2.0 GEOLOGY

2.1.1 Introduction

The primary objective of the geological task in this study was to construct a static geological model suitable for reservoir simulation. As such, this model differs somewhat from a more typical geological model in that its focus is on flow units not on lithology type, facies, and/or sequence stratigraphic units. These model differences will be defined and the particulars will be detailed in the sections below.

The purpose of the reservoir simulation study is to resolve the degree of lateral and vertical communication in the Wabiskaw-McMurray formations. Therefore, all geological activities that do not specifically contribute to the understanding of this relationship by means of history matching wells using the simulator are not relevant to this study. It is important to state this at the outset, so that expectations of the geological output are realistic. On the other hand, there are ancillary findings from this work that will benefit the geological community at large; these also will be discussed in the sections below.

The area included in the geological study is shown on **Figure G-T1**, below. The simulation study area is outlined in red. The buffer area, as defined in the engineering report, is the colour fill outside of the red perimeter. Wells utilized in the correlation effort and in structural mapping are shown in red triangles. Note that the geological study includes a number of wells outside of both the simulation and buffer areas. It is important to note that not all wells currently drilled in the area shown on **Figure G-T1** were available for inclusion in the geological study for the following reasons: no available archived open-hole log LAS or ASCII files; a lack of certain log traces (notably the gamma ray); locations too distant from the main study area; wellbore penetrated only shallower zones; because the wells post-date the start-up date of this study.

The timeframe available for the correlation effort was relatively short given that there are over 1200 wells in the area shown on the location map. However, the requirements of simulation are somewhat more flexible than those governing other aspects of geological study, so that the end results are acceptably reliable despite the time constraints.

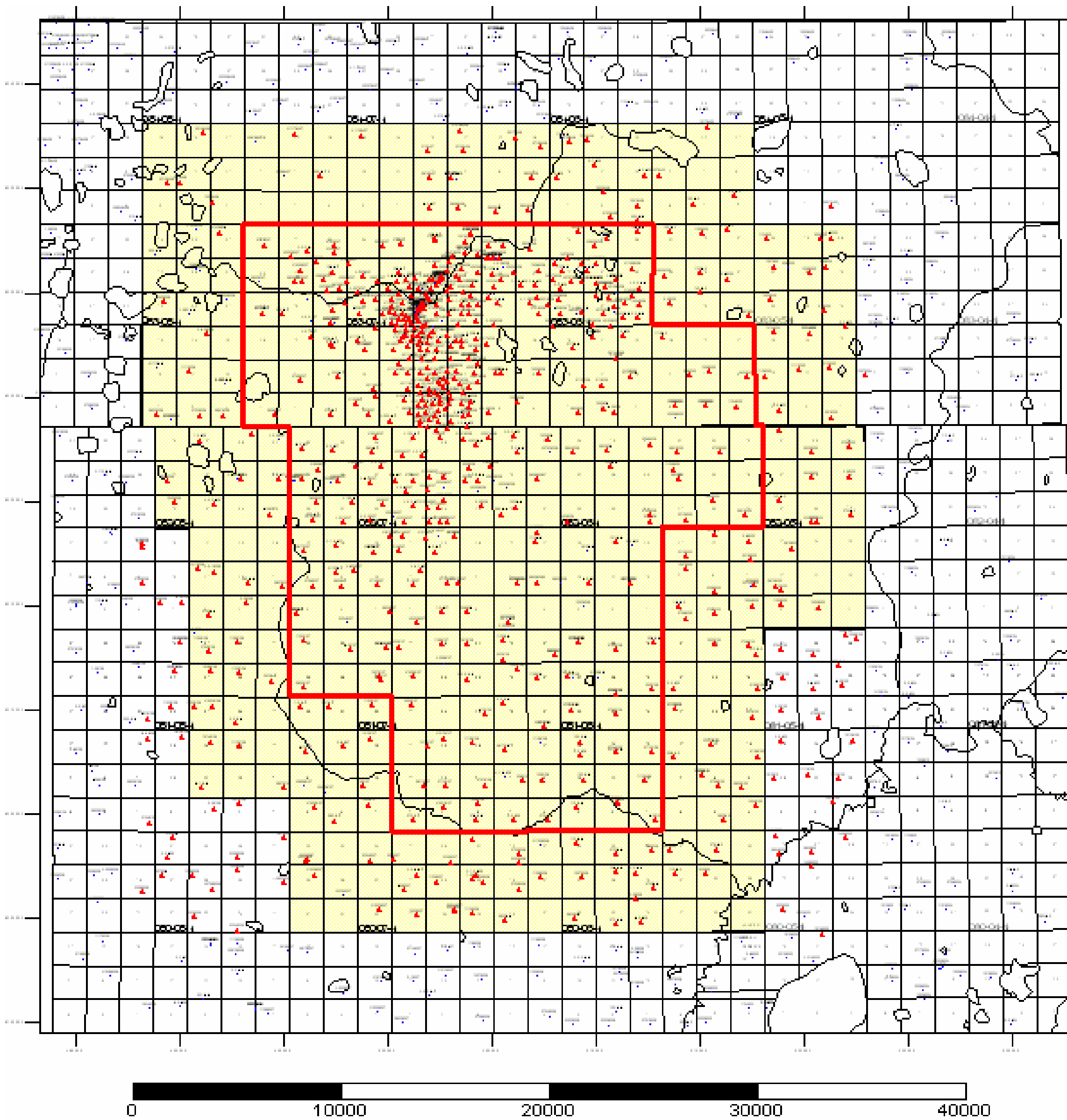

Figure G-T1: *Location Map. Coloured area includes buffer. Red outline is Simulation Study Boundary. Wells used in correlation work denoted by solid red triangles* ▲.

2.1.2 Technical Approach

2.1.2.1 Overview

The fundamental difficulty faced by any geoscientist attempting to subdivide the McMurray Formation of the Surmont region into its constituent stratigraphic units is the restricted spatial geometry of most log-defined rock bodies. A second, but non-stratigraphic problem, is the irregular well density.

The stratigraphic complexity of the McMurray is well known and has been the subject of much research both published and proprietary. In summary, the McMurray Formation in the Surmont study area was deposited on the ridge and valley topography of the underlying Devonian unconformity. This occurred in a fluvial-estuarine-foreshore system characterized by significant tidal influence near the southern shore of the Lower Cretaceous boreal sea. Frequent but modest changes in base level, accommodation space, and sediment flux created ideal conditions for the development of a widely migrating estuarine accretion plain heavily incised by lowstand labyrinthine multi-stage, nested channels.

Well density across the Surmont area is highly variable with high well density in areas currently involved with bitumen recovery and very low density in areas exclusively produced for gas (sometimes less than one well per section). The consequence of this is that through most of the study area, the well spacing exceeds the average width of most lowstand depositional units that fill incised channels.

The approach used to create a useful model, given the inherent complexity of such a system, is quite basic. When the lowstand (channel) elements are removed (using net-to-gross ratio cutoffs and other criteria), the remaining framework consists of more continuous non-lowstand stratigraphic units, which can be correlated over distances that exceed the well spacing. Ranger and Pemberton (1997) have correlated such regional McMurray stratigraphic units over long distances and described them as “stacked, prograding, shoreface parasequences.” Caplan and Ranger (2001) provided detailed descriptions of similar coarsening-upward McMurray cycles in the Surmont area. More recently, Mathison (2004) offered interpretations of these units that include both tidal and wave-dominated intervals. Whatever the specific depositional origin of such units, the fact is that the generally upward coarsening sandstone units and the intervening shales and mudstones can often be correlated over many kilometers.

This then establishes the primary methodology for constructing the underlying framework for the model.

2.1.2.2 Data

The primary data for the correlation phase of this study consisted of gamma ray (GR) logs for 684 wells within the study area. The GR was used as the primary correlation log, because unlike the spontaneous potential (SP) and resistivity logs, it is unaffected by hydrocarbon saturation or variable formation water resistivity (Rw). A digital database was constructed containing the UWI, well name, x-y coordinates, and KB. Wells with core data and dipmeter were also identified in the database.

The data were loaded initially into a proprietary program in order to obtain an overview of the correlation issues. It was during this phase that the methodology for conducting the correlation work, as discussed above, was established. Resistivity and porosity logs were also loaded in their raw unedited form (work on petrophysics was concurrent but not yet available). Total resistivity (Rt) and porosity (Phi) cutoffs were utilized and net-to-gross relationships were approximated. This permitted the identification of major compound, nested, channel complexes. Large tracts of acreage are in fact primarily comprised of such channel complexes in the McMurray Formation. Nonetheless, the exclusion of these areas allowed wells with more consistent correlation markers (remnant interfluves) to be identified. This involved significant jump-correlation across the highly channelized areas.

Later, the correlation work was transferred to PETREL[1] geological software and finalized. Altogether using the two programs, the correlation process involved making over six hundred (600) cross sections of which approximately seventy-five (75) are preserved for this report.

Cores for fifteen (15) wells were described at the Alberta Energy and Utilities Board Core Research Centre in order to calibrate log trace characteristics with lithology, rock quality, and to a lesser extent facies and to study the saturation profile of the cored section. In addition, dipmeters for over fifty (50) wells supplied by ConocoPhillips, were reviewed for applicability to the correlation work.

[1] Copyright of Schlumberger

2.1.2.3 Layering

In terms of reservoir simulation, areally distributed flow units comprise the basic building blocks of the geological model. Numerical models allow flow to occur in three dimensions through the faces of a block ("grid block") of reservoir material. The nature of the reservoir material within any defined flow unit is not consequential, provided that the capillary pressure, relative permeabilities, and endpoint saturations are the same or very similar. Rock units with these similar characteristics are referred to as "rock types". The numerical model requires identification of barriers and changes in the rock type to track flow. Hence, the issue of depositional facies per se can be irrelevant (especially in intervals with significant diagenesis). There may be several rock types within a reservoir, which may or may not coincide with a specific facies. There may be more than one rock type within a flow unit. If present, the distribution of the multiple rock types within the flow unit (layer) does have to be accounted for in the static model.

Flow layers are usually required in simulation, even in homogeneous media, in order to history match pressures and track saturation histories. If the geologist has no useful boundaries by which to separate the column into vertical units, the engineer can mathematically subdivide the column and, accordingly, assign constant petrophysical property values to the cells. In practice, this rarely happens, as almost all real world examples provide some basis for vertical segregation into intervals that have a geological identity.

