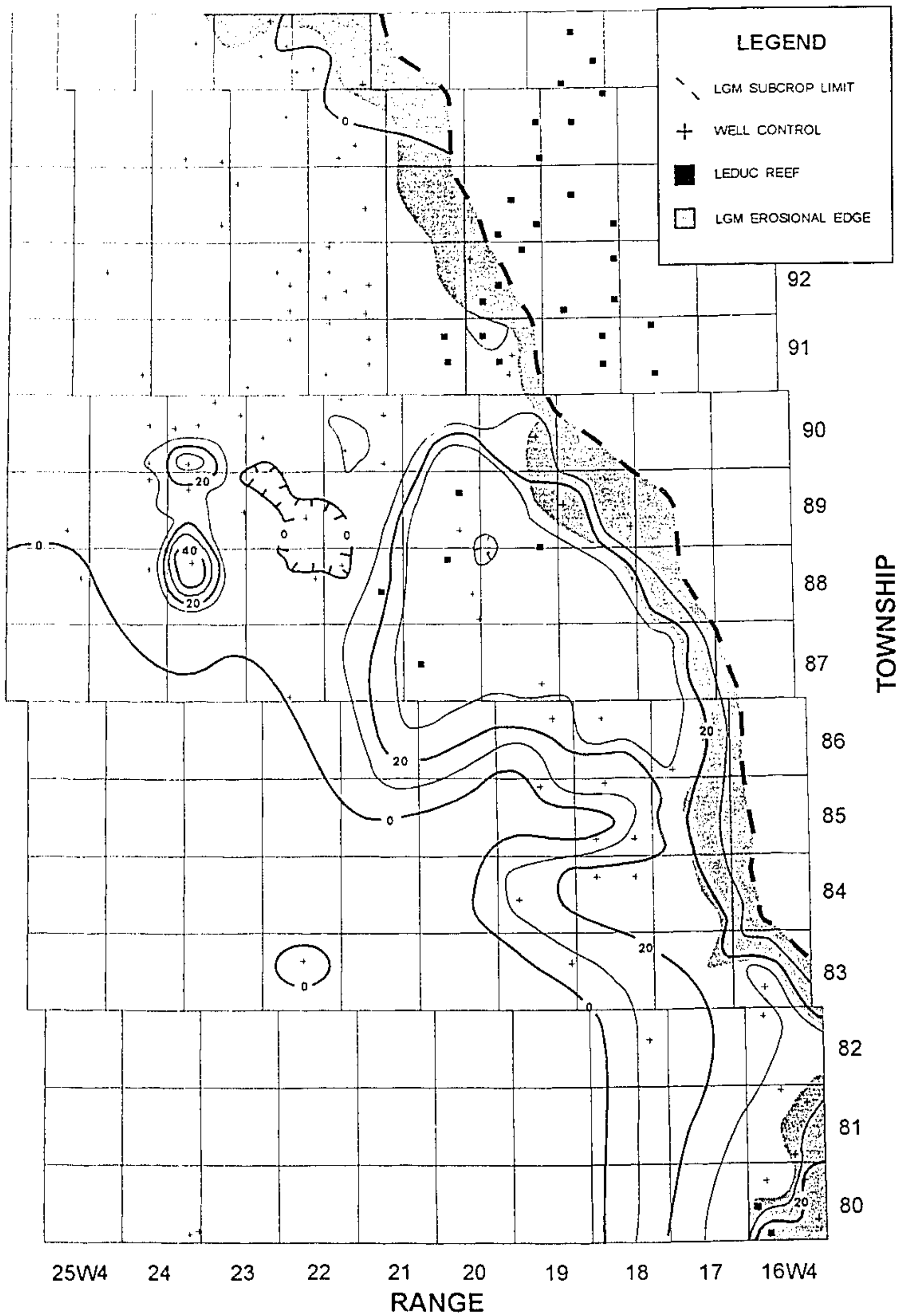


Fig. 4.43 LGM isoporosity map (C.I. = 2 m).

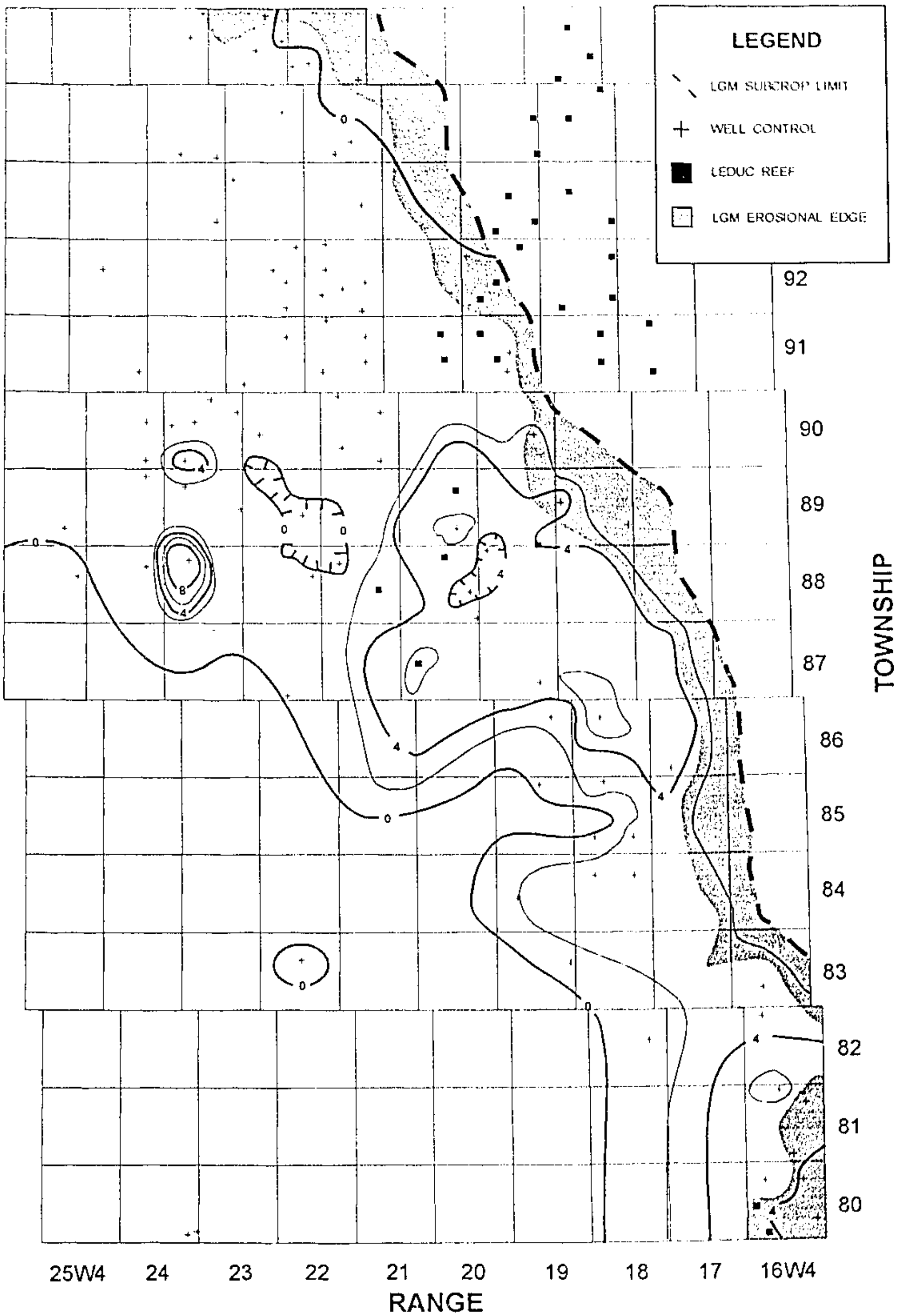
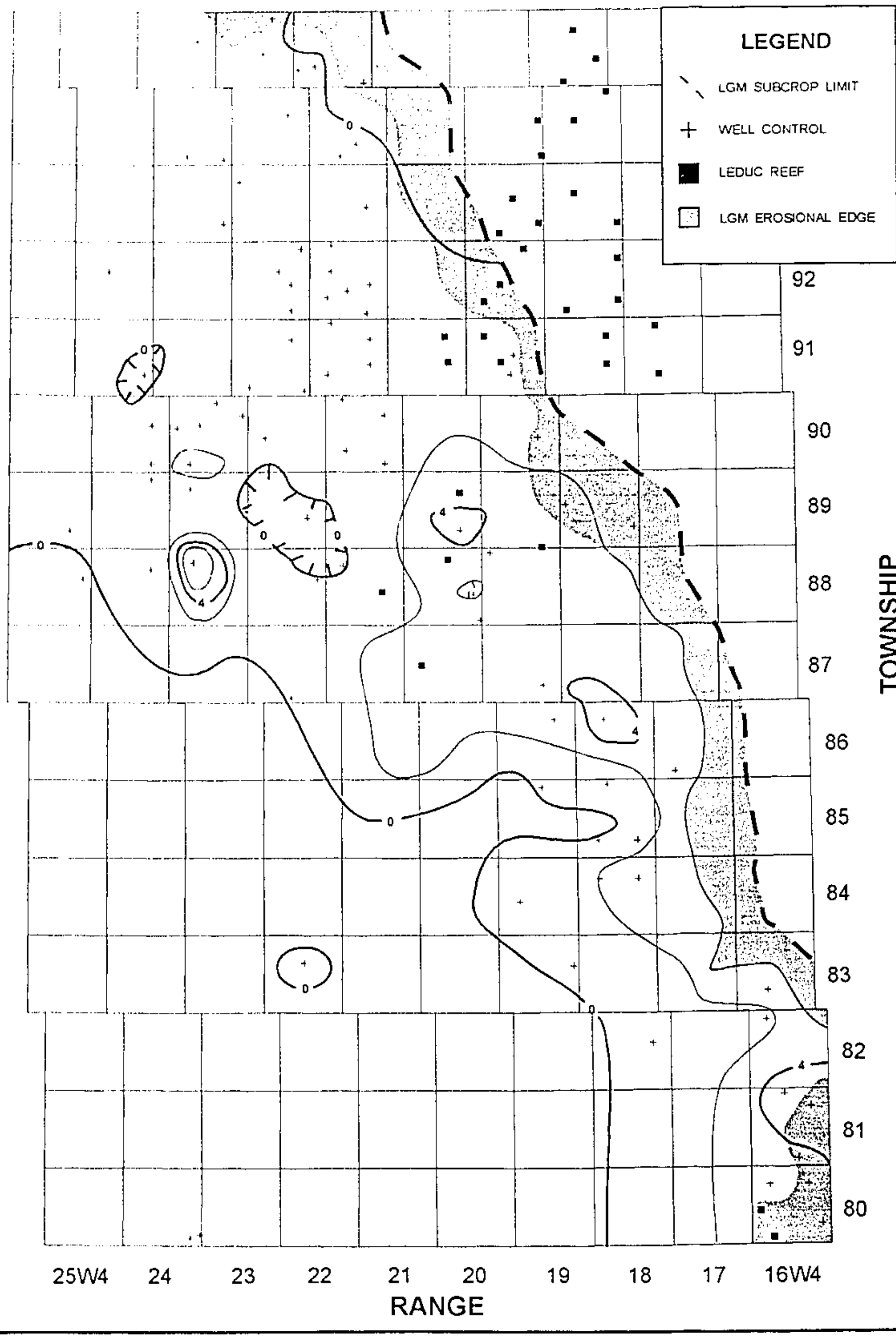


Fig. 4.44 LGM hydrocarbon pore volume map (C.I. = 2 m).

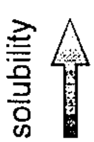


CHAPTER 5

POTENTIAL SEAL CHARACTERISTICS FROM WELL LOG DATA

In order to reduce the bitumen's viscosity and produce bitumen from the Devonian carbonates there must be an effective seal to contain the steam energy in the reservoir. Potential seals are shales or shaly lithologies. Their ability to act as seals during steam injection is dependent on (i) thickness, (ii) mineralogy, (iii) fractures, and (iv) pressure threshold capacity. Generally, thin parts of a shale or shaly unit tend to be breached more easily by natural or artificial fractures. Thus, the thicker a shale or shaly unit, the greater the likelihood that it will act as an effective permeability barrier during steam stimulation.

The mineralogy influences seal effectiveness since certain minerals are more soluble than others. For example, the solubility product (K_{sp}) at 150^{o}C of anhydrite, calcite, and dolomite is as follows (Kharaka et al. 1988):



MINERAL	Ksp
Anhydrite	10^{-6}
Calcite	10^{-10}
Dolomite	10^{-22}

The above list shows that anhydrite is comparatively much more soluble than calcite or dolomite. Therefore, during prolonged steam stimulation, anhydrite would be an extremely poor seal because it is easily dissolved. In a similar fashion, a dolomitic shale would be a better seal than a calcareous shale because the latter is more likely to become breached via dissolution of the calcite.

Fractures also play an important role in the effectiveness of a seal. If fractures are present, the seal is broken, and any steam injected into the reservoir would immediately leak into overlying strata unless there is a downward hydrodynamic gradient. As a result, there would be poor bitumen production due to a lack of communication between injection and recovery wells. Therefore, in order to achieve good production results the seal must not be fractured.

Lastly, the pressure threshold capacity of the seal also influences its overall effectiveness. Mercury injection capillary measurements (MICPM) of the potential seals (SB-1,2, and 3) reveal that they are tight up to an injection pressure of 1000 psi to 5000 psi (Luo et al., 1993). These injection pressures correspond to capillary measurements of approximately 280 - 1200 psi in an oil/water system. Thus, the potential Grosmont seals (SB-1,2, and 3) are strong enough to act as effective seals during steam injection unless they are fractured (Luo et al., 1993).

5.1 Potential Cretaceous Seals

There are only three Cretaceous clastic units directly overlying the Devonian strata in the study area: the McMurray Formation, Wabiskaw Member, and the Clearwater Formation. Due to their heterogeneous distribution and high silt-sand content, the McMurray Formation and Wabiskaw Member would not act as good seals for the thermal recovery of bitumen from the Devonian carbonates (Ranger, personal comm.). Only the Clearwater Formation could act as an excellent seal for the Devonian strata because it is a marine shale which is regionally extensive, very thick, and nearly carbonate-free.

5.1.1 Clearwater Formation

In the northwest corner of the study area, the Clearwater Formation directly overlies the eroded Devonian strata (Figure 5.1). In this area, the

Clearwater Formation could act as an effective seal for the thermal recovery of bitumen from the Nisku, Upper Ireton, UGM3, UGM2, UGM1, and LGM (Figure 5.2).

Fig. 5.1 Location of the Clearwater Formation directly overlying Devonian Strata.

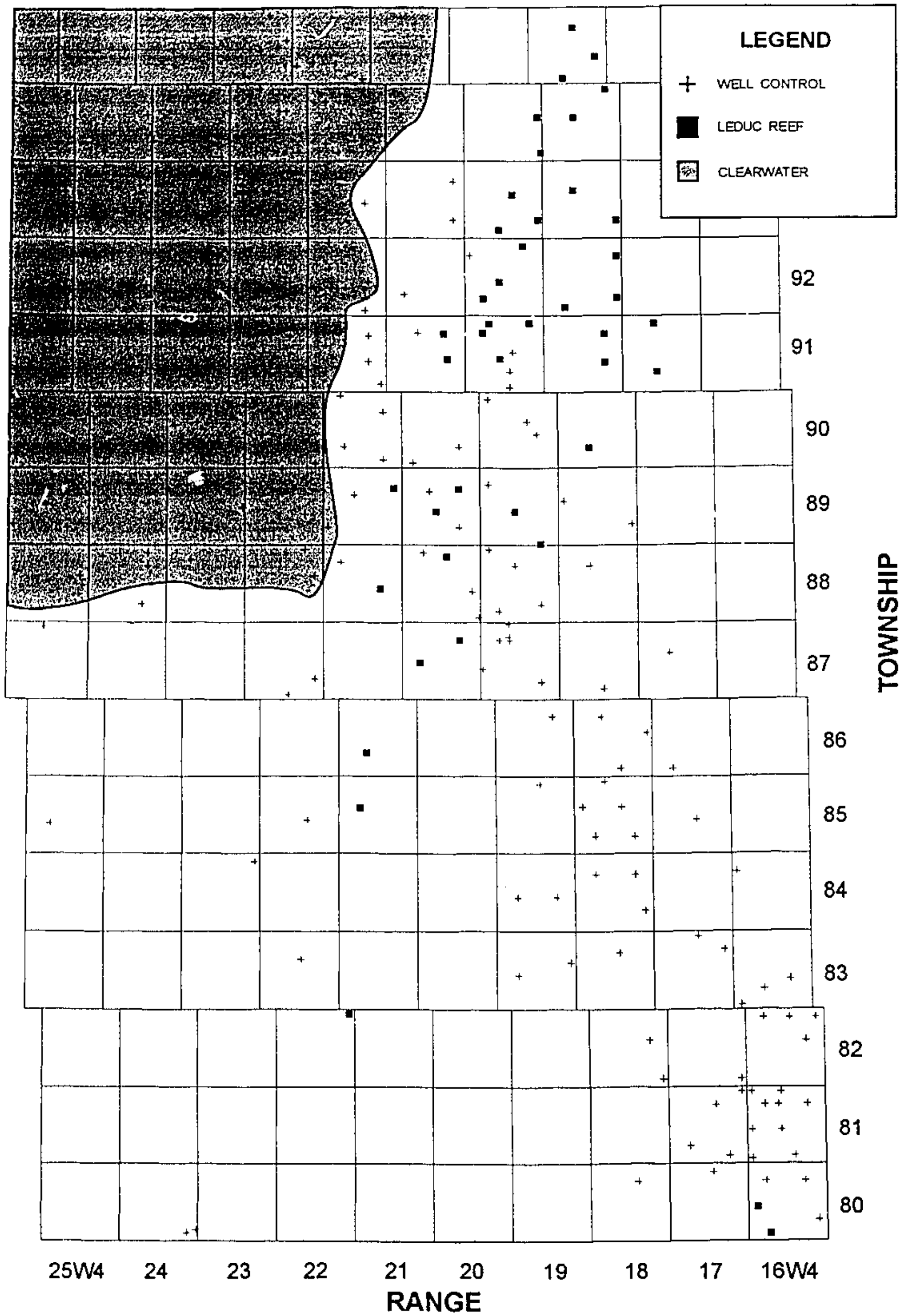
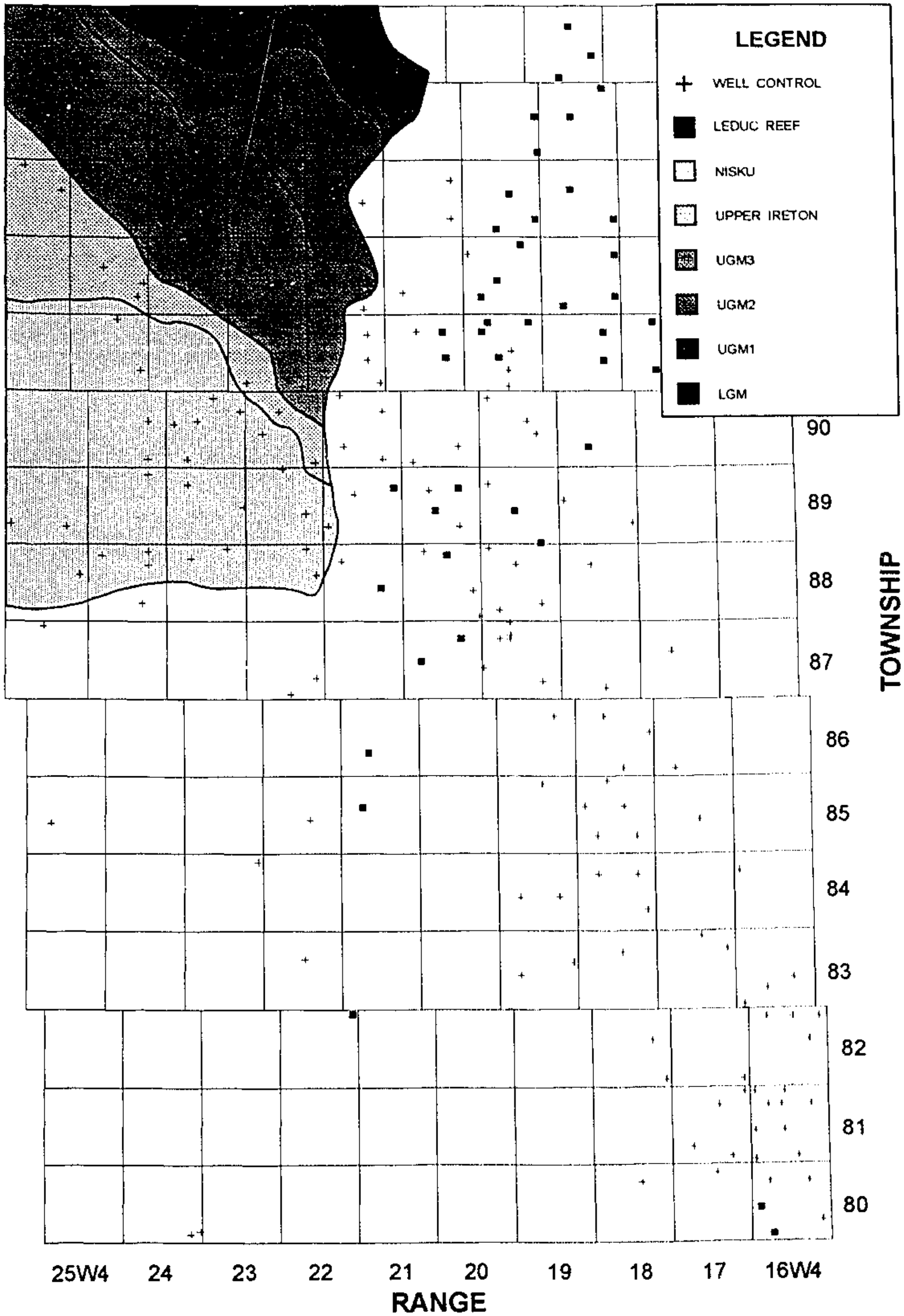


Fig. 5.2 Devonian strata capped by the Clearwater Formation.



5.2 Potential Devonian Seals

There are four potential seals in the Devonian carbonates: the Upper Ireton and the three Grosmont shale breaks (SB-1, 2, and 3). The elevation, thickness, and spatial distribution of the potential Devonian seals are illustrated below by structure contour and isopach maps. In addition, the spatial distribution of "breached" wells for each of the potential Devonian seals is illustrated in "breached" well location maps. A "breached" well is herein defined as a well where "caves" or other porous karst features are developed below a potential seal. Such karst features appear as bore hole washout zones in fairly clean carbonate sections (as discussed in Chapter 3). In "breached" wells, the seal appears to be breached by karst-related fractures. Therefore, the thermal recovery of bitumen from the reservoir underlying the "breached" seal is hindered because steam injected into the reservoir will be lost into overlying strata. The data base for the three shale breaks (SB-1, 2, and 3) is summarized in **Appendix 5**.

5.2.1 Upper Ireton

The Upper Ireton forms a regionally extensive shaly unit on top of the UGM3. However, due to its mixed clastic-carbonate lithology, the Upper Ireton has both seal and reservoir characteristics. The reservoir characteristics were examined previously in Chapter 4. Thus, the elevation, thickness, and location of Upper Ireton "caves" are illustrated in Figures 4.8, 4.9, and 4.10 respectively.

The ability of the Upper Ireton to act as a seal for the thermal recovery of bitumen from the UGM3 is impaired by its lithologic heterogeneity and karst features. South of Township 87, the Upper Ireton is dominated by a dolomitic shale that has potential as a possible seal. North of Township 87, the high carbonate content at the base of the Upper Ireton hinders its ability as a seal for the UGM3. Although the Upper Ireton has a regionally extensive shaly interval at its top, the numerous "caves" developed in the Upper Ireton (Figure 4.10) drastically reduce the effectiveness of the Upper Ireton as a seal north of Township 87.

5.2.2 Shale Break 3

Shale Break 3 (SB-3) is a green dolomitic shale at the base of the UGM3. Its gamma-ray signature consists of a sharp peak between 95 and 115 API units (Figure 2.4). During steam stimulation, SB-3 is expected to act as a top seal for the underlying UGM2 reservoir unit.

The structure contour map of SB-3 shows that its regional strike is 150^0 (Figure 5.3) with a gentle southwest dip of 0.3^0 (approximately 5.2 m/km). The elevation of the top of SB-3 is about 150 m below sea level in the southwest corner of the study area and increases to slightly over 300 m above sea level near the subcrop limit in Township 92. The UGM3 subcrop limit was obtained from Figure 4.16.

The isopach map of SB-3 (Figure 5.4) reveals that the thickness of SB-3 is relatively uniform throughout the study area. Generally, SB-3 ranges between 2 and 4 m in thickness, although several highs and lows are apparent. Most highs are located in the northern part of the study area. Most of the lows are near the subcrop limit south of Township 89, or they occur over the underlying Rimbey-Meadowbrook reef trend north of Township 85. In addition, SB-3 is completely removed by a sinkhole in Township 89, Range 20 W4M (Well 10-16-89-20 W4M).

Examination of well logs reveals that SB-3 has been "breached" in 22 wells. The majority of "breached" wells are concentrated in the UGM3 erosional edge between Townships 85 and 89 (Figure 5.5). It appears, therefore, that the absence of the Upper Ireton combined with a thin SB-3 in this area promoted the penetration of karst waters into the underlying UGM2.

The evaluation of SB-3 reveals that it is both an effective and ineffective seal. SB-3 appears to be an effective seal for the thermal recovery of bitumen from the UGM2 because it is regionally continuous, with the exception of the sinkhole in Township 89, Range 20 W4M. Furthermore, the carbonate content which consists exclusively of dolomite is relatively low (20 - 60%), so dissolution of SB-3 during prolonged steam injection should be relatively minor (Luo et al., 1992). However, SB-3 may be an ineffective seal where it is thin (< 2 m) or near "breached" wells. Where SB-3 is less than 2 m thick, the possibility of fractures (e.g., thief zones) is likely. Likewise, fractures in SB-3 are to be expected near "breached" wells. Therefore, thermal recovery techniques using SB-3 as a seal for UGM2 is recommended in all areas where there are no "breached" wells, and where the thickness of SB-3 is greater than 2 m.

In hindsight, the regional evaluation of SB-3 shows that the Buffalo Creek (14-05-88-19 W4M) and the McLean (13-28-87-19 W4M) pilot sites were situated in poor locations for two reasons. First, SB-3 is about 2 m (Figure 5.4), and therefore it is prone to fracturing. Second, there is a concentration of "breached" wells in the vicinity of the pilot sites (Figure 5.5). Thus, the combination of isopach and "breached" well location maps for SB-3 (Figures 5.4 and 5.5) helps to explain the production problems associated with the pilot sites.

Fig. 5.3 Shale Break 3 structure contour map (C.I. = 25 m).

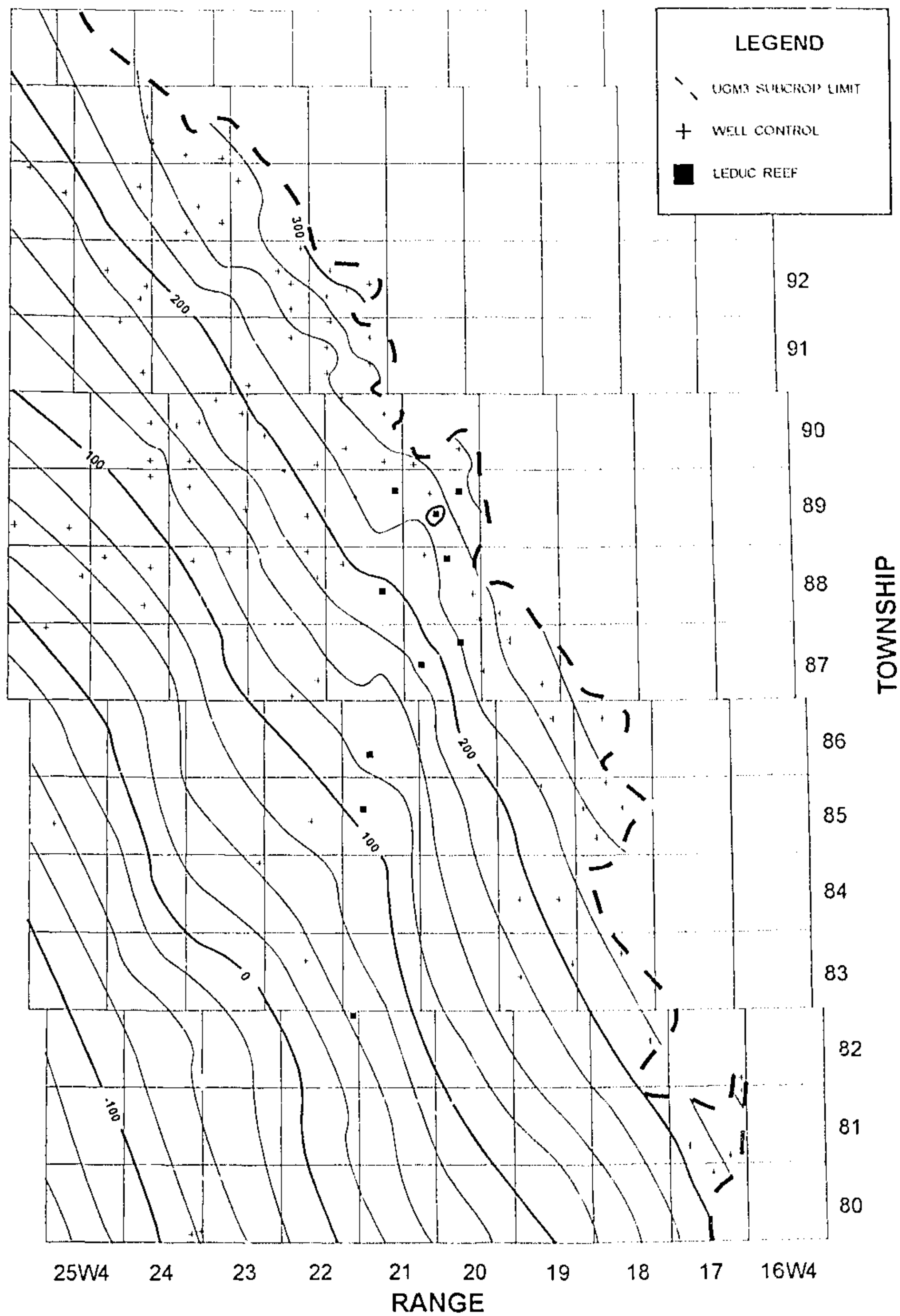


Fig. 5.4 Shale Break 3 isopach map (C.I. = 2 m).

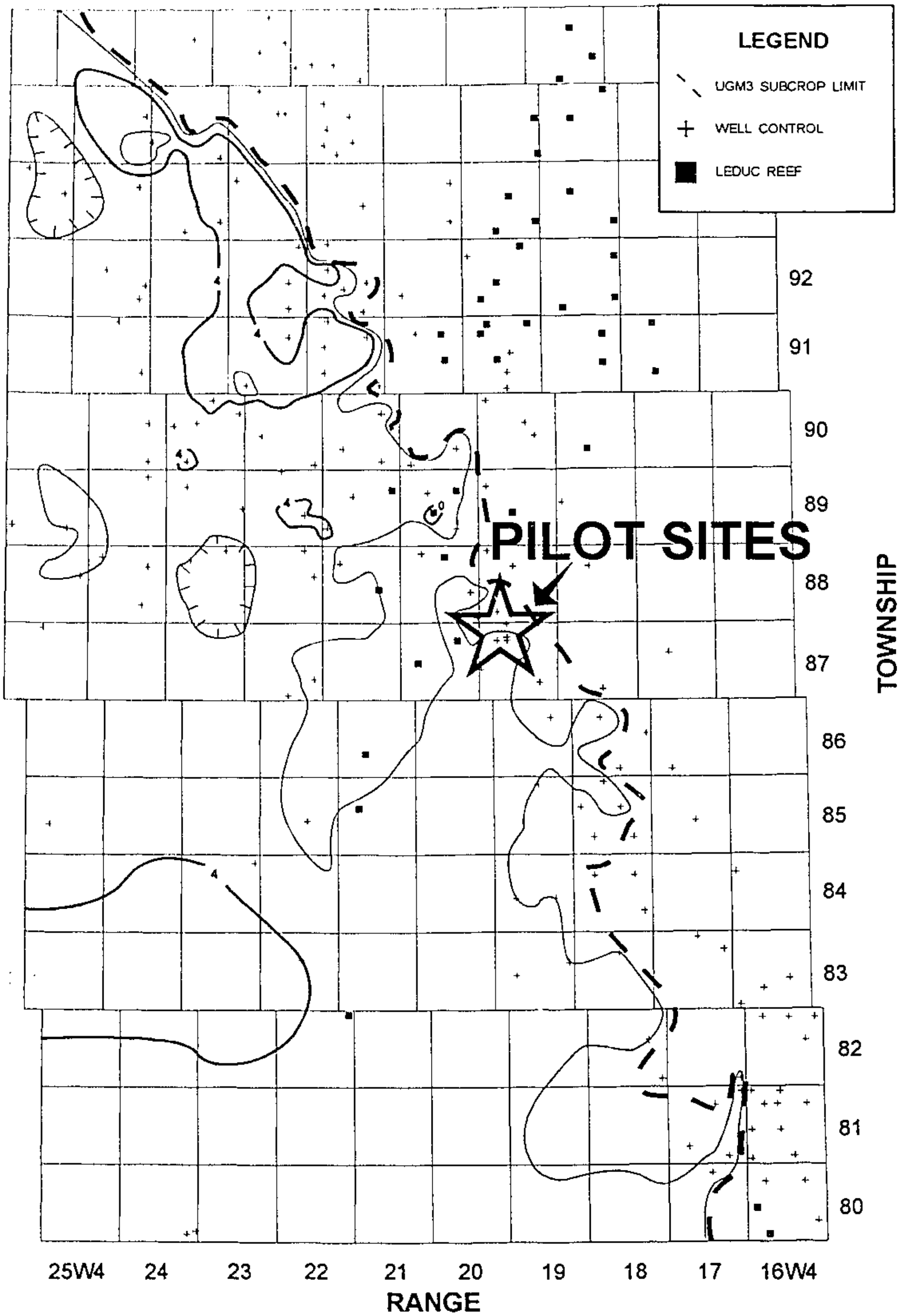
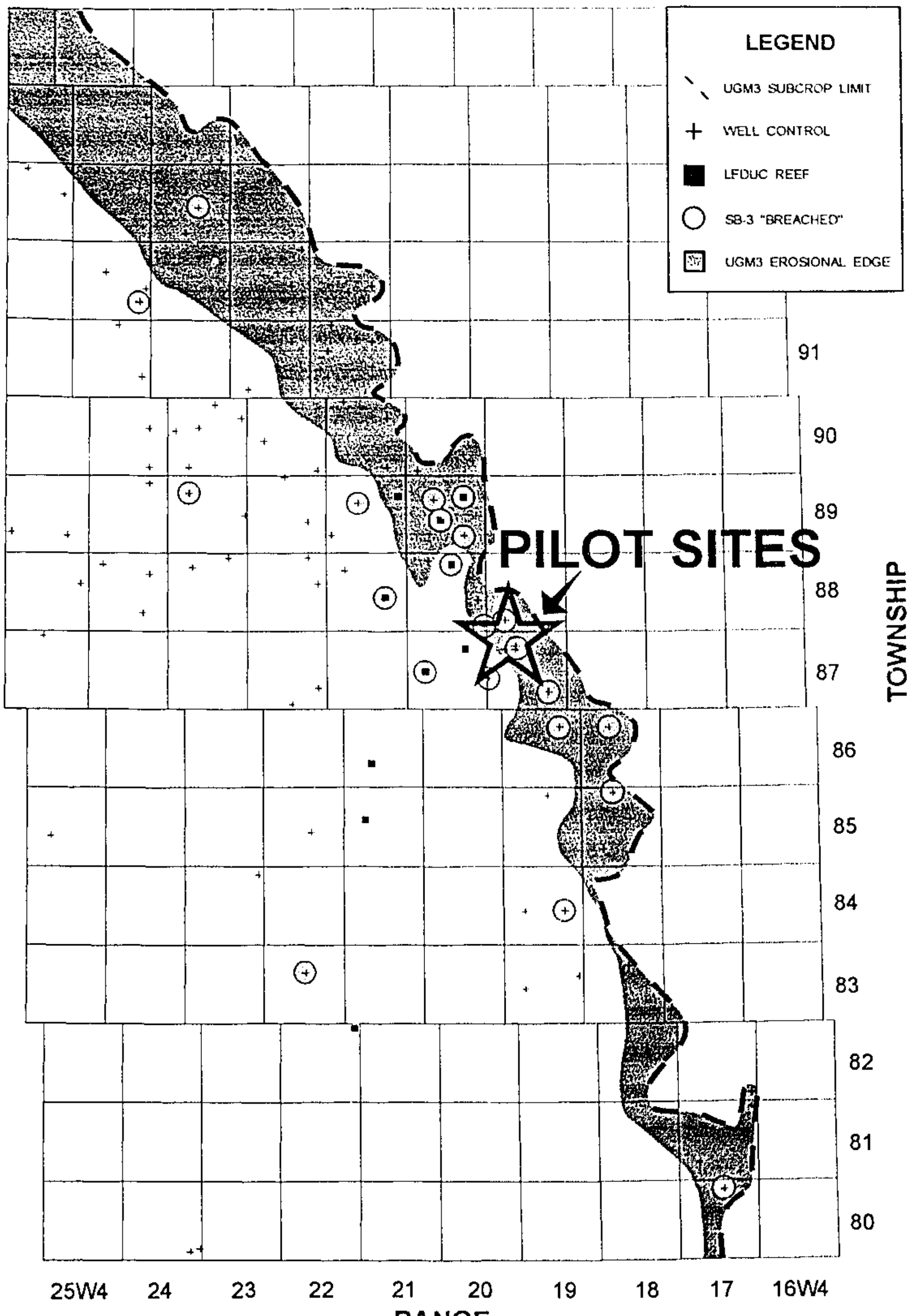


Fig. 5.5 Location of SB-3 "breached" wells.



5.2.3 Shale Break 2

Shale Break 2 (SB-2) is a green dolomitic shale at the base of the UGM2. SB-2 slowly grades upwards into clean carbonates of the UGM2. The gradual increase in carbonate content is reflected in the gamma-ray profile of SB-2 (Figure 2.4). During steam stimulation, SB-2 is expected to act as a seal for the underlying UGM1 reservoir unit.

SB-2 has a regional strike of 150^{0} with a gradual dip to the southwest of 0.3^{0} (approximately 5.2 m/km), as revealed by the structure contour map (Figure 5.6). The elevation of the top of SB-2 ranges from 175 m below sea level in the southwest corner of the study area to more than 300 m above sea level near the subcrop limit in Township 94. Locally, the contours are affected by underlying Leduc reefs (e.g., Township 89, Range 20 W4M). The UGM2 subcrop limit was obtained from Figure 4.23.

The isopach map of SB-2 (Figure 5.7) reveals that SB-2 is generally thickest north of Township 86 (> 8 m). Localized highs (greater than 12 m) are present in the northwest corner of the study area and in an isolated occurrence in well 10-3-86-18 W4M. A slight to significant thinning over Leduc reefs of the underlying Rimbey-Meadowbrook reef trend is recognizable north of Township 86. South of Township 86, SB-2 is relatively uniform and thins to 4 m in Township 80, Range 17 W4M. The thinning of SB-2 in a southerly direction may imply a northern source for the shaly material of SB-2.

SB-2 has been "breached" in 7 wells. The spatial distribution shows that the "breached" wells are concentrated around the sinkhole in Township 89, Range 20 W4M and randomly distributed in the UGM2 erosional edge (Figure 5.8). In addition, one isolated "breached" well is present in Township 89, Range 23 W4M. Thermal recovery from the UGM1 using SB-2 as a seal is not recommended near the "breached" wells.

The ability of SB-2 to act as a seal for the underlying UGM1 appears promising. The isopach map shows that SB-2 forms a continuous seal over the UGM1. However, during steam stimulation, loss of steam may arise under several circumstances. Firstly, where SB-2 is thin, i.e., where thicknesses are less than 3 - 4 m, as around wells 11-14-88-21 W4M, 11-12-91-24 W4M, and 10-22-92-22 W4M, SB-2 may be susceptible to fracturing. Secondly, the effectiveness of SB-2 is impaired by its relatively high carbonate content (65 - 90 % dolomite). During prolonged steam injection dissolution of the carbonate fraction may lead to breaching (Luo et al., 1992). Lastly, SB-2 is not effective near "breached" wells because of fractures.

Fig. 5.6 Shale Break 2 structure contour map (C.I. = 25 m).