At Surmont, the subdivision of the McMurray into layers on the western and south-western margins of the study area (as will be discussed in more detail below) is based on the presence of surfaces defined by continuous shales and mudstones that are flooding events of some type. Remnants (interfluves) of these pre-incision units are found across the remaining part of the study area. The channel complexes that intersect these surfaces are placed vertically in the same units as their lateral neighbors even though facies and rock types are clearly different. This is to allow flow under the influence of a lateral pressure gradient across rock type boundaries.

The flow layers defined for the study, from the top down, are as follows: Basal Wabiskaw; three units in the Upper McMurray (upper, middle and lower; Middle McMurray; and Lower McMurray. This yields a total of six simulation layers.

2.1.2.4 Mapping and Gridding

Mapping and graphics presentations were prepared using both PETREL and SURFER[2] software packages. Much of the preliminary mapping was done on SURFER, such as the first pass net-to-gross mapping and for the identification of the bitumen-water contacts on the east side of the study area using hydrocarbon pore-volume (HPV) maps. Detailed and final mapping was all conducted using PETREL. Final hardcopy maps, digital maps, and the project file itself are all in archived in PETREL format and submitted as a part of this report. SURFER maps are used only sparingly herein to illustrate conceptual ideas. However, the final base maps and cross section index maps are from SURFER, because of limitations with PETREL.

Final net reservoir cutoffs determined from the petrophysical study were used to create summations of average properties for each mapped reservoir layer. These values were mapped using a 50 m x 50 m grid. Interpolated and extrapolated areas characterized by average values that fell below the cutoffs were nulled in the final grids. The geological grid was then upscaled to a 402.34 m x 402.34 m simulation grid, which is one grid cell per legal subdivision (LSD).

The map suite utilized in constructing the static model includes a top of structure map (top of Basal Wabiskaw) and layer maps of gross thickness, net-to-gross ratio, average effective porosity (PhiE), and average permeability (k). The mapped data are based on net reservoir not net gas pay calculations. The net reservoir values include shale volume (Vshale), PhiE, and k cutoffs (in this case 40%, 14%, and .5 mD respectively), but no water saturation cutoff.

2.1.2.5 Comments on Figures and Tables

Geological reports are, by their nature, graphics-intensive. This report is no exception. Nonetheless, in order to facilitate a fluid reading of the text, only selected, essential figures are embedded within the text itself. These are prefixed as **G-T*x*** (Geology-Text-Sequence Number). Most of the report figures consist of colour maps and cross sections, which will be found at the end of the text portion of the report or in attached appendices. These are prefixed as **G-*x*** (Geology-Sequence Number).

[2] Copyright of Golden Software

Many of the figures included at the end of the report are provided as .emf (Enhanced Windows Metafile) digital files, which provide the user with the ability to magnify to large-scale for printing large size maps, or as bitmaps (.bmp), which have less resolution but are usually adequate for cross sections. Maps are generally inconvenient in page-size format, but useful at expanded scales for individual review by interested parties. Also, because .emf files are very large, loading them into text reports is time consuming and cumbersome, hence, another reason for their removal to the end of the report. Figures referred to in the text that are not immediately embedded in the report are indicated by the word "end", e.g**. Figure G-20** (end). All figures that appear within the text are also reproduced in the complete figure sequence at the end of the report.

2.1.3 Regional Geology

With over one trillion barrels of bitumen in place, the Athabasca oil sands of northeastern Alberta are the largest single hydrocarbon deposit in the world (Meyer and Duford, 1989). Accordingly, a voluminous literature exists exhaustively detailing various aspects of the geology of the reservoirs containing the bitumen. It is not the intent here to review this literature or even attempt a summary of key findings, as that would be far beyond the scope of the current project. Moreover, one of the requirements for engaging a geologist to work with the engineering team on this study was that the geologist would be "untainted" with preconceived ideas about the relationship of bitumen and gas in the Athabasca region in general and the Surmont area in particular. That reduces the amount of background material that can be digested in the allotted time.

That being said, one cannot work in a complete vacuum, so that obtaining a regional understanding of the basic stratigraphy and structure is a natural course of action that any competent investigator would undertake before focused work on the objective could begin. The regional framework provides the context through which the detailed study is compared. Further, once the detailed work begins and one's basic conclusions are obtained, it is worthwhile to review the attempts of others doing similar work to ensure that a comprehensive picture has been realized. For such reasons, the following section is presented as an integral part of this work.

2.1.3.1 Regional Geological Background

The McMurray Formation of the Mannville Group is Lower Cretaceous (primarily Aptian) in age (Stott and Aitken, 1993). The Alberta lexicon (1997) describes the McMurray Formation in the Athabasca Oil Sands deposit as mainly fine-grained, moderately sorted quartz sand, saturated throughout with bitumen.

Carrigy (1959) divided the McMurray Formation into three members as follows: The lower member, which is present only in selected depressions on the underlying Devonian surface, consists of conglomerate, poorly sorted argillaceous sand, silt, and clay. The middle member comprises two distinct facies: a lower, massive to thick bedded unit of moderately well sorted, fine grained sand, dominated by large scale trough cross-beds; and an upper unit consisting of solitary sets of inclined strata, up to 25 m thick, with depositional slopes averaging 8° to 12°, consisting of decimeter to meter thick beds of fine grained, rippled sand separated by thin partings of argillaceous silt, with various degrees of burrowing throughout. Strata of the upper member consist of horizontally bedded, argillaceous, very fine-grained sand, which is commonly burrowed and locally bearing a restricted brackish water fauna (Mellon and Wall, 1956). This three-fold breakdown of the formation is applicable throughout the Fort McMurray outcrop area, but is not everywhere evident in the subsurface (Mossop, 1980).

The McMurray averages 60 m thick in the heart of the Athabasca Oil Sands region (Townships 80-100, Ranges 7-11W4M) but thins westward against a Paleozoic high. East of the Athabasca deposit, the McMurray thickness is on the order of 30 m. The formation is recognized in northeastern Alberta as far south as Township 50, where it exhibits patchy bitumen saturation in the Cold Lake Oil Sands deposit.

The McMurray rests unconformably on erosionally truncated Paleozoic formations (mainly Devonian), and is overlain by the Lower Cretaceous Clearwater Formation (Basal Wabiskaw Member) (**Figure G-T2**, below). The McMurray Formation is broadly correlative with the lower Mannville Group of Alberta, the Dina Formation of the Lloydminster region, the Gething Formation of northwestern Alberta and northeastern British Columbia, and the Ellerslie Formation-Ostracod Zone of central Alberta (Stott and Aitken, 1993).

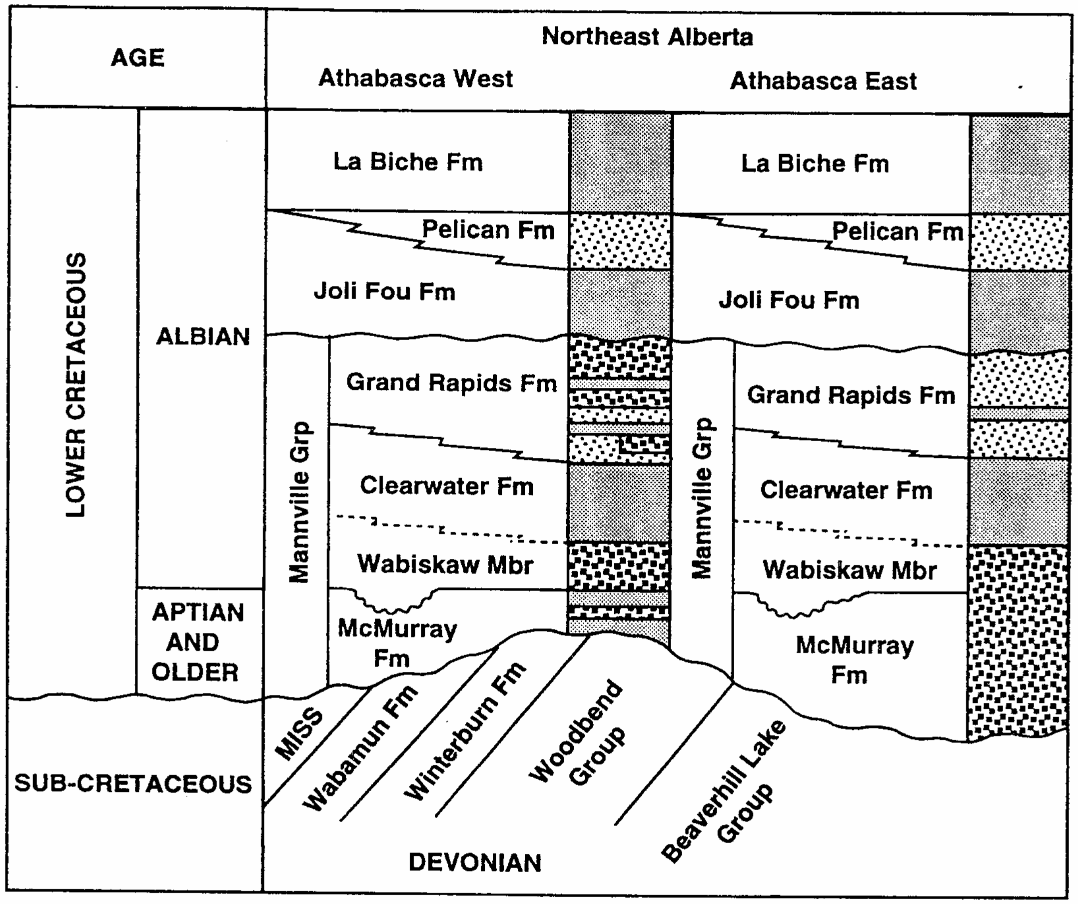

Figure G-T2: *Stratigraphic Column for the Athabasca Area (from Strobl et al., 1995).*

Jeletzky (1971) noted that the McMurray is dominated by terrestrial sediments at its base and becomes more marine upward and northward due to the influence of the southward encroachment of the Boreal Sea. At the end of McMurray time the Boreal Sea transgressed to the south (maximum flooding event) depositing the Wabiskaw glauconitic sand and then the Clearwater sands and shales. Thus, in a gross sense, the McMurray deposit is a result of a slow, complex, punctuated, transgression from the north. Other than some minor authigenic clay deposition (chlorites), there was remarkably little post-depositional (diagenetic) alteration of the McMurray sediments. The sands remain at optimal packing.

2.1.3.2 Regional Mapping

From published tops, several regional maps were prepared in order to visualize the relationship of the Surmont area to the southeastern Athabasca region as a whole. **Figure G-3 (end)** is a structure map of the top of the McMurray (the Surmont study area is outlined in black). **Figure G-4 (end)** is the structure of the top of the Devonian in the same area. **Figure G-T3 (below)** is an isopach prepared by subtracting the top of McMurray from the top of Devonian.