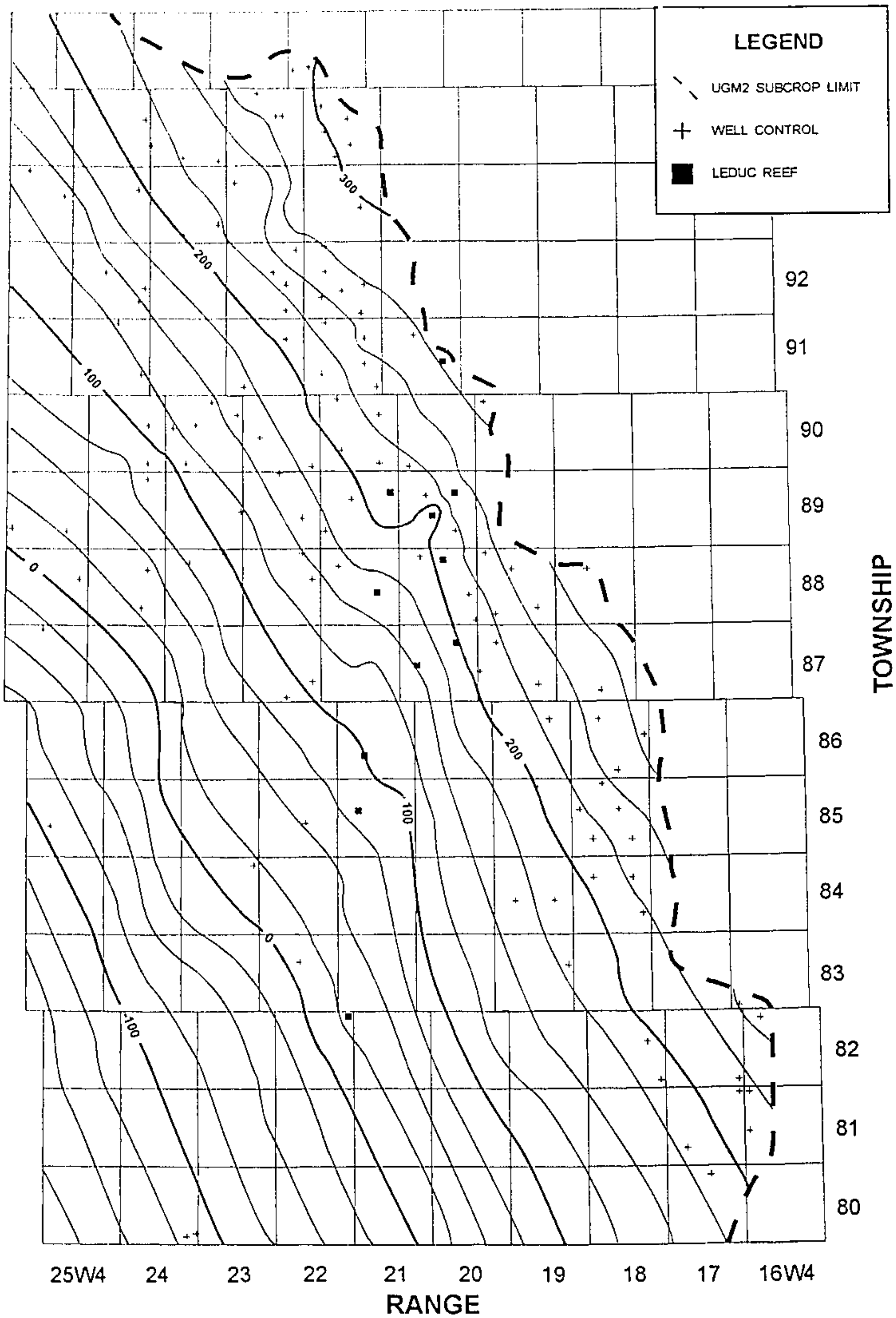


Fig. 5.7 Shale Break 2 isopach map (C.I. = 2 m).

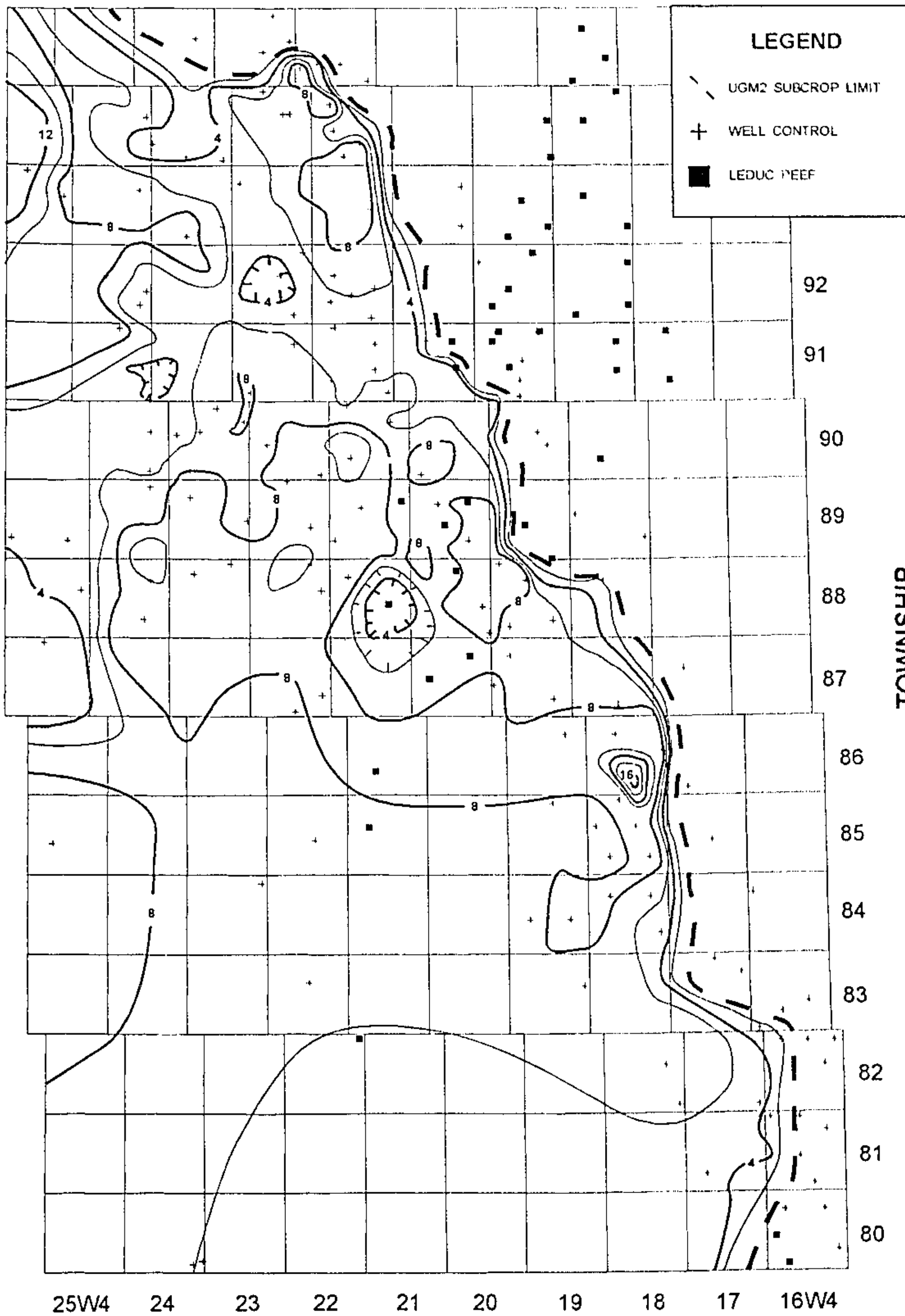
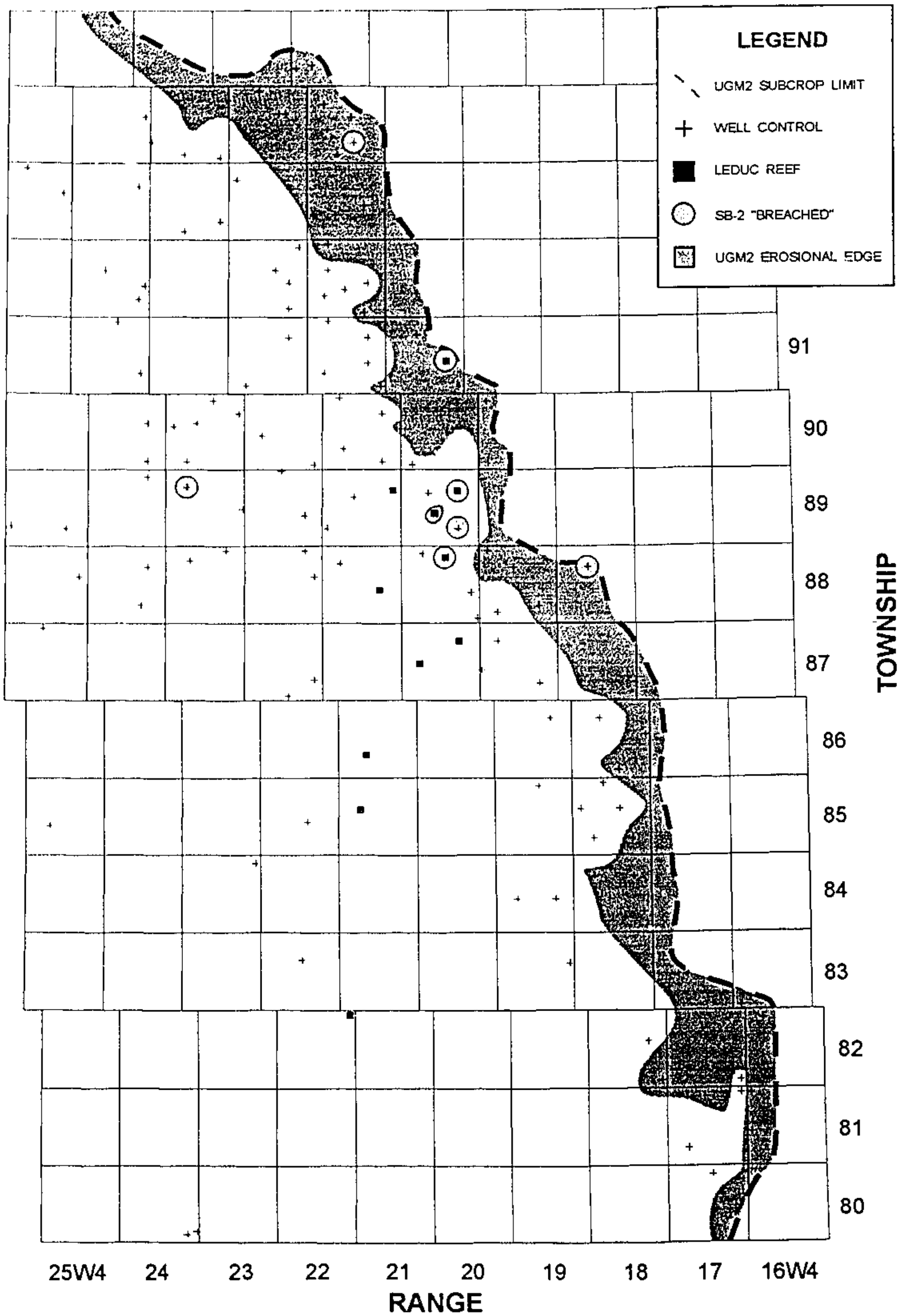


Fig. 5.8 Location of SB-2 "breached" wells.



5.2.4 Shale Break 1

Shale Break 1 (SB-1) is a green calcareous or dolomitic shale at the base of the UGM1. It has a distinctive two-step gamma-ray signature (Figure 2.4). During steam stimulation, SB-1 is could act as a seal for the underlying LGM reservoir unit.

The structure contour map of SB-1 (Figure 5.9) shows that this unit has a regional strike of 150^0 and dips to the southwest at 0.3^0 (approximately 5.2 m/km). The elevation of the top of SB-1 is about 200 m below sea level in the southwest corner of the study area and increases to approximately 300 m above sea level in Township 94. Locally, the contours deviate from the regional trend over Leduc reefs north of Township 88. The UGM1 subcrop limit was obtained from Figure 4.30.

The isopach map of SB-1 (Figure 5.10) shows that SB-1 is thickest near its subcrop limit (6 - 8 m). Locally, there is a noticeable thinning (< 8 m) over Leduc reefs north of Township 87. SB-1 generally thins to less than 3 m towards the southwest which suggests a northeasterly source of the clastic sedimentary material of SB-1. However, the thickness of SB-1 increases in the southwestern most corner of the study area which may imply a different source of clastic material in that region.

SB-1 has been "breached" in only 4 wells (Figure 5.11). Three of the "breached" wells are next to the sinkhole in Township 89, Range 20 W4M and the other one is isolated in Township 89, Range 23 W4M. Thermal recovery techniques using SB-1 as a seal for the LGM are not recommended around these wells because of the likelihood of thief zones.

SB-1 appears to be an excellent seal for the thermal recovery of bitumen from the underlying LGM. The isopach map shows that SB-1 forms a continuous seal over the LGM and there are only a few localized occurrences of "breached" wells. However, the high carbonate content of SB-1 (up to 60%) may result in partial dissolution (e.g., thief zones) during prolonged steam injection (Luo et al., 1992).

Fig. 5.9 Shale Break 1 structure contour map (C.I. = 25 m).

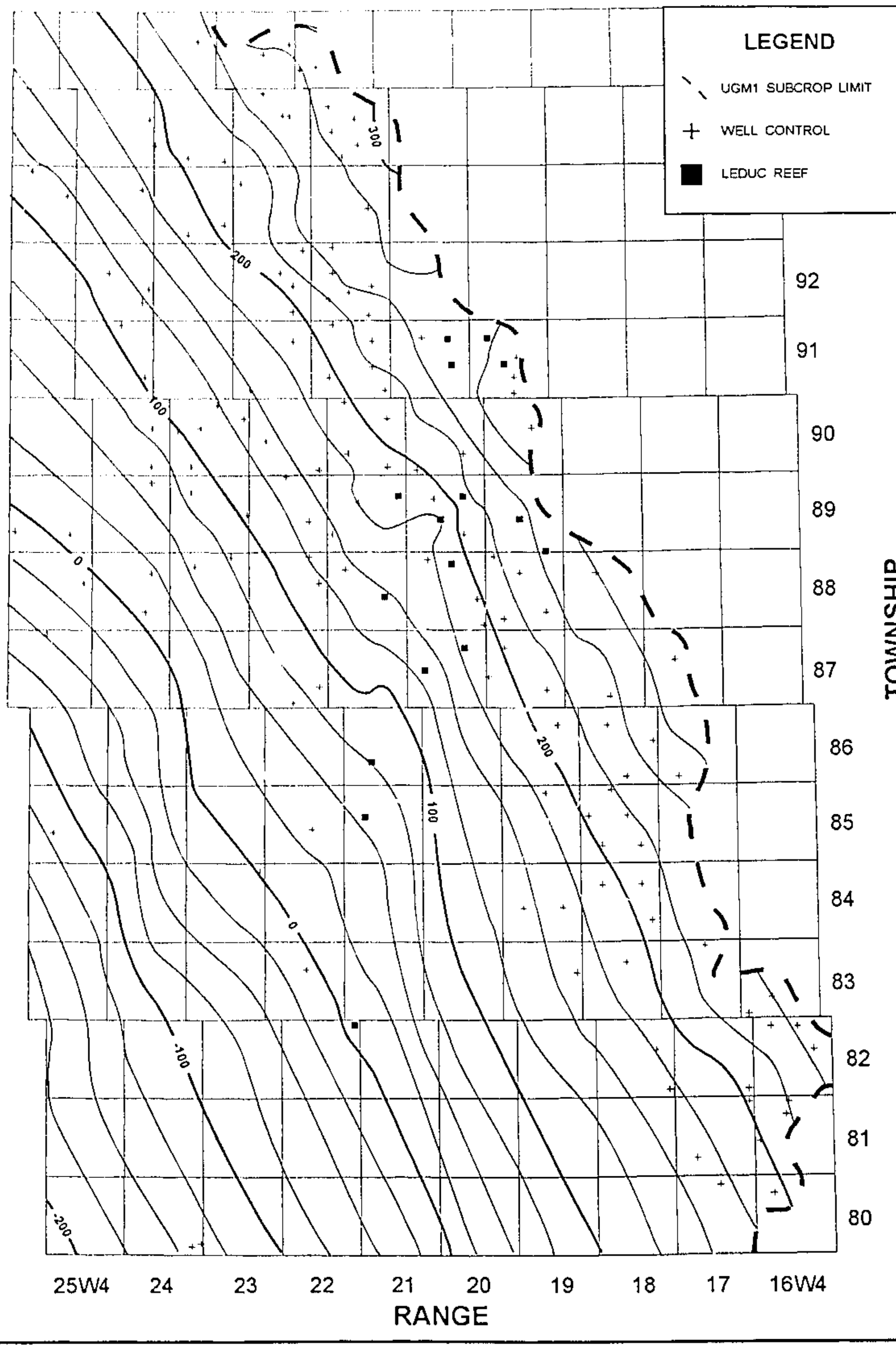


Fig. 5.10 Shale Break 1 isopach map (C.I. = 2 m).

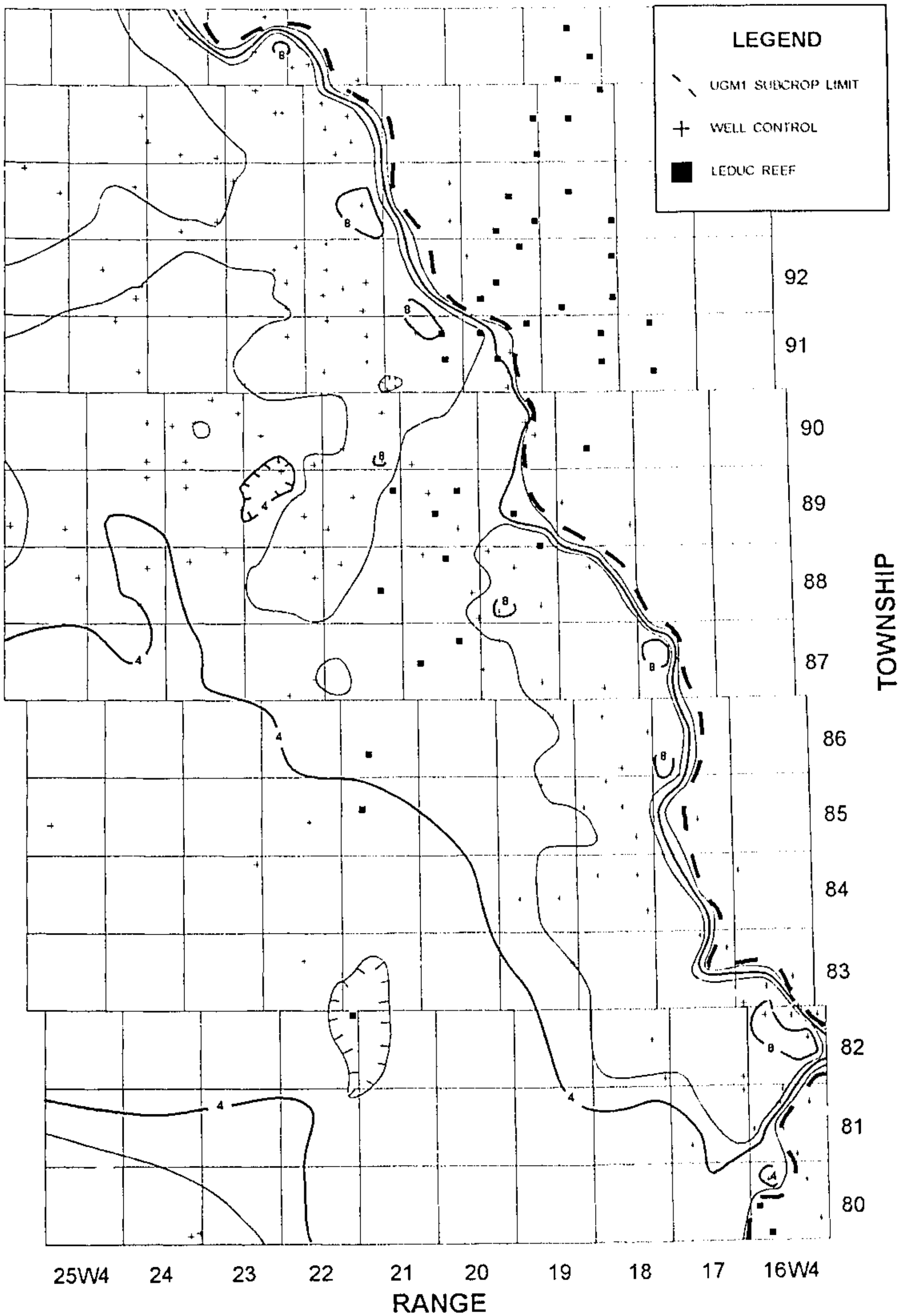
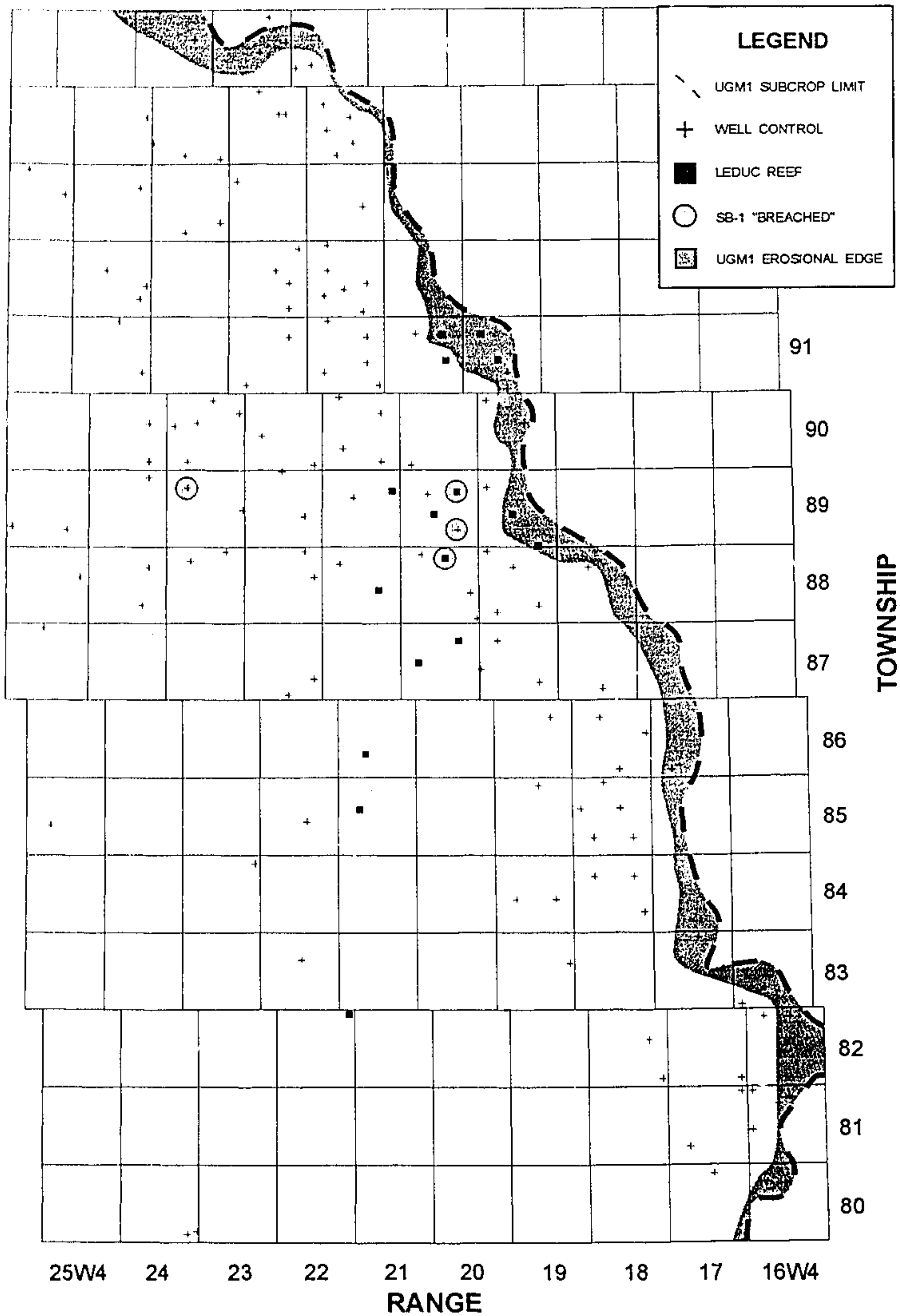


Fig. 5.11 Location of SB-1 "breached" wells.



CHAPTER 6

CORRELATION OF STRATIGRAPHIC AND PETROPHYSICAL PROPERTIES

Five cross sections were constructed to illustrate the regional porosity, "cave" location, and bitumen distribution with respect to depth. The wells chosen for the cross sections were based upon the quality of log suites available and the depths to which they were drilled. The location of the cross sections is illustrated in Figure 6.1. Sections A-A', B-B', and C-C' represent southwest-northeast dip sections of the Grosmont Formation. For cross section C-C', well 10-36-82-22 W4M was projected onto the section line for additional well control. Section D-D' is a northwest-southeast strike section of the Grosmont Formation. Section E-E' is a north-south strike section along the northern extension of the Rimbey-Meadowbrook reef trend.

The datum used in all sections is the base of the UGM1 (SB-1). This datum was chosen because it is regionally continuous, easily recognizable on well logs, and it appears to be a horizontal datum because the underlying LGM generally has a uniform thickness. In those places where the datum was not penetrated, SB-3 was used as a datum. Where SB-3 was removed by erosion, the unconformity surface or the top of the Beaverhill Lake Group was used to estimate the well's vertical position.

In all cross sections, the ratio of the vertical and horizontal scales are the same in order to maintain consistency between the cross sections. A vertical exaggeration of approximately 140X was used. For each of the cross sections, the scale of the gamma-ray log increases from 0 to 150 API units and is represented by a solid line. On the porosity cross sections, the neutron and density porosity logs range in scale from 45 to -15 porosity units. The neutron and density curves are illustrated by dashed and solid lines, respectively. On the "cave" cross sections, the scale of the caliper log ranges from 125 to 375 mm and it is represented by a solid line. Excursions of the caliper log in clean carbonate sections are shaded in red and estimated dimensions of the "cave" are highlighted in orange. For bitumen saturation cross sections, the resistivity log is represented by a solid line and the scale increases logarithmically from 0.1 to 2000 ohms·metre.

The abbreviated symbols used in the cross sections are as follows:

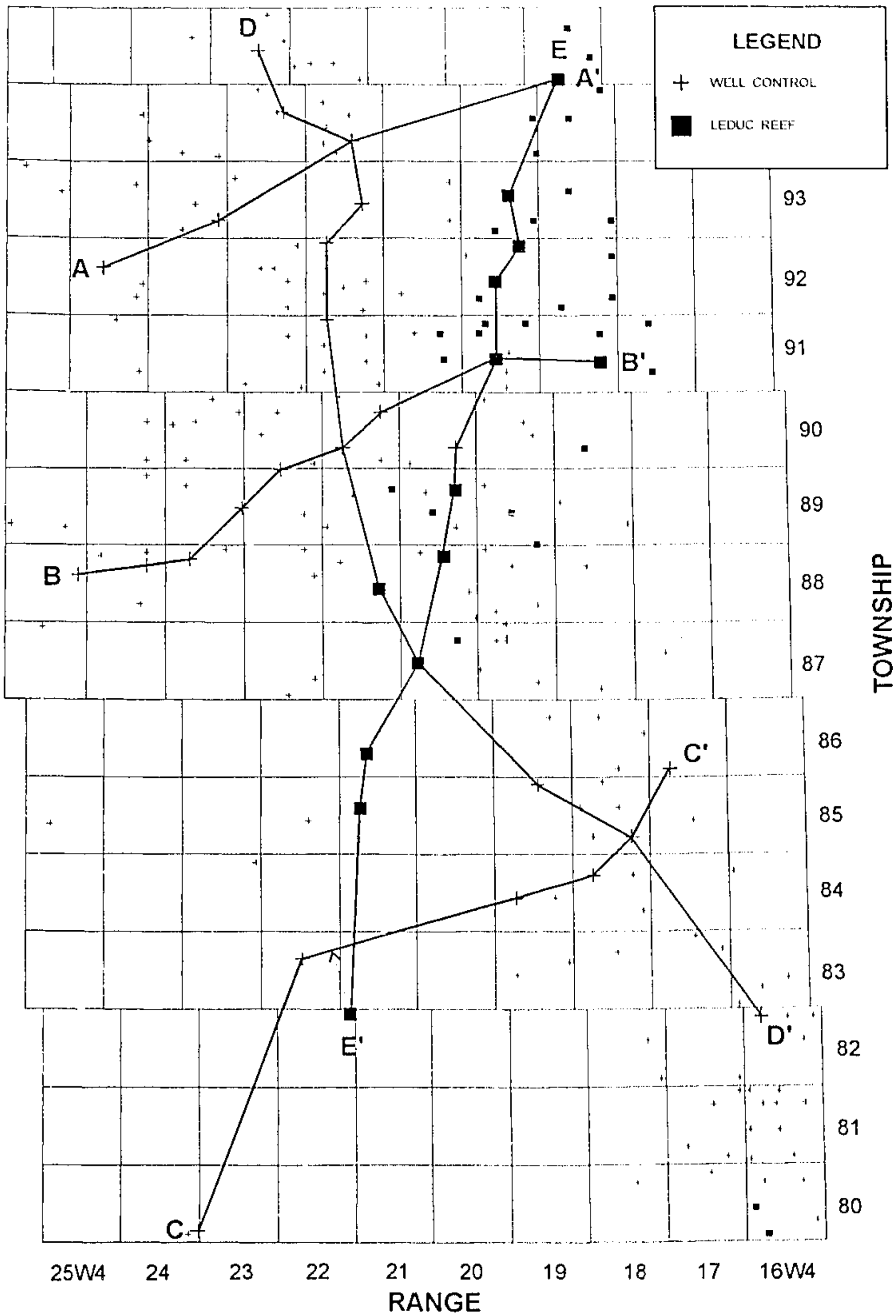
Stratigraphic Abbreviations

CLRWTR	Clearwater Formation
WAB	Wabiskaw Member
McM	McMurray Formation
U/C	Sub-Cretaceous unconformity
BLRDG	Blueridge Member
CALMAR	Calmar Formation
NISKU	Nisku Formation
UPPER IRETON	Upper Ireton
UGM3	Upper Grosmont 3
UGM2	Upper Grosmont 2
UGM1	Upper Grosmont 1
LGM	Lower Grosmont
LOWER IRETON	Lower Ireton
LEDUC	Leduc Formation
COOKING LAKE	Cooking Lake Formation
BVRHLL LAKE	Beaverhill Lake Group

Petrophysical Abbreviations

GR	Gamma-Ray
N-D	Neutron-Density
CAL	Caliper
RES	Resistivity

Fig. 6.1 Location of cross sections.



6.1 A-A' Dip Cross Section

The stratigraphy along section A-A' ranges from the Devonian Leduc Formation to the Cretaceous Clearwater Formation. On the eastern side of the cross section, the Leduc reef is intercepted by the sub-Cretaceous unconformity and Cretaceous clastics of the McMurray Formation are in contact with the Leduc reef (Figures 6.2, 6.3, and 6.4). Towards the southwest, the Leduc reef interfingers with Lower Ireton shales. The Lower Ireton also underlies the Grosmont Formation. Within the Grosmont Formation, the LGM is dominated by the shale embayment. All Grosmont units have a uniform thickness except where they are eroded. The amount of erosion increases to the northeast and the McMurray Formation and Wabiskaw Member pinch out on the northeastern flank of the exposed Grosmont strata. The Upper Ireton present towards the southwest in well 10-21-92-24 W4M. Most of the Devonian strata is covered by deep water marine shales of the Clearwater Formation which would act as an excellent seal during steam stimulation (refer to Chapter 5).

The porosity distribution along A-A' (Figure 6.2) shows that the porosity values are highest near the sub-Cretaceous unconformity and they decrease with depth. In the Grosmont Formation, the porosity in the LGM is comparatively lower than in the other Grosmont units. This is probably related to its limestone-dominated lithology as reflected by the neutron-density response. The remaining Grosmont units (UGM1, UGM2, and UGM3) and the Upper Ireton are dominated by dolomite, as seen by the separation of the neutron-density curves. The dolomitized units also have higher porosity values as compared to the limestone-dominated LGM. Locally, the porosity exceeds the regional values in "caves" in wells 10-21-92-24 W4M and 10-10-94-21 W4M. It appears, therefore, that the distribution of porosity in section A-A' is controlled primarily by its lithology and locally by karst-related dissolution.

There are two "caves" in section A-A' (Figure 6.3). One "cave" occurs in well 10-21-94-21 W4M in the Upper Ireton and UGM3. The other "cave", in well 10-10-94-21 W4M, is present in the UGM2 and UGM1, and SB-2 has been breached in this well. The spatial distribution of the "caves" reveals that they occur in the Grosmont High near the sub-Cretaceous unconformity (Figure 6.3).

The bitumen saturation in the northern part of the study area is quite high (Figure 6.4). In most places the bitumen saturation is greater than 60% and increases to more than 80% near the sub-Cretaceous unconformity. The low bitumen saturation in the thin carbonate unit below the shale embayment is caused by the low porosity in this interval. In the Leduc reef, the lower bitumen saturation (60-80%) situated above the higher bitumen saturation (80-100%) reflects the presence of gas. Generally, the highest bitumen saturations parallel the sub-Cretaceous unconformity and they decrease roughly perpendicular to the unconformity surface.

Fig. 6.2 Porosity distribution (%) across section A-A'.

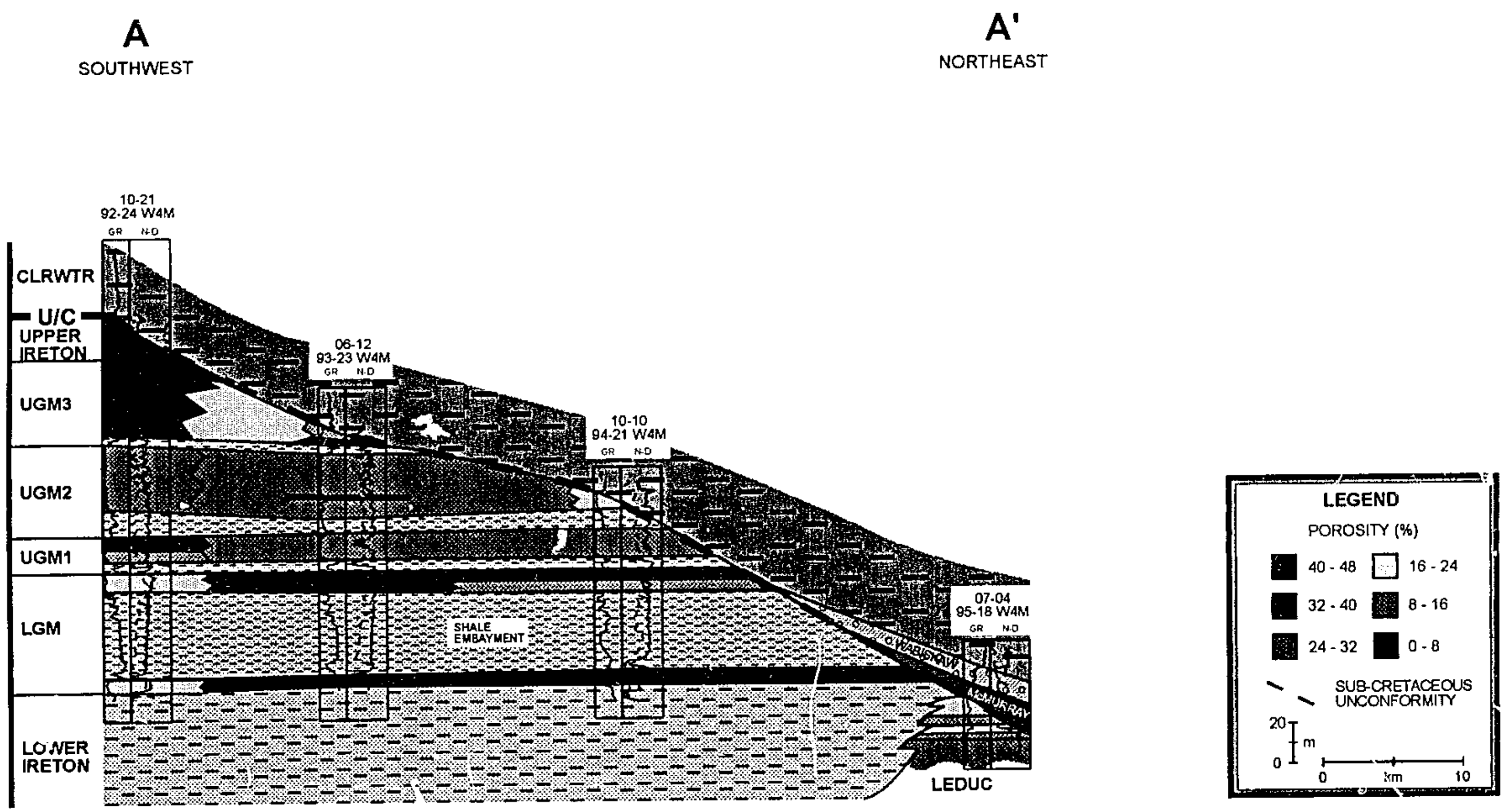


Fig. 6.3 Location of "caves" on section A-A'.

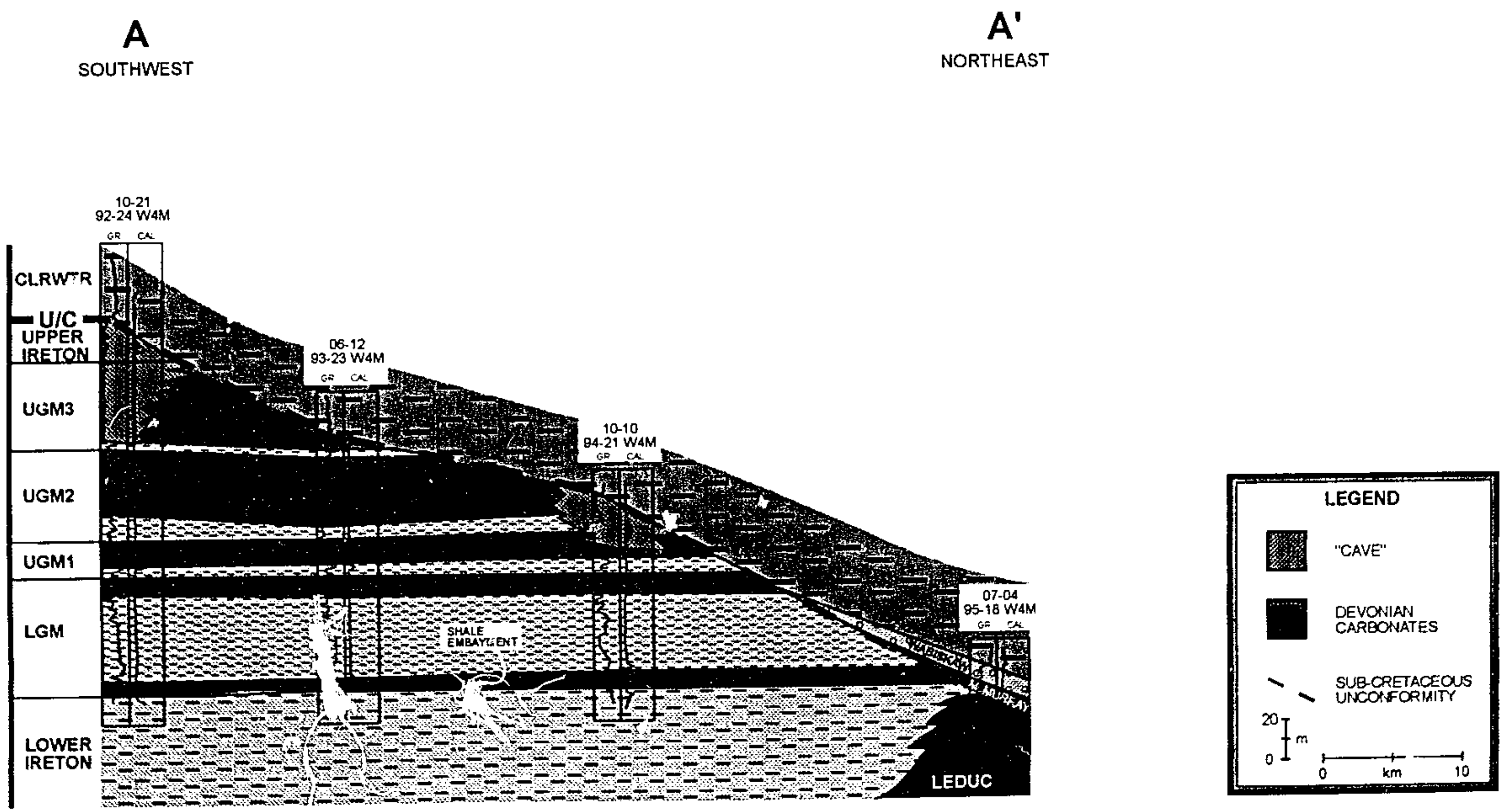
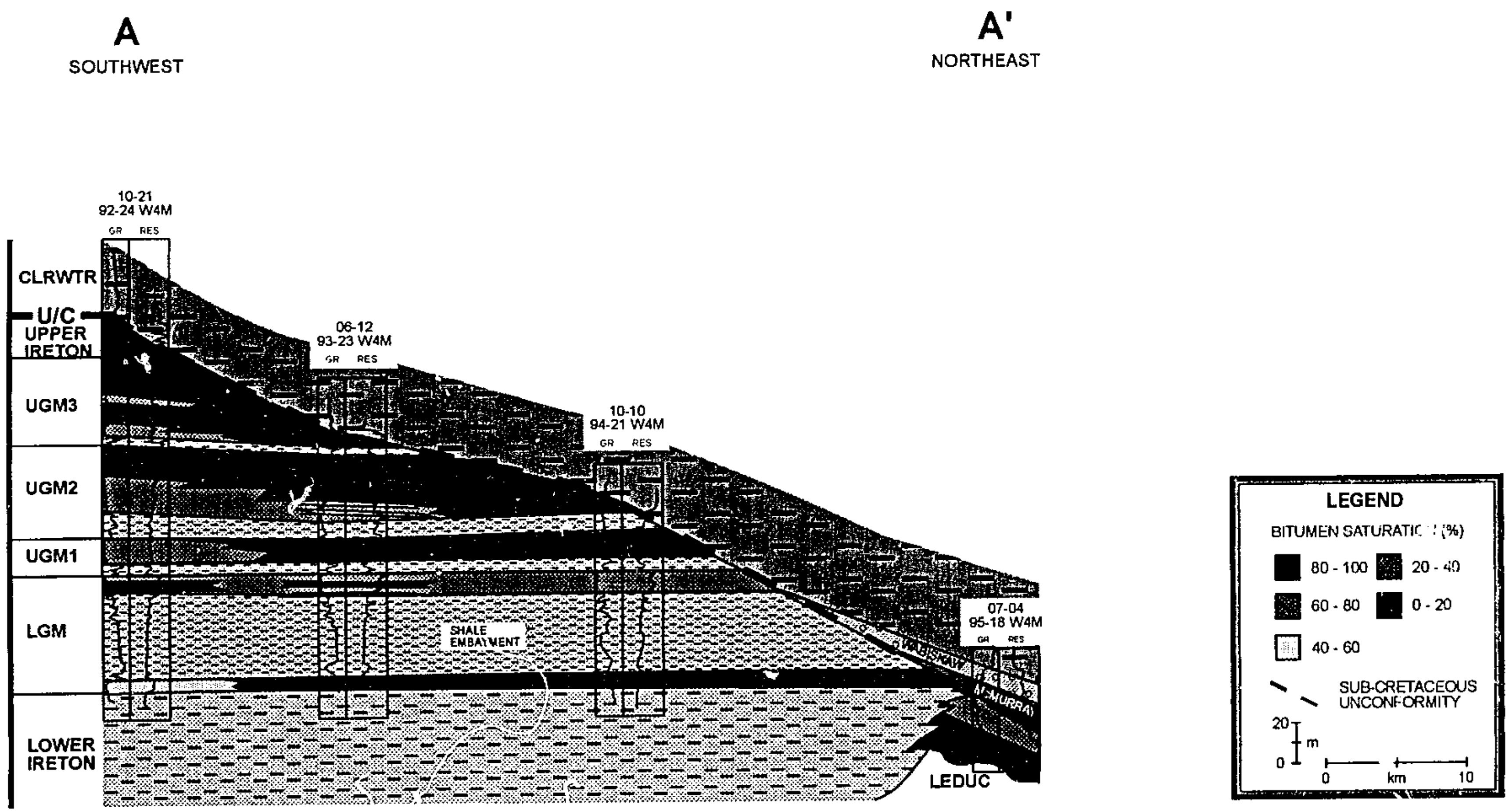


Fig. 6.4 Bitumen saturation (%) across section A-A'.