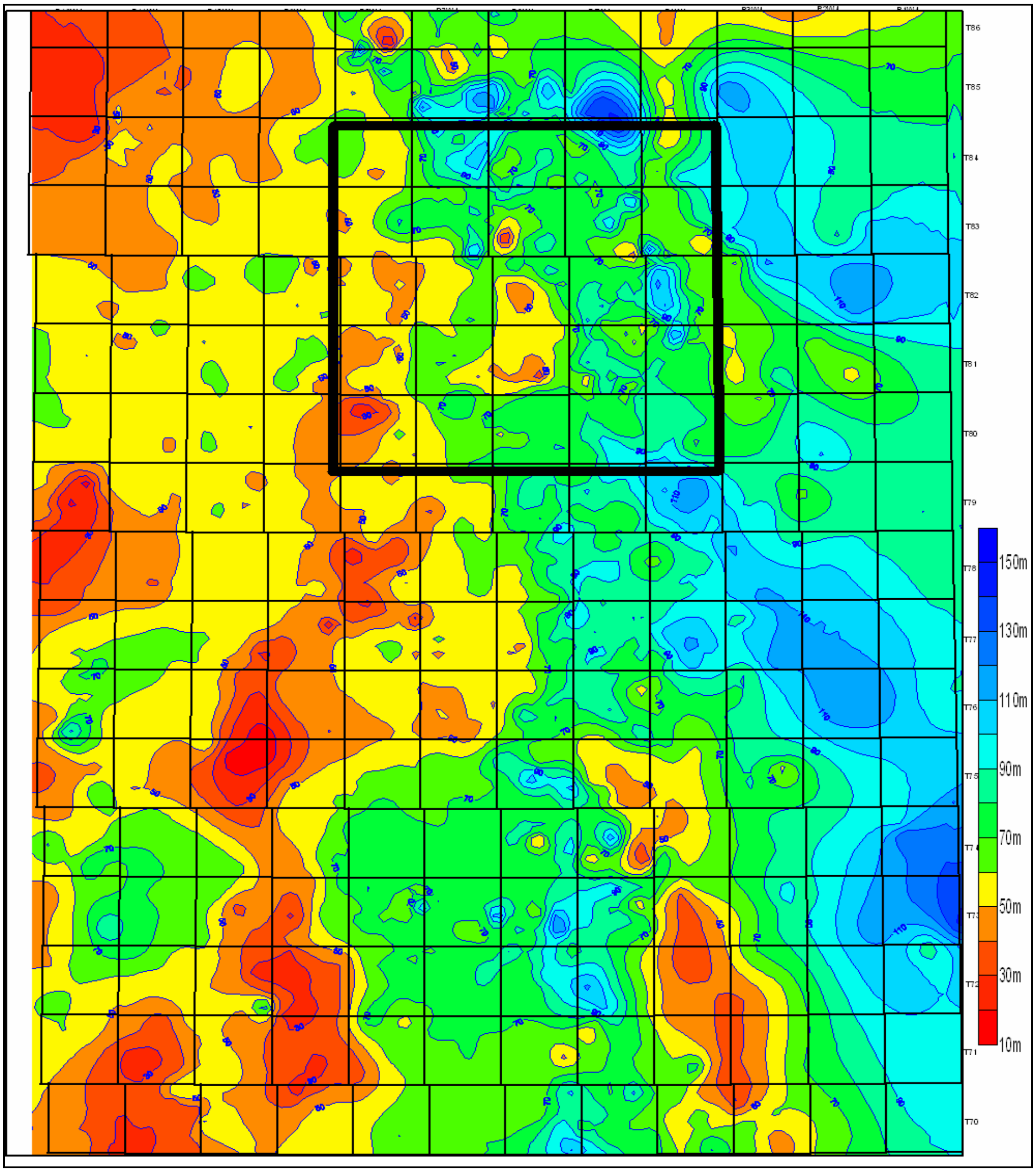

Figure G-T3: *Regional Isopach of the McMurray Formation; Contoured from Public Data; Thin areas in hot colors – thick areas in cold colors; Geological Study Area depicted in Figure G-1 (above) shown here in heavy black outline.*

Note that on **Figure G-T3** the McMurray Formation varies in thickness from less than 10 m (darkest red) to more than 160 m (darkest blue) in the mapped region. If it is assumed that the top of the McMurray was not significantly eroded during Basal Wabiskaw ravinement (ignoring later Wabiskaw channel incisement), then the thickness variations of the McMurray approximate the inverse of the topography of the Devonian unconformity; therefore, areas of thin McMurray deposition represent sites that were islands and/or interfluves of Devonian bedrock through much of McMurray time. These topographic highs had a profound control on McMurray sedimentation. Note the two thick trends on the east side of the map (shades of blue) that trend NNW. These represent valleys on the sub-McMurray unconformity. Compare these with the west side of the map where there are numerous north trending thins (shades of red) that represent highs on the sub-McMurray surface.

The topography on the unconformity is at least partly the result of salt solution in the Middle Devonian Elk Point Group and the associated collapse of the overlying Beaver Hill Lake Group. The degree to which erosion versus salt solution controlled the final topography is unclear; however, it is likely that the deepest valleys resulted from a combination of both. Certainly, the linear nature of the ridges and valleys infers some underlying control on the erosion/dissolution processes. In discussing the thickness and distribution patterns of the Lower Manville in Alberta, Cant and Abrahamson (1996) noted the influence of two major lineament sets (oriented NW-SE and NE-SW). Likewise, Gregor (1997) indicated that linear features, identified in the basement as magnetic anomaly lineaments, have propagated into the Mannville Group in the Lloydminster Heavy Oil Area. Re-activation of basement faults is a common origin of lineaments, which are often represented in younger sediments as fracture zones with minimal or no offset. As will be discussed later in this report, linear structural control on McMurray sedimentation is evident in some places in the Surmont area.

Compare **Figures G-3** (end) and **G-4** (end); neither is identical to the inferred Devonian topography (inverse of McMurray isopach) seen above in **Figure G-T3**. Both structures in **Figures G-3** (end) and **G-4** (end) show a low amplitude anticlinal structure plunging to the SSE. This structure is thought to be a result of post-McMurray salt solution in the Middle Devonian Elk Point Group, subsidence of the foreland basin to the east, and perhaps a Laramide peripheral bulge to the west.

Figure G-T4 (below), from the recently published EUB regional geological study (2003), shows an even larger area than **Figure G-T3 (**above). The Surmont area proper coincides approximately with the excluded area shown by the black arrow. In comparing the two maps one can see that the pattern is the same with regional thinning to the west and thick intervals (dark colors) to the east that mirror the basal topography of the sub-McMurray unconformity.

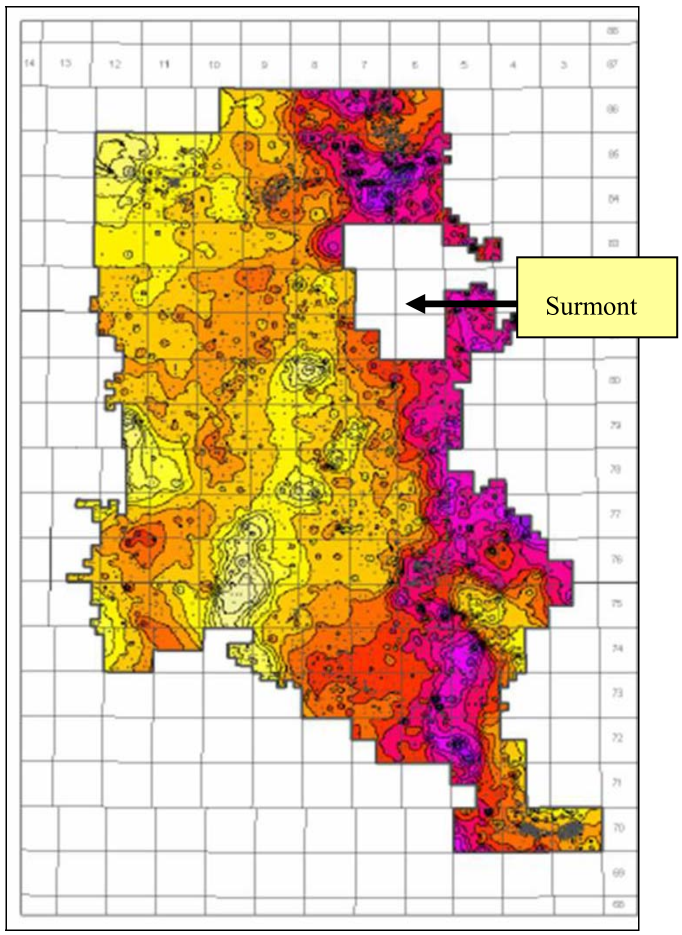

Figure G-T4: *Wabiskaw Marker to Paleozoic Isopach Map; (Fig. 4 from Alberta Energy and Utilities Board: "Athabasca Wabiskaw-McMurray Regional Geological Study," EUB Report 2003-A, December 31, 2003).*

2.1.3.3 Stratigraphic Relationships

A significant amount of work has been conducted in the last 15 years or so on the stratigraphic architecture of the McMurray, especially from a sequence stratigraphic perspective. Although there is no unanimity of opinion, there is a growing consensus that the McMurray can be divided into coherent stratigraphic intervals that can be assigned parasequence-like attributes, which reflect identifiable base level shifts during McMurray time.

Cant and Abrahamson (1996) identified three major units within the McMurray of northeastern Alberta, which are bounded by unconformities and contain major incised channel sands deposited by large-scale lateral accretion. They noted that such sand-filled, fining-upward channels cut into older coarsening-upward cycles.

Ranger and Pemberton (1997) working in the south Athabasca area refuted the notion that the McMurray was too heterogeneous to correlate. They reviewed over 1700 wells and found that "stacked, prograding, shoreface parasequence sets…can be regionally correlated." They identified regional shale units that divide the McMurray into an upper and lower sequence; the upper sequence was subdivided on the same basis into three stratigraphic units that (from top to bottom) they termed the "red", "green", and blue" intervals. The "red" and "blue" units were described as "simple coarsening upward intervals", whereas the middle or "green" unit was stated to be decidedly more complex.

Detailed facies analysis (within the context of regionally correlatable units) has been conducted by Ranger and Pemberton (1997), Caplan and Ranger (2001), Caplan (2002), and by many others.

Mathison (2003) has identified two bounding and two intra-McMurray unconformities, which he has used to subdivide the total interval into three sequences. Sequence 1 includes the "red" and "green units of Ranger and Pemberton (1997); Sequence 2 includes the "Blue" Member and the top of the Middle McMurray (after Carrigy, 1959); Sequence 3 includes the remaining Middle McMurray and the Lower McMurray (after Carrigy, 1959).

More recently, Mathison (2004) reiterated that the Upper McMurray consists of three "regionally mappable stratigraphic units". The upper and lower units (the "red" and "green" of Pemberton and Ranger, 1997) are described as "transgressive brackish marine mudstones (marine flooding units) and overlying progradational deltaic successions". The middle member was described as "a retrogradational, shallow water, wave influenced deltaic assemblage." The reintroduction of Carrigy's (1971) term "deltaic" to describe the Upper McMurray may not be universally greeted with enthusiasm, but the term does correctly incorporate a broad range of conditions encompassing both estuarine and foreshore components. In any case, Mathison's key descriptive term for the upper and lower members is *progradational*, which coheres with the conclusions of others cited above.

Finally, the EUB, whose several Orders and Directives has lead directly to the present study, recently published (December 31, 2003) its "Athabasca Wabiskaw-McMurray Regional Geological Study (Report 2003-A"). The area of the present study was pointedly not included in their work, but the regional results have broad application to the Surmont area. The purpose of the study was to identify where gas pools are associated with bitumen in the Lower Cretaceous of the South Athabasca deposit. Although the stratigraphic nomenclature and divisions suggested by the team of industry and EUB experts differs somewhat from those published and noted above, the overall conceptual argument is the same; "regional stratigraphic units are present and correlatable throughout the study area." They conclude that existing well density is insufficient to recognize local channel occurrence but that compound, nested, channel complexes can be grossly identified and their trends mapped regionally.

2.1.4 Data

2.1.4.1 Well Locations and Log Data

Because of the large number of wells drilled in the Surmont area, data preparation and loading were extensive and time consuming. Initially, unedited logs were used for correlation. Later, as a byproduct of the petrophysical study, a suite of edited, corrected logs became available for use in correlation. The typical corrected log suite included gamma ray, SP, caliper, deep and shallow resistivity, neutron porosity, and density porosity. Later still, the results traces, consisting of a corrected GR, PhiE, and Water Saturation (Sw), were provided and are the data used in many of the gas pool cross sections included as figures with this report.

A spreadsheet containing the basic well information was prepared and is presented herein as **Table G-1** (end). The UWI of each well was simplified for ease of graphic presentation and reference. For example, 100/010808208W4/00 was simplified to 01-08-82-08 and 1AA/163208408W4/00 to A-16-32-84-08.

In total, 1089 locations were loaded into the correlation software for potential use in the study. Many of these wells fell outside of the simulation study area and some even outside of the buffer boundary. Later, useable GR logs for 683 wells were located and loaded. It was immediately noted that many locations were, if not "twins", certainly close enough to warrant deciding whether each well should be included in the study. Because of the difficulty in correlation in many areas due to channel incisement, it was decided to use all of the available wells for correlation. On the other hand, mapping was restricted to results generated from the petrophysical analysis of 648 wells; in essence, property results typically were provided for only one well in a closely spaced group.

2.1.4.2 Cored Wells

Because of the economic importance of the Surmont deposit and complexity of the stratigraphy, a large number of wells have been extensively cored through the McMurray and in some cases the overlying Wabiskaw. Rock property data obtained from laboratory-measured samples from these cores were used extensively in the petrophysical task to normalize and calibrate the open-hole log data. Only the data sets for years 2000 and 2001 were used in the petrophysical task, because they had both horizontal and vertical permeability, as well as porosity measured under overburden conditions. These cores have also been extensively described by the geological community as an aid in deciphering the complex internal architecture of the McMurray, as well as for detailing reservoir predictions in bitumen recovery schemes. Most of these cores are stored at the EUB facility in Calgary, although some are stored at corporate repositories elsewhere.

Cores from ninety-three (93) wells in the study area were identified as being located at the EUB Core Research Centre in Calgary. From among these, twenty were selected because of the availability of core porosity and permeability measurements and/or because they were representative of the stratigraphic variation present in the McMurray-Basal Wabiskaw section. Time permitted completed description of fifteen (15) of the twenty wells (**Table G-2**; end). One well was digitally drafted for final presentation (**Appendix G-1**); the remaining fourteen (14) are in rough draft, hand-written form and not included in this report, but copies will be made available upon request.

2.1.4.3 Dipmeters

Dipmeters for just over one hundred wells, for which GR logs were also available in the Petrel database, were provided courtesy of ConocoPhillips (**Table G-3**; end). These were loaded and intended for help in the structural mapping activity. However, the dips at the top of the Basal Wabisakaw were either poorly represented or of such low magnitude and azimuth variability as to make them unusable for structural mapping. The dipmeters were also used qualitatively to confirm open-hole log responses indicative of channel morphology.

2.1.4.4 Seismic Data

No seismic data per se was provided for structural interpretation in this project. However, given the available well control, such an interpretation is not a critical issue related to the fundamental questions posed to ETI by the Sub-Committee. Upon request, ConocoPhillips kindly donated their current seismic interpretation at the top of the Basal Wabiskaw and at the top of the sub-McMurray unconformity. The accuracy of the structural interpretation, where not tied to well control, was calculated by ConocoPhillips to be between 3 and 7 m, depending on confidence intervals utilized. Indeed, ConocoPhillips indicated that the krigged well data alone, in their opinion, is actually a more accurate predictor of the top of the Basal Wabiskaw than the 2D seismic interpretation. Therefore, clearly for structural purposes (elevation), the 2D seismic is not particularly useful.

The primary purpose in requesting the seismic interpretation was in order to provide some shape to the contouring in areas with minimal well control. This is an important issue, as it helps to restrict the potential orientation and size of the history matched volumes.

2.1.5 Stratigraphy and Correlation

2.1.5.1 Definition of Regional Markers

The single most time consuming aspect of the geological study was obtaining an overview of the correlation issues present in the area depicted on location map **Figure G-1** (above). Recall that the location map encompasses the simulation study area, the buffer, and an additional area outside the buffer. The actual wells utilized are shown as solid red triangles. Study of this map will quickly indicate the wells unavailable or not used for the present study.

Log correlation is an iterative process of pattern recognition based on comparative analysis of log signatures in multiple wells. For this project, the initial correlation task required a significant amount of time, because the investigator had no prior experience in the Surmont area. A number of correlation markers (shales and mudstones) were immediately obvious but the continuity of these markers needed to be established. Some markers persisted through more wells than others.

After three complete correlation sweeps through the available well logs, areas with significant channel sand development were informally mapped, which helped to establish the distributive pattern of channel units versus non-channel units. By exclusion of channels that were clearly incised into the original sedimentary section, cycles of generally upward coarsening units, which are located between significant local and regional shale/mudstone units (*hereinafter shale markers*) can be identified. The most persistent of the markers were then carried through the wells that appeared to be non-incised, which effectively divided the original sequence into a number of correlatable layers.

The stratigraphic scheme developed for this project is shown on **Figure G-T5** (below), which shows the name of the defined markers, the six layers delineated by the markers, and the breakdown of the McMurray into informal Upper, Middle, and Lower intervals. All markers are the lower contact of persistent shale intervals, which represent some type of flooding unit. Although the Basal Wabiskaw appears to have only a limited volume of gas, it is included in the model as Layer 1, because of assumed vertical continuity with underlying McMurray gas.

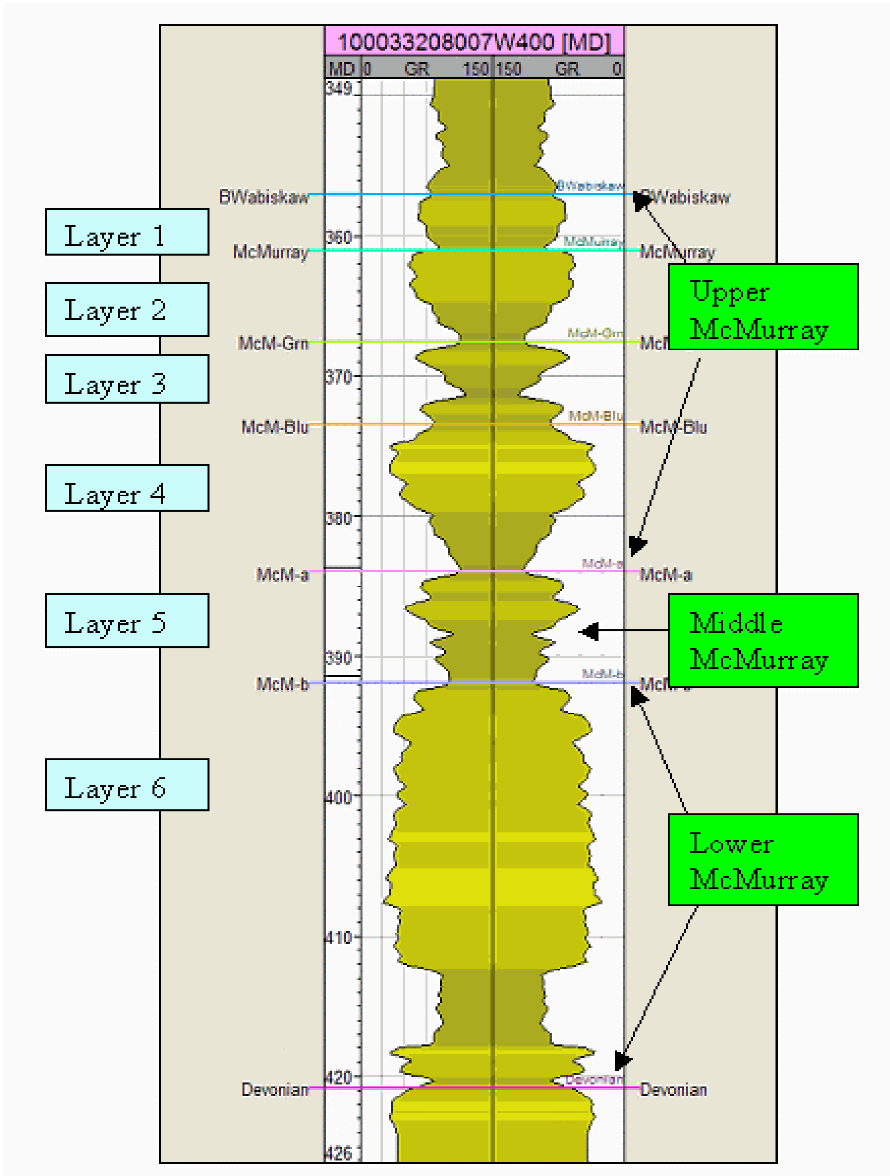

Figure G-T5: *A Typical Well (03-32-80-07) used for Regional Correlations; Figure displays stratigraphic nomenclature used in the study. Note the prominent coarsening-upward cycles in Layers 2 and 4.*

The degree to which the un-incised stratigraphic units can be correlated over a wide area is demonstrated by a group of regional cross sections that are attached to this report (end) as **Figures G-9** (A-A′), **G-10** (B-B′), **G-11** (C-C′), and **G-12** (D-D′); the position of these cross sections are shown below in the index map **Figure G-T6**.