6.2 B-B' Dip Cross Section

The stratigraphy in section B-B' ranges from the top of the Devonian Beaverhill Lake Group to the Cretaceous Clearwater Formation (Figures 6.5, 6.6, and 6.7). The top of the Beaverhill Lake Group is overlain either by carbonates of the Cooking Lake platform on the northeastern side of the section or by Lower Ireton shales towards the southwest. On the Cooking Lake platform, a Leduc reef is present. It is overlain by the McMurray Formation in well 07-14-91-18 W4M. The Lower Ireton interfingers with the Cooking Lake and Leduc Formations, and it also underlies the Grosmont Formation. The LGM comprises the shale embayment, with a small area of clean carbonate in the southwestern end of the section. West of well 16-33-89-22 W4M, the LGM becomes thinner. The other Grosmont units (UGM1, UGM2, and UGM3) are relatively uniform in thickness except where they are eroded along the unconformity. The Upper Ireton, which overlies the UGM3, consists of a silty-argillaceous dolomite unit at the base and gradually becomes dominated by shale near the top. The Upper Ireton is conformably overlain by the Nisku Formation. As in section A-A', the amount of erosion increases to the northeast. However, the distribution of Cretaceous clastics shows that the McMurray Formation and Wabiskaw Member cover more of the Devonian strata than in section A-A'. In section B-B', the Clearwater Formation only covers the Nisku Formation. Therefore, in this area, thermal recovery of bitumen from the Nisku Formation should achieve excellent results using the Clearwater Formation as a seal.

The porosity distribution in section B-B' is heterogeneous. The base of the Cooking Lake Formation has low porosity (< 8 %), but porosity gradually increases as the Leduc contact is approached. The porosity in the Leduc appears to be relatively uniform between 8 and 16 %. However, this may reflect the lack of deep well control, and most of the Leduc and Cooking Lake Formations are not correlated because of the lack of data (white, Figure 6.5). The porosity distribution in the Grosmont shows that there appears to be a general trend of decreasing porosity with depth. The UGM3 has the highest porosity, mostly in the 16 - 24 % range. Locally, porosity exceeds 32 %. The UGM2 has the next highest porosity values and it is generally in the 8 - 16 % range. The UGM1 and the LGM have the lowest porosity values and the ranges from less than 8 % to greater than 24 %. The base of the LGM, as in section A-A', is characterized by less than 8 % porosity. At the base of the Upper Ireton, the porosity distribution in the silty-argillaceous carbonate unit is quite high and exceeds 24 %. The high porosity may be caused by karst-related dissolution because there are "caves" developed in the Upper Ireton. The porosity in the Nisku generally ranges between 16 and 24 % with high porosity (> 24 %) immediately below the sub-Cretaceous unconformity.

The distribution of "caves" reveals that an extensive karst system is present in the Nisku, Upper Ireton, and parts of the UGM3 in the southwestern side of the cross section (Figure 6.6). Other "caves" are present near the sub-Cretaceous unconformity in wells 07-26-90-21 W4M and 07-14-91-18 W4M. It appears, therefore, that the karst system is more intense where there is a lack of McMurray or Wabiskaw sedimentation.

The bitumen distribution in B-B' (Figure 6.7) reveals that the overall bitumen saturation is lower than in section A-A' (Figure 6.4). In section B-B', the bitumen saturation in the Cooking Lake Formation is less than 20% at the base and increases to more than 60% below the Leduc contact. The Leduc Formation has low saturation values, and the majority of the oil may have leaked into the overlying McMurray Formation, or it may have migrated further north along the reef trend. The bitumen saturation in the remaining Devonian strata (Grosmont, Upper Ireton, and Nisku), have very high bitumen saturation values along the sub-Cretaceous unconformity. The bitumen saturation in section B-B' tends to decrease roughly perpendicular to the unconformity surface, as in section A-A' (Figure 6.4).

Fig. 6.5 Porosity distribution (%) across section B-B'.

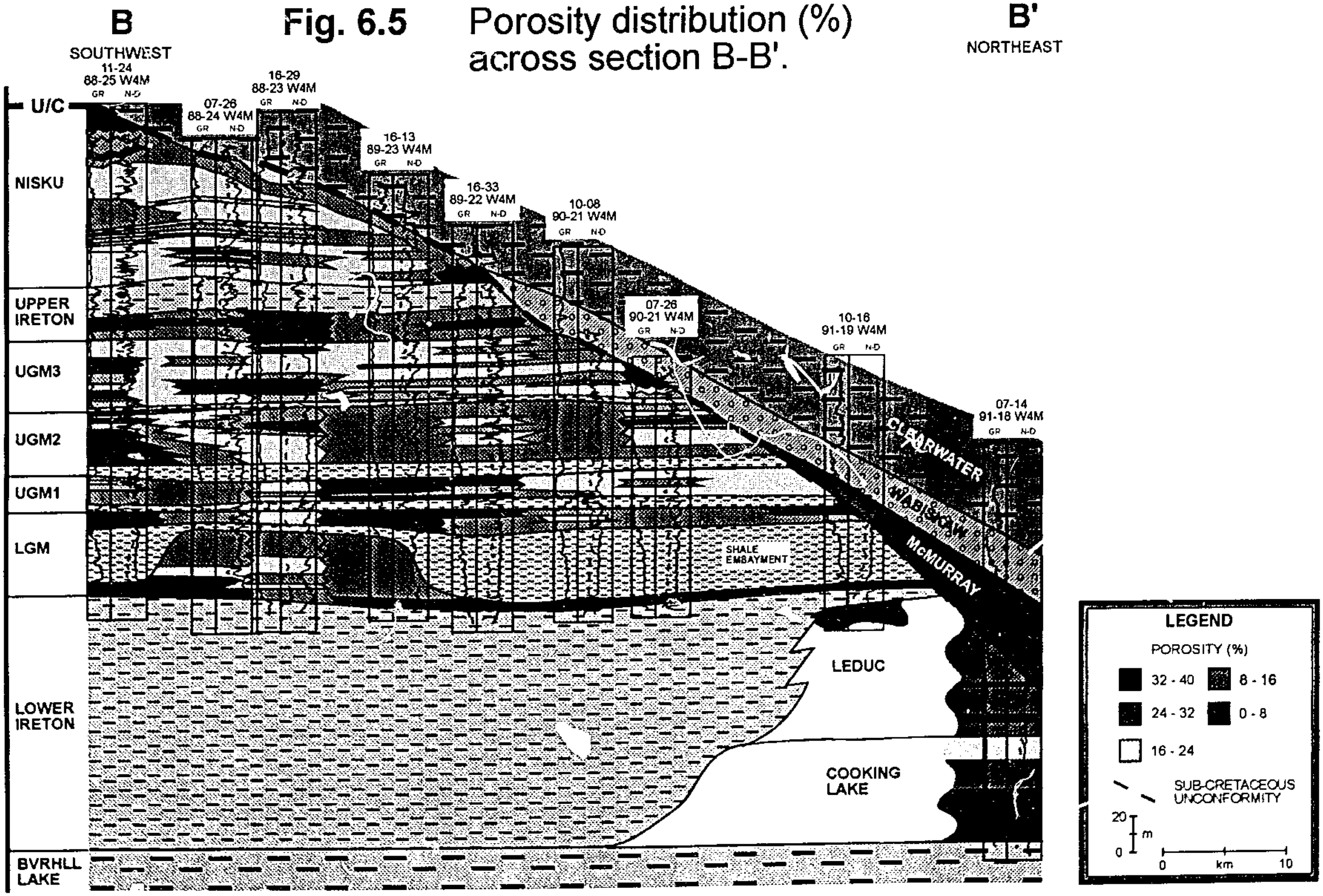


Fig. 6.6 Location of "caves" on section B-B'.

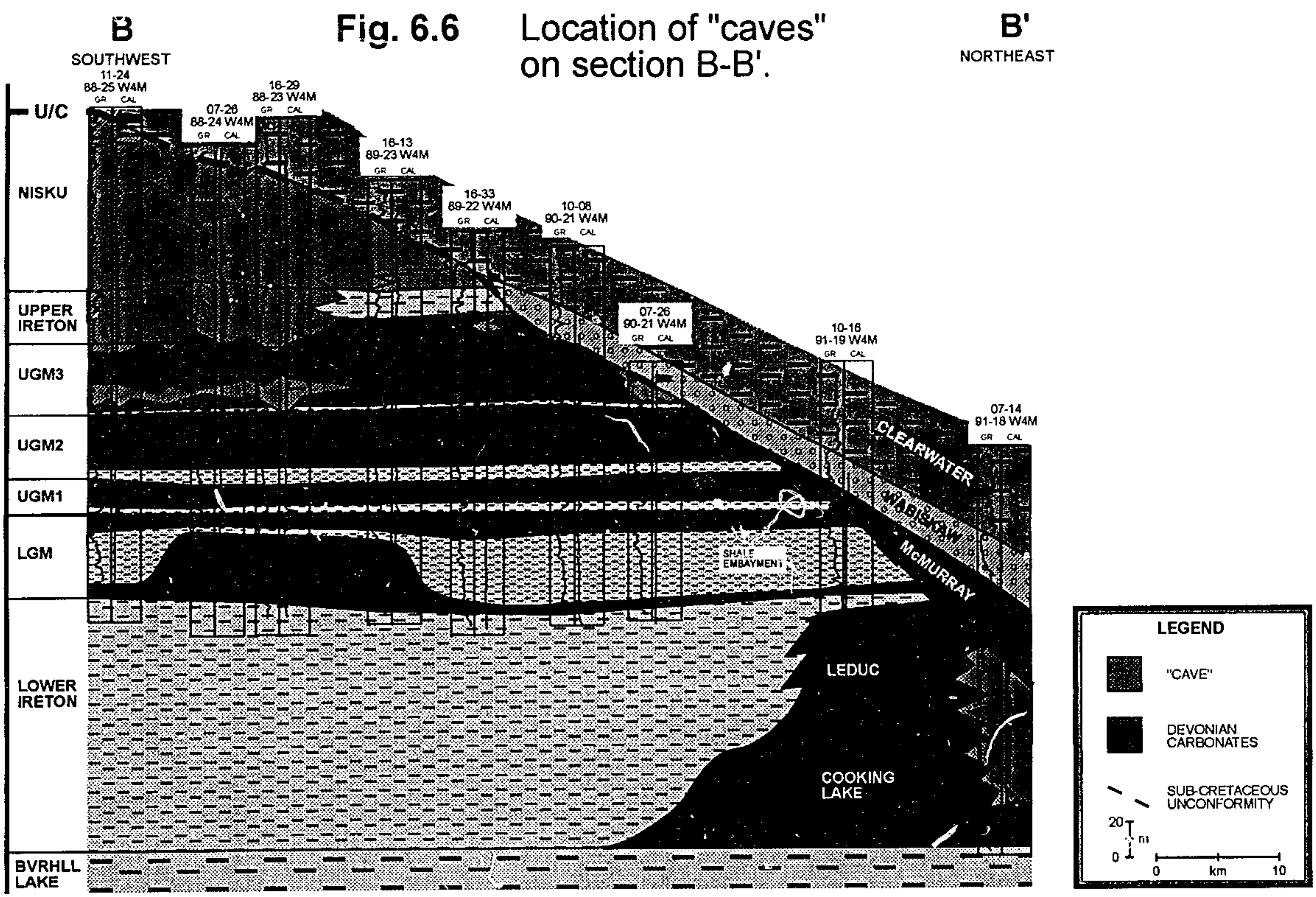
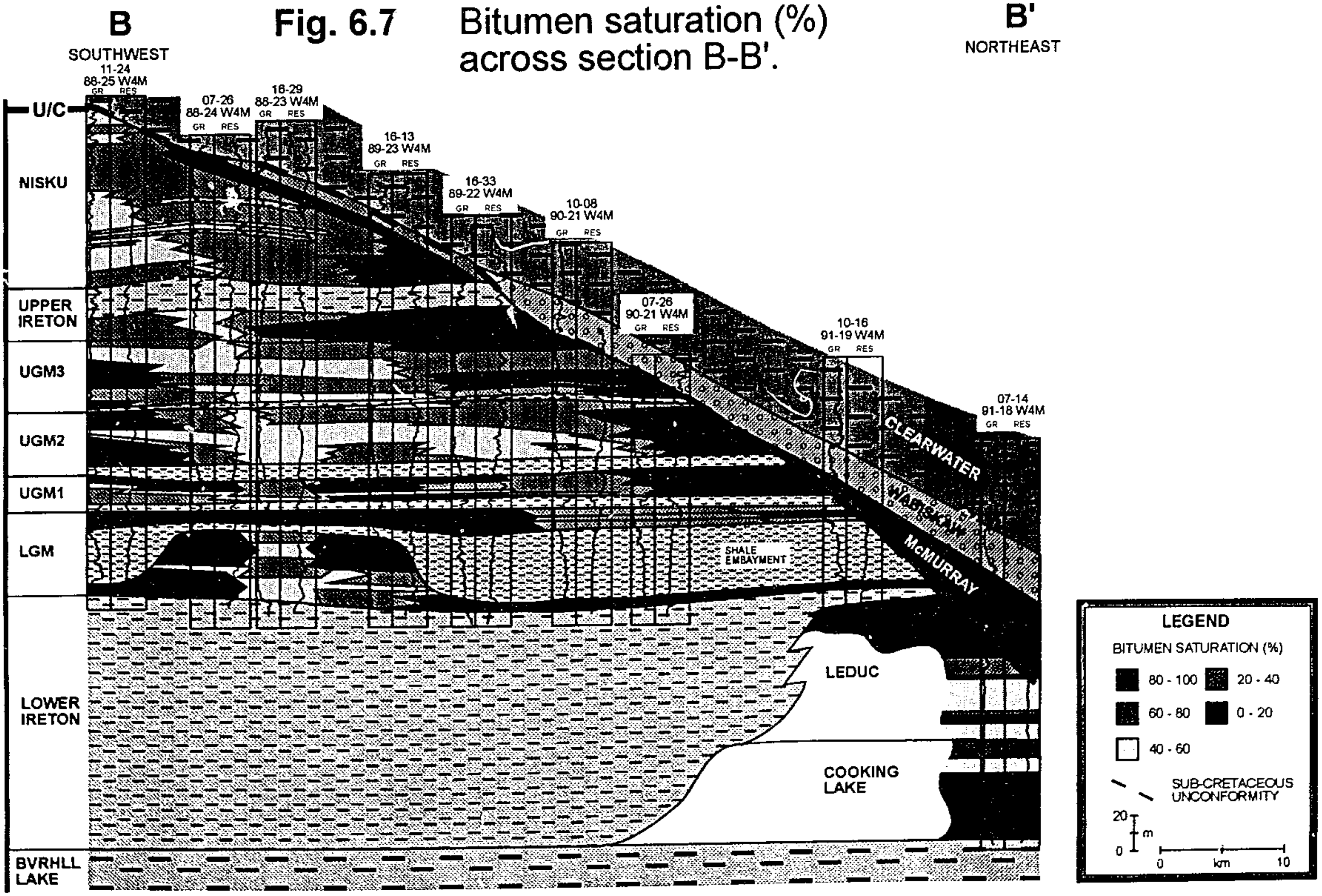


Fig. 6.7 Bitumen saturation (%) across section B-B'.



6.3 C-C' Dip Cross Section

The stratigraphy in section C-C' begins with the top of the Devonian Beaverhill Lake Group and ends in the Cretaceous Clearwater Formation (Figures 6.8, 6.9, and 6.10). The Cooking Lake Formation is thickest east of well 10-36-82-22 W4M and becomes thinner in a southwesterly direction towards well 12-01-80-24 W4M. The Lower Ireton encases both the Leduc and Cooking Lake Formations. The thickness of the Grosmont units are relatively uniform except within the LGM or where they have been eroded. The LGM is slightly thinner over the Leduc reef and thins in a southwesterly direction as the carbonate platform progrades into the Ireton shale basin southwest of well 10-36-82-22 W4M. In addition, minor anhydrite (shaded pink) is recognized in the Grosmont Formation. The anhydrite is present in the LGM in well 10-17-84-19 W4M and in well 12-01-80-24 W4M in the UGM1 and UGM3. The anhydrite in the UGM3 in well 12-01-80-24 W4M may be correlatable to the Hondo Formation located farther south. Anhydrite is recognized on the well logs as having a high resistivity and low neutron-density response. In section C-C', the Upper Ireton is dominated by shale and there is not a carbonate rich sub-unit at the base, as seen further north in sections A-A' and B-B'. The McMurray Formation wraps around the flanks of exposed Devonian strata. The Wabiskaw Member drapes over the underlying McMurray Formation and the remaining exposed Devonian strata.

The porosity distribution in most of the Cooking Lake Formation and all of the Leduc Formation is not available due to the lack of well control and absence of porosity logs (Figure 6.8). Within the LGM, UGM1, and UGM2 the porosity is generally between 8 and 16%. However, there are high porosity intervals associated with the anhydrite in the LGM and with the "cave" near the sub-Cretaceous unconformity in the UGM2. The UGM3 has a higher overall porosity than the other Grosmont units. Correlation of porosity in the Nisku Formation and Blueridge Member is limited by the poor well control.

The location of "caves" in section C-C' shows that the Blueridge Member, Nisku Formation, Upper Ireton, and parts of the UGM3 and UGM2 may be karsted between wells 12-01-80-24 W4M and 13-22-83-22 W4M (Figure 6.9). The lack of well control prevents an accurate outline of this possible "cave". Another "cave" is present on the northeastern side of the cross section, and is developed immediately below the sub-Cretaceous unconformity.

The bitumen saturation in section C-C' (Figure 6.10) is much lower than in the previous two dip cross sections (Figures 6.4 and 6.7), i.e., in the 20-40% range. The highest bitumen saturations are located below the unconformity on the eastern half of the cross section. A slight increase in the bitumen saturation at the base of the LGM in well 13-22-83-22 W4M may represent leakage from the underlying Leduc reef. As in the previous two dip sections (A-A' and B-B'), the bitumen saturation in section C-C' tends to decrease perpendicular to the unconformity surface.

Fig. 6.8 Porosity distribution (%) across section C-C'.

REMOVED DUE TO POOR PRINT QUALITY

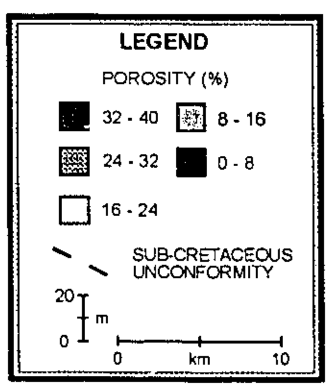


Fig. 6.9 Location of "caves" on section C-C'.

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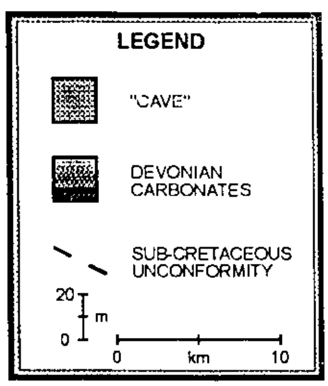

Fig. 6.10 Bitumen saturation (%) across section C-C'.

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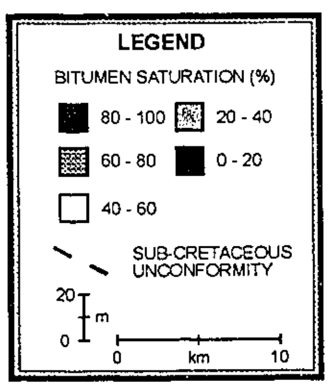

6.4 D-D' Strike Cross Section

The stratigraphy examined in section D-D' spans the Devonian Leduc Formation to the Cretaceous Clearwater Formation (Figures 6.11, 6.12, and 6.13). The Leduc Formation is penetrated by only two wells near the middle of the cross section and it is encased by the Lower Ireton. The Lower Ireton thins over the Leduc reef. All Grosmont units have been variably eroded except the LGM. Even though the LGM has not been truncated by the sub-Cretaceous unconformity in this cross section, there is some thickening of the LGM northwest of the Leduc reef. In addition, the shale embayment is present in the LGM northwest of the Leduc reef. The youngest Devonian strata is the Upper Ireton and its lithology changes from being carbonate-dominated to shale-dominated, depending upon the location and stratigraphic position. The distribution of Cretaceous sediments overlying the Devonian strata is partly dependent upon the Devonian erosional highs (Grosmont High). The McMurray Formation represents a channel deposit and it restricted to the southeastern half of the cross section. It is thickest in well 07-29-84-19 W4M and pinches out onto the flank of the Grosmont High in a northwest direction. The McMurray also becomes thinner towards the southeast. The overlying Wabiskaw Member is relatively uniform in thickness and covers the McMurray Formation as well as some of the Grosmont High in the central part of the study area. It also present to the northwest in well 11-14-93-21 W4M. The overlying Clearwater Formation caps the remaining exposed Devonian strata (Grosmont High) in the northwest and the Wabiskaw member to the southeast.

The porosity distribution across section D-D' is variable (Figure 6.11). Porosity in the Leduc Formation ranges between 8 and 24%. Within the Grosmont Formation, the porosity distribution reveals that the UGM3 and UGM2 are generally more porous than the UGM1 or LGM. There is a thin band of low porosity (< 8%) at the base of the LGM. However, this low porosity band does not persist over the Leduc reef. Throughout the LGM, most of the porosity is in the 8-16% range. In the UGM1, the porosity distribution is variable and the higher porosity values occur in the centre of the cross section. The porosity in most of the UGM2 is in the 8-16% range but increases to more than 32% in association with the "caves". The UGM3 and Upper Ireton have the highest porosity values and almost all of the porosity is greater than 16%.

The distribution of the "caves" in section D-D' is sporadic (Figure 6.12). Usually they occur directly beneath the sub-Cretaceous unconformity. However, in wells 11-14-88-21 W4M and 14-17-87-20 W4M a "cave" is developed in the UGM3 and UGM2 with no apparent connection to the unconformity surface. This deep "cave" may be related to the sinkhole in Township 89, Range 20 W4M.

The highest bitumen saturations in section D-D' occur in the Upper Ireton, UGM3, and UGM2. High bitumen saturations are also present in the UGM1 and LGM but they are concentrated in the northwestern end of the section. The Leduc Formation also has high bitumen saturation at the crest of the reef, possibly because some oil may have leaked from the Leduc Formation and migrated into the overlying LGM.

Fig. 6.11 Porosity distribution (%) across section D-D'.

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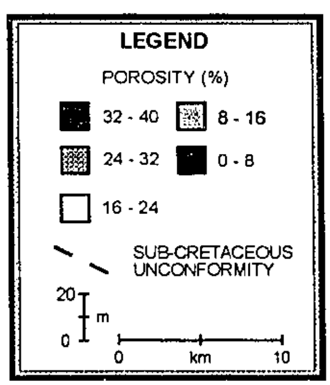

Fig. 6.12 Location of "caves" on section D-D'.

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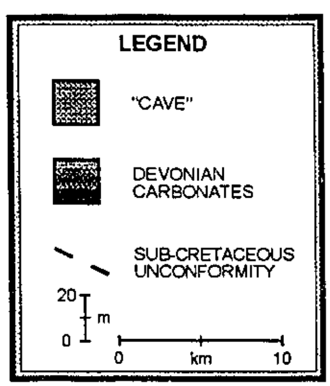

Fig. 6.13 Bitumen saturation (%) across section D-D'.

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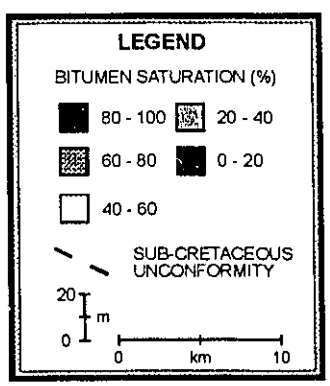

6.5 E-E' Strike Section

The stratigraphy along the strike of the Rimbey-Meadowbrook reef trend (E-E') ranges from the Devonian Beaverhill Lake Group to the Cretaceous Clearwater Formation (Figures 6.14, 6.15, and 6.16). The thickness of the Lower Ireton depends on the height of the Leduc reefs. North of well 13-09-86-21 W4M, the Lower Ireton is relatively thin over the reef trend. However, south of this well, the Lower Ireton is comparatively thicker because the crest of the reef trend is either located further to the east (into the page) or there are no Leduc reefs. A lack of deep well control prevents an accurate understanding of the Rimbey-Meadowbrook reef trend in this area. Overlying the Lower Ireton is the Grosmont Formation. Apart from where it is eroded, the Grosmont Formation is relatively uniform in thickness, but it is slightly thinner north of Township 86 where the Leduc reefs are close to the Grosmont Formation. The Upper Ireton covers the Grosmont Formation and a thin argillaceous-silty carbonate unit is present at the base of the Upper Ireton north of well 13-09-86-21 W4M. The amount of erosion increases to the north and Leduc reefs are in direct contact with the McMurray Formation. The distribution of Cretaceous clastics shows that the McMurray Formation is restricted to the northern half of the section. The Wabiskaw Member, alternatively, is nearly continuous across the cross section. The overlying Clearwater Formation is present across the entire cross section.

The porosity distribution in section E-E' is heterogeneous and the southern end of the section is not correlated due to the lack of porosity logs (Figure 6.14). Porosity distribution in the Cooking Lake, Leduc, and LGM is generally in the 8-16% range, although there are localized highs and lows. The Upper Ireton, UGM3, UGM2, and UGM1 have higher porosity values and the highest porosities are associated with "caves".

The location of "caves" in section E-E' shows that there appears to be an extensive karst system in the central part of the cross section. The depth of the "cave" penetrates into the Leduc Formation. The deep penetration of the "cave" is probably associated with the sinkhole in Township 89, Range 20 W4M. Steam stimulation is not recommended near this "cave" due to the likelihood of breached shale breaks. An isolated "cave" is also present in the

Leduc Formation near the sub-Cretaceous unconformity in well 06-35-92-19 W4M.

The highest bitumen saturations are parallel to the sub-Cretaceous unconformity (Figure 6.16). The bitumen saturation decreases perpendicular to the unconformity surface, in a similar fashion to the other cross sections. The southern half of the section is not correlated due to the lack of resistivity logs.

Fig. 6.14 Porosity distribution (%) across section E-E'.

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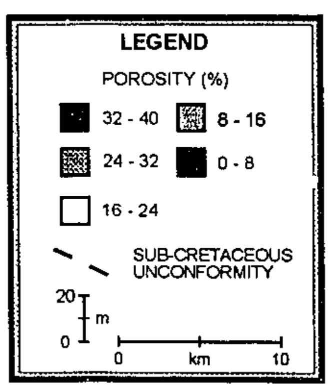

Fig. 6.15 Location of "caves" on section E-E'.

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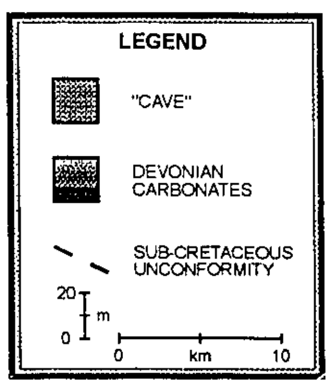

Fig. 6.16 Bitumen saturation (%) across section E-E'.

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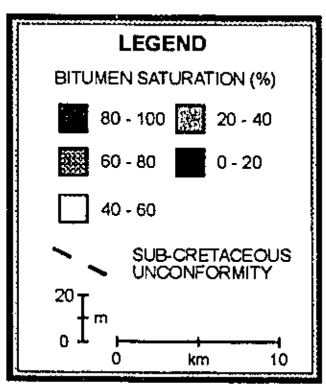


CHAPTER 7

PALEOKARST

The sub-Cretaceous unconformity is a regional erosional surface that sharply separates Devonian carbonates (Leduc Formation, Grosmont Formation, Upper Ireton, Nisku Formation, and Blueridge Member) from overlying Cretaceous clastics. The amount of Devonian strata that was eroded is variable, and at least 350 metres were eroded in the northeastern corner of the study area. Consequently, Devonian carbonates were exposed to meteoric water and an unknown number of karst phases formed. These phases resulted in the development of paleosols, fractures, collapse breccias, and dissolution cavities (Luo et al., 1993). Therefore, the Devonian carbonates in the study area can be classified as a buried paleokarst (cf. Vera et al., 1988).

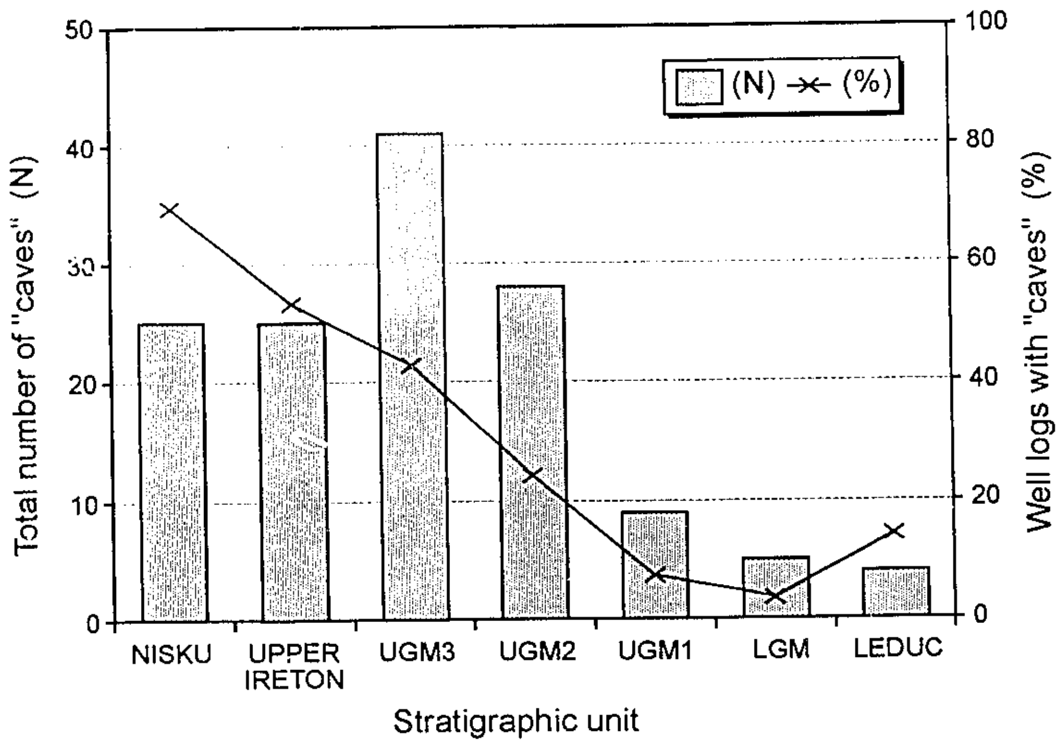
The timing of the karst, like the number of karst phases, is also unknown. Presumably, numerous different karst phases developed as the Devonian strata were being eroded during the Mississippian (?), Pennsylvanian, Permian, Triassic, Jurassic, and Cretaceous periods. In this time interval, the amount of karstification and erosion likely varied in response to climatic changes. The greatest amount of erosion and karstification; therefore, probably occurred during the Jurassic and early Cretaceous (prior to the deposition of the Cretaceous clastics) because the climate was warm and humid.

7.1 "Cave" Statistics

"Caves" are used to identify karst features. On well logs, a "cave" is recognized as an excursion of the caliper log in clean carbonate intervals (Figures 3.5 and 3.6). In addition, the neutron-density porosity readings may display off scale readings if the logging tool loses pad contact with the borehole wall. Core descriptions reveal that most "caves" represent fractures, vugs, collapse breccias, large dissolution cavities, or combinations thereof. The core recovery in "caves" ranges from poor to none (Machel et al., 1991).

The stratigraphic distribution of "caves" shows that the greatest number of "caves" are in the UGM3 (Figure 8.1). However, the greatest percentage of "caves" are in the Nisku Formation. This difference is caused by a lesser number of wells drilled into the Nisku Formation. In general, there is a decreased number (N) and percentage (%) of "caves" as the stratigraphic units become progressively older. Therefore, the higher stratigraphic units (e.g., Nisku Formation) tend to have more "caves" that the lower ones (e.g., LGM).

Fig. 7.1 Stratigraphic distribution of "caves".



The "caves" in the study area range in height from 0.6 m to nearly 200 m (Figure 8.2). The average "cave" height is 23.5 m, but this average is biased by the "caves" that are greater than 50 m in height. Generally, most (60%) "caves" are less than 15 m high and they are located throughout the study area. The large "caves" (i.e., greater than 50 m) are restricted to the western half of the study area (west of Range 19W4M) with the exception of one.

The "caves" range in depth from 1.5 m to nearly 200 m below the sub-Cretaceous unconformity (Figure 8.3). The average "cave" depth is 45 m. Generally, most (60%) "caves" are less than 35 m below the sub-Cretaceous unconformity. The deeper "caves" (greater than 100 m below the sub-Cretaceous unconformity) are all confined to the western half of the study area (west of Range 19W4M).

7.2 Karstification Model

In the study area, reefs and shallow water platform carbonates were deposited in a tropical setting during the late Devonian. However, these carbonates were subaerially exposed for millions of years between the Mississippian (?) and Cretaceous periods. As a result of this lengthy exposure period, at least 350 m of Devonian strata were eroded. In addition, the carbonates were probably subjected to more than one episode of circulating meteoric water. Therefore, the karstification model proposed for the Devonian strata is based upon carbonic acid dissolution and erosion associated with an unknown number of circulating groundwater phases.

Four pieces of evidence support this model. First, a regional unconformity separates eroded Devonian carbonates from overlying Cretaceous clastics. Second, most (60%) "caves" are less than 35 m below the sub-Cretaceous unconformity. Third, the number and percentage of "caves" decrease as the stratigraphic units become progressively older. Fourth, the intensity of fracturing, as seen in core, decreases as the depth below the sub-Cretaceous unconformity increases.

Fig. 7.2 Number of "caves" (N) vs. height (m). "Cave" height is defined as the difference (m) between the top and bottom of the caliper excursion in clean carbonate intervals.

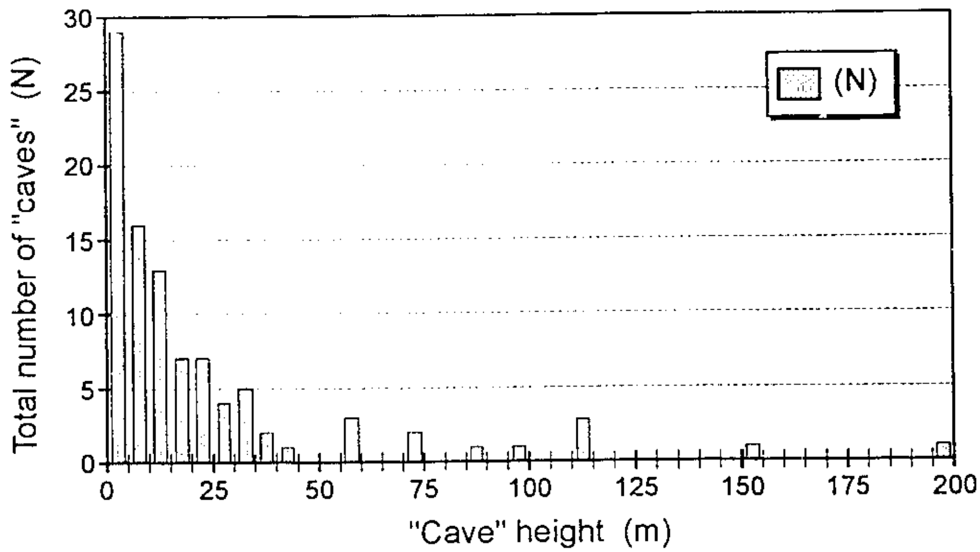
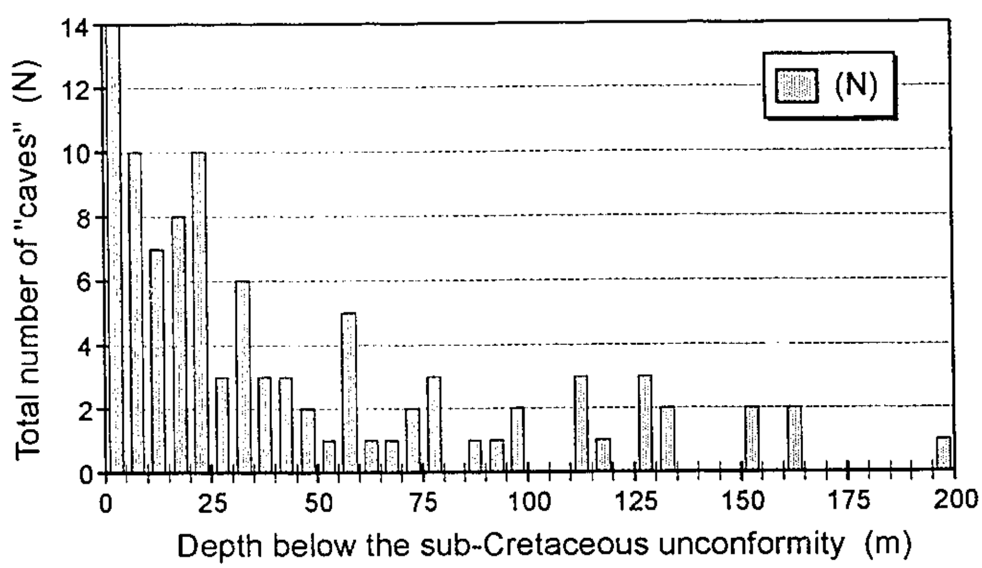


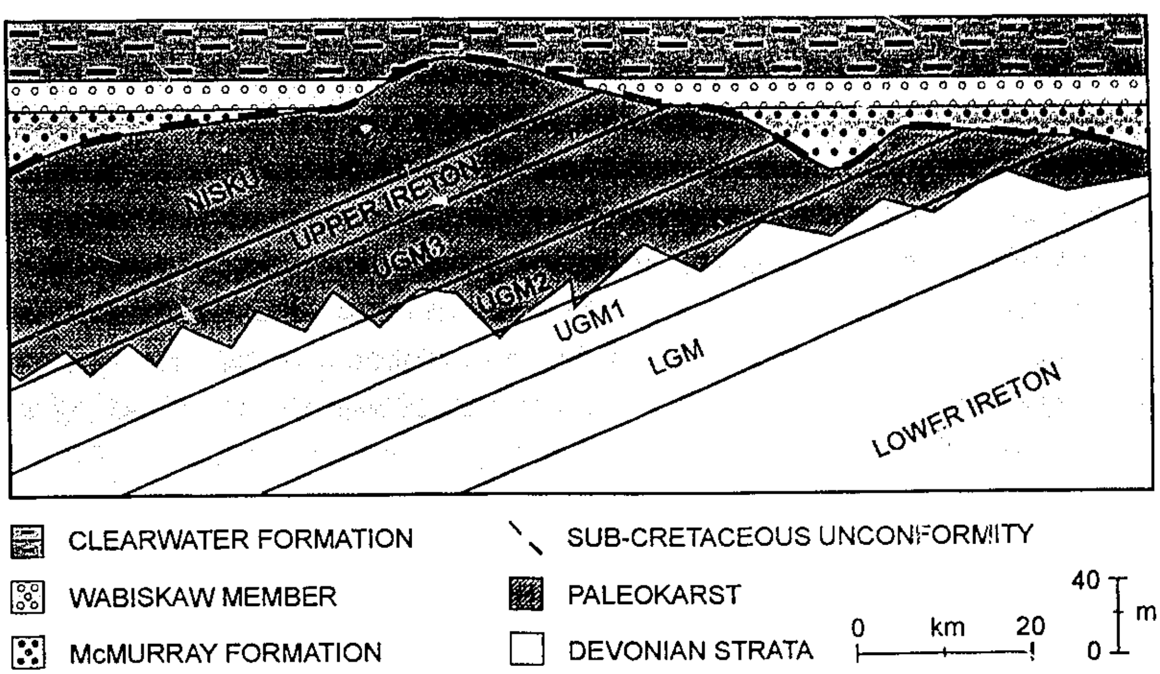
Fig. 7.3 Number of "caves" vs. depth below the sub-Cretaceous unconformity. "Cave" depth is defined as the difference (m) between the sub-Cretaceous unconformity and the bottom of the "cave" as defined by the caliper log.



It is possible, but unlikely, that porosity was generated by sulphuric acid dissolution as in the model proposed for the Carlsbad Cavern, New Mexico (Hill, 1987, 1990). For the formation of Carlsbad Cavern, Hill (1987, 1990) proposed that hydrogen sulphide and carbon dioxide generated in the Delaware basin migrated updip into the Capitan reef limestone. Upon entering the water table in the Capitan reef aquifer, the hydrogen sulphide gas oxidized and converted into sulphuric acid. The sulphuric acid then dissolved the limestone to form Carlsbad Cavern and other caves in the Guadalupe Mountains. The primary reason to reject this model, in the study area, is the lack of H_2S in the natural gas reservoirs (e.g., Liege).

In the study area, karstification appears to be deeper in the western half of the study area than in the eastern side (Figure 8.4). Hence, it looks as if the intensity of karstification increased towards the west. However, this is a misconception. The degree of karstification was probably equal across the study area, but due to erosion, most of the karst was not preserved in the eastern half of the study area. The tilted lower contact of the paleokarst probably reflects the base of a water table(s) that developed prior to the deposition of the overlying Cretaceous clastics.

Fig. 7.4 Spatial distribution of paleokarst in the Devonian strata.