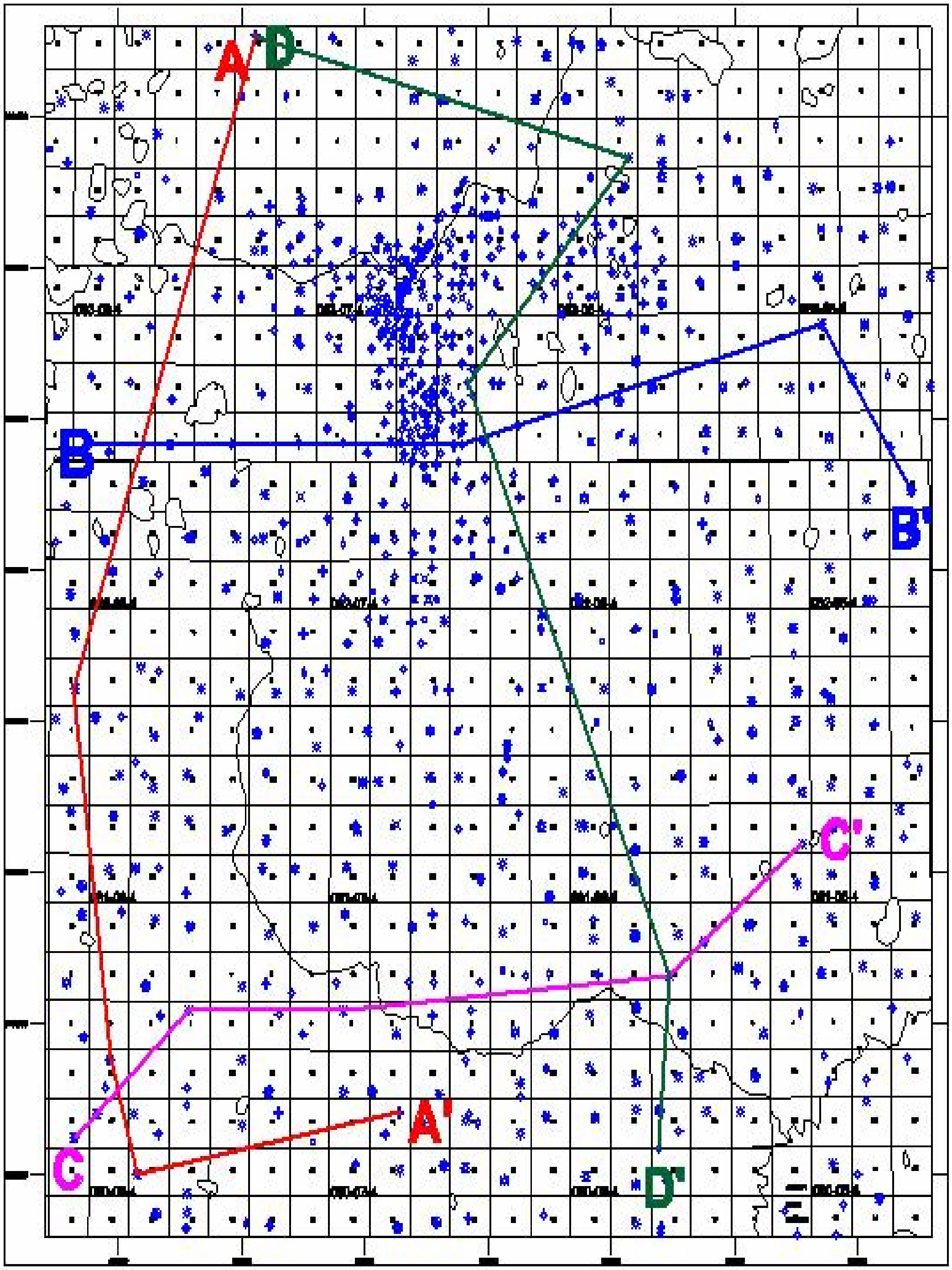

Figure G-T6: *Cross Section Index Map for Regional Correlation Sections based on Gamma Ray Log Signatures.*

An example cross section (**Figure G-T7**) is offered here below to illustrate the log signatures of several regionally un-incised units, especially in the Upper McMurray.

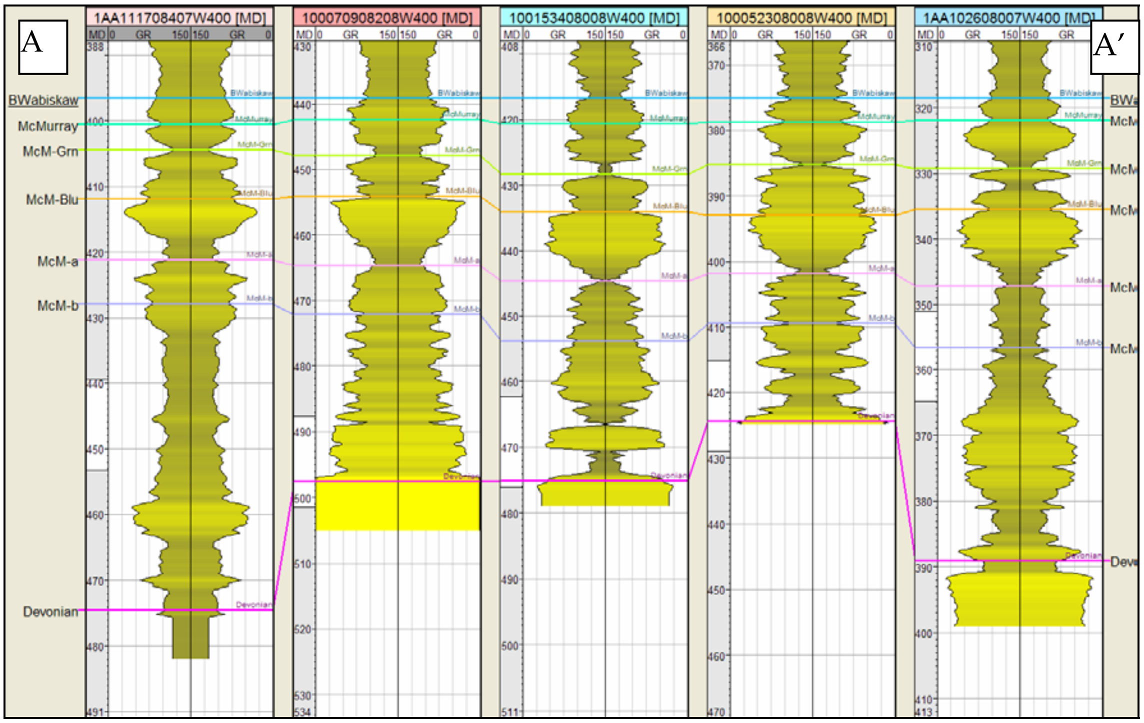

Figure G-T7: *Regional Cross Section A-A′; Distance between endpoints is approximately 40 km; for location of cross section see Index Map in Figure G-12 above. Correlation traces are gamma ray and mirror-imaged gamma ray.*

The Upper McMurray units represented in **Figure G-T7** are areally extensive only on the western and southwestern perimeter of the study area. Elsewhere, profound incisement has removed much of this section. Therefore, a primary objective of the correlation effort was to identify remnant interfluves that contain the original un-incised section between the major channel complexes.

After the marker scheme was developed using the regional cross sections a review of papers dealing with regional McMurray stratigraphic architecture seemed to support the tripartite division of the Upper McMurray. In particular, Ranger and Pemberton (1997) have identified three units within the Upper McMurray whose log signatures are distinct and persistent over wide distances in the south Athabasca area; they referred to these units (from youngest to oldest) as the "red", "green", and "blue" intervals. Although the published sections from their 1997 paper do not overlap with the Surmont area, these units appear to be the same or very similar as the units defined herein for the Surmont area. In consideration of the foregoing and as shown on **Figure G-T7** (above), marker names defining the tops of the middle and lower subdivisions in the Upper McMurray were named McM-Grn and McM-Blu, respectively.

Figure G-13 (end) shows a good example of the contrasts between an older upward coarsening sequence (well 15-34-80-08) in the Upper McMurray and a thin incised channel (indicated by black arrow) at the base of Layer 4 (base of McM-blu) in wells 16-15-81-08 and 15-34-80-08. Fortunately on the west side of the correlation area the amount of incision is generally less than farther east probably due to average higher elevation in McMurray time on the underlying topography. This makes the overall correlation reliability very high in this area, even where some incision has occurred. Nonetheless, even on the west side, a larger channel complex does occur as shown on **Figure G-15** (end). In this example, a large east-west trending amalgamated channel complex can be seen cutting through Layers 2 and 3 in wells 11-35-82-08 and 07-25-82-08 (especially the latter) between two wells to the north and south (11-11-83-08 and 15-22-82-08, respectively).

The relative reliability of the McMurray correlations decreases downward in the section. This is because of greater incision and channel infill in the lower Upper and Middle McMurray intervals and the presence of estuarine-fluvial channels deeper in the section that filled in original topographic lows on the sub-McMurray unconformity. There are few places where upward coarsening can be reliably attributed to Middle McMurray (as defined in this report, i.e. Layer 5) and none in the Lower McMurray (Layer 6). Nonetheless, because nearly all of the gas is found in Layers 1-4, where more precision is warranted, confidence can be maintained in the layering scheme.

In non-incised areas the most persistent marker appears to be the top of the Middle McMurray (McM-a) (see **Figure G-T7** above for example), which is likely a maximum flooding surface. All other shale markers also represent flooding events of some type, but their original extent is hard to estimate, as some variation occurs across the study area. For example, a persistent shale unit divides Layer 3 in many areas but is not as pervasive as the top and bottom of Layer 3. Realization of this fact took several correlation passes. It may be that interruptions of the continuity of the shale in the middle part of Layer 3 are really due to later cut and fill, i.e. small-scale incisement, but in many areas it is just too difficult to discern this type of detail.