7.3 Reservoir Properties affected by Karst

Karst has affected three reservoir properties:

1. porosity,
2. permeability, and
3. seal effectiveness.

The variable porosity in the Grosmont Formation is dependent upon dolomitization and karst. In undolomitized rocks, the porosity is relatively low and averages between 8% and 12% (e.g., LGM). In dolomitized rocks, the porosity usually increases to approximately 20%. In strongly karstified rocks, the porosity is commonly enhanced up to 40%, and locally up to 100% in metre size dissolution cavities. However, karstification can reduce porosity in some intervals via calcite cementation, dedolomitization, and fill porosity with Cretaceous sands and clays (Luo et al., 1993).

The permeability of the Grosmont Formation generally ranges between 10 and 100 md in non-karsted intervals. However, karst-related fractures can significantly increase the permeability. Consequently, extremely high permeability values of 30,000 md can be obtained in fractured core (Machel and Hawlader, 1990; Luo et al., 1992; Luo et al., 1993).

The effectiveness of the shale breaks (e.g., SB-1,2, and 3) to act as seals or vertical permeability barriars during steam stimulation is greatly influenced by karst. If the shale breaks are present and not breached by karst-related fractures, steam stimulation will be successful. However, if steam is injected into regions where a seal is removed by erosion or breached by fractures, the energy of the injected steam may be lost to overlying strata, and communication problems will exist between injection and recovery wells. Therefore, steam stimulation sites should not be located where the seal is eroded or breached (see Chapter 5).

In summary, karst has both improved and degraded the reservoir. Karst has benefited the reservoir because the porosity and permeability is often increased. Karst has locally deteriorated the reservoir because the porosity is sometimes reduced. In addition, karst has locally breached the shale breaks which are expected to act as seals during steam stimulation. Therefore, depending on the location, the effects of karst may either be beneficial or detrimental to the production of bitumen.

7.4 Comparison of the Grosmont and San Andres Formations

The San Andres Formation in the reservoir of the Yates oil field in the Permian basin of west Texas is an excellent analogy for the Grosmont Formation. The San Andres Formation at Yates, like the Grosmont Formation, is a shallow marine carbonate platform was karsted as a result of subaerial exposure (Craig, 1986, 1988, 1990). As a result of karstification, the two formations share the following geological characteristics: collapse breccias, fractures, "caves", "cave" sediment, and sinkholes. In addition, both formations have the greatest abundance of "caves" near the unconformity surface. Furthermore, these formations have similar reservoir characteristics such as increased porosity and permeability and localized porosity reduction due to karstification.

Even though the two formations have quite similar karst features, there are some differences. The Yates "caves" have an average "cave" height of 0.9 m with a range of 0.3 m to 6.4 m (Craig, 1988). The Devonian strata (e.g., Grosmont Formation) have "caves" that average 23.5 m and range in height from 0.6 m to nearly 200 m. This difference can be attributed to two factors. First, the San Andres Formation was subaerially exposed during the late Permian (middle Guadalupian) whereas the Grosmont Formation was exposed for a much longer period of time from the Mississippian (?) to early Cretaceous. Thus, the Yates "caves" should be smaller because the San Andres Formation was exposed for a much shorter time period. Second, there is a difference in the definition of "cave". Craig (1988) defined a "cave" as a caliper excursion that had a minimum corresponding density porosity of 45% (e.g., off scale reading). The definition of "cave" used in this study is similar to Craig's (1988) definition, but it does not have a minimum porosity cutoff value. Therefore, broken, fractured, and rubbly core with a caliper excursion and porosity reading of approximately 35% would be called a "cave" in this study, but not in Craig's (1988) definition. Consequently, a difference in definition results in a difference in "cave" height.

CHAPTER 8

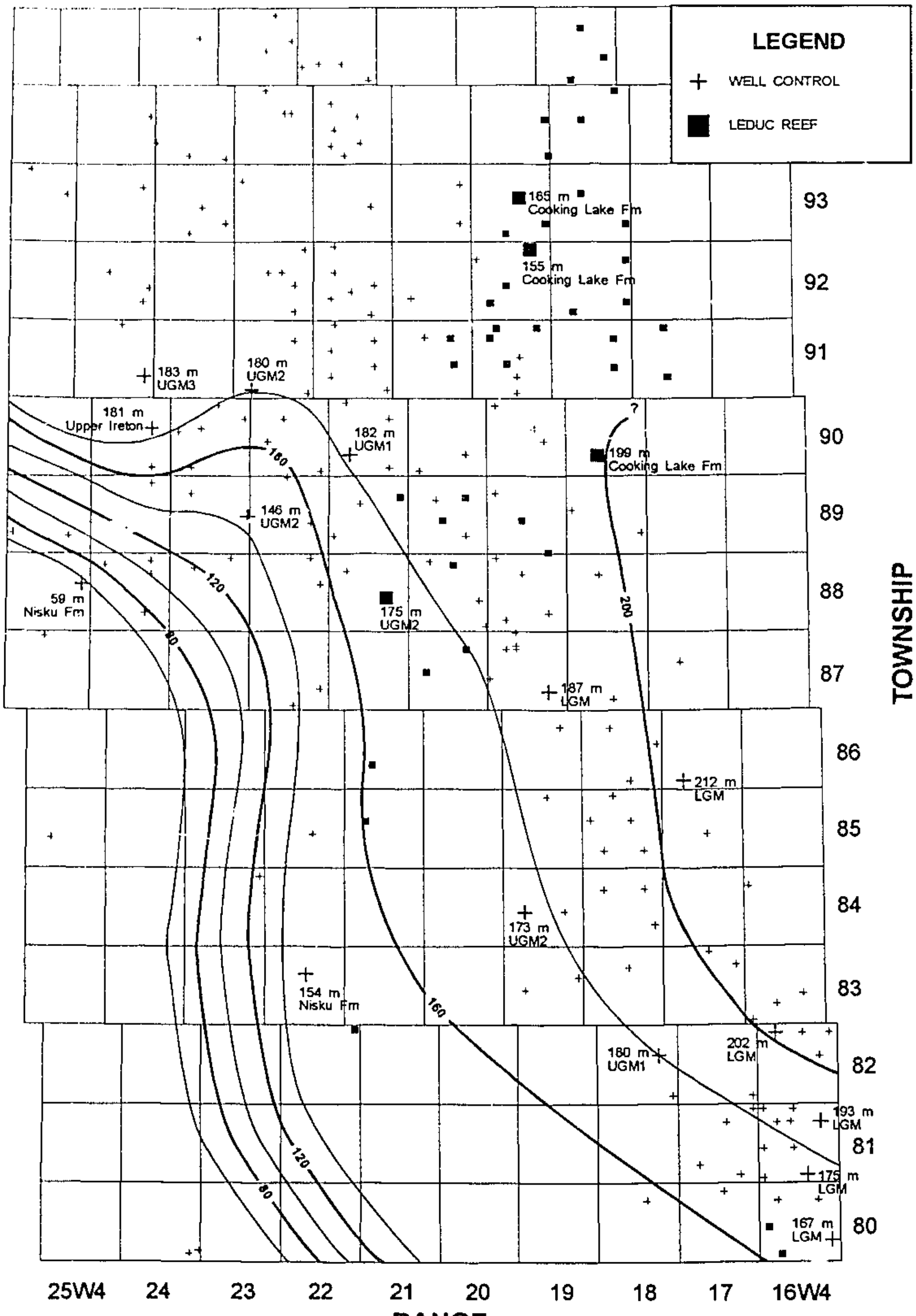
HYDROCARBON CHARACTERISTICS

Within the study area, bitumen and natural gas are contained in the Nisku, Upper Ireton, Grosmont, and Leduc carbonates. In addition, bitumen and natural gas are found in the overlying Wabiskaw Member and McMurray Formation of the Cretaceous Athabasca deposit. In both the Devonian and Cretaceous reservoirs, the bitumen is immobile under present reservoir conditions. However, the bitumen was a free flowing, mature, parraffinic crude oil at the time of migration during the Late Cretaceous. After migration, the oil was transformed into a black viscous bitumen by in-situ biodegradation and water-washing (Gussow, 1955; Deroo et al., 1977). The natural gas that is present in the heavy oil reservoirs is believed to be a by-product of shallow in-situ bacterial activity, and not due to deep hydrothermal cracking, because it is composed predominantly of dry gas (> 95% methane) with less than 2% of the heavier gas fractions (ethane to pentane) (Deroo et al., 1977). The estimated time of gas depletion is unknown because the gas is being generated at a rate that approximately equal production (Pemberton, personal comm.).

8.1 Orientation of the Bitumen-Saturated Zone

The overall bitumen orientation has a northwest-southeast strike and dips gently to the southwest (Figure 7.1). However, it varies in the southwest corner of the study area as the water saturation increases dramatically. The orientation of the bitumen was determined by correlating the base of 80% bitumen saturation. This marker was used because it can be correlated in the east half of the study area where the bitumen saturation is high as well as in the west half of the study area where the bitumen saturation is low.

Fig. 8.1 Structure contour map of the base of 80% bitumen saturation (C.I. = 20 m).



8.2 Origin of the Bitumen

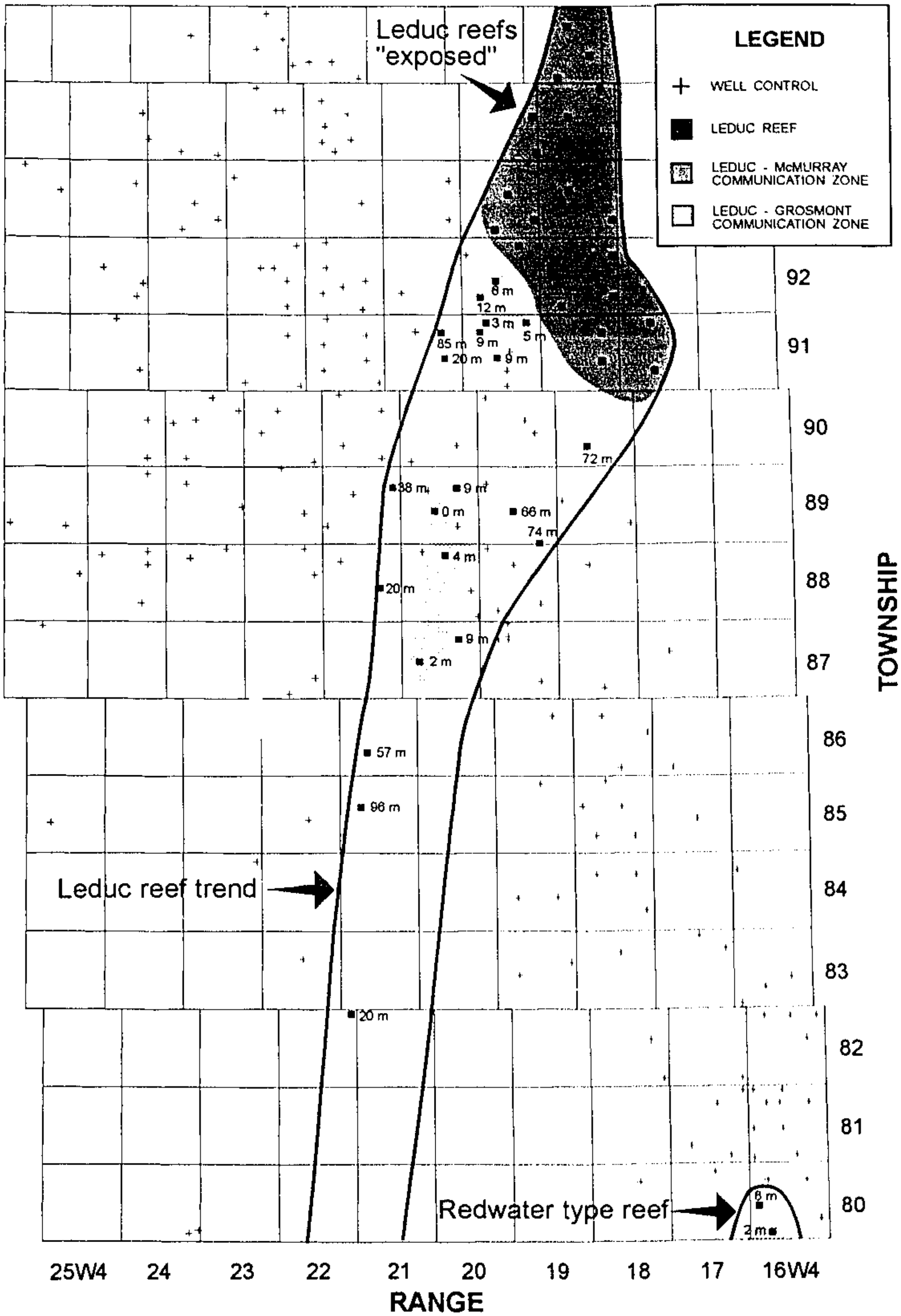
Although the timing of the oil migration is accepted to be in the Late Cretaceous (Gussow, 1955; Deroo et al., 1977; du Rochet, 1985; Allan and Creaney, 1991), the source rock(s) that have generated the oil (now biodegraded into bitumen) is not known. The bitumen's origin is unknown and controversial because the prominent paraffin peaks and some of the biomarkers normally seen in gas chromatographs of conventional light oil are destroyed by intense bacterial activity in bitumen. For example, Deroo et al. (1977) concluded that the oil in the Cretaceous and Devonian bitumen saturated reservoirs originated from Mannville Group shales based on gas chromatographs and geochemistry of the bitumen. However, due to the large volume of bitumen, they also accepted the possibility that Paleozoic rocks may have sourced some of the bitumen. This suspicion was supported by Moshier and Waples (1985). They calculated the potential oil generating capabilities of the Mannville Group shales and concluded that the Mannville Group shales could not generate all of the oil that is contained as bitumen in the Cretaceous oil sands. Therefore, they suggested that there must be additional source rocks.

An additional source rock may be the basinal Triassic shales (du Rochet, 1985). Based on gas chromatographs and oil staining in the Paleozoic rocks, du Rochet (1985) contradicted the work of Deroo et al. (1977) and stated that basinal Triassic shales appear to be responsible for the majority of the bitumen contained in the Cretaceous oil sands and Devonian carbonates of the Grosmont Formation. Allan and Creaney (1991), however, proposed that the Mississippian Exshaw shale and Jurassic Nordegg Member of the Fernie Group are the source rocks for the biodegraded heavy oils. Their work was also based on gas chromatography.

Another possible source rock may be the Devonian Duvernay Formation. There is no geochemical data or gas chromatography to support this theory but the cross sections illustrated in Chapter 6 (Figures 6.4, 6.7, 6.13, and 6.16) show that bitumen is present in the Cooking Lake and Leduc Formations. Therefore, if one assumes that the oil migrated updip along the western margin of the Cooking Lake platform, which is the case in the southern end of the Rimbey-Meadowbrook reef trend (Stoakes and Creaney, 1984), it is quite possible that the Cooking Lake Formation acted as a conduit for the migration of Duvernay sourced oil into northeastern Alberta.

If the Leduc reefs overlying the Cooking Lake Formation were filled with Duvernay sourced oil, it is extremely likely that the oil in the Leduc reefs leaked oil into the Grosmont Formation where the Lower Ireton is less than 6 m thick (Rostron, personal comm.). In the study area, there are three such communication zones between the Leduc and Grosmont Formations (Figure 7.2). Furthermore, bitumen-saturated Leduc reefs are directly overlain by the McMurray Formation (Figure 7.2). Therefore, there is indirect evidence to suggest that the Duvernay Formation may have sourced some of the bitumen in the Devonian and Cretaceous heavy oil reservoirs in northeastern Alberta.

Fig. 8.2 Communication zones between the Leduc Formation and the overlying Grosmont/McMurray Formations.



CHAPTER 9

RECOMMENDATIONS FOR THERMAL RECOVERY SCHEMES

Three conditions must be fulfilled in order to recover bitumen from the Devonian reservoirs (e.g., Nisku, Upper Ireton, and Grosmont). (1) The bitumen saturation must be high enough to produce mostly bitumen with very little water. The minimum bitumen saturation required is not known. Presumably, a minimum bitumen saturation of 60% to 70% is necessary. (2) The seal must be effective and contain the steam energy in the reservoir. (3) Gas must not be present, or the steam will migrate into the gas cap and not heat the bitumen. In addition, the steam will contaminate the gas field(s). The distribution of Devonian gas fields in the study area is shown in Figure 9.1.

In order to identify possible targets for the thermal recovery of bitumen, maps have been created for each reservoir unit which depict the three necessary criteria listed above. In each map, the bitumen content is reflected by the HPV (hydrocarbon pore volume) content. The HPV values were obtained from the respective HPV maps in Chapter 4. The distribution and possible thief zones in the seals are also added to the map. Thief zones, or breached wells, are defined as "caves" developed below a Devonian seal. Near these wells, injected steam may escape into overlying strata via fractures in the seal, and poor bitumen recovery is likely because of the possibility of poor communication between injection and recovery wells. The extent of any possible thief zones is unknown. The thief zones are taken from the location of "breached" well maps in Chapters 4 and 5. Finally, the distribution of the gas is superimposed on the HPV values.

For the Nisku Formation, the Clearwater Formation is expected to act as a seal. Thief zones are not expected with the Cretaceous Clearwater Formation because it is has not been subjected to karstification. The best HPV values which are covered by the Clearwater Formation are located in the west-central part of the study area (Figure 9.2). Unfortunately, the northeastern updip portions of the Nisku are saturated with gas (Liege field). Steam stimulation of the Nisku Formation is not recommended in this area because of the presence of gas.

The potential target zones in the Upper Ireton carbonate unit with the Upper Ireton shale as a seal are illustrated in Figure 9.3. It appears that the HPV increases to the northwest outside of this study area. However, as discussed in Chapter 5, the Upper Ireton shale is not considered to be an regionally effective seal due to abundant thief zones as well as its mixed carbonate-clastic lithology. In addition, the Upper Ireton is saturated with gas between Townships 89 and 91. Therefore, most of the bitumen in the Upper Ireton may not be recovered by using the Upper Ireton shale as a seal. The use of the Clearwater Formation as a seal for the Upper Ireton is a possibility but the erosional edge of the Upper Ireton which is capped by the Clearwater Formation is comparatively narrow (Figure 5.2).

Recovery of bitumen from the UGM3 can be attempted by using either the Clearwater Formation or the Upper Ireton shale as a seal. The erosional edge of the UGM3 which is covered by the Clearwater Formation is rather narrow but it is a prime target since the Clearwater Formation should be an excellent seal. Exploitation of the UGM3 using the Clearwater Formation is recommended where the HPV is greater than 4 m between Townships 90 to 92 (Figure 9.4). However, steam stimulation should wait until the gas is depleted (Liege field). Another alternative, that is, using the Upper Ireton as a seal for the UGM3 looks promising because of the large bitumen saturated area covered by the Upper Ireton (Figure 9.5). However, the numerous thief zones makes exploitation risky and recovery of bitumen from the UGM3 using the Upper Ireton as a seal is not recommended. To further complicate matters, there is gas present south of Township 84 (Granor and House fields).

The recovery of bitumen from the UGM2 using SB-3 as a seal appears promising north of Township 89 where there are not as many thief zones (Figure 9.6). However, gas is present (Liege field) and steam stimulation is not recommended until the gas is depleted. South of Township 89, gas is intermittently present along the erosional edge (Saleski, Granor, and House fields). In addition, there are more thief zones and exploitation is riskier.

Therefore, steam stimulation is not recommended south of Township 89 even after the gas is depleted.

Recovery of bitumen from the UGM1 using SB-2 as a seal is recommended north of Township 90 because SB-2 does not appear to have many thief zones (Figure 9.7). However, the HPV in the UGM1 is not as great as in the other reservoir units because the UGM1 is approximately half as thick as the other units. The steam stimulation, however, must wait until the gas from the Liege gas field is depleted .

The thermal recovery of bitumen from the LGM using SB-1 as a seal may be effective near the erosional edge south of Township 89 because SB-1 does not appear to have many thief zones (Figure 9.8). However, the bitumen cannot be recovered until the gas is depleted from the Saleski, Granor, and House fields. Recovery of bitumen from the isolated high in Township 88, Range 23 W4M is not recommended since the high HPV reflects the high porosity in this well and not high concentrations of bitumen.

Fig. 9.1 Location of Devonian gas fields.

(modified after GSA Map 1559A Gas Pools of Western Canada, 1981)

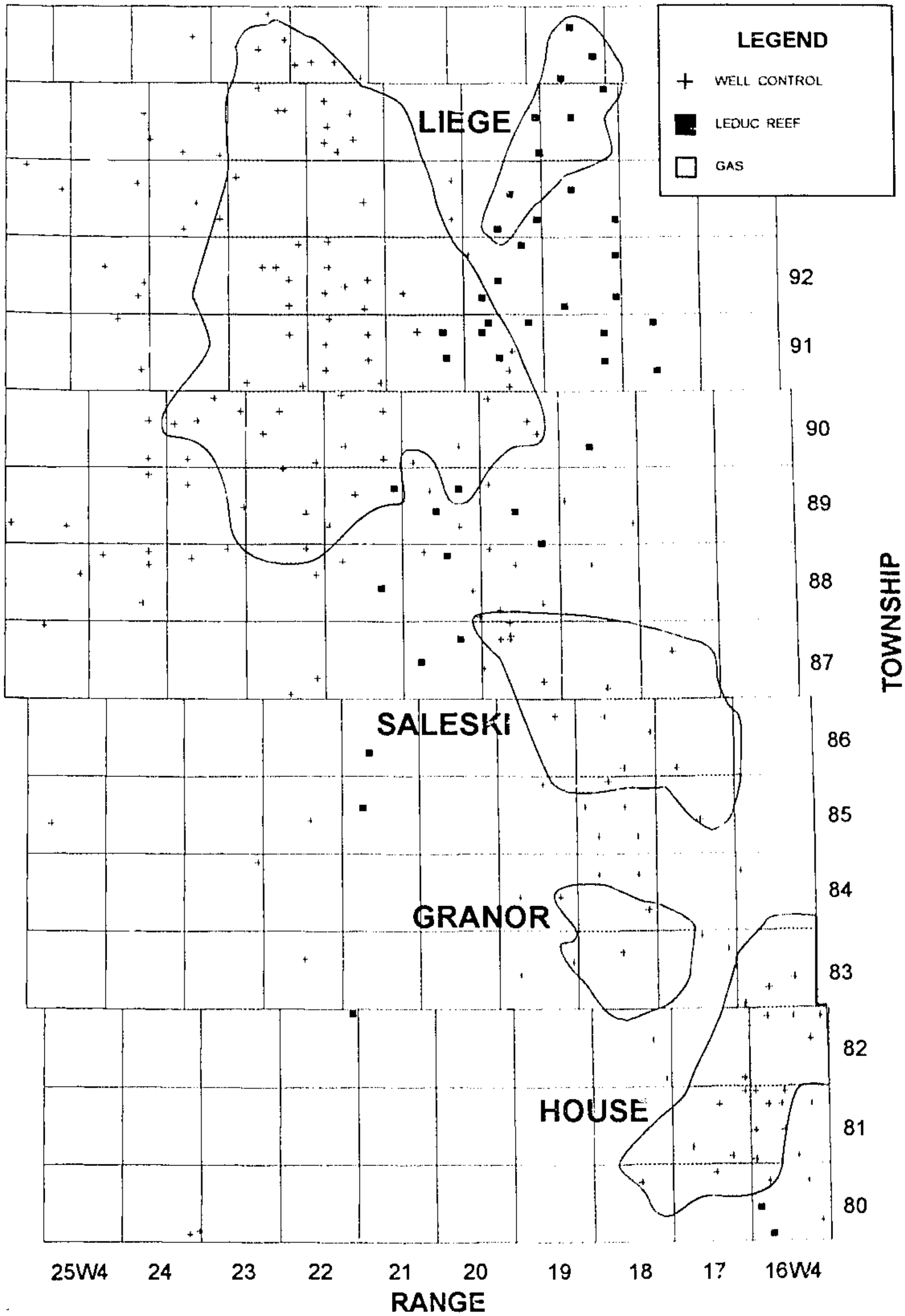


Fig. 9.2 Potential thermal recovery sites for the Nisku Formation using the Clearwater Formation as a seal.

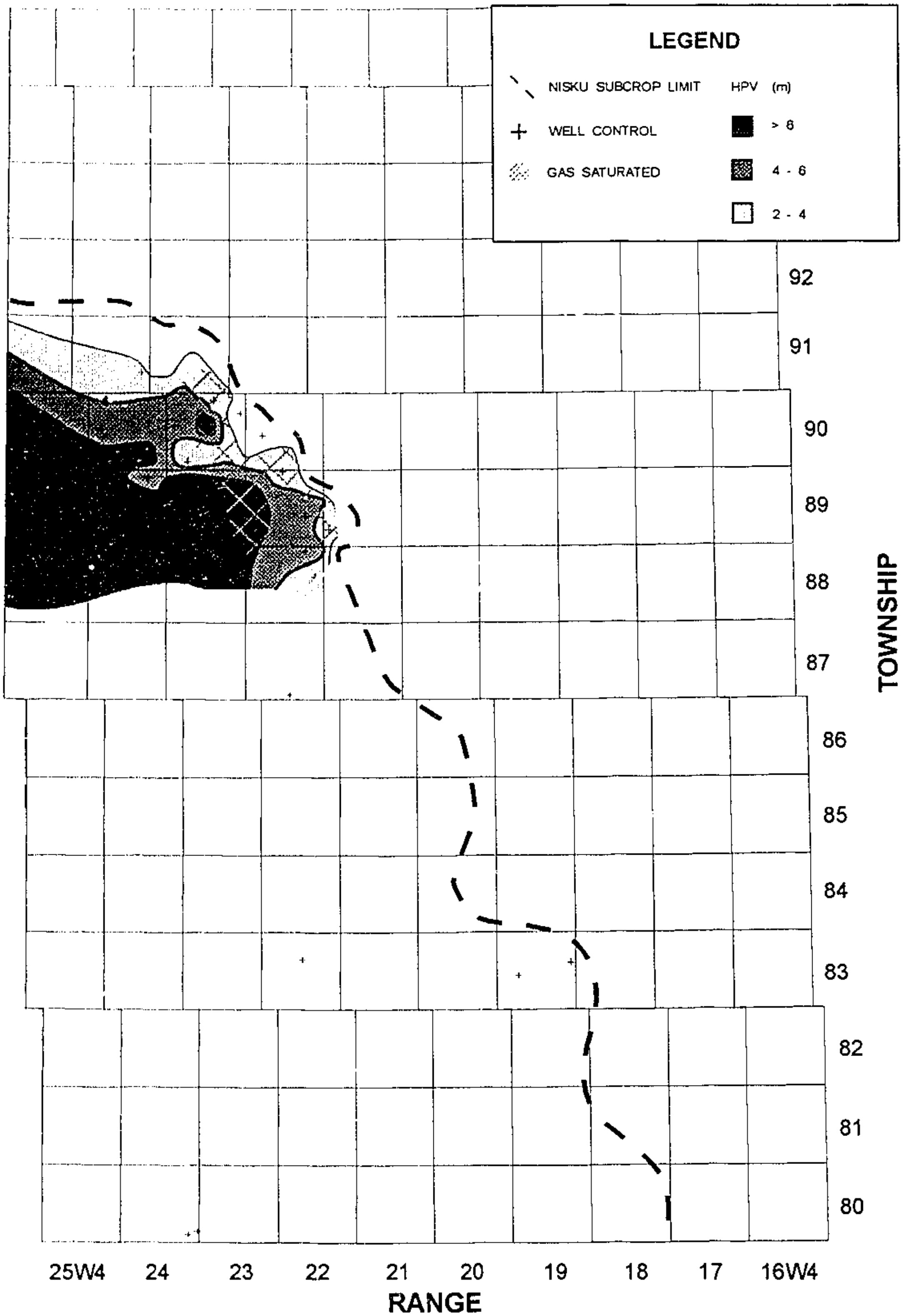


Fig. 9.3 Potential thermal recovery sites for the Upper Ireton carbonate using the Upper Ireton shale as a seal.

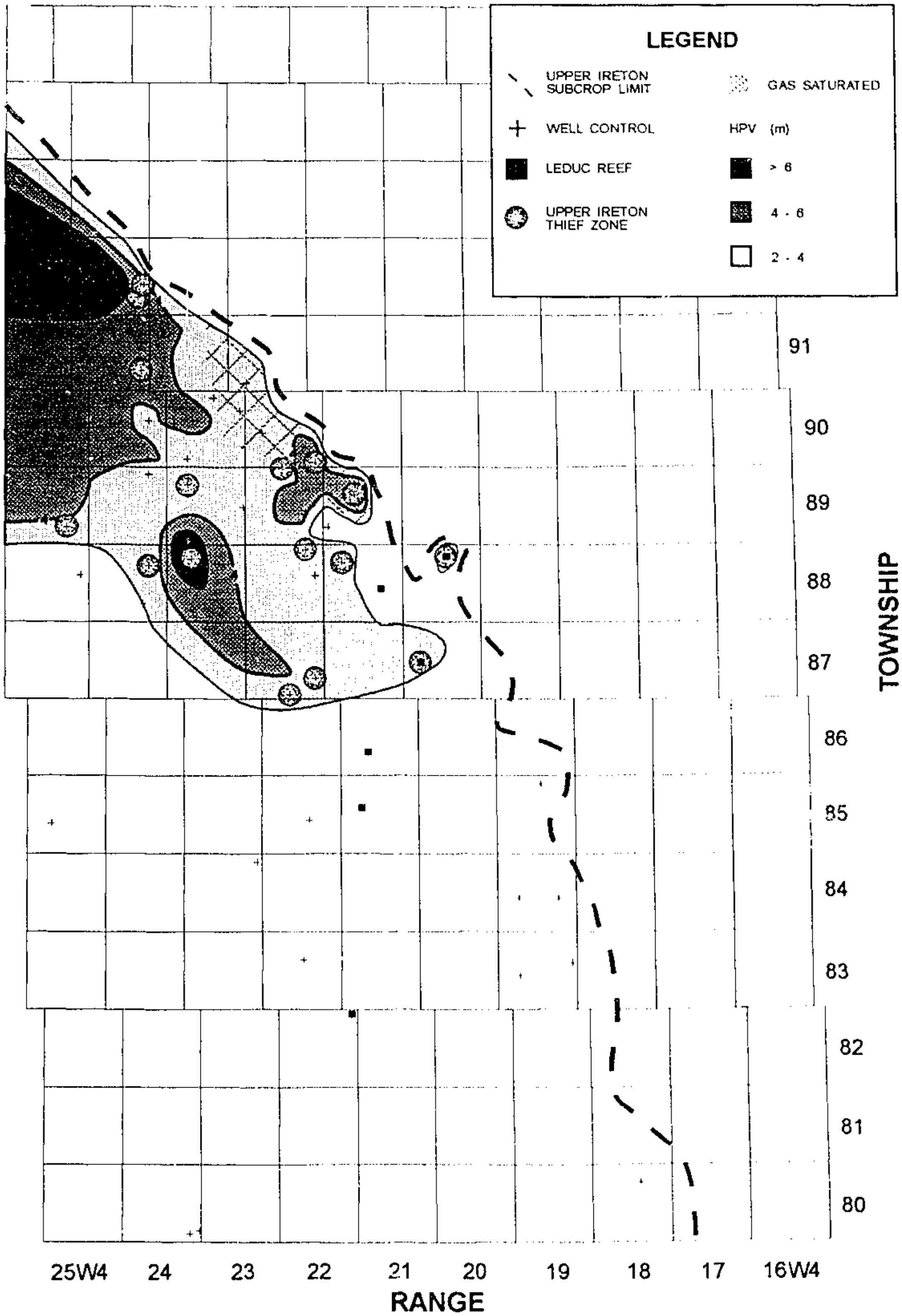


Fig. 9.4 Potential thermal recovery sites for the UGM3 using the Clearwater Formation as a seal.

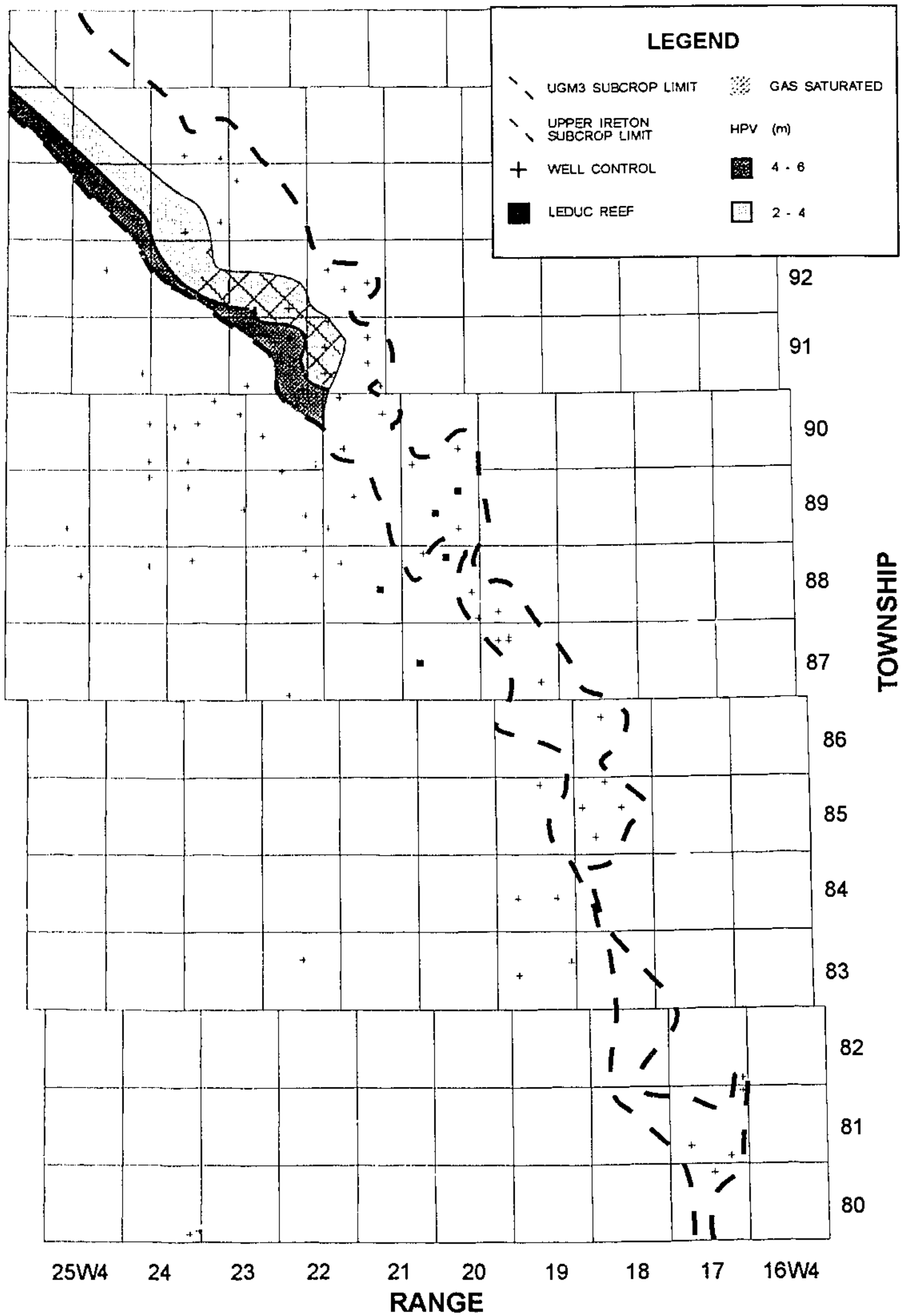


Fig. 9.5 Potential thermal recovery sites for the UGM3 using the Upper Ireton shale as a seal.

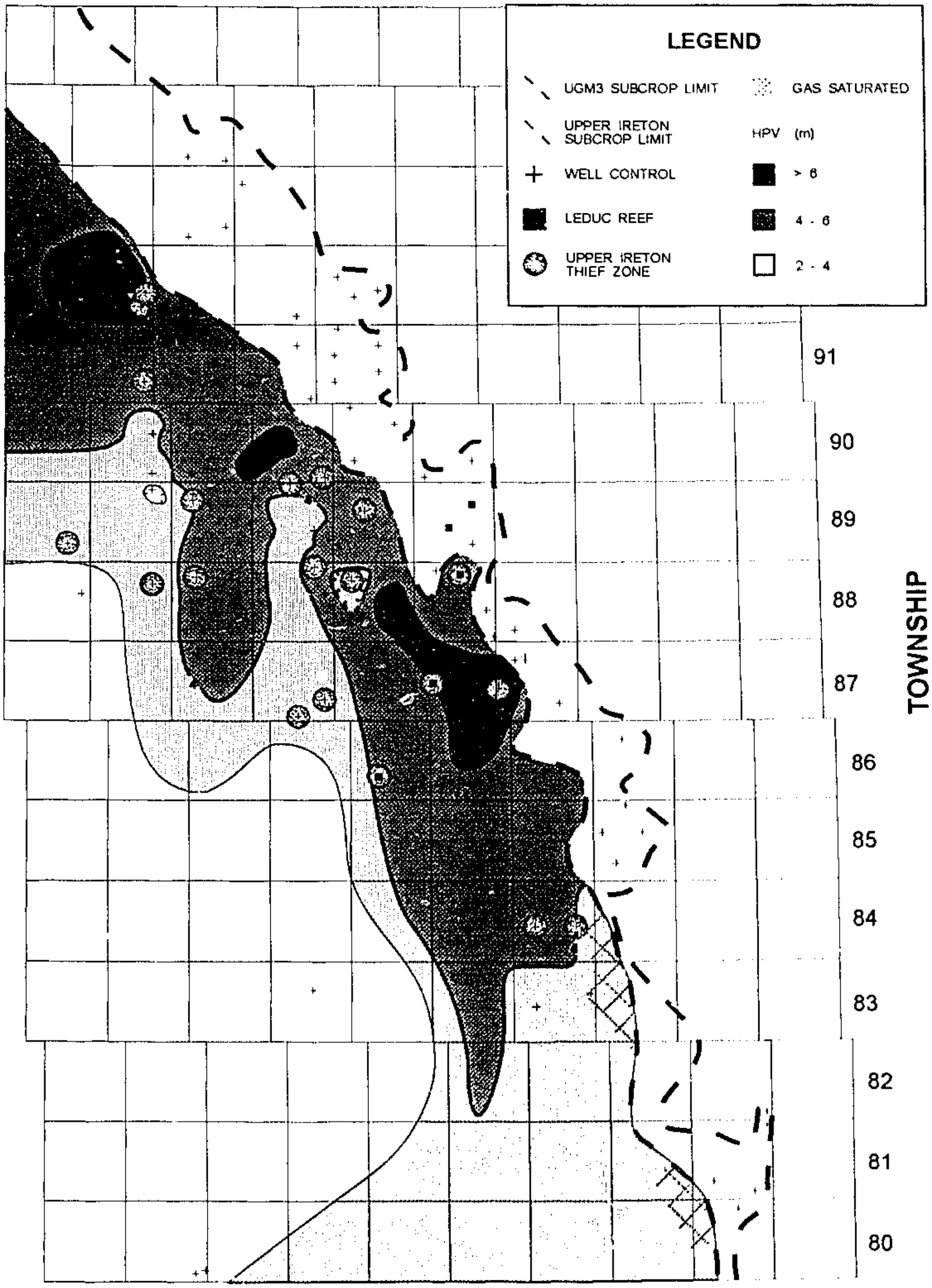


Fig. 9.6 Potential thermal recovery sites for the UGM2 using SB-3 as a seal.

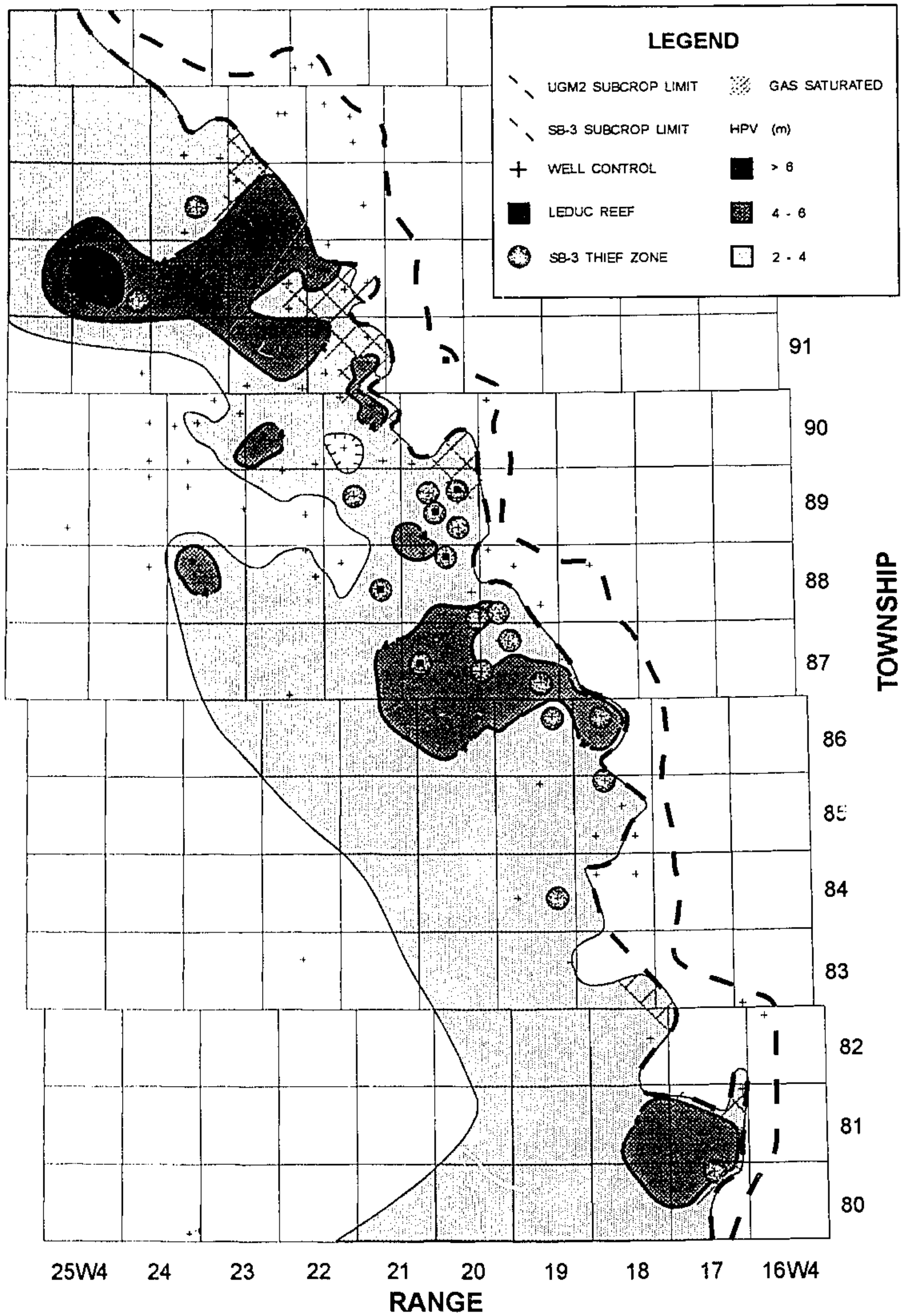


Fig. 9.7 Potential thermal recovery sites for the UGM1 using SB-2 as a seal.

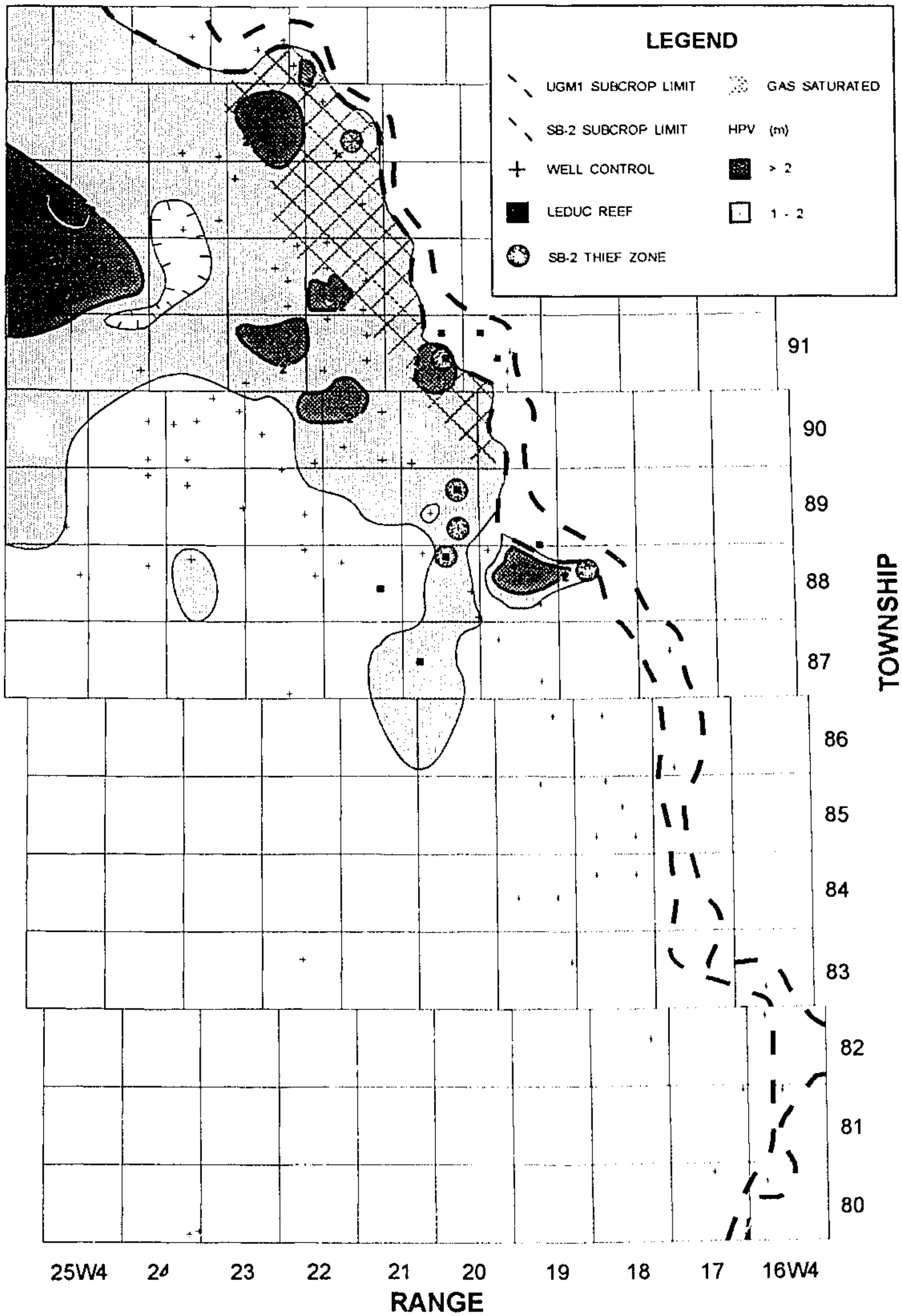
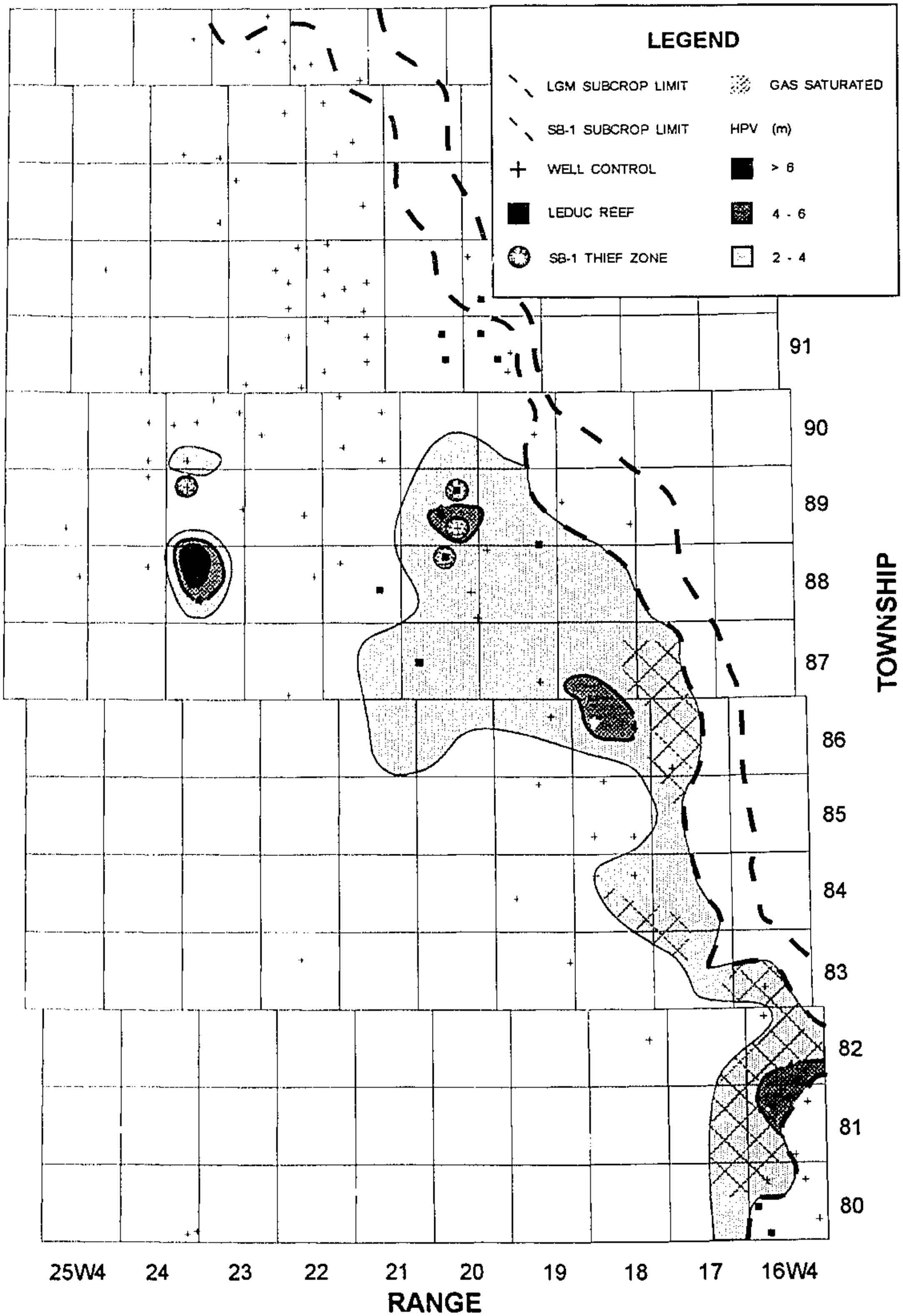


Fig. 9.8 Potential thermal recovery sites for the LGM using SB-1 as a seal.



CHAPTER 10

CONCLUSIONS

The prime objective of this thesis is to identify targets for the thermal recovery of bitumen from the Grosmont Formation as well as from the juxtaposed Upper Ireton and Nisku Formation. As a result of the analysis of over 200 wells, this goal was accomplished and the following conclusions have been drawn.

1. The Upper Devonian Grosmont Formation is a giant heavy oil deposit and contains up to 50 X 10^9 m^3 (264 X 10^9 bbl) of bitumen. However, the bitumen cannot be exploited until the gas fields located along the updip erosional edge are depleted. Currently, the gas production is declining, and as of 1991 only approximately 30% of the initial gas reserves (e.g., Liege, Saleski, House, and Granor) are remaining (E.R.C.B., 1991). However, the date of gas depletion is unknown because it appears that the gas reserves are being replenished by in-situ bacterial activity.

2. When the gas is depleted, production of the bitumen via steam injection will still be risky. All of the potential Devonian seals have been breached by karst-related fractures to various degrees. An alternative, and possibly better seal, is the Cretaceous Clearwater Formation because it is a uniform, regionally extensive marine shale that is not karstified. In general, the Devonian seals in the lower stratigraphic units (e.g., SB-1) appear to be more effective than the higher seals (e.g., Upper Ireton shale, SB-3). However, the lower reservoir units (e.g., LGM) typically have the lowest bitumen saturations.

3. Well log evaluation of the reservoir and seal characteristics reveal that there are "sweet spots" in the Devonian strata that (i) are highly bitumen saturated and (ii) appear to have an effective seal. Therefore, once the gas is depleted, the best targets are:

1. Nisku Formation capped by the Clearwater Formation.

2. UGM2 capped by SB-3 between Townships 90 and 95.
3. UGM1 capped by SB-2 between Townships 90 and 95.
4. LGM capped by SB-1 south of Township 88.
3. UGM3 capped by the Clearwater Formation.

A secondary objective was to investigate the Leduc reefs underlying the Grosmont Formation. Results from this study reveal that:

4. The Leduc-Cooking Lake contact can be identified in the study area by using resistivity logs.

5. Leduc reefs have been truncated by the sub-Cretaceous unconformity and are capped by the McMurray Formation.

6. There is a pronounced thinning of the LGM north of Township 86 over Leduc reefs.

7. There are three communication zones between the Grosmont and Leduc Formations where the Lower Ireton is less than 6 m thick.

8. The margin of the Cooking Lake platform probably acted as a conduit for Duvernay-sourced oil and may have leaked oil into Leduc reefs in northeastern Alberta.

Additional results that arose from well log analysis show that:

9. Calculations between core and well log analyses may not be the same due to high vuggy porosity and lost core.

10. Sonic logs usually have severe cycle skipping problems due to the intense fracturing and "caves" (borehole washouts in clean carbonate sections). Therefore, the sonic log was not used in porosity calculations. The neutron-density response, alternatively, generally yields good porosity values in fractured intervals, but within "caves" the readings may go off scale due to lost pad contact.

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APPENDIX 1: UNCONFORMITY DATA

Pages 177-180

UNCONFORMITY DATA								
TWN	WELL ID					ELEVATION (m)	UNIT EXPOSED (DEVONIAN)	UNIT DEPOSITED (CRETACEOUS)
	LSD	SEC	TWN	RGE	MER			
T 80	10	5	80	16	W4M	168.3	LGM	MCM
	11	12	80	16	W4M	179.8	LGM	MCM
	10	18	80	16	W4M	184.6	LGM	MCM
	11	26	80	16	W4M	188.2	LGM	MCM
	11	29	80	16	W4M	207.2	UGM1	MCM
	6	34	80	17	W4M	217.8	UGM3	MCM
	10	27	80	18	W4M	203.2	NISKU	MCM
	12	1	80	24	W4M	98.8	BLUERIDGE	MCM
	16	1	80	24	W4M	98.6	BLUERIDGE	MCM
T 81	10	3	81	16	W4M	202.9	LGM	MCM
	6	6	81	16	W4M	224.2	UGM2	MCM
	10	16	81	16	W4M	216.9	LGM	MCM
	11	18	81	16	W4M	240.7	UGM2	MCM
	10	26	81	16	W4M	224.8	LGM	MCM
	11	28	81	16	W4M	226.2	UGM1	MCM
	11	29	81	16	W4M	240.3	UGM2	MCM
	11	31	81	16	W4M	251.4	UGM2	MCM
	10	33	81	16	W4M	232.5	UGM1	MCM
	10	2	81	17	W4M	240.2	UGM3	MCM
	7	8	81	17	W4M	226.8	UGM3	MCM
	10	27	81	17	W4M	218.2	UGM2	MCM
	10	36	81	17	W4M	251.4	UGM3	MCM
T 82	10	23	82	16	W4M	266.9	UGM1	MCM
	6	32	82	16	W4M	261.1	UGM2	MCM
	6	34	82	16	W4M	263.9	UGM1	MCM
	6	36	82	16	W4M	258.7	LGM	MCM
	10	1	82	17	W4M	248.9	UGM3	MCM
	10	1	82	18	W4M	209.6	UGM2	MCM
	10	23	82	18	W4M	228.4	UGM3	WAB
	10	36	82	22	W4M	199.1	BLUERIDGE	WAB
T 83	7	6	83	16	W4M	263.1	UGM2	MCM
	11	9	83	16	W4M	257.7	UGM1	MCM
	6	14	83	16	W4M	232.2	LGM	MCM
	11	25	83	17	W4M	228.9	LGM	MCM
	11	34	83	17	W4M	239.8	UGM1	MCM
	6	27	83	18	W4M	250.9	UGM3	MCM
	10	17	83	19	W4M	238.6	NISKU	WAB
	10	24	83	19	W4M	258.6	NISKU	WAB
	13	22	83	22	W4M	170.4	BLUERIDGE	MCM
T 84	11	30	84	16	W4M	226.8	LGM	MCM
	11	12	84	18	W4M	237.1	UGM2	MCM
	7	26	84	18	W4M	235.4	UGM2	MCM
	7	29	84	18	W4M	222.3	UGM2	MCM
	10	14	84	19	W4M	254.3	U. IRETON	WAB
	10	17	84	19	W4M	244.3	U. IRETON	WAB
	7	36	84	23	W4M	198.0	BLUERIDGE	MCM
T 85	11	15	85	17	W4M	249.3	LGM	MCM
	7	8	85	18	W4M	271.8	UGM3	MCM
	7	11	85	18	W4M	256.0	UGM2	MCM
	10	19	85	18	W4M	273.8	UGM3	MCM
	10	22	85	18	W4M	280.1	UGM3	WAB
	11	33	85	18	W4M	286.9	UGM3	WAB
	6	34	85	19	W4M	275.0	U. IRETON	WAB
	10	20	85	21	W4M	226.0	NISKU	WAB
	10	15	85	22	W4M	252.3	BLUERIDGE	WAB
	8	17	85	25	W4M	163.8	WABAMUN	WAB
T 86	10	5	86	17	W4M	266.6	UGM1	MCM
	10	3	86	18	W4M	280.4	UGM2	WAB
	7	24	86	18	W4M	288.7	UGM2	WAB
	12	28	86	18	W4M	289.6	UGM3	WAB
	11	26	86	19	W4M	286.5	UGM3	WAB
	13	9	86	21	W4M	217.4	NISKU	WAB
	11	21	87	17	W4M	295.0	UGM1	WAB
	14	3	87	18	W4M	286.6	UGM2	WAB
	7	11	87	19	W4M	287.9	UGM3	WAB
	5	18	87	19	W4M	277.0	U. IRETON	WAB

UNCONFORMITY DATA								
TWN	WELL ID					ELEVATION (m)	UNIT EXPOSED (DEVONIAN)	UNIT DEPOSITED (CRETACEOUS)
	LSD	SEC	TWN	RGE	MER			
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	13	28	87	19	W4M	282.3	UGM3	MCM
	11	29	87	19	W4M	278.7	UGM3	MCM
	13	33	87	19	W4M	282.7	UGM3	MCM
	14	17	87	20	W4M	235.6	U.IRETON	WAB
	11	26	87	20	W4M	271.0	U.IRETON	WAB
	6	3	87	22	W4M	210.4	NISKU	WAB
	11	12	87	22	W4M	218.0	NISKU	WAB
	10	33	87	25	W4M	174.9	BLUERIDGE	WAB
T 88	6	28	88	18	W4M	288.6	UGM2	MCM
	14	5	88	19	W4M	278.7	UGM3	MCM
	7	11	88	19	W4M	269.0	UGM2	MCM
	7	28	88	19	W4M	265.2	UGM2	MCM
	10	31	88	19	W4M	249.9	UGM2	MCM
	8	1	88	20	W4M	277.2	UGM3	MCM
	6	13	88	20	W4M	252.0	UGM3	MCM
	7	32	88	20	W4M	240.3	UGM3	WAB
	3	34	88	20	W4M	285.1	U. IRETON	CLW
	11	14	88	21	W4M	249.5	U. IRETON	WAB
	11	29	88	21	W4M	249.5	U. IRETON	WAB
	11	24	88	22	W4M	253.5	NISKU	CLW
	10	35	88	22	W4M	267.9	NISKU	CLW
	16	29	88	23	W4M	237.3	NISKU	CLW
	10	35	88	23	W4M	249.3	NISKU	CLW
	5	11	88	24	W4M	200.5	NISKU	WAB
	7	26	88	24	W4M	211.4	NISKU	CLW
	4	32	88	24	W4M	217.0	NISKU	CLW
	7	35	88	24	W4M	214.9	NISKU	CLW
	11	24	88	25	W4M	204.1	NISKU	CLW
T 89	10	12	89	18	W4M	295.3	LGM	MCM
	6	19	89	18	W4M	259.7	LGM	MCM
	2	2	89	19	W4M	264.2	UGM1	MCM
	10	16	89	19	W4M	245.2	UGM1	MCM
	10	30	89	19	W4M	261.7	UGM2	MCM
	6	11	89	20	W4M	273.7	UGM3	WAB
	10	16	89	20	W4M	190.5	UGM2	WAB
	6	26	89	20	W4M	270.1	UGM3	WAB
	4	28	89	20	W4M	259.3	UGM3	WAB
	6	7	89	21	W4M	274.1	NISKU	CLW
	14	21	89	21	W4M	284.1	U. IRETON	WAB
	6	25	89	21	W4M	273.0	UGM3	WAB
	7	14	89	22	W4M	272.1	NISKU	CLW
	16	33	89	22	W4M	271.2	NISKU	CLW
	16	13	89	23	W4M	257.6	NISKU	CLW
	10	29	89	23	W4M	250.2	NISKU	CLW
	7	35	89	24	W4M	239.8	NISKU	CLW
	12	7	89	25	W4M	200.2	NISKU	CLW
	6	11	89	25	W4M	208.5	NISKU	CLW
T 90	11	9	90	18	W4M	273.8	LGM	MCM
	11	14	90	19	W4M	266.9	LGM	MCM
	10	22	90	19	W4M	284.0	UGM1	MCM
	7	31	90	19	W4M	281.9	UGM2	WAB
	8	6	90	20	W4M	249.3	UGM3	WAB
	11	11	90	20	W4M	283.6	UGM3	WAB
	10	2	90	21	W4M	272.4	UGM3	WAB
	10	8	90	21	W4M	263.9	UGM3	WAB
	7	26	90	21	W4M	281.6	UGM3	WAB
	11	32	90	21	W4M	286.6	UGM3	WAB
	6	1	90	22	W4M	277.9	U. IRETON	CLW
	11	17	90	22	W4M	269.4	NISKU	CLW
	7	28	90	22	W4M	273.9	U. IRETON	CLW
	10	5	90	23	W4M	230.7	NISKU	CLW
	7	19	90	23	W4M	264.9	NISKU	CLW
	11	21	90	23	W4M	273.0	NISKU	CLW
	7	25	90	23	W4M	271.8	NISKU	CLW
	7	34	90	23	W4M	269.0	NISKU	CLW

UNCONFORMITY DATA								
TWN	WELL ID					ELEVATION (m)	UNIT EXPOSED (DEVONIAN)	UNIT DEPOSITED (CRETACEOUS)
	LSD	SEC	TWN	RGE	MER			
	10	2	90	24	W4M	232.5	NISKU	CLW
	10	23	90	24	W4M	252.8	NISKU	CLW
T 91	10	9	91	17	W4M	268.5	LEDUC	MCM
	6	33	91	17	W4M	254.2	LEDUC	MCM
	7	14	91	18	W4M	255.8	LEDUC	MCM
	10	26	91	18	W4M	260.3	LEDUC	MCM
	6	3	91	19	W4M	285.5	UGM1	MCM
	11	10	91	19	W4M	286.0	UGM1	MCM
	10	16	91	19	W4M	281.3	UGM1	MCM
	2	22	91	19	W4M	286.8	UGM1	MCM
	11	29	91	19	W4M	273.2	UGM1	MCM
	8	32	91	19	W4M	INC	INC	INC
	8	35	91	19	W4M	262.0	LGM	MCM
	10	14	91	20	W4M	279.1	UGM2	WAB
	11	26	91	20	W4M	274.5	UGM1	WAB
	11	28	91	20	W4M	285.6	UGM2	WAB
	10	1	91	21	W4M	262.7	UGM2	WAB
	11	8	91	21	W4M	283.9	UGM3	CLW
	7	14	91	21	W4M	290.4	UGM3	WAB
	11	20	91	21	W4M	270.5	UGM3	CLW
	7	26	91	21	W4M	293.1	UGM3	WAB
	10	32	91	21	W4M	286.2	UGM3	CLW
	7	1	91	22	W4M	267.7	UGM3	CLW
	11	5	91	22	W4M	264.2	U. IRETON	CLW
	7	26	91	22	W4M	274.1	UGM3	CLW
	11	12	91	24	W4M	244.2	NISKU	CLW
	10	34	91	24	W4M	240.4	NISKU	CLW
T 92	10	5	92	18	W4M	264.4	LEDUC	MCM
	7	12	92	18	W4M	259.2	LEDUC	MCM
	10	25	92	18	W4M	259.5	LEDUC	MCM
	6	8	92	19	W4M	279.1	LGM	MCM
	10	16	92	19	W4M	263.5	LGM	MCM
	11	30	92	19	W4M	276.5	LGM	MCM
	6	35	92	19	W4M	254.9	LEDUC	MCM
	11	8	92	20	W4M	311.4	UGM2	WAB
	6	2	92	21	W4M	295.0	UGM3	WAB
	11	8	92	21	W4M	291.0	UGM3	CLW
	10	14	92	21	W4M	308.0	UGM3	CLW
	1	16	92	21	W4M	301.0	UGM3	CLW
	10	20	92	21	W4M	303.2	UGM3	CLW
	10	32	92	21	W4M	305.9	UGM2	CLW
	10	2	92	22	W4M	281.6	UGM3	CLW
	10	14	92	22	W4M	287.9	UGM3	CLW
	10	21	92	22	W4M	280.6	UGM3	CLW
	10	22	92	22	W4M	284.8	UGM3	CLW
	6	36	92	22	W4M	300.3	UGM3	CLW
	5	12	92	24	W4M	246.2	U. IRETON	CLW
	7	13	92	24	W4M	241.6	U. IRETON	CLW
	10	21	92	24	W4M	234.7	U. IRETON	CLW
T 93	7	12	93	18	W4M	281.6	LEDUC	MCM
	11	21	93	18	W4M	276.2	LEDUC	MCM
	10	4	93	19	W4M	272.9	LEDUC	MCM
	7	12	93	19	W4M	266.8	LEDUC	MCM
	7	22	93	19	W4M	266.0	LEDUC	MCM
	5	12	93	20	W4M	297.1	LGM	WAB
	5	25	93	20	W4M	287.6	LGM	MCM
	11	14	93	21	W4M	303.2	UGM2	WAB
	10	30	93	22	W4M	273.1	UGM3	CLW
	10	4	93	23	W4M	258.5	UGM3	CLW
	6	12	93	23	W4M	268.1	UGM3	CLW
	10	15	93	23	W4M	261.7	UGM3	CLW
	4	25	93	24	W4M	248.8	UGM3	CLW
	11	24	93	25	W4M	229.5	U. IRETON	CLW
	10	33	93	25	W4M	223.6	U. IRETON	CLW
	6	21	94	18	W4M	277.5	LEDUC	MCM
	9	35	94	18	W4M	266.7	LEDUC	MCM

UNCONFORMITY DATA								
TWN	WELL ID					ELEVATION (m)	UNIT EXPOSED (DEVONIAN)	UNIT DEPOSITED (CRETACEOUS)
	LSD	SEC	TWN	RGE	MER			
T 94	9	1	94	19	W4M	283.7	LEDUC	MCM
	7	24	94	19	W4M	280.8	LEDUC	MCM
	11	4	94	21	W4M	309.5	UGM2	CLW
	6	8	94	21	W4M	306.0	UGM2	CLW
	10	10	94	21	W4M	320.1	UGM2	CLW
	10	17	94	21	W4M	299.4	UGM2	CLW
	11	22	94	21	W4M	304.6	UGM2	CLW
	11	29	94	21	W4M	301.3	UGM2	CLW
	16	22	94	22	W4M	284.6	UGM2	CLW
	14	23	94	22	W4M	295.5	UGM2	CLW
	11	33	94	22	W4M	285.2	UGM2	CLW
	6	1	94	23	W4M	275.3	UGM3	CLW
	10	4	94	23	W4M	261.9	UGM3	CLW
	12	7	94	23	W4M	252.9	UGM3	CLW
	10	24	94	24	W4M	253.0	UGM3	CLW
T 95	7	4	95	18	W4M	279.9	LEDUC	MCM
	4	13	95	18	W4M	272.1	LEDUC	MCM
	6	27	95	18	W4M	278.3	LEDUC	MCM
	6	1	95	21	W4M	271.9	LGM	CLW
	6	7	95	21	W4M	296.5	UGM2	CLW
	10	8	95	21	W4M	300.3	UGM2	CLW
	11	10	95	21	W4M	283.8	LGM	CLW
	10	15	95	22	W4M	281.5	UGM1	CLW
	7	24	95	22	W4M	286.7	UGM1	CLW
	6	35	95	22	W4M	269.3	LGM	CLW
	10	23	95	23	W4M	249.2	UGM1	CLW

CLW = CLEARWATER FORMATION
WAB = WABISKAW MEMBER
MCM = McMURRAY FORMATION

WABAMUN = WABAMUN GROUP
BLUERIDGE = BLUERIDGE MEMBER
NISKU = NISKU FORMATION
U. IRETON = UPPER IRETON
UGM3 = UPPER GROSMONT 3
UGM2 = UPPER GROSMONT 2
UGM1 = UPPER GROSMONT 1
LGM = LOWER GROSMONT
LEDUC = LEDUC FORMATION

INC = INCOMPLETE LOG SUITE

APPENDIX 2: "CAVE" DISTRIBUTION

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"CAVE" DISTRIBUTION

TWN	WELL ID LSD	SEC	TWN	RGE	MER	LEDUC	LGM	UGM1	UGM2	UGM3	U. IRETON	NISKU
T 80	10	5	80	16	W4M	NO	NO	E	E	E	E	E
	11	12	80	16	W4M		CAVE	E	E	E	E	E
	10	18	80	16	W4M	NO	NO	E	E	E	E	E
	11	26	80	16	W4M		NO	E	E	E	E	E
	11	29	80	16	W4M		NO	NO	E	E	E	E
	6	34	80	17	W4M		NO	NO	CAVE	NO	E	E
	10	27	80	18	W4M		N/P	N/P	N/P	N/P	N/P	CAVE
	12	1	80	24	W4M		NO	NO	NO	NO	CAVE	CAVE
	16	1	80	24	W4M		NO	NO	NO	NO	NO	NO
T 81	10	3	81	16	W4M		NO	E	E	E	E	E
	6	6	81	16	W4M		N/P	N/P	N/P	E	E	E
	10	16	81	16	W4M		NO	E	E	E	E	E
	11	18	81	16	W4M		NO	NO	NO	E	E	E
	10	26	81	16	W4M		NO	E	E	E	E	E
	11	28	81	16	W4M		NO	NO	E	E	E	E
	11	29	81	16	W4M		N/P	N/P	N/P	E	E	E
	11	31	81	16	W4M		N/P	N/P	NC	E	E	E
	10	33	81	16	W4M		NO	NO	E	E	E	E
	10	2	81	17	W4M		N/P	N/P	NO	NO	E	E
	7	8	81	17	W4M		NO	NO	NO	CAVE	E	E
	10	27	81	17	W4M		N/P	N/P	INC	E	E	E
	10	36	81	17	W4M		NO	NO	NO	NO	E	E
T 82	10	23	82	16	W4M		INC	INC	E	E	E	E
	6	32	82	16	W4M		NO	NO	NO	E	E	E
	6	34	82	16	W4M		OLD	OLD	E	E	E	E
	6	36	82	16	W4M		NO	E	E	E	E	E
	10	1	82	17	W4M		OLD	OLD	OLD	OLD	E	E
	10	1	82	18	W4M		OLD	OLD	OLD	E	E	E
	10	23	82	16	W4M		NO	NO	NO	NO	E	E
	10	36	82	22	W4M	NO	NO	NO	NO	NO	NO	NO
T 83	7	6	83	16	W4M		NO	NO	NO	E	E	E
	11	9	83	16	W4M		INC	INC	E	E	E	E
	6	14	83	16	W4M		OLD	E	E	E	E	E
	11	25	83	17	W4M		NO	E	E	E	E	E
	11	34	83	17	W4M		OLD	OLD	E	E	E	E
	6	27	83	18	W4M		N/P	N/P	N/P	NO	E	E
	10	17	83	19	W4M		N/P	N/P	N/P	NO	NO	NO
	10	24	83	19	W4M		NO	NO	NO	NO	NO	NO
	13	22	83	22	W4M		NO	NO	CAVE	CAVE	CAVE	CAVE
T 84	11	30	84	16	W4M		NO	E	E	E	E	E
	11	12	84	18	W4M		OLD	OLD	OLD	E	E	E
	7	26	84	18	W4M		NO	NO	NO	E	E	E
	7	29	84	18	W4M		NO	NO	CAVE	E	E	E
	10	14	84	19	W4M		NO	NO	CAVE	CAVE	CAVE	E
	10	17	84	19	W4M		NO	NO	NO	CAVE	CAVE	E
	7	36	84	23	W4M		NO	NO	NO	CAVE	CAVE	CAVE
T 85	11	15	85	17	W4M		NO	E	E	E	E	E
	7	8	85	18	W4M		NO	NO	NO	CAVE	E	E
	7	11	85	18	W4M		NO	NO	CAVE	E	E	E
	10	19	85	18	W4M		INC	INC	INC	INC	E	E
	10	22	85	18	W4M		NO	NO	NO	NO	E	E
	11	33	85	18	W4M		NO	NO	CAVE	CAVE	E	E
	6	34	85	19	W4M		NO	NO	NO	NO	NO	NO
	10	20	85	21	W4M	INC	INC	INC	INC	INC	INC	INC
	10	15	85	22	W4M		OLD	OLD	OLD	OLD	OLD	OLD
	8	17	85	25	W4M		OLD	OLD	OLD	OLD	OLD	OLD
T 86	10	5	86	17	W4M		NO	NO	E	E	E	E
	10	3	86	18	W4M		OLD	OLD	OLD	E	E	E
	7	24	86	18	W4M		OLD	OLD	OLD	E	E	E
	12	28	86	18	W4M		NO	NO	CAVE	CAVE	E	E
	11	26	86	19	W4M		NO	NO	CAVE	CAVE	E	E
	13	9	86	21	W4M	NO	NO	NO	NO	CAVE	CAVE	CAVE
	11	21	87	17	W4M		NO	CAVE	E	E	E	E
	14	3	87	18	W4M		OLD	OLD	OLD	E	E	E
	7	11	87	19	W4M		NO	NO	CAVE	CAVE	E	E
	5	18	87	19	W4M		NO	NO	CAVE	CAVE	CAVE	E

"CAVE" DISTRIBUTION

TWN	WELL ID LSD	SEC	TWN	RGE	MER	LEDUC	LGM	UGM1	UGM2	UGM3	U. IRETON	NISKU
T 87	12	28	87	19	W4M		N/P	N/P	CAVE	CAVE	E	E
	13	28	87	19	W4M		N/P	N/P	INC	INC	E	E
	11	29	87	19	W4M		NO	NO	NO	CAVE	E	E
	13	33	87	19	W4M		N/P	N/P	N/P	CAVE	E	E
	14	17	87	20	W4M	NO	NO	NO	CAVE	CAVE	CAVE	E
	11	26	87	20	W4M	INC	INC	INC	INC	INC	INC	E
	6	3	87	22	W4M		NO	NO	NO	NO	CAVE	CAVE
	11	12	87	22	W4M		NO	NO	NO	CAVE	CAVE	CAVE
	10	33	87	25	W4M		NO	NO	NO	CAVE	CAVE	CAVE
T 88	6	28	88	18	W4M		N/P	CAVE	CAVE	E	E	E
	14	5	88	19	W4M		NO	NO	CAVE	CAVE	E	E
	7	11	88	19	W4M		NO	NO	CAVE	E	E	E
	7	28	88	19	W4M		NO	NO	NO	E	E	E
	10	31	88	19	W4M		NO	NO	NO	E	E	E
	8	1	88	20	W4M		NO	NO	CAVE	CAVE	E	E
	6	13	88	20	W4M		NO	NO	NO	NO	E	E
	7	32	88	20	W4M		NO	NO	NO	NO	E	E
	3	34	88	20	W4M	CAVE	CAVE	CAVE	CAVE	CAVE	CAVE	E
	11	14	88	21	W4M	NO	NO	NO	CAVE	NO	NO	E
	11	29	88	21	W4M		NO	NO	NO	NO	CAVE	E
	11	24	88	22	W4M		NO	NO	NO	NO	NO	CAVE
	10	35	88	22	W4M		NO	NO	NO	NO	CAVE	CAVE
	16	29	88	23	W4M		NO	NO	NO	CAVE	CAVE	CAVE
	10	35	88	23	W4M		NO	NO	NO	NO	NO	NO
	5	11	88	24	W4M		INC	INC	INC	INC	INC	INC
	7	26	88	24	W4M		NO	NO	NO	CAVE	CAVE	CAVE
	4	32	88	24	W4M		N/P	N/P	OLD	OLD	OLD	OLD
	7	35	88	24	W4M		N/P	N/P	N/P	N/P	NO	NO
	11	24	88	25	W4M		NO	NO	NO	CAVE	CAVE	CAVE
T 89	10	12	89	18	W4M		NO	E	E	E	E	E
	6	19	89	18	W4M		NO	E	E	E	E	E
	2	2	89	19	W4M	NO	NO	CAVE	E	E	E	E
	10	16	89	19	W4M	INC	INC	E	E	E	E	E
	10	30	89	19	W4M		N/P	N/P	N/P	E	E	E
	6	11	89	20	W4M		CAVE	CAVE	CAVE	CAVE	E	E
	10	16	89	20	W4M	INC	INC	INC	INC	E	E	E
	6	26	89	20	W4M	CAVE	CAVE	CAVE	CAVE	CAVE	E	E
	4	28	89	20	W4M		NO	NO	CAVE	CAVE	E	E
	6	7	89	21	W4M		N/P	N/P	N/P	NO	NO	CAVE
	14	21	89	21	W4M		N/P	N/P	CAVE	CAVE	CAVE	E
	6	25	89	21	W4M	INC	INC	INC	INC	INC	E	E
	7	14	89	22	W4M		NO	NO	NO	NO	NO	CAVE
	16	33	89	22	W4M		NO	NO	NO	NO	CAVE	CAVE
	16	13	89	23	W4M		NO	NO	NO	NO	NO	CAVE
	10	29	89	23	W4M		CAVE	CAVE	CAVE	CAVE	CAVE	CAVE
	7	35	89	24	W4M		NO	NO	NO	NO	NO	CAVE
	12	7	89	25	W4M		OLD	OLD	OLD	OLD	OLD	OLD
	6	11	89	25	W4M		NO	NO	NO	CAVE	CAVE	CAVE
T 90	11	9	90	18	W4M	NO	NO	E	E	E	E	E
	11	14	90	19	W4M		NO	E	E	E	E	E
	10	22	90	19	W4M		N/P	E	E	E	E	E
	7	31	90	19	W4M		N/P	N/P	NO	E	E	E
	8	6	90	20	W4M		N/P	NO	NO	NO	E	E
	11	11	90	20	W4M		N/P	N/P	N/P	CAVE	E	E
	10	2	90	21	W4M		NO	NO	NO	NO	E	E
	10	8	90	21	W4M		NO	NO	NO	NO	E	E
	7	26	90	21	W4M		NO	NO	NO	CAVE	E	E
	11	32	90	21	W4M		NO	NO	NO	NO	E	E
	6	1	90	22	W4M		NO	NO	NO	NO	CAVE	E
	11	17	90	22	W4M		NO	NO	NO	NO	NO	CAVE
	7	28	90	22	W4M		N/P	N/P	N/P	N/P	N/P	E
	10	5	90	23	W4M		NO	NO	NO	NO	NO	CAVE
	7	19	90	23	W4M		NO	NO	NO	NO	NO	NO
	11	21	90	23	W4M		NO	NO	NO	NO	NO	CAVE
	7	25	90	23	W4M		NO	NO	NO	NO	NO	NO
	7	34	90	23	W4M		NO	NO	NO	NO	NO	CAVE

"CAVE" DISTRIBUTION

TWN	WELL ID LSD	SEC	TWN	RGE	MER	LEDUC	LGM	UGM1	UGM2	UGM3	U. IRETON	NISKU
	10	2	90	24	W4M		NO	NO	NO	NO	NO	NO
	10	23	90	24	W4M		NO	NO	NO	NO	NO	NO
T 91	10	9	91	17	W4M	INC	E	E	E	E	E	E
	6	33	91	17	W4M	NO	E	E	E	E	E	E
	7	14	91	18	W4M	CAVE	E	E	E	E	E	E
	10	26	91	18	W4M	NO	E	E	E	E	E	E
	6	3	91	19	W4M		N/P	NO	E	E	E	E
	11	10	91	19	W4M		NO	NO	E	E	E	E
	10	16	91	19	W4M	NO	NO	NO	E	E	E	E
	2	22	91	19	W4M		NO	NO	E	E	E	E
	11	29	91	19	W4M	NO	NO	NO	E	E	E	E
	8	32	91	19	W4M	NO	NO	INC	E	E	E	E
	8	35	19	19	W4M	NO	NO	E	E	E	E	E
	10	14	91	20	W4M	NO	NO	CAVE	NO	E	E	E
	11	26	91	20	W4M	NO	NO	NO	E	E	E	E
	11	28	91	20	W4M		NO	NO	NO	E	E	E
	10	1	91	21	W4M		INC	INC	CAVE	E	E	E
	11	8	91	21	W4M		NO	NO	NO	NO	E	E
	7	14	91	21	W4M		NO	NO	NO	NO	E	E
	11	20	91	21	W4M		N/P	N/P	N/P	NO	E	E
	7	26	91	21	W4M		NO	NO	NO	NO	E	E
	10	32	91	21	W4M		NO	NO	NO	CAVE	E	E
	7	1	91	22	W4M		N/P	N/P	N/P	NO	E	E
	11	5	91	22	W4M		NO	NO	NO	NO	NO	E
	7	26	91	22	W4M		NO	NO	NO	NO	E	E
	11	12	91	24	W4M		NO	NO	CAVE	CAVE	CAVE	CAVE
	10	34	91	24	W4M	INC	INC	INC	INC	INC	INC	INC
T 92	10	5	92	18	W4M	NO	E	E	E	E	E	E
	7	12	92	18	W4M	NO	E	E	E	E	E	E
	10	25	92	18	W4M	INC	E	E	E	E	E	E
	6	8	92	19	W4M	NO	NO	E	E	E	E	E
	10	16	92	19	W4M	NO	NO	E	E	E	E	E
	11	30	92	19	W4M		NO	E	E	E	E	E
	6	35	92	19	W4M	CAVE	E	E	E	E	E	E
	11	8	92	20	W4M		N/P	N/P	INC	E	E	E
	6	2	92	21	W4M		NO	NO	NO	E	E	E
	11	8	92	21	W4M		NO	NO	NO	NO	E	E
	10	14	92	21	W4M		NO	NO	NO	NO	E	E
	1	16	92	21	W4M		NO	NO	NO	CAVE	E	E
	10	20	92	21	W4M		NO	NO	NO	NO	E	E
	10	32	92	21	W4M		NO	NO	NO	E	E	E
	10	2	92	22	W4M		NO	NO	NO	NO	E	E
	10	14	92	22	W4M		NO	NO	NO	CAVE	E	E
	10	21	92	22	W4M		N/P	N/P	N/P	N/P	E	E
	10	22	92	22	W4M		NO	NO	NO	NO	E	E
	6	36	92	22	W4M		NO	NO	NO	NO	E	E
	5	12	92	24	W4M		NO	NO	CAVE	CAVE	INC	E
	7	13	92	24	W4M		NO	NO	NO	CAVE	CAVE	E
	10	21	92	24	W4M		NO	NO	NO	CAVE	CAVE	E
T 93	7	12	93	18	W4M	INC	E	E	E	E	E	E
	11	21	93	18	W4M	INC	E	E	E	E	E	E
	10	4	93	19	W4M	NO	E	E	E	E	E	E
	7	12	93	19	W4M	NO	E	E	E	E	E	E
	7	22	93	19	W4M	NO	E	E	E	E	E	E
	5	12	93	20	W4M		N/P	E	E	E	E	E
	5	2[illegible]	93	20	W4M		N/P	E	E	E	E	E
	11	14	93	21	W4M		NO	NO	NO	E	E	E
	10	30	93	22	W4M		NO	NO	NO	NO	E	E
	10	4	93	23	W4M		NO	NO	NO	CAVE	E	E
	6	12	93	23	W4M		NO	NO	NO	NO	E	E
	10	15	93	23	W4M		N/P	N/P	CAVE	CAVE	E	E
	4	25	93	24	W4M		INC	INC	INC	INC	E	E
	11	24	93	25	W4M		INC	INC	INC	INC	INC	E
	10	33	93	25	W4M		INC	INC	INC	INC	INC	E
	6	21	94	18	W4M	INC	E	E	E	E	E	E
	9	35	94	18	W4M	INC	E	E	E	E	E	E