2.1.5.2 Channel Complexes

Channel complexes can consist of the original topographic fill in the Lower McMurray but everywhere else are generally associated with some amount of later incision. Two types of backfilled-incised channels occur: sand complexes, (which predominate) and shale/mudstone/siltstone (hereinafter shale) complexes. The peculiar nature of the shale channels warrants some comment. Where sufficient well control occurs to map them, they can be shown to be quite linear. They often parallel (in close proximity) thick sand channels. An example of a shale channel is shown below as **Figure G-T8** (a copy of all cross section figures at a larger scale is found at the end of the report).

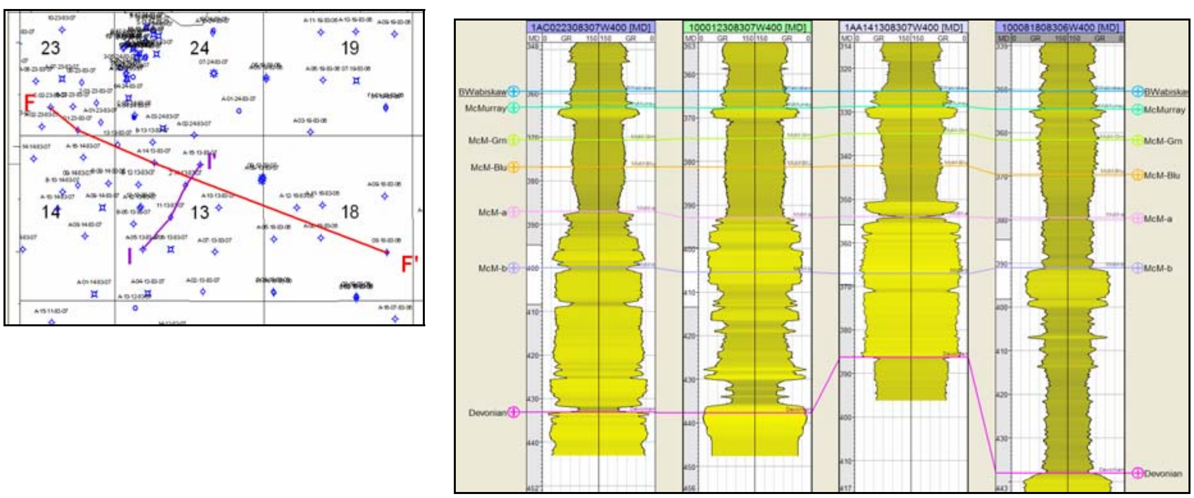

Figure G-T8: *Cross Section F-F'; Shale Channel along Depositional Strike; Distance between endpoints is approximately 4 km.*

Strobl et al. (1997) described vertical accretion channels in the Syncrude mine that incise previously deposited channel sands and other units. These channels are commonly composed of interbedded very fine-grained sandstone and mudstones. Many are described as "mud dominated" and are up to 20 m thick and 300 m wide (no length is given because of limited exposures), forming formidable local barriers to fluid flow.

The shale channels depicted in **Figure G-T8** can exceed 20 m in thickness, which is quite extraordinary. It has been suggested that perhaps these shale channels, like those in the Syncrude mine, are later incisions that cross cut the slightly older sand channels, but that thesis can be easily refuted by comparison of log signatures in areas of high well density on cross section trajectories that are constructed perpendicular to the strike of the channels, as in **Figure G-T9** below.

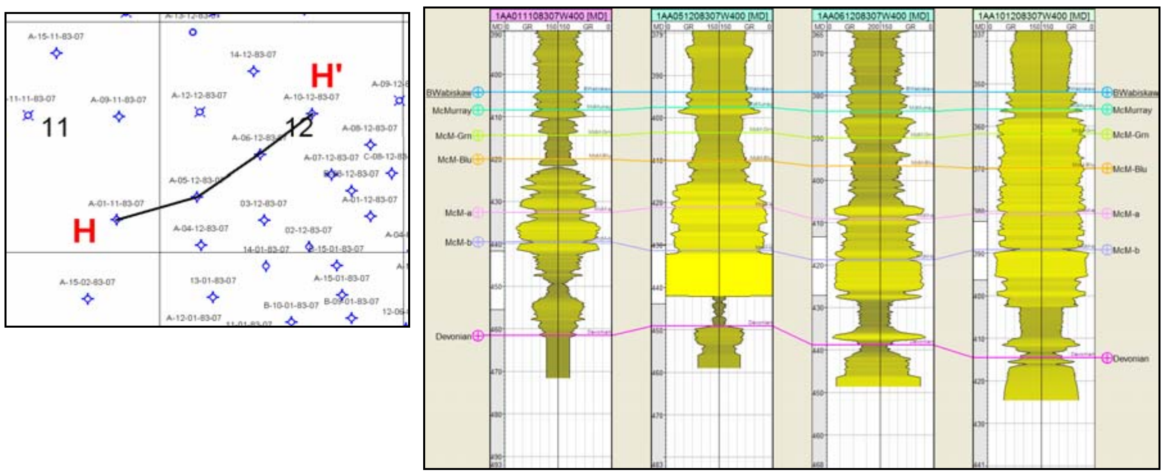

Figure G-T9: *Cross Section H-H'; Relationships of Sand and Shale Channels perpendicular to Depositional Strike; Note the gradational changes from dominantly shale to dominantly sand from left to right.*

Clearly there is underlying structural control on the orientation and location of those axes of the sand channels that are tethered to linear, parallel, proximal shale channels. It is assumed that continuous linear subsidence due to salt dissolution during deposition of the Middle and Upper McMurray is the primary control on this peculiar depositional pattern. The salt dissolution of the Middle Devonian Elk Point Group could have been controlled by groundwater movement along fracture zones related to basement faulting (lineaments). This would account for the narrow, linear, persistent nature of the features. The seismic interpretation of ConocoPhillips seems to support the presence of some linear trends related to salt collapse. Unfortunately, the highly variable well density across the study area prohibits stating (from well control) that such linear trends are an isolated, localized phenomenon or whether they are widespread. Additional cross-sections showing the facies changes between the two types of incised channel fill are illustrated in Figures G-17 (end) through G-21 (end).

2.1.5.3 Discussion

The major challenge of the correlation process was to be able to identify the widespread, lowstand, multi-stage, nested channel complexes and separate these areas from the regional framework identified by mappable coarsening-upward depositional cycles. At Surmont the mapped petrophysical properties provide a macro-scale basis for identifying channel systems. Permeability maps are very useful because of the fact that the best-developed channel sandstone complexes show up as high permeability trends. Net-to-gross maps are also quite useful. For example, **Figure G-T10** (below) is a net-to-gross map for Layer 3. The sinuous trends in red are amalgamated channel complexes.

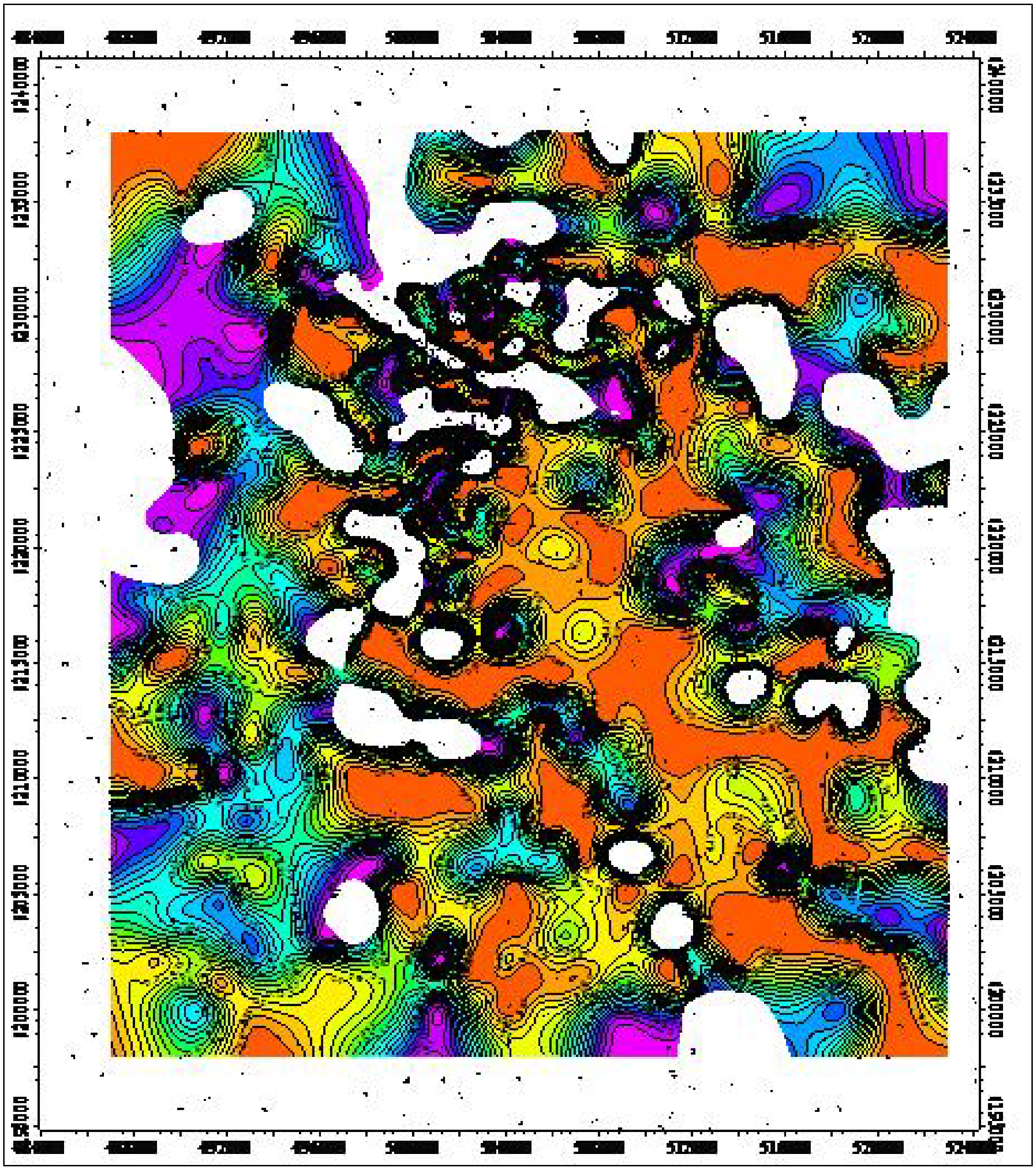

Figure G-T10: *Layer 3 Net-to-Gross Thickness Map. White cutouts represent areas of non-reservoir (eliminated by petrophysical cutoffs). Hot colours are areas of the highest net-to-gross values, which identify channel complexes.*

The difficulty in constructing a through-going layer system in the Surmont area is how to confidently project regional markers (and hence layer boundaries) in places where multiple channels (with their attendant complex facies packages) *irregularly* crosscut the coarsening-upward sequences. It is in such circumstances, that no two geologists are likely to make the correlations quite the same way. It is why one could spend years working in the area and yet find it necessary to change a previous correlation based on a new point of well control becoming available. In these cases, it is inevitable that differences of opinion on the validity of a correlation will arise.