"CAVE" DISTRIBUTION

TWN	WELL ID LSD	SEC	TWN	RGE	MER	LEDUC	LGM	UGM1	UGM2	UGM3	U. IRETON	NISKU
T 94	9	1	94	19	W4M	INC	E	E	E	E	E	E
	7	24	94	19	W4M	INC	E	E	E	E	E	E
	11	4	94	21	W4M		NO	NO	NO	E	E	E
	6	8	94	21	W4M		N/P	N/P	N/P	E	E	E
	10	10	94	21	W4M		NO	CAVE	CAVE	E	E	E
	10	17	94	21	W4M		NO	NO	NO	E	E	E
	11	22	94	21	W4M		INC	INC	INC	E	E	E
	11	29	94	21	W4M		NO	NO	NO	E	E	E
	16	22	94	22	W4M		INC	INC	INC	E	E	E
	14	23	94	22	W4M		NO	NO	NO	E	E	E
	11	33	94	22	W4M		NO	NO	NO	E	E	E
	6	1	94	23	W4M		NO	NO	NO	NO	E	E
	10	4	94	23	W4M		NO	NO	NO	NO	E	E
	12	7	94	23	W4M		INC	INC	INC	INC	E	E
	10	24	94	24	W4M		NO	INC	INC	INC	E	E
T 95	7	4	95	18	W4M	NO	E	E	E	E	E	E
	4	13	95	18	W4M	INC	E	E	E	E	E	E
	6	27	95	18	W4M	INC	E	E	E	E	E	E
	6	1	95	21	W4M		NO	E	E	E	E	E
	6	7	95	21	W4M		NO	NO	NO	E	E	E
	10	8	95	21	W4M		NO	NO	NO	E	E	E
	11	10	95	21	W4M		NO	E	E	E	E	E
	10	15	95	22	W4M		NO	NO	E	E	E	E
	7	24	95	22	W4M		NO	NO	E	E	E	E
	6	35	95	22	W4M		NO	E	E	E	E	E
	10	23	95	23	W4M		NO	NO	E	E	E	E
TOTAL NO. OF "CAVES"						4	5	9	28	41	25	25

E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE

NO = NO "CAVES" RECOGNIZED
CAVE = "CAVES" PRESENT

APPENDIX 3: RESERVOIR CHARACTERISTICS

NISKU RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 80	10	5	80	16	W4M	E	E	E	E	E	E
	11	12	80	16	W4M	E	E	E	E	E	E
	10	18	80	16	W4M	E	E	E	E	E	E
	11	26	80	16	W4M	E	E	E	E	E	E
	11	29	80	16	W4M	E	E	E	E	E	E
	6	34	80	17	W4M	E	E	E	E	E	E
	10	27	80	18	W4M	203.2	6.1	21.0	INC	INC	INC
	12	1	80	24	W4M	76.8	93.5	8.7	8.0	1.1	0.5
	16	1	80	24	W4M	81.1	90.5	10.6	6.0	0.8	0.4
T 81	10	3	81	16	W4M	E	E	E	E	E	E
	6	[illegible]	81	16	W4M	E	E	E	E	E	E
	10	16	81	16	W4M	E	E	E	E	E	E
	11	18	81	16	W4M	E	E	E	E	E	E
	10	26	81	16	W4M	E	E	E	E	E	E
	11	28	81	16	W4M	E	E	E	E	E	E
	11	29	81	16	W4M	E	E	E	E	E	E
	11	31	81	16	W4M	E	E	E	E	E	E
	10	33	81	16	W4M	E	E	E	E	E	E
	10	2	81	17	W4M	E	E	E	E	E	E
	7	8	81	17	W4M	E	[illegible]	E	E	E	E
	10	27	81	17	W4M	E	E	E	E	E	E
	10	36	81	17	W4M	E	E	E	E	E	E
T 82	10	23	82	16	W4M	E	E	E	E	E	E
	6	32	82	16	W4M	E	E	E	E	E	E
	6	34	82	16	W4M	E	E	E	E	E	E
	6	36	82	16	W4M	E	E	E	E	E	E
	10	1	82	17	W4M	E	E	E	E	E	E
	10	1	82	18	W4M	E	E	E	E	E	E
	10	23	82	18	W4M	E	E	E	E	E	E
	10	36	82	22	W4M	179.6	64.0	INC	INC	INC	INC
T 83	7	6	83	16	W4M	E	E	E	E	E	E
	11	9	83	16	W4M	E	E	E	E	E	E
	6	14	83	16	W4M	E	E	E	E	E	E
	11	25	83	17	W4M	E	E	E	E	E	E
	11	34	83	17	W4M	E	E	E	E	E	E
	6	27	83	18	W4M	E	E	E	E	E	E
	10	17	83	19	W4M	238.6	16.8	9.7	8.8	0.9	0.7
	10	24	83	19	W4M	258.6	8.0	15.0	2.5	0.3	0.2
	13	22	83	22	W4M	156.9	61.0	19.1	12.5	3.1	1.7
T 84	11	[illegible]	84	16	W4M	E	E	E	E	E	E
	11	12	84	18	W4M	E	E	E	E	E	E
	7	26	84	18	W4M	E	E	E	E	E	E
	7	29	84	18	W4M	E	E	E	E	E	E
	10	14	84	19	W4M	E	E	E	E	E	E
	10	17	84	19	W4M	E	E	E	E	E	E
	7	36	84	23	W4M	173.6	62.8	INC	INC	INC	INC
T 85	11	15	85	17	W4M	E	E	E	E	E	E
	7	8	85	18	W4M	E	E	E	E	E	E
	7	11	85	18	W4M	E	E	E	E	E	E
	10	19	85	18	W4M	E	E	E	E	E	E
	10	22	85	18	W4M	E	E	E	E	E	E
	11	33	85	18	W4M	E	E	E	E	E	E
	6	34	85	19	W4M	E	E	E	E	E	E
	10	20	85	21	W4M	226.0	48.8	INC	INC	INC	INC
	10	15	85	22	W4M	201.4	61.9	OLD	OLD	OLD	OLD
	8	17	85	25	W4M	94.3	94.0	OLD	OLD	OLD	OLD
T 86	10	5	86	17	W4M	E	E	E	E	E	E
	10	3	86	18	W4M	E	E	E	E	E	E
	7	24	86	18	W4M	E	E	E	E	E	E
	12	28	86	18	W4M	E	E	E	E	E	E
	11	26	86	19	W4M	E	E	E	E	E	E
	13	9	86	21	W4M	217.4	30.5	INC	INC	INC	INC
	11	21	87	17	W4M	E	E	E	E	E	E
	14	3	87	18	W4M	E	E	E	E	E	E
	7	11	87	19	W4M	E	E	E	E	E	E
	5	18	87	19	W4M	E	E	E	E	E	E

NISKU RESERVOIR CHARACTERISTICS

TWN	LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	12	28	87	19	W4M	E	E	E	E	E	E
	13	28	87	19	W4M	E	E	E	E	E	E
	11	29	87	19	W4M	E	E	E	E	E	E
	13	33	87	19	W4M	E	E	E	E	E	E
T 87	14	17	87	20	W4M	E	E	E	E	E	E
	11	26	87	20	W4M	E	E	E	E	E	E
	6	3	87	22	W4M	210.4	33.0	20.4	29.0	6.0	4.1
	11	12	87	22	W4M	218.0	26.5	INC	INC	INC	INC
	10	33	87	25	W4M	155.9	78.0	INC	INC	INC	INC
	6	28	88	18	W4M	E	E	E	E	E	E
	14	5	88	19	W4M	E	E	E	E	E	E
	7	11	88	19	W4M	E	E	E	E	E	E
	7	28	88	19	W4M	E	E	E	E	E	E
	10	31	88	19	W4M	E	E	E	E	E	E
	8	1	88	20	W4M	E	E	E	E	E	E
	6	13	88	20	W4M	E	E	E	E	E	E
	7	32	88	20	W4M	E	E	E	E	E	E
	3	34	88	20	W4M	E	E	E	E	E	E
	11	14	88	21	W4M	E	E	E	E	E	E
T 88	11	29	88	21	W4M	E	E	E	E	E	E
	11	24	88	22	W4M	253.5	19.8	21.6	19.2	4.2	3.2
	10	35	88	22	W4M	267.9	29.5	25.6	24.5	6.3	5.1
	16	29	88	23	W4M	237.3	63.5	19.2	53.5	10.3	7.3
	10	35	88	23	W4M	249.3	51.8	16.4	INC	INC	INC
	5	11	88	24	W4M	200.5	75.9	INC	INC	INC	INC
	7	26	88	24	W4M	211.4	64.5	23.2	51.5	12.0	8.1
	4	32	88	24	W4M	217.0	84.0	OLD	OLD	OLD	OLD
	7	35	88	24	W4M	214.9	62.5	24.2	51.5	12.5	9.9
	11	24	88	25	W4M	204.1	96.5	22.5	44.0	9.9	6.4
	10	12	89	18	W4M	E	E	E	E	E	E
	6	19	89	18	W4M	E	E	E	E	E	E
	2	2	89	19	W4M	E	E	E	E	E	E
	10	16	89	19	W4M	E	E	E	E	E	E
	10	30	89	19	W4M	E	E	E	E	E	E
	6	11	89	20	W4M	E	E	E	E	E	E
	10	16	89	20	W4M	E	E	E	E	E	E
	6	26	89	20	W4M	E	E	E	E	E	E
	4	28	89	20	W4M	E	E	E	E	E	E
	6	7	89	21	W4M	274.1	14.6	19.4	13.1	2.5	2.2
T 89	14	21	89	21	W4M	E	E	E	E	E	E
	6	25	89	21	W4M	E	E	E	E	E	E
	7	14	89	22	W4M	272.1	19.5	28.5	18.9	5.4	4.7
	16	33	89	22	W4M	271.2	13.7	34.1	12.5	4.3	3.8
	16	13	89	23	W4M	257.6	40.5	21.4	38.0	8.1	6.4
	10	29	89	23	W4M	250.2	48.5	25.6	39.0	10.0	8.0
	7	35	89	24	W4M	239.8	55.0	20.2	41.0	8.6	5.7
	12	7	89	25	W4M	200.2	88.4	OLD	OLD	OLD	OLD
	6	11	89	25	W4M	208.5	79.0	27.0	55.0	14.9	11.2
	11	9	90	18	W4M	E	E	E	E	E	E
	11	14	90	19	W4M	E	E	E	E	E	E
	10	22	90	19	W4M	E	E	E	E	E	E
	7	31	90	19	W4M	E	E	E	E	E	E
	8	6	90	20	W4M	E	E	E	E	E	E
	11	11	90	20	W4M	E	E	E	E	E	E
	10	2	90	21	W4M	E	E	E	E	E	E
	10	8	90	21	W4M	E	E	E	E	E	E
	7	26	90	21	W4M	E	E	E	E	E	E
	11	32	90	21	W4M	E	E	E	E	E	E
T 90	6	1	90	22	W4M	E	E	E	E	E	E
	11	17	90	22	W4M	269.4	7.9	33.1	4.9	1.6	1.4
	7	28	90	22	W4M	E	E	E	E	E	E
	10	5	90	23	W4M	230.7	17.5	29.2	12.0	3.5	2.9
	7	19	90	23	W4M	264.9	43.0	15.1	36.0	5.6	4.5
	11	21	90	23	W4M	273.0	34.8	23.4	32.0	7.5	6.3
	7	25	90	23	W4M	271.8	7.5	20.8	6.0	1.2	0.8
	7	34	90	23	W4M	269.0	19.0	18.3	17.5	3.2	2.7

NISKU RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	10	2	90	24	W4M	232.5	52.0	20.7	39.5	8.2	6.5
	10	23	90	24	W4M	252.8	40.0	21.5	30.5	6.6	4.8
	10	9	91	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	E	E	E	E	E	E
	11	10	91	19	W4M	E	E	E	E	E	E
	10	16	91	19	W4M	E	E	E	E	E	E
	2	22	91	19	W4M	E	E	E	E	E	E
	11	29	91	19	W4M	E	E	E	E	E	E
	8	32	91	19	W4M	E	E	E	E	E	E
	8	35	91	19	W4M	E	E	E	E	E	E
T 91	10	14	91	20	W4M	E	E	E	E	E	E
	11	26	91	20	W4M	E	E	E	E	E	E
	11	28	91	20	W4M	E	E	E	E	E	E
	10	1	91	21	W4M	E	E	E	E	E	E
	11	8	91	21	W4M	E	E	E	E	E	E
	7	14	91	21	W4M	E	E	E	E	E	E
	11	20	91	21	W4M	E	E	E	E	E	E
	7	28	91	21	W4M	E	E	E	E	E	E
	10	32	91	21	W4M	E	E	E	E	E	E
	7	1	91	22	W4M	E	E	E	E	E	E
	11	5	91	22	W4M	E	E	E	E	E	E
	7	26	91	22	W4M	E	E	E	E	E	E
	11	12	91	24	W4M	244.2	13.0	22.2	11.0	2.4	2.0
	10	34	91	24	W4M	240.4	7.9	INC	INC	INC	INC
	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	E	E	E	E	E	E
	10	16	92	19	W4M	E	E	E	E	E	E
	11	30	92	19	W4M	E	E	E	E	E	E
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	E	E	E	E	E	E
	6	2	92	21	W4M	E	E	E	E	E	E
	11	8	92	21	W4M	E	E	E	E	E	E
	10	14	92	21	W4M	E	E	E	E	E	E
T 92	1	16	92	21	W4M	E	E	E	E	E	E
	10	20	92	21	W4M	E	E	E	E	E	E
	10	32	92	21	W4M	E	E	E	E	E	E
	10	2	92	22	W4M	E	E	E	E	E	E
	10	14	92	22	W4M	E	E	E	E	E	E
	10	21	92	22	W4M	E	E	E	E	E	E
	10	22	92	22	W4M	E	E	E	E	E	E
	6	36	92	22	W4M	E	E	E	E	E	E
	5	12	92	24	W4M	E	E	E	E	E	E
	7	13	92	24	W4M	E	E	E	E	E	E
	10	21	92	24	W4M	E	E	E	E	E	E
	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	19	W4M	E	E	E	E	E	E
	7	12	93	19	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	E	E	E	E	E	E
	5	25	93	20	W4M	E	E	E	E	E	E
T 93	11	14	93	21	W4M	E	E	E	E	E	E
	10	30	93	22	W4M	E	E	E	E	E	E
	10	4	93	23	W4M	E	E	E	E	E	E
	6	12	93	23	W4M	E	E	E	E	E	E
	10	15	93	23	W4M	E	E	E	E	E	E
	4	25	93	24	W4M	E	E	E	E	E	E
	11	24	93	25	W4M	E	E	E	E	E	E
	10	33	93	25	W4M	E	E	E	E	E	E
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

NISKU RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	9	1	94	19	W4M	E	E	E	E	E	E
	7	24	94	19	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	E	E	E	E	E	E
	6	8	94	21	W4M	E	E	E	E	E	E
	10	10	94	21	W4M	E	E	E	E	E	E
	10	17	94	21	W4M	E	E	E	E	E	E
	11	22	94	21	W4M	E	E	E	E	E	E
T 94	11	29	94	21	W4M	E	E	E	E	E	E
	16	22	94	22	W4M	E	E	E	E	E	E
	14	23	94	22	W4M	E	E	E	E	E	E
	11	33	94	22	W4M	E	E	E	E	E	E
	6	1	94	23	W4M	E	E	E	E	E	E
	10	4	94	23	W4M	E	E	E	E	E	E
	12	7	94	23	W4M	E	E	E	E	E	E
	10	24	94	24	W4M	E	E	E	E	E	E
	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	E	E	E	E	E	E
	6	7	95	21	W4M	E	E	E	E	E	E
T 95	10	8	95	21	W4M	E	E	E	E	E	E
	11	10	95	21	W4M	E	E	E	E	E	E
	10	15	95	22	W4M	E	E	E	E	E	E
	7	24	95	22	W4M	E	E	E	E	E	E
	6	35	95	22	W4M	E	E	E	E	E	E
	10	23	95	23	W4M	E	E	E	E	E	E

E = ERODED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE

UPPER IRETON RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 80	10	5	80	16	W4M	E	E	E	E	E	E
	11	12	80	16	W4M	E	E	E	E	E	E
	10	18	80	16	W4M	E	E	E	E	E	E
	11	26	80	16	W4M	E	E	E	E	E	E
	11	29	80	16	W4M	E	E	E	E	E	E
	6	34	80	17	W4M	E	E	E	E	E	E
	10	27	80	18	W4M	197.1	N/P	N/P	N/P	N/P	N/P
	12	1	80	24	W4M	-16.7	21.0	D.S.	D.S.	D.S.	D.S.
	16	1	80	24	W4M	-9.4	23.5	D.S.	D.S.	D.S.	D.S.
T 81	10	3	81	16	W4M	E	E	E	E	E	E
	6	6	81	16	W4M	E	E	E	E	E	E
	10	16	81	16	W4M	E	E	E	E	E	E
	11	18	81	16	W4M	E	E	E	E	E	E
	10	26	81	16	W4M	E	E	E	E	E	E
	11	28	81	16	W4M	E	E	E	E	E	E
	11	29	81	16	W4M	E	E	E	E	E	E
	11	31	81	16	W4M	E	E	E	E	E	E
	10	33	81	16	W4M	E	E	E	E	E	E
	10	2	81	17	W4M	E	E	E	E	E	E
	7	8	81	17	W4M	E	E	E	E	E	E
	10	27	81	17	W4M	E	E	E	E	E	E
	10	36	81	17	W4M	E	E	E	E	E	E
T 82	10	23	82	16	W4M	E	E	E	E	E	E
	6	32	82	16	W4M	E	E	E	E	E	E
	6	34	82	16	W4M	E	E	E	E	E	E
	6	36	82	16	W4M	E	E	E	E	E	E
	10	1	82	17	W4M	E	E	E	E	E	E
	10	1	82	18	W4M	E	E	E	E	E	E
	10	23	82	18	W4M	E	E	E	E	E	E
	10	36	82	22	W4M	115.5	23.8	D.S.	D.S.	D.S.	D.S.
T 83	7	6	83	16	W4M	E	E	E	E	E	E
	11	9	83	16	W4M	E	E	E	E	E	E
	6	14	83	16	W4M	E	E	E	E	E	E
	11	25	83	17	W4M	E	E	E	E	E	E
	11	34	83	17	W4M	E	E	E	E	E	E
	6	27	83	18	W4M	E	E	E	E	E	E
	10	17	83	19	W4M	221.8	27.7	D.S.	D.S.	D.S.	D.S.
	10	24	83	19	W4M	250.6	25.0	D.S.	D.S.	D.S.	D.S.
	13	22	83	22	W4M	95.9	25.5	D.S.	D.S.	D.S.	D.S.
T 84	11	30	84	16	W4M	E	E	E	E	E	E
	11	12	84	18	W4M	E	E	E	E	E	E
	7	26	84	18	W4M	E	E	E	E	E	E
	7	29	84	18	W4M	E	E	E	E	E	E
	10	14	84	19	W4M	254.3	17.0	D.S.	D.S.	D.S.	D.S.
	10	17	84	19	W4M	244.3	25.5	D.S.	D.S.	D.S.	D.S.
	7	36	84	23	W4M	110.8	17.7	D.S.	D.S.	D.S.	D.S.
T 85	11	15	85	17	W4M	E	E	E	E	E	E
	7	8	85	18	W4M	E	E	E	E	E	E
	7	11	85	18	W4M	E	E	E	E	E	E
	10	19	85	18	W4M	E	E	E	E	E	E
	10	22	85	18	W4M	E	E	E	E	E	E
	11	33	85	18	W4M	E	E	E	E	E	E
	6	34	85	19	W4M	275.0	16.0	D.S.	D.S.	D.S.	D.S.
	10	20	85	21	W4M	177.2	28.7	D.S.	D.S.	D.S.	D.S.
	10	15	85	22	W4M	139.5	25.0	D.S.	D.S.	D.S.	D.S.
	8	17	85	25	W4M	0.3	25.0	D.S.	D.S.	D.S.	D.S.
T 86	10	5	86	17	W4M	E	E	E	E	E	E
	10	3	86	18	W4M	E	E	E	E	E	E
	7	24	86	18	W4M	E	E	E	E	E	E
	12	28	86	18	W4M	E	E	E	E	E	E
	11	26	86	19	W4M	E	E	E	E	E	E
	13	9	86	21	W4M	186.9	24.5	D.S.	D.S.	D.S.	D.S.
	11	21	87	17	W4M	E	E	E	E	E	E
	14	3	87	18	W4M	E	E	E	E	E	E
	7	11	87	19	W4M	E	E	E	E	E	E
	5	18	87	19	W4M	277.0	15.2	D.S.	D.S.	D.S.	D.S.

UPPER IRETON RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	12	28	87	19	W4M	E	E	E	E	E	E
	13	28	87	19	W4M	E	E	E	E	E	E
	11	29	87	19	W4M	E	E	E	E	E	E
	13	33	87	19	W4M	E	E	E	E	E	E
T 87	14	17	87	20	W4M	235.6	22.0	34.3	11.6	4.0	3.4
	11	26	87	20	W4M	271.0	14.5	INC	INC	INC	INC
	6	3	87	22	W4M	177.4	29.0	26.9	20.5	5.5	3.8
	11	12	87	22	W4M	191.5	25.5	INC	INC	INC	INC
	10	33	87	25	W4M	77.9	38.0	INC	INC	INC	INC
	6	28	88	18	W4M	E	E	E	E	E	E
	14	5	88	19	W4M	E	E	E	E	E	E
	7	11	88	19	W4M	E	E	E	E	E	E
	7	28	88	19	W4M	E	E	E	E	E	E
	10	31	88	19	W4M	E	E	E	E	E	E
	8	1	88	20	W4M	E	E	E	E	E	E
	6	13	88	20	W4M	E	E	E	E	E	E
	7	32	88	20	W4M	E	E	E	E	E	E
	3	34	88	20	W4M	285.1	20.4	30.4	11.6	3.5	2.6
	11	14	88	21	W4M	249.5	19.0	33.8	3.0	1.0	0.5
T 88	11	29	88	21	W4M	249.5	21.3	22.7	12.8	2.9	2.2
	11	24	88	22	W4M	233.7	27.1	25.6	9.5	2.8	2.3
	10	35	88	22	W4M	238.4	23.5	28.7	10.5	3.0	2.4
	16	29	88	23	W4M	173.8	31.0	38.3	20.0	7.7	6.1
	10	35	88	23	W4M	197.5	31.4	25.7	INC	INC	INC
	5	11	88	24	W4M	124.6	29.9	INC	INC	INC	INC
	7	26	88	24	W4M	146.9	35.0	33.0	16.5	5.6	2.8
	4	32	88	24	W4M	133.0	33.0	OLD	OLD	OLD	OLD
	7	35	88	24	W4M	152.4	N/P	N/P	N/P	N/P	N/P
-	11	24	88	25	W4M	107.6	28.0	31.4	1.0	0.3	0.2
	10	12	89	18	W4M	E	E	E	E	E	E
	6	19	89	18	W4M	E	E	E	E	E	E
	2	2	89	19	W4M	E	E	E	E	E	E
	10	16	89	19	W4M	E	E	E	E	E	E
	10	30	89	19	W4M	E	E	E	E	E	E
	6	11	89	20	W4M	E	E	E	E	E	E
	10	16	89	20	W4M	E	E	E	E	E	E
	6	26	89	20	W4M	E	E	E	E	E	E
	4	28	89	20	W4M	E	E	E	E	E	E
	6	7	89	21	W4M	259.5	28.4	31.2	5.5	1.7	1.5
T 89	14	21	89	21	W4M	264.1	27.7	30.4	20.7	6.3	4.8
	6	25	89	21	W4M	E	E	E	E	E	E
	7	14	89	22	W4M	252.6	29.3	30.3	15.9	5.1	4.3
	16	33	89	22	W4M	257.5	29.6	31.8	14.0	4.5	3.8
	16	13	89	23	W4M	217.1	29.0	31.5	9.5	3.0	2.6
	10	29	89	23	W4M	201.7	30.0	33.3	8.5	2.8	2.5
	7	35	89	24	W4M	184.8	32.5	31.0	13.0	4.1	2.9
	12	7	89	25	W4M	111.7	33.5	OLD	OLD	OLD	OLD
	6	11	89	25	W4M	129.5	34.0	29.0	25.0	7.3	3.9
	11	9	90	18	W4M	E	E	E	E	E	E
	11	14	90	19	W4M	E	E	E	E	E	E
	10	22	90	19	W4M	E	E	E	E	E	E
	7	31	90	19	W4M	E	E	E	E	E	E
	8	6	90	20	W4M	E	E	E	E	E	E
	11	11	90	20	W4M	E	E	E	E	E	E
	10	2	90	21	W4M	E	E	E	E	E	E
	10	8	90	21	W4M	E	E	E	E	E	E
	7	26	90	21	W4M	E	E	E	E	E	E
	11	32	90	21	W4M	E	E	E	E	E	E
T 90	6	1	90	22	W4M	277.9	32.3	32.5	15.6	5.1	4.4
	11	17	90	22	W4M	261.5	30.5	35.1	9.2	3.2	2.9
	7	28	90	22	W4M	273.9	N/P	N/P	N/P	N/P	N/P
	10	5	90	23	W4M	213.2	34.0	31.8	11.0	3.5	3.1
	7	19	90	23	W4M	221.9	32.5	25.2	19.0	4.8	4.1
	11	21	90	23	W4M	238.2	32.9	32.5	15.2	5.0	4.4
	7	25	90	23	W4M	264.3	33.0	32.4	8.0	2.6	2.4
	7	34	90	23	W4M	250.0	32.0	28.2	13.0	3.7	3.3

UPPER IRETON RESERVOIR CHARACTERISTICS											
TWN	WELL ID					ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	LSD	SEC	TWN	RGE	MER						
	10	2	90	24	W4M	180.5	36.0	32.3	16.0	5.2	4.3
	10	23	90	24	W4M	212.8	35.5	33.0	13.0	4.3	3.6
	10	9	91	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	E	E	E	E	E	E
	11	10	91	19	W4M	E	E	E	E	E	E
	10	16	91	19	W4M	E	E	E	E	E	E
	2	22	91	19	W4M	E	E	E	E	E	E
	11	29	91	19	W4M	E	E	E	E	E	E
	8	32	91	19	W4M	E	E	E	E	E	E
	8	35	91	19	W4M	E	E	E	E	E	E
T 91	10	14	91	20	W4M	E	E	E	E	E	E
	11	26	91	20	W4M	E	E	E	E	E	E
	11	28	91	20	W4M	E	E	E	E	E	E
	10	1	91	21	W4M	E	E	E	E	E	E
	11	8	91	21	W4M	E	E	E	E	E	E
	7	14	91	21	W4M	E	E	E	E	E	E
	11	20	91	21	W4M	E	E	E	E	E	E
	7	26	91	21	W4M	E	E	E	E	E	E
	10	32	91	21	W4M	E	E	E	E	E	E
	7	1	91	22	W4M	E	E	E	E	E	E
	11	5	91	22	W4M	264.2	22.5	26.6	15.5	4.1	3.8
	7	26	91	22	W4M	E	E	E	E	E	E
	11	12	91	24	W4M	231.2	37.0	30.5	15.5	4.7	4.1
	10	34	91	24	W4M	232.5	26.8	INC	INC	INC	INC
	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	E	E	E	E	E	E
	10	16	92	19	W4M	E	E	E	E	E	E
	11	30	92	19	W4M	E	E	E	E	E	E
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	E	E	E	E	E	E
	6	2	92	21	W4M	E	E	E	E	E	E
	11	8	92	21	W4M	E	E	E	E	E	E
	10	14	92	21	W4M	E	E	E	E	E	E
T 92	1	16	92	21	W4M	E	E	E	E	E	E
	10	20	92	21	W4M	E	E	E	E	E	E
	10	32	92	21	W4M	E	E	E	E	E	E
	10	2	92	22	W4M	E	E	E	E	E	E
	10	14	92	22	W4M	E	E	E	E	E	E
	10	21	92	22	W4M	E	E	E	E	E	E
	10	22	92	22	W4M	E	E	E	E	E	E
	6	36	92	22	W4M	E	E	E	E	E	E
	5	12	92	24	W4M	246.2	27.7	28.2	INC	INC	INC
	7	13	92	24	W4M	241.6	11.0	32.0	INC	INC	INC
	10	21	92	24	W4M	234.7	17.5	44.7	15.0	6.7	6.2
	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	19	W4M	E	E	E	E	E	E
	7	12	93	19	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	E	E	E	E	E	E
	5	25	93	20	W4M	E	E	E	E	E	E
T 93	11	14	93	21	W4M	E	E	E	E	E	E
	10	30	93	22	W4M	E	E	E	E	E	E
	10	4	93	23	W4M	E	E	E	E	E	E
	6	12	93	23	W4M	E	E	E	E	E	E
	10	15	93	23	W4M	E	E	E	E	E	E
	4	25	93	24	W4M	E	E	E	E	E	E
	11	24	93	25	W4M	229.5	11.5	INC	INC	INC	INC
	10	33	93	25	W4M	223.6	15.2	INC	INC	INC	INC
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

UPPER IRETON RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	9	1	94	19	W4M	E	E	E	E	E	E
	7	24	94	19	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	E	E	E	E	E	E
	6	8	94	21	W4M	E	E	E	E	E	E
	10	10	94	21	W4M	E	E	E	E	E	E
	10	17	94	21	W4M	E	E	E	E	E	E
	11	22	94	21	W4M	E	E	E	E	E	E
T 94	11	29	94	21	W4M	E	E	E	E	E	E
	16	22	94	22	W4M	E	E	E	E	E	E
	14	23	94	22	W4M	E	E	E	E	E	E
	11	33	94	22	W4M	E	E	E	E	E	E
	6	1	94	23	W4M	E	E	E	E	E	E
	10	4	94	23	W4M	E	E	E	E	E	E
	12	7	94	23	W4M	E	E	E	E	E	E
	10	24	94	24	W4M	E	E	E	E	E	E
	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	E	E	E	E	E	E
	6	7	95	21	W4M	E	E	E	E	E	E
T 95	10	8	95	21	W4M	E	E	E	E	E	E
	11	10	95	21	W4M	E	E	E	E	E	E
	10	15	95	22	W4M	E	E	E	E	E	E
	7	24	95	22	W4M	E	E	E	E	E	E
	6	35	95	22	W4M	E	E	E	E	E	E
	10	23	95	23	W4M	E	E	E	E	E	E

E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE
D.S. = DOLOMITIC SHALE

UGM3 RESERVOIR CHARACTERISTICS

TWN	WELL ID					ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	LSD	SEC	TWN	RGE	MER						
T 80	10	5	80	16	W4M	E	E	E	E	E	E
	11	12	80	16	W4M	E	E	E	E	E	E
	10	18	80	16	W4M	E	E	E	E	E	E
	11	26	80	16	W4M	E	E	E	E	E	E
	11	29	80	16	W4M	E	E	E	E	E	E
	6	34	80	17	W4M	217.8	2.0	SB-3	0.0	0.0	0.0
	10	27	80	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	12	1	80	24	W4M	-37.7	44.5	10.0	18.0	2.1	1.5
	16	1	80	24	W4M	-32.9	44.0	9.9	21.0	2.4	1.5
T 81	10	3	81	16	W4M	E	E	E	E	E	E
	6	6	81	16	W4M	E	E	E	E	E	E
	10	16	81	16	W4M	E	E	E	E	E	E
	11	18	81	16	W4M	E	E	E	E	E	E
	10	26	81	16	W4M	E	E	E	E	E	E
	11	28	81	16	W4M	E	E	E	E	E	E
	11	29	81	16	W4M	E	E	E	E	E	E
	11	31	81	16	W4M	E	E	E	E	E	E
	10	33	81	16	W4M	E	E	E	E	E	E
	10	2	81	17	W4M	240.2	13.0	19.4	2.5	0.6	0.3
	7	8	81	17	W4M	226.8	19.5	22.0	OLD	OLD	OLD
	10	27	81	17	W4M	E	E	E	E	E	E
	10	36	81	17	W4M	251.4	8.0	26.4	5.0	1.3	1.2
T 82	10	23	82	16	W4M	E	E	E	E	E	E
	6	32	82	16	W4M	E	E	E	E	E	E
	6	34	82	16	W4M	E	E	E	E	E	E
	6	36	82	16	W4M	E	E	E	E	E	E
	10	1	82	17	W4M	248.9	2.4	SB-3	0.0	0.0	0.0
	10	1	82	18	W4M	E	E	E	E	E	E
	10	23	82	18	W4M	226.4	10.0	19.5	5.0	1.0	0.8
	10	36	82	22	W4M	91.8	35.7	INC	INC	INC	INC
T 83	7	6	83	16	W4M	E	E	E	E	E	E
	11	9	83	16	W4M	E	E	E	E	E	E
	6	14	83	16	W4M	E	E	E	E	E	E
	11	25	83	17	W4M	E	E	E	E	E	E
	11	34	83	17	W4M	E	E	E	E	E	E
	6	27	83	18	W4M	250.9	9.8	OLD	OLD	OLD	OLD
	10	17	83	19	W4M	194.1	25.0	20.8	18.9	4.1	3.0
	10	24	83	19	W4M	225.6	24.5	17.7	26.5	4.8	4.2
	13	22	83	22	W4M	70.4	35.0	20.5	0.0	0.0	0.0
T 84	11	30	84	16	W4M	E	E	E	E	E	E
	11	12	84	18	W4M	E	E	E	E	E	E
	7	26	84	18	W4M	E	E	E	E	E	E
	7	29	84	18	W4M	E	E	E	E	E	E
	10	14	84	19	W4M	237.3	29.0	21.7	23.5	3.7	4.0
	10	17	84	19	W4M	218.8	31.0	23.5	26.0	6.2	4.5
	7	36	84	23	W4M	93.1	43.9	INC	INC	INC	INC
T 85	11	15	85	17	W4M	E	E	E	E	E	E
	7	8	85	18	W4M	271.8	29.0	22.1	27.5	6.0	4.6
	7	11	85	18	W4M	E	E	E	E	E	E
	10	19	85	18	W4M	273.8	28.1	INC	INC	INC	INC
	10	22	85	18	W4M	280.1	17.4	24.0	15.6	3.7	3.2
	11	33	85	18	W4M	286.9	20.0	22.8	18.0	4.1	3.5
	6	34	85	19	W4M	259.0	33.0	23.6	26.5	5.9	4.5
	10	20	85	21	W4M	148.6	31.4	INC	INC	INC	INC
	10	15	85	22	W4M	114.5	32.9	OLD	OLD	OLD	OLD
	8	17	85	25	W4M	-24.7	36.0	OLD	OLD	OLD	OLD
T 86	10	5	86	17	W4M	E	E	E	E	E	E
	10	3	86	18	W4M	E	E	E	E	E	E
	7	24	86	18	W4M	E	E	E	E	E	E
	12	28	86	18	W4M	289.6	8.0	26.9	6.5	1.6	1.1
	11	26	86	19	W4M	286.5	30.0	24.2	INC	INC	INC
	13	9	86	21	W4M	162.4	31.5	INC	INC	INC	INC
	11	21	87	17	W4M	E	E	E	E	E	E
	14	3	87	18	W4M	E	E	E	E	E	E
	7	11	87	19	W4M	287.9	27.7	27.8	22.6	6.3	5.4
	5	18	87	19	W4M	261.7	30.5	26.5	INC	INC	INC

UGM3 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	12	28	87	19	W4M	281.2	29.0	24.9	24.0	5.8	5.0
	13	28	87	19	W4M	282.3	28.0	24.4	33.5	8.2	6.8
	11	29	87	19	W4M	278.7	31.0	23.9	28.0	8.2	6.6
	13	33	87	19	W4M	282.7	N/P	N/P	N/P	N/P	N/P
T 87	14	17	87	20	W4M	213.7	33.5	25.9	28.4	7.3	6.0
	11	26	87	20	W4M	256.5	34.0	INC	INC	INC	INC
	6	3	87	22	W4M	148.4	32.0	18.5	21.0	4.2	2.5
	11	12	87	22	W4M	166.0	29.5	INC	INC	INC	INC
	10	33	87	25	W4M	39.9	38.0	INC	INC	INC	INC
	6	28	88	18	W4M	E	E	E	E	E	E
	14	5	88	19	W4M	278.7	29.3	18.0	INC	INC	INC
	7	11	88	19	W4M	E	E	E	E	E	E
	7	28	88	19	W4M	E	E	E	E	E	E
	10	31	88	19	W4M	E	E	E	E	E	E
	8	1	88	20	W4M	277.2	37.0	26.1	25.5	6.7	5.6
	6	13	88	20	W4M	252.0	11.0	23.3	8.5	2.0	1.7
	7	32	88	20	W4M	240.3	26.0	24.0	20.0	4.8	4.0
	3	34	88	20	W4M	264.6	32.6	21.9	27.4	6.6	5.1
	11	14	88	21	W4M	230.5	38.0	24.1	31.5	7.6	6.4
T 88	11	29	88	21	W4M	228.2	34.2	15.0	29.9	4.6	3.5
	11	24	88	22	W4M	206.6	35.4	20.5	27.7	5.7	4.1
	10	35	88	22	W4M	214.9	36.0	20.7	31.5	6.5	4.6
	16	29	88	23	W4M	142.8	37.0	28.8	32.5	9.4	6.3
	10	35	88	23	W4M	166.1	35.1	12.3	INC	INC	INC
	5	11	88	24	W4M	94.7	35.1	INC	INC	INC	INC
	7	26	88	24	W4M	111.9	36.5	21.9	24.0	5.7	3.1
	4	32	88	24	W4M	100.0	40.0	OLD	OLD	OLD	OLD
	7	35	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	24	88	25	W4M	79.6	39.0	18.1	3.5	0.9	0.5
	10	12	89	18	W4M	E	E	E	E	E	E
	6	19	89	18	W4M	E	E	E	E	E	E
	2	2	89	19	W4M	E	E	E	E	E	E
	10	16	89	19	W4M	E	E	E	E	E	E
	10	30	89	19	W4M	E	E	E	E	E	E
	6	11	89	20	W4M	273.7	27.5	28.0	25.0	7.0	5.6
	10	16	89	20	W4M	E	E	E	E	E	INC
	6	26	89	20	W4M	270.1	7.0	17.8	4.0	0.7	0.7
	4	28	89	20	W4M	259.4	25.3	27.9	INC	INC	INC
	6	7	89	21	W4M	231.1	35.4	21.3	31.1	6.6	5.7
T 89	14	21	89	21	W4M	256.4	34.8	21.1	30.5	6.5	4.9
	6	25	89	21	W4M	273.0	32.9	INC	INC	INC	INC
	7	14	89	22	W4M	223.4	35.4	17.3	31.1	5.4	3.9
	16	33	89	22	W4M	227.9	35.4	20.5	30.8	6.4	4.9
	16	13	89	23	W4M	188.1	35.0	20.5	25.5	5.2	3.4
	10	29	89	23	W4M	171.7	41.0	22.7	24.5	6.1	4.0
	7	35	89	24	W4M	152.3	38.0	21.2	12.5	3.4	1.9
	12	7	89	25	W4M	78.2	42.7	OLD	OLD	OLD	OLD
	6	11	89	25	W4M	95.5	40.0	18.8	30.5	6.0	3.6
	11	9	90	18	W4M	E	E	E	E	E	E
	11	14	90	19	W4M	E	E	E	E	E	E
	10	22	90	19	W4M	E	E	E	E	E	E
	7	31	90	19	W4M	E	E	E	E	E	E
	8	6	90	20	W4M	249.3	6.1	SB-3	0.0	0.0	0.0
	11	11	90	20	W4M	283.6	15.0	20.1	10.5	2.1	1.7
	10	2	90	21	W4M	272.4	31.0	INC	INC	INC	INC
	10	8	90	21	W4M	263.9	35.0	21.1	28.0	5.5	4.1
	7	26	90	21	W4M	281.6	19.0	29.3	15.5	4.6	3.7
	11	32	90	21	W4M	286.6	39.0	20.8	34.5	7.2	6.0
T 90	6	1	90	22	W4M	245.6	34.2	22.0	29.9	6.6	5.1
	11	17	90	22	W4M	231.0	38.4	28.8	29.9	8.5	6.9
	7	28	90	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	5	90	23	W4M	179.2	41.0	21.9	36.0	8.0	5.1
	7	19	90	23	W4M	189.4	39.0	17.7	28.0	5.4	5.4
	11	21	90	23	W4M	205.3	37.8	19.7	31.7	6.7	4.9
	7	25	90	23	W4M	231.3	38.5	21.3	30.0	6.4	4.6
	7	34	90	23	W4M	218.0	40.0	18.2	30.0	5.6	4.4