Fortunately, such differences will not affect the outcome of the flow model, which is based primarily on the dominant reservoir mechanism determined from engineering. Minor correlation changes, however, may influence the selection of new (gas) drill sites, so the local geology must always be carefully reviewed and adjusted for the purposes intended. To gain some further insight on why minor changes of the correlations within channel sand packages are not critical please review the diagrammatic cross section in **Figure G-T11** below.

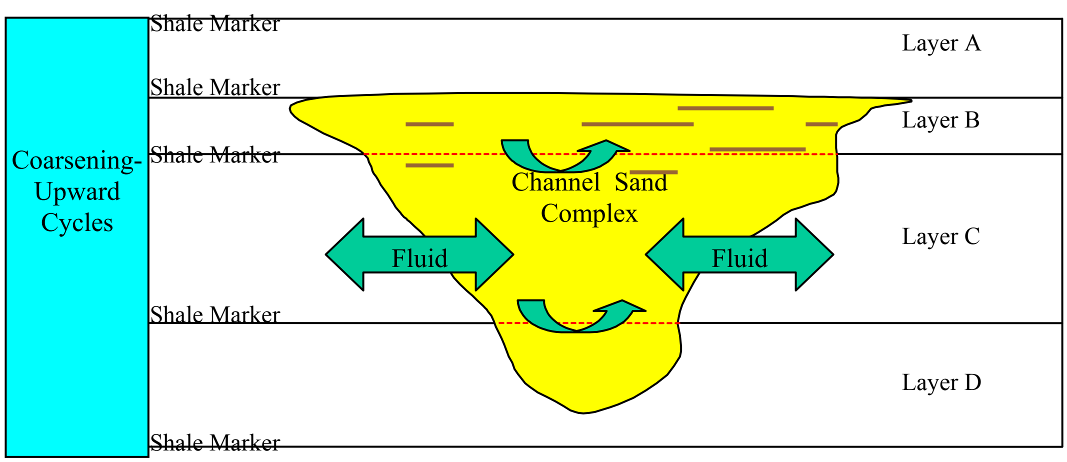

Figure G-T11: *Diagrammatic Cross Section of Sandstone Filled Channel Complex incised in Coarsening-Upward Cycles; Note the constraints on fluid flow in the non-channel areas by the continuous shale markers (barriers) versus discontinuous shale "baffles" (Brown Lines) within channel column. The dashed Red Lines represent layer boundaries projected through channels as used in the model. The relative position of Red Lines can change without impacting model results.*

2.1.5.4 Correlation Results

Using the methodology cited above, the correlation network was completed in the study area. The layers and markers are graphically presented above in **Figure G-T5** and are defined as follows:

Layer 1: Basal Wabiskaw to Top McM (Basal Wabiskaw)
Layer 2: Top McM to McM-Green Mkr
Layer 3: McM-Green Mk to McM-Blue Mkr
Layer 4: McM-Blue to McM(a)
Layer 5: McM(a) to McM(b)
Layer 6: McM(b) to Devonian

The resulting tops are presented as **Table G-4** (end). A full range of examples of (GR) correlation cross sections are provided as **Figures G-9** to **G-25** (end).

2.1.6 Core Review

Cores from ninety-three (93) wells in the study area were identified as being located at the EUB Core Research Centre in Calgary. From among these, twenty were selected because of their availability of core porosity and permeability measurements and/or because they were representative of the stratigraphic variation present in the McMurray-Basal Wabiskaw section. Time permitted completed descriptions of fifteen (15) of the twenty wells (see **Table G-2**; end). One well was digitally drafted for final presentation (**Appendix G-1**, end) (in .emf format); the remaining fourteen (14) are in rough draft hand-written form. Core photos are provided on disk as **Appendix G-2**.

The locations of the described cores are shown below on **Figure G-T12**. Note that the distribution of the described wells incorporates representatives of all major facies assemblages and rock types in the Surmont area.

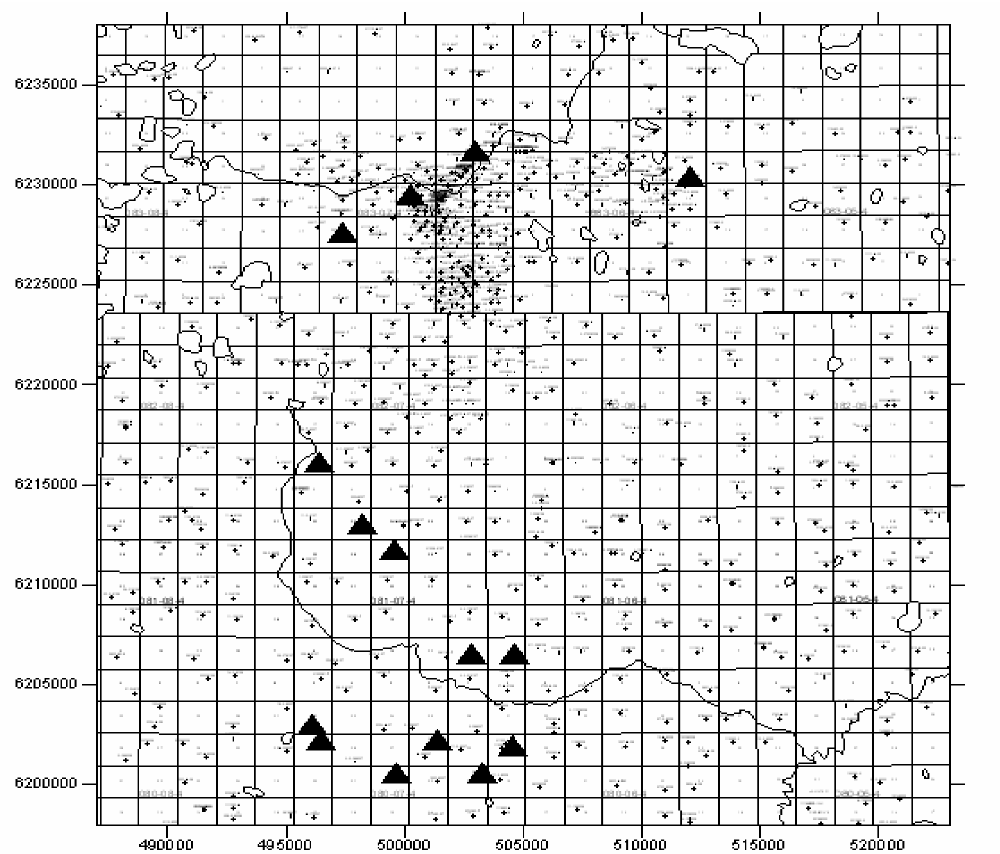

Figure G-T12: *Index Map showing Locations of Described Cores*

McMurray cores, in the Athabasca region in general and in the Surmont area in particular, have been extensively described and interpreted by industry experts. The same range of environments cited by others (e.g. Ranger and Pemberton, 1997) was described in cores for this study and will not be repeated here. The primary purpose for an independent review in the present study was to provide calibration to the log signatures. Interestingly, the most important information gleaned from the core work related to saturation issues. From the described cores, it is clear that bitumen saturation is not limited to conventionally identified bitumen intervals. Bitumen saturation was evident in all intervals where elevated permeability was present, including gas intervals west of and above a regional but irregular basal bitumen-water contact (see discussion below). This supports reports in the literature (e.g. Strobl et al., 1997) of bitumen saturation being directly related to reservoir quality. This provides a nice way to visually separate reservoir from non-reservoir.

2.1.7 Seals and Fluid Contacts

2.1.7.1 Gas-Water Contacts

A primary geological task was the identification of fluid contacts, especially gas-water contacts. These data were needed by the petrophysicist for summations, as this project utilized a net reservoir approach (no Sw cutoff) to calculate properties; in this case, it is difficult to correctly calculate gas versus water zone summations without the contact data. Neutron-density crossover was used to delimit the gas zones and pick the contacts. Gas-water (G-W) contacts were detected in 364 study wells.

Initially there was some concern that too many shaly zones would skew the data, however, there are so many good quality thick sands with excellent sharp boundaries that there is very high confidence in the picks overall. Besides, the transition zone, even in shaly zones, is relatively thin in gas-bearing reservoirs. The contacts are provided in **Table G-5** (end).

When plotted on a base map, the G-W data in a gross sense are *graduated* from the southeast to the northwest with no sharp boundaries. This implies (but does not prove) that the gas has been generated in place and fills existing traps in their current structural configuration. Although there are striking stratigraphic controls on the spatial dimensions of the gas accumulation in some pools, by and large, all of the pools are on closed highs and conversely closed lows are rather devoid of gas. These highs and lows are subtle, broad, low relief features.

2.1.7.2 Bitumen-Water Contacts

In the process of identifying the gas-water contact, an attempt was made to also pick the basal bitumen-water contact. Although not germane to the primary objective of this study, the data reveal interesting issues related to understanding the migration history and structural history of the Surmont area. On the east side of the study area, there is clearly a line to the east of which there is no bitumen saturation. This line is not uniform and is found at different structural elevations in different locations, as shown on **Figure G-T13** below.