UGM3 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	10	2	90	24	W4M	144.5	37.0	19.5	22.0	5.0	2.9
	10	23	90	24	W4M	177.3	39.0	19.3	25.0	5.7	3.7
	10	9	91	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	E	E	E	E	E	E
	11	10	91	19	W4M	E	E	E	E	E	E
	10	16	91	19	W4M	E	E	E	E	E	E
	2	22	91	19	W4M	E	E	E	E	E	E
	11	29	91	19	W4M	E	E	E	E	E	E
	8	32	91	19	W4M	E	E	E	E	E	E
	8	35	91	19	W4M	E	E	E	E	E	E
T 91	10	14	91	20	W4M	E	E	E	E	E	E
	11	26	91	20	W4M	E	E	E	E	E	E
	11	28	91	20	W4M	E	E	E	E	E	E
	10	1	91	21	W4M	E	E	E	E	E	E
	11	8	91	21	W4M	283.9	40.5	INC	INC	INC	INC
	7	14	91	21	W4M	290.4	21.0	18.3	14.0	2.8	2.1
	11	20	91	21	W4M	270.5	33.5	12.9	25.0	3.2	2.2
	7	26	91	21	W4M	293.1	8.5	19.6	2.0	0.4	0.2
	10	32	91	21	W4M	286.2	22.0	18.5	12.0	2.4	1.9
	7	1	91	22	W4M	267.7	N/P	N/P	N/P	N/P	N/P
	11	5	91	22	W4M	241.7	42.0	18.9	35.5	6.7	5.7
	7	26	91	22	W4M	274.1	36.6	26.4	23.5	6.3	5.2
	11	12	91	24	W4M	194.2	41.0	18.5	35.5	6.6	4.5
	10	34	91	24	W4M	205.7	43.5	INC	INC	INC	INC
	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	E	E	E	E	E	E
	10	16	92	19	W4M	E	E	E	E	E	E
	11	30	92	19	W4M	E	E	E	E	E	E
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	E	E	E	E	E	E
	6	2	92	21	W4M	295.0	10.0	12.4	9.5	1.2	0.8
	11	8	92	21	W4M	291.0	18.0	OLD	OLD	OLD	OLD
	10	14	92	21	W4M	308.0	6.0	24.5	4.0	1.0	0.9
T 92	1	16	92	21	W4M	301.0	9.0	16.6	3.0	0.7	0.6
	10	20	92	21	W4M	303.2	6.5	SB-3	0.0	0.0	0.0
	10	32	92	21	W4M	E	E	E	E	E	E
	10	2	92	22	W4M	281.6	31.0	18.3	25.5	4.7	3.4
	10	14	92	22	W4M	287.9	28.0	INC	INC	INC	INC
	10	21	92	22	W4M	280.6	N/P	N/P	N/P	N/P	N/P
	10	22	92	22	W4M	284.8	26.0	INC	INC	INC	INC
	6	36	92	22	W4M	300.3	8.0	INC	INC	INC	INC
	5	12	92	24	W4M	218.5	43.3	24.0	INC	INC	INC
	7	13	92	24	W4M	230.6	43.0	33.0	INC	INC	INC
	10	21	92	24	W4M	217.2	44.0	41.4	38.0	15.7	13.3
	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	18	W4M	E	E	E	E	E	E
	7	12	93	18	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	E	E	E	E	E	E
	5	25	93	20	W4M	E	E	E	E	E	E
T 93	11	14	93	21	W4M	E	E	E	E	E	E
	10	30	93	22	W4M	273.1	8.5	15.6	3.5	0.5	0.4
	10	4	93	23	W4M	258.5	21.0	22.7	17.0	4.1	3.6
	6	12	93	23	W4M	268.1	13.0	20.0	6.5	1.3	1.2
	10	15	93	23	W4M	261.7	11.0	INC	INC	INC	INC
	4	25	93	24	W4M	248.8	23.0	INC	INC	INC	INC
	11	24	93	25	W4M	218.0	41.0	INC	INC	INC	INC
	10	33	93	25	W4M	208.3	36.6	INC	INC	INC	INC
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

UGM3 RESERVOIR CHARACTERISTICS											
TWN	WELL ID					ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	LSD	SEC	TWN	RGE	MER						
T 94	9	1	94	19	W4M	E	E	E	E	E	E
	7	24	94	19	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	E	E	E	E	E	E
	6	8	94	21	W4M	E	E	E	E	E	E
	10	10	94	21	W4M	E	E	E	E	E	E
	10	17	94	21	W4M	E	E	E	E	E	E
	11	22	94	21	W4M	E	E	E	E	E	E
	11	29	94	21	W4M	E	E	E	E	E	E
	16	22	94	22	W4M	E	E	E	E	E	E
	14	23	94	22	W4M	E	E	E	E	E	E
	11	33	94	22	W4M	E	E	E	E	E	E
	6	1	94	23	W4M	275.3	10.0	17.2	3.5	0.5	0.4
	10	4	94	23	W4M	261.9	5.5	SB-3	0.0	0.0	0.0
	12	7	94	23	W4M	252.9	10.1	INC	INC	INC	INC
	10	24	94	24	W4M	253.0	8.0	INC	INC	INC	INC
T 95	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	E	E	E	E	E	E
	6	7	95	21	W4M	E	E	E	E	E	E
	10	8	95	21	W4M	E	E	E	E	E	E
	11	10	95	21	W4M	E	E	E	E	E	E
	10	15	95	22	W4M	E	E	E	E	E	E
	7	24	95	22	W4M	E	E	E	E	E	E
	6	35	95	22	W4M	E	E	E	E	E	E
	10	23	95	23	W4M	E	E	E	E	E	E

E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE
SB-3 = SHALE BREAK 3 REMAINING

UGM2 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 80	10	5	80	16	W4M	E	E	E	E	E	E
	11	12	80	16	W4M	E	E	E	E	E	E
	10	18	80	16	W4M	E	E	E	E	E	E
	11	26	80	16	W4M	E	E	E	E	E	E
	11	29	80	16	W4M	E	E	E	E	E	E
	6	34	80	17	W4M	215.8	34.0	23.1	25.0	5.8	4.4
	10	27	80	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	12	1	80	24	W4M	-82.2	40.0	12.0	7.5	1.2	0.5
	16	1	80	24	W4M	-76.9	40.0	9.8	14.0	1.5	0.7
T 81	10	3	81	16	W4M	E	E	E	E	E	E
	6	6	81	16	W4M	224.2	N/P	N/P	N/P	N/P	N/P
	10	16	81	16	W4M	E	E	E	E	E	E
	11	18	81	16	W4M	240.7	28.7	16.8	INC	INC	INC
	10	26	81	16	W4M	E	E	E	E	E	E
	11	28	81	16	W4M	E	E	E	E	E	E
	11	29	81	16	W4M	240.3	N/P	N/P	N/P	N/P	N/P
	11	31	81	16	W4M	251.4	35.4	16.0	INC	INC	INC
	10	33	81	16	W4M	E	E	E	E	E	E
	10	2	81	17	W4M	227.2	N/P	18.2	N/P	N/P	N/P
	7	8	81	17	W4M	207.2	30.5	21.1	OLD	OLD	OLD
	10	27	81	17	W4M	218.2	N/P	N/P	N/P	N/P	N/P
	10	36	81	17	W4M	243.4	28.0	18.4	23.0	4.2	3.6
T 82	10	23	82	16	W4M	E	E	E	E	E	E
	6	32	82	16	W4M	261.1	7.9	16.8	4.3	0.7	0.6
	6	34	82	16	W4M	E	E	E	E	E	E
	6	36	82	16	W4M	E	E	E	E	E	E
	10	1	82	17	W4M	246.5	27.7	OLD	OLD	OLD	OLD
	10	1	82	18	W4M	209.6	28.1	OLD	OLD	OLD	OLD
	10	23	82	18	W4M	218.4	31.0	17.5	26.0	4.3	3.5
	10	36	82	22	W4M	56.1	30.2	INC	INC	INC	INC
T 83	7	6	83	16	W4M	263.1	7.0	10.4	INC	INC	INC
	11	9	83	16	W4M	E	E	E	E	E	E
	6	14	83	16	W4M	E	E	E	E	E	E
	11	25	83	17	W4M	E	E	E	E	E	E
	11	34	83	17	W4M	E	E	E	E	E	E
	6	27	83	18	W4M	241.2	N/P	N/P	N/P	N/P	N/P
	10	17	83	19	W4M	169.1	N/P	N/P	N/P	N/P	N/P
	10	24	83	19	W4M	201.1	30.0	13.7	20.5	2.9	2.0
	13	22	83	22	W4M	35.4	32.0	13.5	0.5	0.1	0.0
T 84	11	30	84	16	W4M	E	E	E	E	E	E
	11	12	84	18	W4M	237.1	21.0	OLD	OLD	OLD	OLD
	7	26	84	18	W4M	235.4	12.0	13.9	4.5	0.7	0.4
	7	29	84	18	W4M	222.3	24.0	24.4	16.5	4.0	3.3
	10	14	84	19	W4M	208.3	31.0	20.0	22.5	4.2	3.3
	10	17	84	19	W4M	187.8	32.0	18.0	22.0	4.2	2.6
	7	36	84	23	W4M	49.2	34.8	INC	INC	INC	INC
T 85	11	15	85	17	W4M	E	E	E	E	E	E
	7	8	85	18	W4M	242.8	33.0	16.3	18.5	3.2	2.6
	7	11	85	18	W4M	256.0	27.0	22.6	17.0	3.9	2.7
	10	19	85	18	W4M	245.7	31.4	INC	INC	INC	INC
	10	22	85	18	W4M	262.7	31.7	19.3	23.5	4.5	3.6
	11	33	85	18	W4M	266.9	33.0	20.1	23.5	4.8	3.9
	6	34	85	19	W4M	226.0	33.0	18.7	21.5	3.6	2.8
	10	20	85	21	W4M	117.1	36.3	INC	INC	INC	INC
	10	15	85	22	W4M	81.6	36.0	OLD	OLD	OLD	OLD
	8	17	85	25	W4M	-60.7	42.0	OLD	OLD	OLD	OLD
T 86	10	5	86	17	W4M	E	E	E	E	E	E
	10	3	86	18	W4M	280.4	36.0	OLD	OLD	OLD	OLD
	7	24	86	18	W4M	288.7	19.2	OLD	OLD	OLD	OLD
	12	28	86	18	W4M	281.6	34.0	21.9	24.0	5.3	4.3
	11	26	86	19	W4M	256.5	34.5	17.7	22.0	4.1	3.4
	13	9	86	21	W4M	130.9	39.0	INC	INC	INC	INC
	11	21	87	17	W4M	E	E	E	E	E	E
	14	3	87	18	W4M	286.6	32.0	OLD	OLD	OLD	OLD
	7	11	87	19	W4M	260.2	33.8	22.3	26.2	5.8	4.9
	5	18	87	19	W4M	231.2	33.8	22.4	INC	INC	INC

UGM2 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 87	12	28	87	19	W4M	252.2	N/P	20.5	N/P	N/P	N/P
	13	28	87	19	W4M	254.3	N/P	N/P	N/P	N/P	N/P
	11	29	87	19	W4M	247.7	34.5	9.1	21.0	3.1	2.5
	13	33	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	14	17	87	20	W4M	180.1	33.8	26.3	26.2	6.8	5.0
	11	26	87	20	W4M	222.5	32.5	INC	INC	INC	INC
	6	3	87	22	W4M	116.4	37.0	17.3	19.5	3.6	2.1
	11	12	87	22	W4M	136.5	37.5	INC	INC	INC	INC
	10	33	87	25	W4M	1.9	35.0	INC	INC	INC	INC
T 88	6	28	88	18	W4M	288.6	3.5	SB-2	0.0	0.0	0.0
	14	5	88	19	W4M	243.4	32.6	15.0	INC	INC	INC
	7	11	88	19	W4M	269.0	19.5	23.7	8.5	2.2	1.8
	7	28	88	19	W4M	265.2	21.5	17.3	6.5	1.2	0.7
	10	31	88	19	W4M	249.9	19.8	15.4	9.8	1.4	1.0
	8	1	88	20	W4M	240.2	35.0	26.0	21.5	5.4	4.7
	6	13	88	20	W4M	241.0	34.5	17.6	25.0	4.4	3.5
	7	32	88	20	W4M	214.3	31.0	22.6	21.5	4.9	4.1
	3	34	88	20	W4M	232.0	34.2	18.7	22.6	4.2	3.0
	11	14	88	21	W4M	192.5	32.0	22.6	21.0	4.5	2.9
	11	29	88	21	W4M	194.1	37.8	13.2	16.5	2.2	1.6
	11	24	88	22	W4M	171.2	38.1	17.6	18.9	3.3	2.3
	10	35	88	22	W4M	178.9	39.0	17.4	19.5	3.4	2.1
	16	29	88	23	W4M	105.8	40.0	23.9	30.0	7.2	4.1
	10	35	88	23	W4M	131.0	41.2	5.6	INC	INC	INC
	5	11	88	24	W4M	59.7	39.6	INC	INC	INC	INC
	7	26	88	24	W4M	75.4	40.5	17.3	8.5	1.5	0.8
	4	32	88	24	W4M	60.0	N/P	OLD	OLD	OLD	OLD
	7	35	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	24	88	25	W4M	40.6	34.0	9.1	2.5	0.6	0.4
T 89	10	12	89	18	W4M	E	E	E	E	E	E
	6	19	89	18	W4M	E	E	E	E	E	E
	2	2	89	19	W4M	E	E	E	E	E	E
	10	16	89	19	W4M	E	E	E	E	E	E
	10	30	89	19	W4M	261.7	N/P	N/P	N/P	N/P	N/P
	6	11	89	20	W4M	246.2	35.0	20.2	24.5	5.0	3.8
	10	16	89	20	W4M	190.6	6.1	INC	INC	INC	INC
	6	26	89	20	W4M	263.1	33.0	18.1	24.5	4.4	3.6
	4	28	89	20	W4M	234.0	33.5	19.3	INC	INC	INC
	6	7	89	21	W4M	195.7	N/P	18.6	N/P	N/P	N/P
	14	21	89	21	W4M	221.7	37.8	13.8	26.5	3.8	2.7
	6	25	89	21	W4M	240.1	34.8	10.6	INC	INC	INC
	7	14	89	22	W4M	188.0	38.4	8.6	11.6	1.2	0.7
	16	33	89	22	W4M	192.5	40.2	16.4	26.8	4.6	2.8
	16	13	89	23	W4M	153.1	39.0	9.8	17.0	2.4	1.3
	10	29	89	23	W4M	130.7	40.0	18.7	9.5	2.2	1.2
	7	35	89	24	W4M	114.3	36.0	13.9	3.0	0.6	0.3
	12	7	89	25	W4M	35.5	32.0	OLD	OLD	OLD	OLD
	6	11	89	25	W4M	55.5	34.0	10.7	18.0	1.9	1.2
T 90	11	9	90	18	W4M	E	E	E	E	E	E
	11	14	90	19	W4M	E	E	E	E	E	E
	10	22	90	19	W4M	E	E	E	E	E	E
	7	31	90	19	W4M	281.9	7.0	SB-2	0.0	0.0	0.0
	8	6	90	20	W4M	243.2	30.8	16.4	22.6	3.7	3.1
	11	11	90	20	W4M	268.6	N/P	N/P	N/P	N/P	N/P
	10	2	90	21	W4M	241.4	38.0	12.0	27.5	3.3	2.5
	10	8	90	21	W4M	228.9	39.0	10.8	23.0	2.6	1.6
	7	26	90	21	W4M	262.6	36.0	20.0	29.0	5.9	4.5
	11	32	90	21	W4M	247.6	37.0	14.5	31.0	4.5	3.6
	6	1	90	22	W4M	211.5	39.0	15.4	28.7	4.4	3.4
	11	17	90	22	W4M	192.6	40.2	17.4	31.1	5.5	4.4
	7	28	90	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	5	90	23	W4M	138.2	38.0	16.0	18.0	3.3	1.9
	7	19	90	23	W4M	150.4	35.0	9.9	10.5	1.4	0.8
	11	21	90	23	W4M	167.5	39.0	14.5	20.1	3.7	2.3
	7	25	90	23	W4M	192.8	41.5	13.4	32.5	3.4	2.2
	7	34	90	23	W4M	178.0	39.0	12.1	20.5	2.7	1.7

UGM2 RESERVOIR CHARACTERISTICS

TWN	LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	10	2	90	24	W4M	107.5	37.0	14.6	7.0	1.3	0.7
	10	23	90	24	W4M	138.3	34.0	12.4	12.5	1.9	1.0
T 91	10	9	91	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	E	E	E	E	E	E
	11	10	91	19	W4M	E	E	E	E	E	E
	10	16	91	19	W4M	E	E	E	E	E	E
	2	22	91	19	W4M	E	E	E	E	E	E
	11	29	91	19	W4M	E	E	E	E	E	E
	8	32	91	19	W4M	E	E	E	E	E	E
	8	35	91	19	W4M	E	E	E	E	E	E
	10	14	91	20	W4M	279.1	4.9	14.6	0.9	0.1	0.1
	11	26	91	20	W4M	E	E	E	E	E	E
	11	28	91	20	W4M	285.6	18.6	4.8	OLD	OLD	OLD
	10	1	91	21	W4M	262.7	35.0	INC	INC	INC	INC
	11	8	91	21	W4M	243.4	37.0	14.4	30.0	4.3	3.5
	7	14	91	21	W4M	269.4	37.0	16.7	31.0	5.3	4.0
	11	20	91	21	W4M	237.0	N/P	N/P	N/P	N/P	N/P
	7	26	91	21	W4M	284.6	36.5	15.5	28.0	4.3	3.4
	10	32	91	21	W4M	264.2	36.5	15.7	31.0	4.9	4.0
	7	1	91	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	5	91	22	W4M	199.7	39.0	13.4	31.5	4.2	3.2
	7	26	91	22	W4M	237.5	38.4	19.6	29.9	5.9	5.2
	11	12	91	24	W4M	153.2	33.0	13.5	14.5	2.0	1.1
	10	34	91	24	W4M	162.2	48.0	INC	INC	INC	INC
T 92	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	E	E	E	E	E	E
	10	16	92	19	W4M	E	E	E	E	E	E
	11	30	92	19	W4M	E	E	E	E	E	E
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	311.4	N/P	N/P	N/P	N/P	N/P
	6	2	92	21	W4M	285.0	38.0	INC	INC	INC	INC
	11	8	92	21	W4M	273.0	35.0	INC	INC	INC	INC
	10	14	92	21	W4M	302.0	36.0	12.1	22.0	2.9	1.7
	1	16	92	21	W4M	292.0	36.0	9.4	28.0	2.9	2.2
	10	20	92	21	W4M	296.7	36.5	19.4	29.5	5.8	4.7
	10	32	92	21	W4M	305.9	39.0	15.4	27.0	4.2	3.5
	10	2	92	22	W4M	250.6	36.5	15.4	30.5	4.7	3.7
	10	14	92	22	W4M	259.9	36.0	14.7	29.5	4.4	3.5
	10	21	92	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	22	92	22	W4M	258.8	35.0	17.5	30.5	5.3	4.4
	6	36	92	22	W4M	292.3	37.0	INC	INC	INC	INC
	5	12	92	24	W4M	175.2	35.1	22.0	INC	INC	INC
	7	13	92	24	W4M	187.6	36.0	21.0	INC	INC	INC
	10	21	92	24	W4M	173.2	39.0	29.7	31.0	9.2	7.4
T 93	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	19	W4M	E	E	E	E	E	E
	7	12	93	19	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	E	E	E	E	E	E
	5	25	93	20	W4M	E	E	E	E	E	E
	11	14	93	21	W4M	303.2	18.0	12.4	5.3	0.7	0.5
	10	30	93	22	W4M	264.6	37.5	14.0	32.5	4.6	3.7
	10	4	93	23	W4M	237.5	45.0	13.5	34.5	4.6	3.7
	6	12	93	23	W4M	255.1	39.0	14.3	35.0	5.0	4.0
	10	15	93	23	W4M	250.7	N/P	N/P	N/P	N/P	N/P
	4	25	93	24	W4M	225.8	35.0	INC	INC	INC	INC
	11	24	93	25	W4M	177.0	46.0	INC	INC	INC	INC
	10	33	93	25	W4M	171.7	48.8	INC	INC	INC	INC
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

UGM2 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 94	9	1	94	18	W4M	E	E	E	E	E	E
	7	24	94	18	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	309.5	21.5	INC	INC	INC	INC
	6	8	94	21	W4M	306.0	N/P	N/P	N/P	N/P	N/P
	10	10	94	21	W4M	320.1	19.0	15.8	8.5	1.4	1.1
	10	17	94	21	W4M	299.4	7.6	INC	INC	INC	INC
	11	22	94	21	W4M	304.6	4.0	INC	INC	INC	INC
	11	29	94	21	W4M	301.3	9.5	SB-2	0.0	0.0	0.0
	16	22	94	22	W4M	284.6	13.0	SB-2	0.0	0.0	0.0
	14	23	94	22	W4M	295.5	15.5	9.3	4.5	0.5	0.3
	11	33	94	22	W4M	285.2	10.4	INC	INC	INC	INC
	6	1	94	23	W4M	265.3	36.0	14.1	31.0	4.4	3.6
	10	4	94	23	W4M	256.4	35.0	9.4	26.5	2.6	2.0
	12	7	94	23	W4M	242.8	32.3	INC	INC	INC	INC
	10	24	94	24	W4M	245.0	34.5	INC	INC	INC	INC
T 95	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	E	E	E	E	E	E
	6	7	95	21	W4M	296.5	10.0	SB-2	0.0	0.0	0.0
	10	8	95	21	W4M	300.3	5.2	SB-2	0.0	0.0	0.0
	11	10	95	21	W4M	E	E	E	E	E	E
	10	15	95	22	W4M	E	E	E	E	E	E
	7	24	95	22	W4M	E	E	E	E	E	E
	6	35	95	22	W4M	E	E	E	E	E	E
	10	23	95	23	W4M	E	E	E	E	E	E

E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE
SB-2 = SHALE BREAK 2 REMAINING

UGM1 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 80	10	5	80	16	W4M	E	E	E	E	E	E
	11	12	80	16	W4M	E	E	E	E	E	E
	10	18	80	16	W4M	E	E	E	E	E	E
	11	26	80	16	W4M	E	E	E	E	E	E
	11	29	80	16	W4M	207.2	16.0	12.8	10.5	1.4	1.1
	6	34	80	17	W4M	181.8	14.0	10.4	9.5	1.0	0.6
	10	27	80	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	12	1	80	24	W4M	-122.2	25.0	5.7	5.5	0.5	0.3
	16	1	80	24	W4M	-116.9	25.0	7.5	3.0	0.3	0.2
T 81	10	3	81	16	W4M	E	E	E	E	E	E
	6	6	81	16	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	16	81	16	W4M	E	E	E	E	E	E
	11	18	81	16	W4M	212.1	17.7	10.0	INC	INC	INC
	10	26	81	16	W4M	E	E	E	E	E	E
	11	28	81	16	W4M	226.2	9.2	17.7	INC	INC	INC
	11	29	81	16	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	31	81	16	W4M	216.0	N/P	N/P	N/P	N/P	N/P
	10	33	81	16	W4M	232.5	11.6	6.5	2.7	0.2	0.1
	10	2	81	17	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	7	8	81	17	W4M	176.8	14.6	9.6	OLD	OLD	OLD
	10	27	81	17	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	36	81	17	W4M	215.4	17.0	10.3	9.0	1.0	0.7
T 82	10	23	82	16	W4M	266.9	20.1	10.5	INC	INC	INC
	6	32	82	16	W4M	253.2	19.8	8.4	2.1	1.9	0.1
	6	34	82	16	W4M	263.9	15.9	OLD	OLD	OLD	OLD
	6	36	82	16	W4M	E	E	E	E	E	E
	10	1	82	17	W4M	218.8	18.3	OLD	OLD	OLD	OLD
	10	1	82	18	W4M	181.5	15.9	OLD	OLD	OLD	OLD
	10	23	82	18	W4M	187.4	16.0	11.8	7.0	0.8	0.7
	10	36	82	22	W4M	25.9	11.6	INC	INC	INC	INC
T 83	7	6	83	16	W4M	256.1	19.5	10.6	INC	INC	INC
	11	9	83	16	W4M	257.8	15.2	7.0	4.6	0.4	0.3
	6	14	83	16	W4M	E	E	E	E	E	E
	11	25	83	17	W4M	E	E	E	E	E	E
	11	34	83	17	W4M	239.8	13.4	OLD	OLD	OLD	OLD
	6	27	83	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	17	83	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	24	83	19	W4M	171.1	15.5	3.9	0.0	0.0	0.0
	13	22	83	22	W4M	3.4	13.0	11.7	0.0	0.0	0.0
T 84	11	30	84	16	W4M	E	E	E	E	E	E
	11	12	84	18	W4M	216.0	12.8	OLD	OLD	OLD	OLD
	7	26	84	18	W4M	223.4	16.0	8.5	0.5	0.6	0.0
	7	29	84	18	W4M	198.3	16.0	7.2	4.5	0.4	0.2
	10	14	84	19	W4M	177.3	18.0	6.1	0.0	0.0	0.0
	10	17	84	19	W4M	155.8	16.0	6.7	0.0	0.0	0.0
	7	36	84	23	W4M	14.4	14.6	INC	INC	INC	INC
T 85	11	15	85	17	W4M	E	E	E	E	E	E
	7	8	85	18	W4M	209.8	16.0	5.8	0.0	0.0	0.0
	7	11	85	18	W4M	229.0	16.0	10.8	0.0	0.0	0.0
	10	19	85	18	W4M	214.3	16.2	INC	INC	INC	INC
	10	22	85	18	W4M	231.0	15.2	7.8	0.6	0.6	0.0
	11	33	85	18	W4M	233.9	16.0	9.2	1.0	0.1	0.1
	6	34	85	19	W4M	193.0	16.0	13.3	0.0	0.0	0.0
	10	20	85	21	W4M	80.9	14.6	INC	INC	INC	INC
	10	15	85	22	W4M	45.6	15.2	OLD	OLD	OLD	OLD
	8	17	85	25	W4M	-102.7	19.0	OLD	OLD	OLD	OLD
T 86	10	5	86	17	W4M	266.6	15.2	9.8	2.7	0.3	0.1
	10	3	86	18	W4M	244.4	16.8	OLD	OLD	OLD	OLD
	7	24	86	18	W4M	269.5	16.2	OLD	OLD	OLD	OLD
	12	28	86	18	W4M	247.6	15.0	10.6	3.5	0.4	0.2
	11	26	86	19	W4M	222.0	15.5	6.8	0.0	0.0	0.0
	13	9	86	21	W4M	91.9	15.5	INC	INC	INC	INC
	11	21	87	17	W4M	295.0	10.5	11.9	1.0	0.2	0.2
	14	3	87	18	W4M	254.6	16.8	OLD	OLD	OLD	OLD
	7	11	87	19	W4M	226.3	17.7	9.8	3.1	0.4	0.2
	5	18	87	19	W4M	197.4	15.6	13.4	INC	INC	INC

UGM1 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 87	12	28	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	13	28	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	29	87	19	W4M	213.2	15.5	5.8	6.0	0.6	0.5
	13	33	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	14	17	87	20	W4M	146.3	16.2	18.1	10.4	1.9	1.3
	11	26	87	20	W4M	190.0	15.5	INC	INC	INC	INC
	6	3	87	22	W4M	79.4	18.0	7.7	0.0	0.0	0.0
	11	12	87	22	W4M	99.0	18.0	INC	INC	INC	INC
	10	33	87	25	W4M	-33.1	20.0	INC	INC	INC	INC
T 88	6	28	88	18	W4M	285.1	16.5	23.4	9.5	2.2	1.9
	14	5	88	19	W4M	216.8	16.8	9.0	INC	INC	INC
	7	11	88	19	W4M	249.5	17.5	13.3	9.5	1.3	1.0
	7	28	88	19	W4M	243.7	17.0	10.6	8.0	0.9	2.8
	10	31	88	19	W4M	230.1	16.5	11.7	7.6	0.9	0.6
	8	1	88	20	W4M	205.2	16.0	13.6	9.5	1.3	1.0
	6	13	88	20	W4M	206.5	15.9	13.4	9.5	1.3	1.0
	7	32	88	20	W4M	183.3	16.0	13.9	9.0	1.1	0.8
	3	34	88	20	W4M	197.9	15.2	19.4	9.1	1.7	1.2
	11	14	88	21	W4M	160.5	17.0	17.1	6.0	1.2	0.7
	11	29	88	21	W4M	156.3	19.5	13.0	9.8	1.3	0.9
	11	24	88	22	W4M	133.1	18.9	7.4	2.7	0.3	0.2
	10	35	88	22	W4M	139.9	19.0	10.0	3.5	0.5	0.2
	16	29	88	23	W4M	65.8	16.0	20.3	10.0	2.1	1.3
	10	35	88	23	W4M	89.8	16.8	5.5	INC	INC	INC
	5	11	88	24	W4M	20.0	15.2	INC	INC	INC	INC
	7	26	88	24	W4M	34.9	15.0	13.3	4.5	0.7	0.3
	4	32	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	7	35	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	24	88	25	W4M	6.6	20.0	10.2	1.0	0.2	0.1
T 89	10	12	89	18	W4M	E	E	E	E	E	E
	6	19	89	18	W4M	E	E	E	E	E	E
	2	2	89	19	W4M	264.2	16.8	17.7	10.7	1.9	1.4
	10	16	89	19	W4M	245.2	11.0	OLD	OLD	OLD	OLD
	10	30	89	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	6	11	89	20	W4M	211.2	15.5	19.9	9.5	1.9	1.4
	10	16	89	20	W4M	184.5	13.4	INC	INC	INC	INC
	6	26	89	20	W4M	230.1	17.0	19.2	11.0	2.1	1.8
	4	28	89	20	W4M	200.5	17.1	20.6	INC	INC	INC
	6	7	89	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	14	21	89	21	W4M	183.8	N/P	N/P	N/P	N/P	N/P
	6	25	89	21	W4M	205.3	16.8	9.5	INC	INC	INC
	7	14	89	22	W4M	149.6	18.9	5.5	2.7	0.2	0.1
	16	33	89	22	W4M	152.3	17.7	9.7	4.9	0.7	0.5
	16	13	89	23	W4M	114.1	17.0	16.3	2.0	0.3	0.2
	10	29	89	23	W4M	90.7	16.0	11.2	3.0	0.4	0.2
	7	35	89	24	W4M	78.3	19.0	10.6	0.0	0.0	0.0
	12	7	89	25	W4M	3.5	21.3	OLD	OLD	OLD	OLD
	6	11	89	25	W4M	21.5	19.0	13.7	11.5	1.6	1.0
T 90	10	9	90	18	W4M	E	E	E	E	E	E
	11	14	90	19	W4M	E	E	E	E	E	E
	10	22	90	19	W4M	284.0	5.5	INC	INC	INC	INC
	7	31	90	19	W4M	274.9	N/P	N/P	N/P	N/P	N/P
	8	6	90	20	W4M	212.4	17.7	14.6	12.4	1.8	1.0
	11	11	90	20	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	2	90	21	W4M	205.4	21.0	18.8	12.0	2.3	2.0
	10	8	90	21	W4M	189.9	17.0	19.0	9.5	1.6	1.2
	7	26	90	21	W4M	226.6	21.0	17.3	13.5	2.3	1.8
	11	32	90	21	W4M	210.6	21.0	20.8	14.0	2.9	2.6
	6	1	90	22	W4M	172.5	17.7	19.0	11.0	2.1	1.4
	11	17	90	22	W4M	152.3	17.7	16.2	10.1	1.7	0.9
	7	28	90	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	5	90	23	W4M	100.2	16.0	14.8	3.5	0.6	0.3
	7	19	90	23	W4M	115.4	22.5	17.5	4.5	1.0	0.6
	11	21	90	23	W4M	128.5	19.5	14.8	5.8	1.2	0.7
	7	25	90	23	W4M	151.3	17.5	13.4	11.0	1.0	0.6
	7	34	90	23	W4M	139.0	20.0	12.3	11.5	1.4	0.8

UGM1 RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	10	2	90	24	W4M	70.5	20.0	17.8	7.0	1.4	0.7
	10	23	90	24	W4M	104.3	23.0	15.8	9.0	1.6	0.8
T 91	10	8	81	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	285.5	5.0	SB-1	0.0	0.0	0.0
	11	10	91	19	W4M	286.0	4.5	SB-1	0.0	0.0	0.0
	10	16	91	19	W4M	281.3	4.0	SB-1	0.0	0.0	0.0
	2	22	91	19	W4M	266.8	3.0	SB-1	0.0	0.0	0.0
	11	29	91	19	W4M	273.2	7.9	20.7	0.6	0.1	0.1
	6	32	91	19	W4M	INC	INC	INC	INC	INC	INC
	8	35	91	19	W4M	E	E	E	E	E	E
	10	14	91	20	W4M	274.3	18.9	21.1	11.6	2.4	2.1
	11	26	91	20	W4M	274.5	17.0	14.1	8.0	1.2	1.0
	11	28	91	20	W4M	267.0	20.7	15.6	OLD	OLD	OLD
	10	1	91	21	W4M	227.7	19.0	INC	INC	INC	INC
	11	8	91	21	W4M	206.4	20.0	12.2	12.1	1.5	1.2
	7	14	91	21	W4M	232.4	19.0	16.5	11.0	1.9	1.5
	11	20	91	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	7	26	91	21	W4M	248.1	20.0	18.0	11.5	2.1	1.9
	10	32	91	21	W4M	227.7	20.5	15.0	12.5	1.9	1.7
	7	1	91	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	5	91	22	W4M	160.7	18.0	13.8	11.0	1.5	1.1
	7	26	91	22	W4M	199.1	20.7	20.9	13.4	2.8	2.5
	11	12	91	24	W4M	120.2	23.0	15.9	13.0	2.1	1.1
	10	34	91	24	W4M	114.2	9.8	INC	INC	INC	INC
T 92	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	E	E	E	E	E	E
	10	16	92	19	W4M	E	E	E	E	E	E
	11	30	92	19	W4M	E	E	E	E	E	E
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	6	2	92	21	W4M	247.0	21.0	12.1	12.5	2.0	1.7
	11	8	92	21	W4M	238.0	20.0	20.5	12.0	2.5	2.2
	10	14	92	21	W4M	266.0	21.0	11.5	8.0	1.0	0.6
	1	16	92	21	W4M	256.0	21.0	17.9	14.0	2.5	2.1
	10	20	92	21	W4M	260.2	20.5	18.2	12.0	2.2	1.9
	10	32	92	21	W4M	266.9	20.0	16.8	11.5	1.9	1.7
	10	2	92	22	W4M	214.1	22.5	14.5	15.5	2.2	1.8
	10	14	92	22	W4M	223.9	22.0	13.8	13.5	1.9	1.5
	10	21	92	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	22	92	22	W4M	223.8	23.0	20.0	15.5	2.2	1.9
	6	36	92	22	W4M	255.3	21.0	17.5	12.5	2.2	1.5
	5	12	92	24	W4M	140.1	22.9	18.0	INC	INC	INC
	7	13	92	24	W4M	151.6	22.0	23.0	INC	INC	INC
	10	21	92	24	W4M	134.2	24.0	31.6	12.0	3.8	2.5
T 93	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	19	W4M	E	E	E	E	E	E
	7	12	93	19	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	E	E	E	E	E	E
	5	25	93	20	W4M	E	E	E	E	E	E
	11	14	93	21	W4M	285.2	19.8	15.4	11.6	1.8	1.5
	10	30	93	22	W4M	227.1	22.0	15.2	14.5	2.2	1.9
	10	4	93	23	W4M	192.5	13.0	13.6	5.5	0.7	0.5
	6	12	93	23	W4M	216.1	16.0	15.7	8.5	1.4	1.2
	10	15	93	23	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	4	25	93	24	W4M	190.8	24.0	INC	INC	INC	INC
	11	24	93	25	W4M	131.0	16.0	INC	INC	INC	INC
	10	33	93	25	W4M	123.0	11.0	INC	INC	INC	INC
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

UGM1 RESERVOIR CHARACTERISTICS												
TWN	WELL ID					ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	LSD	SEC	TWN	RGE	MER						
T 94	9	1	94	19	W4M	E	E	E	E	E	E
	7	24	94	19	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	288.0	20.0	14.5	12.0	1.8	1.6
	6	8	94	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	10	94	21	W4M	301.1	19.0	14.4	11.5	1.6	1.2
	10	17	94	21	W4M	291.8	20.7	INC	INC	INC	INC
	11	22	94	21	W4M	300.6	20.5	INC	INC	INC	INC
	11	29	94	21	W4M	291.9	20.1	11.9	7.0	1.3	1.1
	16	22	94	22	W4M	271.6	23.0	INC	INC	INC	INC
	14	23	94	22	W4M	280.0	22.5	18.7	15.0	2.8	2.5
	11	33	94	22	W4M	274.8	23.5	INC	INC	INC	INC
	6	1	94	23	W4M	229.3	22.5	22.8	16.0	2.1	1.8
	10	4	94	23	W4M	221.4	24.0	8.3	16.0	1.4	1.1
	12	7	94	23	W4M	210.5	21.3	INC	INC	INC	INC
	10	24	94	24	W4M	210.5	24.0	INC	INC	INC	INC
T 95	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	E	E	E	E	E	E
	6	7	95	21	W4M	286.5	21.0	16.5	13.0	2.0	1.7
	10	8	95	21	W4M	295.1	21.0	18.5	13.4	2.5	2.3
	11	10	95	21	W4M	E	E	E	E	E	E
	10	15	95	22	W4M	281.5	14.3	13.5	3.4	0.5	0.3
	7	24	95	22	W4M	286.7	18.0	20.9	3.5	0.7	0.3
	6	35	95	22	W4M	E	E	E	E	E	E
	10	23	95	23	W4M	249.2	13.4	24.9	7.3	1.6	1.2

E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE
SB-1 = SHALE BREAK 1 REMAINING

LGM RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
T 80	10	5	80	16	W4M	168.3	27.0	17.5	21.5	4.3	3.3
	11	12	80	16	W4M	179.8	15.0	17.6	15.0	2.7	2.2
	10	18	80	16	W4M	184.6	45.0	11.1	35.5	4.2	2.8
	11	26	80	16	W4M	188.2	23.5	15.4	19.0	3.3	2.8
	11	29	80	16	W4M	191.2	46.0	13.4	37.0	5.2	3.4
	6	34	80	17	W4M	167.8	N/P	N/P	N/P	N/P	N/P
	10	27	80	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	12	1	80	24	W4M	-147.2	8.0	7.6	0.0	0.0	0.0
	16	1	80	24	W4M	-141.9	9.0	6.4	0.0	0.0	0.0
T 81	10	3	81	16	W4M	202.9	34.0	14.8	31.5	4.8	3.9
	6	6	81	16	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	16	81	16	W4M	216.9	N/P	12.0	N/P	N/P	N/P
	11	18	81	16	W4M	194.4	N/P	15.6	N/P	N/P	N/P
	10	26	81	16	W4M	224.8	38.0	14.7	35.0	5.3	4.4
	11	28	81	16	W4M	217.1	45.7	19.6	INC	INC	INC
	11	29	81	16	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	31	81	16	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	33	81	16	W4M	220.9	43.9	17.1	37.8	6.9	5.4
	10	2	81	17	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	7	8	81	17	W4M	162.1	N/P	11.5	OLD	OLD	OLD
	10	27	81	17	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	36	81	17	W4M	198.4	N/P	N/P	N/P	N/P	N/P
T 82	10	23	82	16	W4M	246.8	37.2	13.0	INC	INC	INC
	6	32	82	16	W4M	233.4	42.7	11.2	23.8	2.7	1.8
	6	34	82	16	W4M	248.1	42.7	OLD	OLD	OLD	OLD
	6	36	82	16	W4M	258.7	43.9	18.0	OLD	OLD	OLD
	10	1	82	17	W4M	200.5	N/P	N/P	N/P	N/P	N/P
	10	1	82	18	W4M	165.7	N/P	N/P	N/P	N/P	N/P
	10	23	82	18	W4M	171.4	42.0	12.8	12.0	1.7	0.8
	10	36	82	22	W4M	14.3	51.2	INC	INC	INC	INC
T 83	7	6	83	16	W4M	236.6	49.0	15.2	INC	INC	INC
	11	9	83	16	W4M	242.5	39.9	9.4	32.6	3.3	2.5
	6	14	83	16	W4M	232.2	16.2	OLD	OLD	OLD	OLD
	11	25	83	17	W4M	228.9	N/P	15.2	N/P	N/P	N/P
	11	34	83	17	W4M	226.4	N/P	N/P	N/P	N/P	N/P
	6	27	83	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	17	83	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	24	83	19	W4M	155.6	41.0	9.1	9.0	1.1	0.6
	13	22	83	22	W4M	-9.6	58.0	13.6	5.0	0.6	0.3
T 84	11	30	84	16	W4M	226.8	10.7	9.2	OLD	OLD	OLD
	11	12	84	18	W4M	203.2	N/P	N/P	N/P	N/P	N/P
	7	26	84	18	W4M	207.4	41.5	11.6	26.5	3.6	2.7
	7	29	84	18	W4M	182.3	41.0	11.2	23.0	3.0	2.0
	10	14	84	19	W4M	159.3	N/P	13.0	N/P	N/P	N/P
	10	17	84	19	W4M	139.8	49.0	12.3	14.0	1.7	0.9
	7	36	84	23	W4M	-0.2	54.0	INC	INC	INC	INC
T 85	11	15	85	17	W4M	249.3	39.6	INC	INC	INC	INC
	7	8	85	18	W4M	193.8	41.0	10.9	0.0	0.0	0.0
	7	11	85	18	W4M	213.0	46.0	13.2	15.5	2.5	1.6
	10	19	85	18	W4M	198.2	N/P	N/P	N/P	N/P	N/P
	10	22	85	18	W4M	215.8	N/P	12.0	N/P	N/P	N/P
	11	33	85	18	W4M	217.9	N/P	12.2	19.0	2.6	1.7
	6	34	85	19	W4M	177.0	N/P	12.4	4.5	0.7	0.4
	10	20	85	21	W4M	66.2	52.4	INC	INC	INC	INC
	10	15	85	22	W4M	30.3	54.9	OLD	OLD	OLD	OLD
	8	17	85	25	W4M	-121.7	40.0	OLD	OLD	OLD	OLD
T 86	10	5	86	17	W4M	251.4	39.3	13.0	29.9	4.2	2.9
	10	3	86	18	W4M	227.6	41.8	OLD	OLD	OLD	OLD
	7	24	86	18	W4M	253.4	39.9	OLD	OLD	OLD	OLD
	12	28	86	18	W4M	232.6	41.0	16.7	35.5	6.2	4.6
	11	26	86	19	W4M	206.5	40.5	11.1	23.5	3.1	2.2
	13	9	86	21	W4M	76.4	44.5	INC	INC	INC	INC
	11	21	87	17	W4M	284.5	N/P	12.0	N/P	N/P	N/P
	14	3	87	18	W4M	237.8	41.2	OLD	OLD	OLD	OLD
	7	11	87	19	W4M	208.6	N/P	15.7	35.4	5.8	3.7
	5	18	87	19	W4M	181.8	43.3	13.3	INC	INC	INC

LGM RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	12	28	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	13	28	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	29	87	19	W4M	197.7	N/P	10.1	N/P	N/P	N/P
	13	33	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
T 87	14	17	87	20	W4M	130.1	39.0	13.9	32.2	4.9	2.7
	11	26	87	20	W4M	174.5	43.5	INC	INC	INC	INC
	6	3	87	22	W4M	61.4	50.0	10.4	1.0	0.2	0.1
	11	12	87	22	W4M	81.0	49.0	INC	INC	INC	INC
	10	33	87	25	W4M	-53.1	50.0	INC	INC	INC	INC
	6	28	88	18	W4M	268.6	N/P	N/P	N/P	N/P	N/P
	14	5	88	19	W4M	200.0	43.9	9.5	INC	INC	INC
	7	11	88	19	W4M	232.0	N/P	N/P	N/P	N/P	N/P
	7	28	88	19	W4M	226.7	N/P	12.0	N/P	N/P	N/P
	10	31	88	19	W4M	213.6	41.8	12.0	27.4	3.9	2.8
	8	1	88	20	W4M	189.2	N/P	14.7	39.0	5.9	3.4
	6	13	88	20	W4M	190.7	42.7	10.6	30.2	3.6	2.0
	7	32	88	20	W4M	167.3	N/P	12.7	N/P	N/P	N/P
	3	34	88	20	W4M	182.6	40.5	17.1	31.9	5.8	3.0
	11	14	88	21	W4M	143.5	40.0	13.7	19.0	2.8	1.6
T 88	11	29	88	21	W4M	136.7	N/P	4.7	0.0	0.0	0.0
	11	24	88	22	W4M	114.2	51.8	6.0	1.5	0.2	0.1
	10	35	88	22	W4M	120.9	N/P	N/P	N/P	N/P	N/P
	16	29	88	23	W4M	49.8	48.0	22.2	46.5	11.0	6.3
	10	35	88	23	W4M	73.1	46.8	8.7	INC	INC	INC
	5	11	88	24	W4M	4.8	52.7	INC	INC	INC	INC
	7	26	88	24	W4M	19.9	48.0	11.2	4.0	0.7	0.4
	4	32	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	7	35	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	24	88	25	W4M	-13.4	52.0	7.4	0.0	0.0	0.0
	10	12	89	18	W4M	295.3	33.5	9.8	2.0	0.2	0.1
	6	19	89	18	W4M	259.7	28.0	17.3	22.5	4.2	3.4
	2	2	89	19	W4M	247.5	39.6	12.1	31.7	4.0	3.2
	10	16	89	19	W4M	234.2	32.3	OLD	OLD	OLD	OLD
	10	30	89	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	6	11	89	20	W4M	195.7	40.0	16.6	38.0	6.2	4.4
	10	16	89	20	W4M	171.0	38.0	INC	INC	INC	INC
	6	26	89	20	W4M	213.1	40.0	12.0	37.5	4.6	3.6
	4	28	89	20	W4M	183.4	39.0	16.6	INC	INC	INC
	6	7	89	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
T 89	14	21	89	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	6	25	89	21	W4M	188.6	44.2	9.4	INC	INC	INC
	7	14	89	22	W4M	130.7	N/P	6.9	0.0	0.0	0.0
	16	33	89	22	W4M	134.6	54.9	8.7	0.0	0.0	0.0
	16	13	89	23	W4M	97.1	53.0	12.1	2.0	0.3	0.1
	10	29	89	23	W4M	74.7	50.0	14.4	13.5	1.9	0.9
	7	35	89	24	W4M	59.3	51.0	10.0	3.5	0.5	0.3
	12	7	89	25	W4M	-16.9	54.6	OLD	OLD	OLD	OLD
	6	11	89	25	W4M	2.5	57.0	5.0	1.0	0.1	0.0
	11	9	90	18	W4M	273.8	14.3	INC	INC	INC	INC
	11	14	90	19	W4M	266.9	30.5	14.9	13.0	2.1	1.6
	10	22	90	19	W4M	278.5	N/P	N/P	N/P	N/P	N/P
	7	31	90	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	8	6	90	20	W4M	194.7	N/P	N/P	N/P	N/P	N/P
	11	11	90	20	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	2	90	21	W4M	184.4	50.0	10.5	9.0	1.1	0.6
	10	8	90	21	W4M	172.9	54.0	12.2	10.0	1.6	0.9
	7	26	90	21	W4M	205.6	53.0	11.9	9.0	1.3	0.8
	11	32	90	21	W4M	189.6	N/P	12.7	9.5	1.3	1.0
T 90	6	1	90	22	W4M	154.8	N/P	N/P	N/P	N/P	N/P
	11	17	90	22	W4M	134.6	53.7	7.2	1.8	0.2	0.1
	7	28	90	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	5	90	23	W4M	84.2	52.0	13.0	31.0	4.5	2.7
	7	19	90	23	W4M	92.9	55.0	6.9	1.0	0.1	0.1
	11	21	90	23	W4M	109.0	53.0	13.0	5.2	0.8	0.4
	7	25	90	23	W4M	133.8	54.7	12.1	9.0	0.8	0.4
	7	34	90	23	W4M	119.0	54.0	11.6	8.5	1.0	0.6

LGM RESERVOIR CHARACTERISTICS

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	10	2	90	24	W4M	50.5	51.0	13.1	12.5	1.9	1.0
	10	23	90	24	W4M	81.3	55.0	17.2	4.5	1.0	0.7
T 91	10	9	9	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	280.5	N/P	10.0	N/P	N/P	N/P
	11	10	91	19	W4M	281.5	45.0	9.5	3.5	0.6	0.4
	10	16	91	19	W4M	277.3	45.5	9.3	6.0	0.7	0.5
	2	22	91	19	W4M	283.8	41.3	8.2	1.0	0.2	0.1
	11	29	91	19	W4M	265.2	43.3	10.7	12.5	1.4	1.1
	8	32	91	19	W4M	279.7	42.1	INC	INC	INC	INC
	8	35	91	19	W4M	262.0	7.3	OLD	OLD	OLD	OLD
	10	14	91	20	W4M	255.4	42.7	7.9	4.6	0.4	0.3
	11	26	91	20	W4M	257.5	53.0	9.8	8.0	1.1	0.9
	11	28	91	20	W4M	246.3	52.7	8.0	OLD	OLD	OLD
	10	1	91	21	W4M	208.7	54.5	INC	INC	INC	INC
	11	8	91	21	W4M	186.4	53.0	13.1	8.5	1.2	0.9
	7	14	91	21	W4M	213.4	52.0	12.1	8.0	1.1	0.8
	11	20	91	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	7	26	91	21	W4M	228.1	52.5	13.3	8.0	1.3	0.9
	10	32	91	21	W4M	207.2	53.0	11.0	8.0	1.2	0.9
	7	1	91	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	5	91	22	W4M	142.7	56.0	16.1	8.5	1.4	0.8
	7	26	91	22	W4M	178.4	54.3	19.8	8.8	1.8	1.5
	11	12	91	24	W4M	97.2	54.0	5.4	0.5	0.0	0.0
	10	34	91	24	W4M	104.5	53.7	INC	INC	INC	INC
T 92	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	279.1	41.5	12.2	7.6	0.9	0.[illegible]
	10	16	92	19	W4M	263.5	4.9	8.3	2.7	0.2	0.1
	11	30	92	19	W4M	276.5	30.0	8.4	0.5	0.1	0.0
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	6	2	92	21	W4M	226.0	52.0	15.8	8.0	1.0	0.9
	11	8	92	21	W4M	218.0	53.0	17.1	7.5	1.3	1.0
	10	14	92	21	W4M	245.0	52.0	11.8	5.5	0.9	0.5
	1	16	92	21	W4M	235.0	54.0	14.0	8.0	1.0	0.8
	10	20	92	21	W4M	239.7	53.0	16.0	6.5	1.1	0.8
	10	32	92	21	W4M	246.9	54.0	18.7	6.5	1.2	1.1
	10	2	92	22	W4M	191.6	54.5	15.0	8.5	1.6	1.3
	10	14	92	22	W4M	201.9	55.0	12.4	7.0	0.9	0.5
	10	21	92	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	22	92	22	W4M	200.8	54.0	15.2	7.5	1.1	0.9
	6	36	92	22	W4M	234.3	N/P	17.6	7.0	1.3	0.8
	5	12	92	24	W4M	117.2	54.3	15.0	INC	INC	INC
	7	13	92	24	W4M	129.6	53.0	9.0	INC	INC	INC
	10	21	92	24	W4M	110.2	54.0	19.4	11.5	2.2	1.5
T 93	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	19	W4M	E	E	E	E	E	E
	7	12	93	19	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	297.1	N/P	N/P	N/P	N/P	N/P
	5	25	93	20	W4M	287.6	N/P	N/P	N/P	N/P	N/P
	11	14	93	21	W4M	265.4	54.3	9.3	5.5	0.5	0.4
	10	30	93	22	W4M	205.0	N/P	6.2	3.0	0.2	0.2
	10	4	93	23	W4M	179.5	N/P	N/P	N/P	N/P	N/P
	6	12	93	23	W4M	200.0	54.0	7.3	3.5	0.3	0.2
	10	15	93	23	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	4	25	93	24	W4M	166.8	53.0	INC	INC	INC	INC
	11	24	93	25	W4M	115.0	58.0	INC	INC	INC	INC
	10	33	93	25	W4M	112.0	56.1	INC	INC	INC	INC
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

LGM RESERVOIR CHARACTERISTICS

TWN	WELL ID					ELEVATION (m)	THICKNESS (m)	POROSITY (%)	NET PAY (m)	ISOPOROSITY (m)	HPV (m)
	LSD	SEC	TWN	RGE	MER						
T 94	9	1	94	19	W4M	E	E	E	E	E	E
	7	24	94	19	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	268.0	N/P	8.0	5.0	0.4	0.3
	6	6	94	21	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	10	94	21	W4M	282.1	55.0	9.3	2.0	0.2	0.1
	10	17	94	21	W4M	271.1	N/P	N/P	N/P	N/P	N/P
	11	22	94	21	W4M	280.1	N/P	N/P	N/P	N/P	N/P
	11	29	94	21	W4M	271.8	54.6	0.6	0.0	0.0	0.0
	16	22	94	22	W4M	248.6	56.0	INC	INC	INC	INC
	14	23	94	22	W4M	257.5	56.0	8.0	1.0	1.0	0.1
	11	33	94	22	W4M	251.3	54.9	INC	INC	INC	INC
	6	1	94	23	W4M	206.8	55.0	7.6	4.5	0.4	0.2
	10	4	94	23	W4M	197.4	N/P	7.2	1.5	0.1	0.1
	12	7	94	23	W4M	189.2	55.8	INC	INC	INC	INC
	10	24	94	24	W4M	186.5	N/P	INC	INC	INC	INC
T 95	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	271.9	31.0	8.0	0.0	0.0	0.0
	6	7	95	21	W4M	265.5	N/P	8.3	1.5	0.2	0.1
	10	8	95	21	W4M	274.1	N/P	8.2	4.3	0.4	0.2
	11	10	95	21	W4M	283.8	N/P	INC	INC	INC	INC
	10	15	95	22	W4M	267.2	53.7	9.9	1.5	0.2	0.1
	7	24	95	22	W4M	268.7	N/P	13.0	0.0	0.0	0.0
	6	35	95	22	W4M	269.3	54.5	9.0	3.5	0.3	0.2
	10	23	95	23	W4M	235.8	N/P	14.5	4.0	0.4	0.3

E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE
OLD = OLD LOG SUITE

APPENDIX 4: LGM SHALE EMBAYMENT

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LGM SHALE EMBAYMENT DATA							
TWN	WELL ID					ELEVATION (m)	THICKNESS (m)
	LSD	SEC	TWN	RGE	MER		
T80	10	5	80	16	W4M	CLEAN	CLEAN
	11	12	80	16	W4M	CLEAN	CLEAN
	10	18	80	16	W4M	CLEAN	CLEAN
	11	26	80	16	W4M	CLEAN	CLEAN
	11	29	80	16	W4M	CLEAN	CLEAN
	6	34	80	17	W4M	CLEAN	CLEAN
	10	27	80	18	W4M	N/P	N/P
	12	1	80	24	W4M	CLEAN	CLEAN
	16	1	80	24	W4M	CLEAN	CLEAN
T 81	10	3	81	16	W4M	CLEAN	CLEAN
	6	6	81	16	W4M	N/P	N/P
	10	16	81	16	W4M	CLEAN	CLEAN
	11	18	81	16	W4M	CLEAN	CLEAN
	10	26	81	16	W4M	CLEAN	CLEAN
	11	28	81	16	W4M	CLEAN	CLEAN
	11	29	81	16	W4M	N/P	N/P
	11	31	81	16	W4M	N/P	N/P
	10	33	81	16	W4M	CLEAN	CLEAN
	10	2	81	17	W4M	N/P	N/P
	7	8	81	17	W4M	N/P	N/P
	10	27	81	17	W4M	N/P	N/P
	10	36	81	17	W4M	CLEAN	CLEAN
T 82	10	23	82	16	W4M	CLEAN	CLEAN
	6	32	82	16	W4M	CLEAN	CLEAN
	6	34	82	16	W4M	CLEAN	CLEAN
	6	36	82	16	W4M	CLEAN	CLEAN
	10	1	82	17	W4M	N/P	N/P
	10	1	82	18	W4M	N/P	N/P
	10	23	82	18	W4M	CLEAN	CLEAN
	10	36	82	22	W4M	CLEAN	CLEAN
T 83	7	6	83	16	W4M	CLEAN	CLEAN
	11	9	83	16	W4M	CLEAN	CLEAN
	6	14	83	16	W4M	CLEAN	CLEAN
	11	25	83	17	W4M	N/P	N/P
	11	34	83	17	W4M	N/P	N/P
	6	27	83	18	W4M	N/P	N/P
	10	17	83	19	W4M	N/P	N/P
	10	24	83	19	W4M	CLEAN	CLEAN
	13	22	83	22	W4M	CLEAN	CLEAN
T 84	11	30	84	16	W4M	CLEAN	CLEAN
	11	12	84	18	W4M	N/P	N/P
	7	26	84	18	W4M	CLEAN	CLEAN
	7	29	84	18	W4M	CLEAN	CLEAN
	10	14	84	19	W4M	N/P	N/P
	10	17	84	19	W4M	CLEAN	CLEAN
	7	36	84	23	W4M	CLEAN	CLEAN
T 85	11	15	85	17	W4M	CLEAN	CLEAN
	7	8	85	18	W4M	CLEAN	CLEAN
	7	11	85	18	W4M	CLEAN	CLEAN
	10	19	85	18	W4M	CLEAN	CLEAN
	10	22	85	18	W4M	CLEAN	CLEAN
	11	33	85	18	W4M	CLEAN	CLEAN
	6	34	85	19	W4M	CLEAN	CLEAN
	10	20	85	21	W4M	CLEAN	CLEAN
	10	15	85	22	W4M	CLEAN	CLEAN
	8	17	85	25	W4M	CLEAN	CLEAN
T 86	10	5	86	17	W4M	CLEAN	CLEAN
	10	3	86	18	W4M	CLEAN	CLEAN
	7	24	86	18	W4M	CLEAN	CLEAN
	12	28	86	18	W4M	CLEAN	CLEAN
	11	26	86	19	W4M	CLEAN	CLEAN
	13	9	86	21	W4M	CLEAN	CLEAN
	11	21	87	17	W4M	CLEAN	CLEAN
	14	3	87	18	W4M	CLEAN	CLEAN
	7	11	87	19	W4M	CLEAN	CLEAN
	5	18	87	19	W4M	CLEAN	CLEAN

LGM SHALE EMBAYMENT DATA							
TWN	WELL ID					ELEVATION (m)	THICKNESS (m)
	LSD	SEC	TWN	RGE	MER		
T 87	12	28	87	19	W4M	N/P	N/P
	13	28	87	19	W4M	N/P	N/P
	11	29	87	19	W4M	CLEAN	CLEAN
	13	33	87	19	W4M	N/P	N/P
	14	17	87	20	W4M	CLEAN	CLEAN
	11	26	87	20	W4M	CLEAN	CLEAN
	6	3	87	22	W4M	CLEAN	CLEAN
	11	12	87	22	W4M	CLEAN	CLEAN
	10	33	87	25	W4M	-63.1	15.0
T 88	6	28	88	18	W4M	N/P	N/P
	14	5	88	19	W4M	191.0	1.1
	7	11	88	19	W4M	N/P	N/P
	7	28	88	19	W4M	220.2	1.5
	10	31	88	19	W4M	205.7	1.2
	8	1	88	20	W4M	CLEAN	CLEAN
	6	13	88	20	W4M	CLEAN	CLEAN
	7	32	88	20	W4M	159.8	1.5
	3	34	88	20	W4M	CLEAN	CLEAN
	11	14	88	21	W4M	137.0	5.0
	11	29	88	21	W4M	123.3	N/P
	11	24	88	22	W4M	100.8	26.8
	10	35	88	22	W4M	111.9	1.5
	16	29	88	23	W4M	41.8	2.5
	10	35	88	23	W4M	63.3	3.7
	5	11	88	24	W4M	CLEAN	CLEAN
	7	26	88	24	W4M	13.4	1.5
	4	32	88	24	W4M	N/P	N/P
	7	35	88	24	W4M	N/P	N/P
	11	24	88	25	W4M	-25.4	26.5
T 89	10	12	89	18	W4M	295.3	26.0
	6	19	89	18	W4M	CLEAN	CLEAN
	2	2	89	19	W4M	CLEAN	CLEAN
	10	16	89	19	W4M	CLEAN	CLEAN
	10	30	89	19	W4M	N/P	N/P
	6	11	89	20	W4M	CLEAN	CLEAN
	10	16	89	20	W4M	155.0	8.8
	6	26	89	20	W4M	CLEAN	CLEAN
	4	28	89	20	W4M	177.6	0.9
	6	7	89	21	W4M	N/P	N/P
	14	21	89	21	W4M	N/P	N/P
	6	25	89	21	W4M	181.5	15.2
	7	14	89	22	W4M	117.3	N/P
	16	33	89	22	W4M	121.2	33.5
	16	13	89	23	W4M	89.1	6.5
	10	29	89	23	W4M	64.7	2.5
	7	35	89	24	W4M	CLEAN	CLEAN
	12	7	89	25	W4M	-24.5	40.5
	6	11	89	25	W4M	-10.0	34.5
T 90	11	9	90	18	W4M	E	E
	11	14	90	19	W4M	E	E
	10	22	90	19	W4M	271.0	N/P
	7	31	90	19	W4M	N/P	N/P
	8	6	90	20	W4M	N/P	N/P
	11	11	90	20	W4M	N/P	N/P
	10	2	90	21	W4M	177.4	37.5
	10	8	90	21	W4M	160.9	36.0
	7	26	90	21	W4M	195.6	37.5
	11	32	90	21	W4M	178.6	N/P
	6	1	90	22	W4M	N/P	N/P
	11	17	90	22	W4M	123.0	36.0
	7	28	90	22	W4M	N/P	N/P
	10	5	90	23	W4M	77.2	7.0
	7	19	90	23	W4M	82.4	36.0
	11	21	90	23	W4M	99.2	36.0
	7	25	90	23	W4M	123.3	37.5
	7	34	90	23	W4M	110.0	37.5

LGM SHALE EMBAYMENT DATA

TWN	WELL ID LSD	SEC	TWN	RGE	MER	ELEVATION (m)	THICKNESS (m)
	10	2	90	24	W4M	37.5	24.0
	10	23	90	24	W4M	73.3	39.0
T 91	10	9	91	17	W4M	E	E
	6	33	91	17	W4M	E	E
	7	14	91	18	W4M	E	E
	10	26	91	18	W4M	E	E
	6	3	91	19	W4M	272.5	N/P
	11	10	91	19	W4M	274.5	34.0
	10	16	91	19	W4M	269.8	29.0
	2	22	91	19	W4M	278.8	35.0
	11	29	91	19	W4M	255.1	27.7
	8	32	91	19	W4M	273.6	24.4
	8	35	91	19	W4M	E	E
	10	14	91	20	W4M	249.9	30.5
	11	26	91	20	W4M	248.5	36.0
	11	28	91	20	W4M	237.7	36.0
	10	1	91	21	W4M	197.7	38.0
	11	8	91	21	W4M	176.4	38.0
	7	14	91	21	W4M	203.9	37.5
	11	20	91	21	W4M	N/P	N/P
	7	26	91	21	W4M	218.6	37.5
	10	32	91	21	W4M	197.7	39.0
	7	1	91	22	W4M	N/P	N/P
	11	5	91	22	W4M	132.7	38.0
	7	26	91	22	W4M	169.3	39.0
	11	12	91	24	W4M	89.2	39.5
	10	34	91	24	W4M	96.2	40.5
T 92	10	5	92	18	W4M	E	E
	7	12	92	18	W4M	E	E
	10	25	92	18	W4M	E	E
	6	8	92	19	W4M	276.7	31.1
	10	16	92	19	W4M	E	E
	11	30	92	19	W4M	276.5	20.5
	6	35	92	19	W4M	E	E
	11	8	92	20	W4M	N/P	N/P
	6	2	92	21	W4M	217.0	39.5
	11	8	92	21	W4M	209.0	38.0
	10	14	92	21	W4M	232.0	33.5
	1	16	92	21	W4M	226.0	40.0
	10	20	92	21	W4M	231.7	39.5
	10	32	92	21	W4M	238.9	40.0
	10	2	92	22	W4M	181.6	40.0
	10	14	92	22	W4M	192.9	40.5
	10	21	92	22	W4M	N/P	N/P
	10	22	92	22	W4M	192.3	40.0
	6	36	92	22	W4M	226.3	N/P
	5	12	92	24	W4M	109.6	40.5
	7	13	92	24	W4M	122.6	40.0
	10	21	92	24	W4M	103.2	41.0
T 93	7	12	93	18	W4M	E	E
	11	21	93	18	W4M	E	E
	10	4	93	19	W4M	E	E
	7	12	93	19	W4M	E	E
	7	22	93	19	W4M	E	E
	5	12	93	20	W4M	N/P	N/P
	5	25	93	20	W4M	N/P	N/P
	11	14	93	21	W4M	257.4	38.7
	10	30	93	22	W4M	194.1	N/P
	10	4	93	23	W4M	N/P	N/P
	6	12	93	23	W4M	189.6	38.0
	10	15	93	23	W4M	N/P	N/P
	4	25	93	24	W4M	159.8	40.0
	11	24	93	25	W4M	106.5	[illegible]
	10	33	93	25	W4M	102.2	40.2
	6	21	94	18	W4M	E	E
	9	35	94	18	W4M	E	E

LGM SHALE EMBAYMENT DATA

TWN	WELL ID					ELEVATION (m)	THICKNESS (m)
	LSD	SEC	TWN	RGE	MER		
T 94	9	1	94	19	W4M	E	E
	7	24	94	19	W4M	E	E
	11	4	94	21	W4M	258.0	N/P
	6	8	94	21	W4M	N/P	N/P
	10	10	94	21	W4M	271.6	36.5
	10	17	94	21	W4M	260.4	N/P
	11	22	94	21	W4M	270.6	N/P
	11	29	94	21	W4M	262.0	37.2
	16	22	94	22	W4M	238.6	37.0
	14	23	94	22	W4M	247.0	37.0
	11	33	94	22	W4M	244.3	39.0
	6	1	94	23	W4M	198.3	37.0
	10	4	94	23	W4M	N/P	N/P
	12	7	94	23	W4M	181.2	41.2
	10	24	94	24	W4M	178.0	N/P
T95	7	4	95	18	W4M	E	E
	4	13	95	18	W4M	E	E
	6	27	95	18	W4M	E	E
	6	1	95	21	W4M	271.9	25.5
	6	7	95	21	W4M	257.5	N/P
	10	8	95	21	W4M	265.8	N/P
	11	10	95	21	W4M	276.8	39.0
	10	15	95	22	W4M	258.7	38.1
	7	24	95	22	W4M	261.2	N/P
	6	35	95	22	W4M	260.8	39.0
	10	23	95	23	W4M	227.5	N/P

CLEAN = CLEAN CARBONATE
E = ERODED
N/P = NOT PENETRATED

APPENDIX 5: SHALE BREAK DATA

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SHALE BREAK DATA

TWN	WELL ID					ELEVATION (m)			THICKNESS (m)		
	LSD	SEC	TWN	RGE	MER	SB-1	SB-2	SB-3	SB-1	SB-2	SB-3
T 80	10	5	80	16	W4M	E	E	E	E	E	E
	11	12	80	16	W4M	E	E	E	E	E	E
	10	18	80	16	W4M	E	E	F	E	E	E
	11	26	80	16	W4M	E	E	E	E	E	E
	11	29	80	16	W4M	195.2	E	E	4.0	E	E
	6	34	80	17	W4M	171.8	185.8	217.8	4.0	4.0	2.0
	10	27	80	18	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	12	1	80	24	W4M	-140.2	-117.7	-80.2	7.0	4.5	2.0
	16	1	80	24	W4M	-133.9	-110.9	-73.9	8.0	6.0	3.0
T 81	10	3	81	16	W4M	E	E	E	E	E	E
	6	6	81	16	W4M	N/P	N/P	E	N/P	N/P	E
	10	16	81	16	W4M	E	E	E	E	E	E
	11	18	81	16	W4M	201.4	216.0	E	7.0	4.0	E
	10	26	81	16	W4M	E	E	E	E	E	E
	11	28	81	16	W4M	223.2	E	E	6.1	E	E
	11	29	81	16	W4M	N/P	N/P	E	N/P	N/P	E
	11	31	81	16	W4M	N/P	219.7	E	N/P	3.7	E
	10	33	81	16	W4M	228.2	E	E	7.3	E	E
	10	2	81	17	W4M	N/P	N/P	230.7	N/P	N/P	3.5
	7	8	81	17	W4M	165.8	181.0	208.5	3.7	4.3	1.2
	10	27	81	17	W4M	N/P	N/P	E	N/P	N/P	E
	10	36	81	17	W4M	204.4	219.4	245.9	6.0	4.0	2.5
T 82	10	23	82	16	W4M	255.9	E	E	9.2	E	E
	6	32	82	16	W4M	241.6	256.3	E	8.2	3.1	E
	6	34	82	16	W4M	255.7	E	E	7.6	E	E
	6	36	82	16	W4M	E	E	E	E	E	E
	10	1	82	17	W4M	208.1	223.0	248.9	7.6	4.3	2.4
	10	1	82	18	W4M	171.8	187.6	E	6.1	6.1	E
	10	23	82	18	W4M	177.9	194.4	220.4	6.5	7.0	2.0
	10	36	82	22	W4M	16.2	31.7	58.2	1.8	5.8	2.1
T 83	7	6	83	16	W4M	244.1	259.1	E	7.5	3.0	E
	11	9	83	16	W4M	250.4	E	E	7.9	E	E
	6	14	83	16	W4M	E	E	E	E	E	E
	11	25	83	17	W4M	E	E	E	E	E	E
	11	34	83	17	W4M	234.3	E	E	7.9	E	E
	6	27	83	18	W4M	N/P	N/P	243.3	N/P	N/P	2.1
	10	17	83	19	W4M	N/P	N/P	171.5	N/P	N/P	2.4
	10	24	83	19	W4M	161.6	178.6	203.1	6.0	7.5	2.0
	13	22	83	22	W4M	-7.1	10.9	39.4	2.5	7.5	4.0
T 84	11	30	84	16	W4M	E	E	E	E	E	E
	11	12	84	18	W4M	209.9	221.5	E	6.7	5.5	E
	7	26	84	18	W4M	213.9	230.9	E	6.5	7.5	E
	7	29	84	18	W4M	188.8	206.3	E	6.5	8.0	E
	10	14	84	19	W4M	166.8	186.3	210.3	7.5	9.0	2.0
	10	17	84	19	W4M	144.8	162.8	189.8	5.0	7.0	2.0
	7	36	84	23	W4M	2.7	21.8	52.9	2.9	7.3	3.7
T 85	11	15	85	17	W4M	E	E	E	E	E	E
	7	8	85	18	W4M	199.8	217.3	243.8	6.0	7.5	1.0
	7	11	85	18	W4M	220.0	237.5	E	7.0	8.5	E
	10	19	85	18	W4M	204.3	222.0	247.6	6.1	7.6	1.8
	10	22	85	18	W4M	222.2	239.2	264.8	6.4	8.2	2.1
	11	33	85	18	W4M	224.9	241.9	269.4	7.0	8.0	2.5
	6	34	85	19	W4M	183.0	201.0	228.0	6.0	8.0	2.0
	10	20	85	21	W4M	69.0	88.2	119.2	2.7	7.3	2.1
	10	15	85	22	W4M	33.7	52.9	83.4	3.4	7.3	1.8
	8	17	85	25	W4M	-118.7	-93.7	-57.2	3.0	9.0	3.5
T 86	10	5	86	17	W4M	259.6	E	E	8.2	E	E
	10	3	86	18	W4M	234.8	260.4	E	7.3	16.2	E
	7	24	86	18	W4M	261.0	278.1	E	7.6	8.5	E
	12	28	86	18	W4M	239.1	256.6	284.6	6.5	9.0	3.0
	11	26	86	19	W4M	212.5	230.5	258.0	6.0	8.5	1.5
	13	9	86	21	W4M	81.4	100.9	132.4	5.0	9.0	1.5
	11	21	87	17	W4M	292.5	E	E	8.0	E	E
	14	3	87	18	W4M	244.8	262.5	E	7.0	7.9	E
	7	11	87	19	W4M	215.0	233.3	261.7	6.4	7.0	1.5
	5	18	87	19	W4M	187.3	205.6	233.7	5.5	8.2	2.4

SHALE BREAK DATA											
TWN	WELL ID					ELEVATION (m)			THICKNESS (m)		
	LSD	SEC	TWN	RGE	MER	SB-1	SB-2	SB-3	SB-1	SB-2	SB-3
	12	28	87	19	W4M	N/P	N/P	255.2	N/P	N/P	3.0
	13	28	87	19	W4M	N/P	N/P	255.8	N/P	N/P	1.5
	11	29	87	19	W4M	203.7	220.7	249.7	6.0	7.5	2.0
	13	33	87	19	W4M	N/P	N/P	N/P	N/P	N/P	N/P
T 87	14	17	87	20	W4M	135.6	153.3	182.0	5.5	7.0	1.8
	11	26	87	20	W4M	179.0	197.0	225.0	4.5	7.0	2.5
	6	3	87	22	W4M	65.9	86.9	118.9	4.5	7.5	2.5
	11	12	87	22	W4M	87.0	107.5	138.0	6.0	8.5	1.5
	10	33	87	25	W4M	-49.1	-30.6	4.4	4.0	2.5	2.5
	6	28	88	18	W4M	275.6	288.6	E	7.0	3.5	E
	14	5	88	19	W4M	208.5	224.4	251.2	8.5	7.6	1.8
	7	11	88	19	W4M	238.5	256.5	E	6.5	7.0	E
	7	28	88	19	W4M	233.2	252.2	E	6.5	8.5	E
	10	31	88	19	W4M	219.7	239.8	E	6.1	9.8	E
	8	1	88	20	W4M	195.7	213.7	241.7	6.5	8.5	1.5
	6	13	88	20	W4M	196.2	215.7	243.4	5.5	9.2	2.4
	7	32	88	20	W4M	171.8	191.3	215.8	4.5	8.0	1.5
	3	34	88	20	W4M	187.2	205.8	233.5	4.6	7.9	1.5
	11	14	88	21	W4M	148.5	163.5	194.5	5.0	3.0	2.0
T 88	11	29	88	21	W4M	143.4	166.0	195.9	6.7	9.8	1.8
	11	24	88	22	W4M	120.3	142.3	174.6	6.1	9.2	3.4
	10	35	88	22	W4M	127.4	149.9	181.9	6.5	10.0	3.0
	16	29	88	23	W4M	54.3	74.8	107.8	4.5	9.0	2.0
	10	35	88	23	W4M	78.6	99.3	132.8	5.5	9.5	1.8
	5	11	88	24	W4M	8.7	28.9	62.1	4.0	8.8	2.4
	7	26	88	24	W4M	22.9	44.9	77.9	3.0	10.0	2.5
	4	32	88	24	W4M	N/P	N/P	62.0	N/P	N/P	2.0
	7	35	88	24	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	24	88	25	W4M	-8.4	11.6	42.6	5.0	5.0	2.0
	10	12	89	18	W4M	E	E	E	E	E	E
	6	19	89	18	W4M	E	E	E	E	E	E
	2	2	89	19	W4M	253.6	E	E	6.1	E	E
	10	16	89	19	W4M	237.5	E	E	3.4	E	E
	10	30	89	19	W4M	N/P	N/P	E	N/P	N/P	E
	6	11	89	20	W4M	200.7	220.2	248.2	5.0	9.0	2.0
	10	16	89	20	W4M	175.6	195.6	E	4.6	6.1	E
	6	26	89	20	W4M	218.1	238.1	265.6	5.0	8.0	2.5
	4	28	89	20	W4M	188.9	208.4	236.5	5.5	7.9	2.4
	6	7	89	21	W4M	N/P	N/P	199.7	N/P	N/P	4.0
T 89	14	21	89	21	W4M	N/P	192.7	224.7	N/P	8.8	3.1
	6	25	89	21	W4M	194.4	213.3	242.8	5.8	7.9	2.7
	7	14	89	22	W4M	138.0	158.7	192.0	7.3	9.2	4.0
	16	33	89	22	W4M	137.7	160.8	195.6	3.1	8.5	3.1
	16	13	89	23	W4M	101.1	121.6	155.6	4.0	7.5	2.5
	10	29	89	23	W4M	79.7	100.2	133.7	5.0	9.5	3.0
	7	35	89	24	W4M	63.3	84.8	116.8	4.0	6.5	2.5
	12	7	89	25	W4M	-11.7	8.1	38.0	6.1	4.6	2.4
	6	11	89	25	W4M	7.0	26.0	57.5	4.5	4.5	2.0
	11	9	90	18	W4M	E	E	E	E	E	E
	11	14	90	19	W4M	E	E	E	E	E	E
	10	22	90	19	W4M	284.0	E	E	5.5	E	E
	7	31	90	19	W4M	N/P	279.9	E	N/P	5.0	E
	8	6	90	20	W4M	199.3	220.6	246.2	4.6	8.2	3.1
	11	11	90	20	W4M	N/P	N/P	271.6	N/P	N/P	3.0
	10	2	90	21	W4M	192.4	213.4	244.4	8.0	8.0	3.0
	10	8	90	21	W4M	178.9	200.9	231.9	6.0	11.0	3.0
	7	26	90	21	W4M	212.6	232.6	265.6	7.0	6.0	3.0
	11	32	90	21	W4M	195.6	216.6	249.6	6.0	8.0	2.0
T 90	6	1	90	22	W4M	161.2	181.0	213.9	6.4	8.5	2.4
	11	17	90	22	W4M	140.1	160.2	195.3	5.5	7.9	2.7
	7	28	90	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	5	90	23	W4M	88.2	108.2	142.2	4.0	8.0	4.0
	7	19	90	23	W4M	97.9	119.9	153.4	5.0	4.5	3.0
	11	21	90	23	W4M	115.1	134.9	170.0	6.1	6.4	2.4
	7	25	90	23	W4M	139.1	159.3	195.3	5.3	8.0	2.5
	7	34	90	23	W4M	123.0	145.0	182.5	4.0	6.0	4.5

SHALE BREAK DATA

TWN	WELL ID					ELEVATION (m)			THICKNESS (m)		
	LSD	SEC	TWN	RGE	MER	SB-1	SB-2	SB-3	SB-1	SB-2	SB-3
	10	2	90	24	W4M	55.5	76.0	110.0	5.0	5.5	2.5
	10	23	90	24	W4M	86.8	109.3	141.3	5.5	5.0	3.0
	10	9	91	17	W4M	E	E	E	E	E	E
	6	33	91	17	W4M	E	E	E	E	E	E
	7	14	91	18	W4M	E	E	E	E	E	E
	10	26	91	18	W4M	E	E	E	E	E	E
	6	3	91	19	W4M	285.5	E	E	5.0	E	E
	11	10	91	19	W4M	286.0	E	E	4.5	E	E
	10	16	91	19	W4M	281.3	E	E	4.0	E	E
	2	22	91	19	W4M	286.8	E	E	3.0	E	E
	11	29	91	19	W4M	272.3	E	E	7.0	E	E
	8	32	91	19	W4M	INC	E	E	INC	E	E
	8	35	91	19	W4M	E	E	E	E	E	E
T 91	10	14	91	20	W4M	263.0	279.1	E	7.6	4.9	E
	11	26	91	20	W4M	265.5	E	E	8.0	E	E
	11	28	91	20	W4M	254.2	270.6	E	7.9	3.7	E
	10	1	91	21	W4M	214.7	234.7	E	6.0	7.0	E
	11	8	91	21	W4M	192.9	212.4	248.9	6.5	6.0	5.5
	7	14	91	21	W4M	219.9	236.9	273.4	6.5	4.5	4.0
	11	20	91	21	W4M	N/P	N/P	242.0	N/P	N/P	5.0
	7	26	91	21	W4M	235.1	253.1	289.1	7.0	5.0	4.5
	10	32	91	21	W4M	214.2	232.2	269.2	7.0	4.5	5.0
	7	1	91	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	11	5	91	22	W4M	148.7	168.7	205.7	6.0	8.0	6.0
	7	26	91	22	W4M	185.1	205.2	241.2	6.7	6.1	3.7
	11	12	91	24	W4M	102.2	124.2	156.7	5.0	4.0	3.5
	10	34	91	24	W4M	109.7	123.4	165.1	5.2	9.2	2.9
	10	5	92	18	W4M	E	E	E	E	E	E
	7	12	92	18	W4M	E	E	E	E	E	E
	10	25	92	18	W4M	E	E	E	E	E	E
	6	8	92	19	W4M	E	E	E	E	E	E
	10	16	92	19	W4M	E	E	E	E	E	E
	11	30	92	19	W4M	E	E	E	E	E	E
	6	35	92	19	W4M	E	E	E	E	E	E
	11	8	92	20	W4M	N/P	N/P	E	N/P	N/P	E
	6	2	92	21	W4M	233.0	252.0	E	7.0	5.0	E
	11	8	92	21	W4M	224.5	242.5	276.0	6.5	4.5	3.0
	10	14	92	21	W4M	252.0	272.0	303.0	7.0	6.0	1.0
T 92	1	16	92	21	W4M	241.5	262.0	295.0	6.5	6.0	3.0
	10	20	92	21	W4M	247.2	266.7	301.7	7.5	6.5	5.0
	10	32	92	21	W4M	253.9	274.9	E	7.0	8.0	E
	10	2	92	22	W4M	197.6	219.1	254.1	6.0	5.0	3.5
	10	14	92	22	W4M	208.4	227.9	262.9	6.5	4.0	3.0
	10	21	92	22	W4M	N/P	N/P	N/P	N/P	N/P	N/P
	10	22	92	22	W4M	206.8	227.3	262.8	6.0	3.5	4.0
	6	36	92	22	W4M	240.8	261.3	297.8	6.5	6.0	5.5
	5	12	92	24	W4M	122.7	144.7	178.8	5.5	4.6	3.7
	7	13	92	24	W4M	135.6	157.1	190.6	6.0	5.5	3.0
	10	21	92	24	W4M	117.2	142.2	176.7	7.0	8.0	3.5
	7	12	93	18	W4M	E	E	E	E	E	E
	11	21	93	18	W4M	E	E	E	E	E	E
	10	4	93	19	W4M	E	E	E	E	E	E
	7	12	93	19	W4M	E	E	E	E	E	E
	7	22	93	19	W4M	E	E	E	E	E	E
	5	12	93	20	W4M	E	E	E	E	E	E
	5	25	93	20	W4M	E	E	E	E	E	E
T 93	11	14	93	21	W4M	273.6	293.4	E	8.2	8.2	E
	10	30	93	22	W4M	211.1	232.1	269.1	6.0	5.0	4.5
	10	4	93	23	W4M	185.5	201.5	240.5	6.0	9.0	3.0
	6	12	93	23	W4M	206.1	222.1	259.6	6.0	6.0	4.5
	10	15	93	23	W4M	N/P	N/P	254.7	N/P	N/P	4.0
	4	25	93	24	W4M	172.8	197.3	228.3	6.0	6.5	2.5
	11	24	93	25	W4M	120.0	139.0	178.5	5.0	8.0	1.5
	10	33	93	25	W4M	116.9	136.7	173.9	4.9	13.7	2.1
	6	21	94	18	W4M	E	E	E	E	E	E
	9	35	94	18	W4M	E	E	E	E	E	E

SHALE BREAK DATA

TWN	WELL ID					ELEVATION (m)			THICKNESS (m)		
	LSD	SEC	TWN	RGE	MER	SB-1	SB-2	SB-3	SB-1	SB-2	SB-3
	9	1	94	19	W4M	E	E	E	E	E	E
	7	24	94	19	W4M	E	E	E	E	E	E
	11	4	94	21	W4M	275.0	298.0	E	7.0	10.0	E
	6	8	94	21	W4M	N/P	N/P	E	N/P	N/P	E
	10	10	94	21	W4M	289.1	310.1	E	7.0	9.0	E
	10	17	94	21	W4M	278.4	297.6	E	7.3	5.8	E
	11	22	94	21	W4M	288.1	304.6	E	8.0	4.0	E
T 94	11	29	94	21	W4M	279.1	301.3	E	7.3	9.5	E
	16	22	94	22	W4M	255.6	278.6	E	7.0	7.0	E
	14	23	94	22	W4M	264.5	286.5	E	7.0	6.5	E
	11	33	94	22	W4M	259.3	280.6	E	7.9	5.8	E
	6	1	94	23	W4M	212.3	233.8	269.8	5.5	4.5	4.5
	10	4	94	23	W4M	202.9	225.4	260.4	5.5	4.0	4.0
	12	7	94	23	W4M	194.1	213.3	250.5	4.9	2.7	7.6
	10	24	94	24	W4M	191.5	216.0	249.5	5.0	5.5	4.5
	7	4	95	18	W4M	E	E	E	E	E	E
	4	13	95	18	W4M	E	E	E	E	E	E
	6	27	95	18	W4M	E	E	E	E	E	E
	6	1	95	21	W4M	E	E	E	E	E	E
	6	7	95	21	W4M	272.5	294.5	E	7.0	8.0	E
T 95	10	8	95	21	W4M	280.8	300.3	E	6.7	5.2	E
	11	10	95	21	W4M	E	E	E	E	E	E
	10	15	95	22	W4M	273.9	E	E	6.7	E	E
	7	24	95	22	W4M	276.7	E	E	8.0	E	E
	6	35	95	22	W4M	E	E	E	E	E	E
	10	23	95	23	W4M	241.9	E	E	6.1	E	E

SB-1 = SHALE BREAK 1
SB-2 = SHALE BREAK 2
SB-3 = SHALE BREAK 3
E = ERODED
N/P = NOT PENETRATED
INC = INCOMPLETE LOG SUITE

PROFESSIONAL STATEMENT

I, Eugene Anthony Dembicki, as a registered Professional Geologist with the Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA) state that the work contained in this thesis, is to the best of my knowledge, true and accurate.

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Dec. 6, 1993

Date