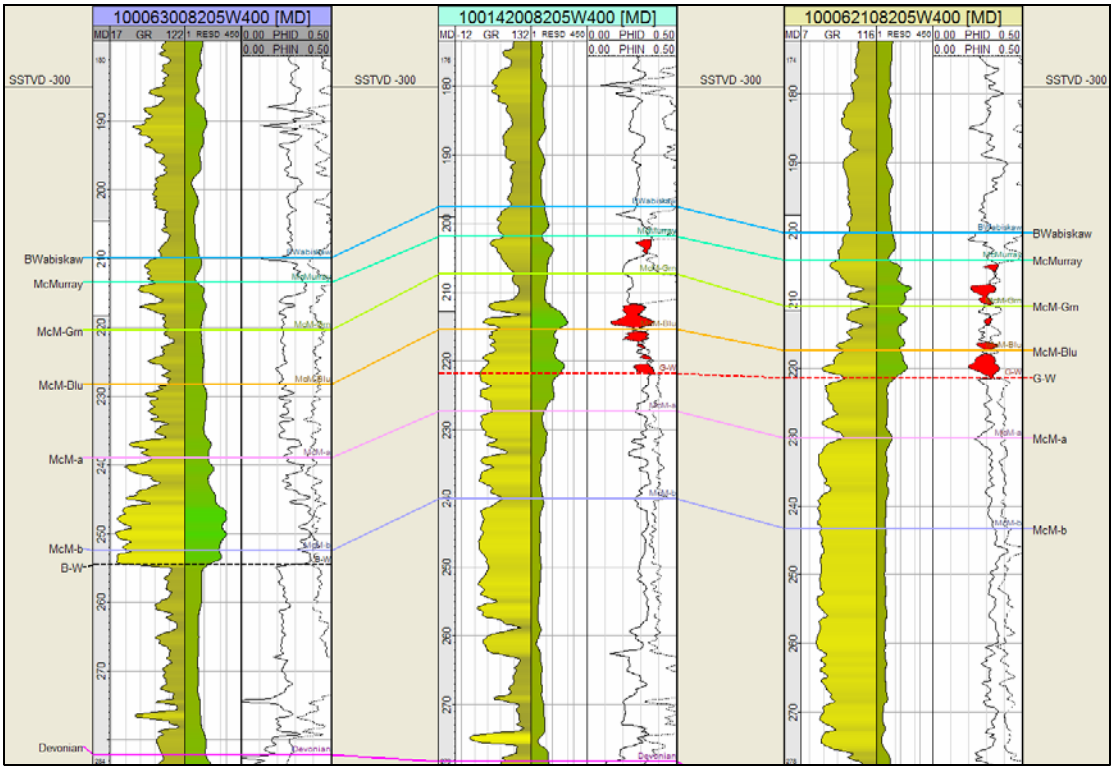

Figure G-T13: *Cross Section FC-1 to FC-1'; Flattened on Structural Datum TVDSS (-300); Bitumen-water contact in 06-30-82-05 is absent in wells to east at same elevation. Note gas-water contacts in Red and gas column (in Red fill) from neutron-density crossover. For location of cross section see figures at end of report.*

Additional examples of cross sections and locations maps showing variation in the bitumen-water contact are depicted on **Figures G-30 to G-32** (end).

The variable line showing the position of the eastern edge of the bitumen accumulation (true basal bitumen-water contact) on a layer-by-layer basis can be gleaned indirectly by looking at calculated Hydrocarbon Pore-Volume (HPV) maps. An example generated in Surfer is shown below as **Figure G-T14**.

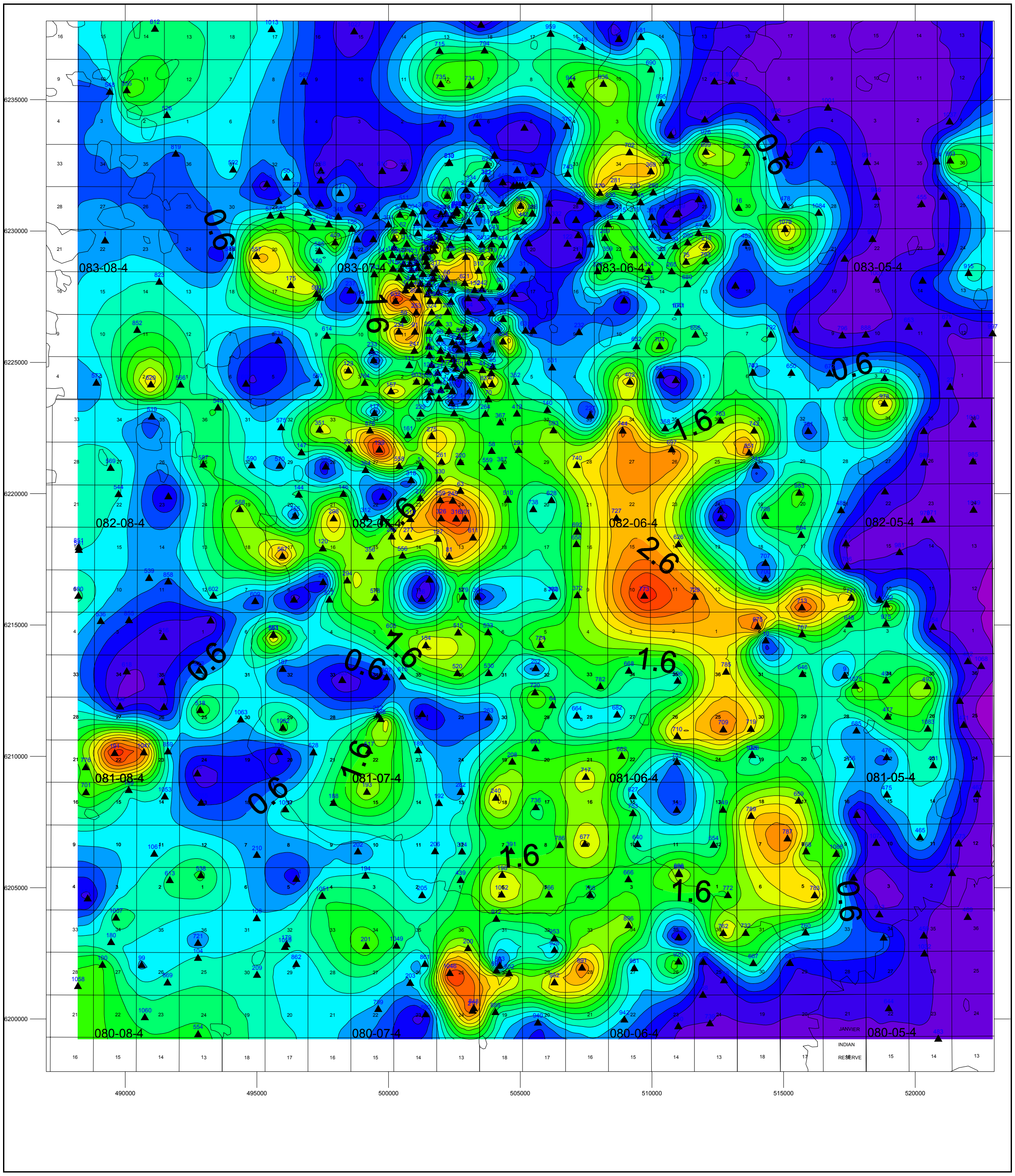

Figure G-T14: Layer 4 - HPV; Note the sinuous line on the east side separating Blue and Purple colours; this is approximately the position of the basal bitumen-water contact.

At least sixty-six (66) wells were identified in the eastern part of the study wells that have zero bitumen. In areas west of the true basal bitumen-water contact (as roughly shown in the figure above), there are a number of wells that contain a basal water leg that has a different character than wells to the east. In these "updip" wells the water saturations, based on the Rw used for the study, calculate Sw much less than 100%, as shown in **Figures G-T15 (**below) and **G-28** (end). It is likely that the water salinities in these wells are different from the salinity of the water below the true contact, which implies that the water in such wells is immobile.

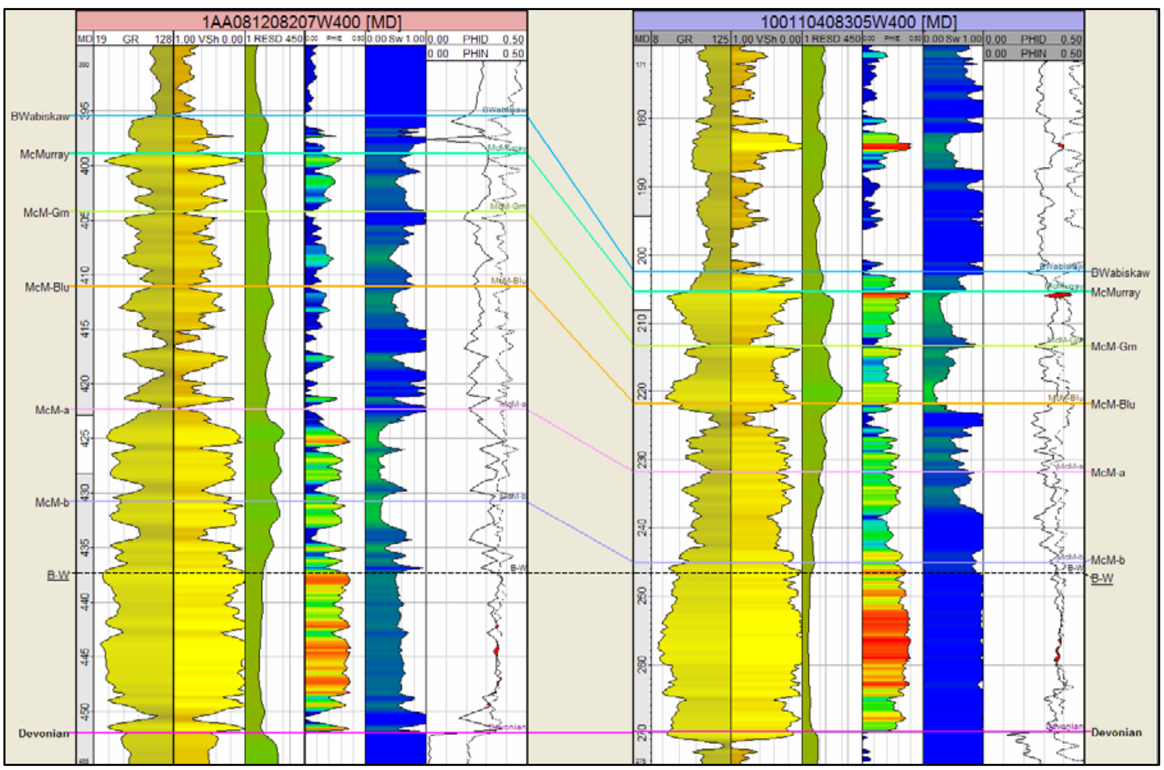

Figure G-T15: *Bitumen-Water Contacts in two Surmont Wells. The well on the right contains a true basal bitumen-water contact (Rt = <3 ohms) with calculated Sw approaching 100% in good quality sands. Contrast with well on the left, where Rt = >10 ohms and Sw is averaging 60%+.*

2.1.7.3 Seals

The issue of sealing of the hydrocarbon traps in the McMurray and Basal Wabiskaw intervals at Surmont is complicated. The top of the Basal Wabiskaw acts as a top seal in a general sense across the area. However, this is not a universal phenomenon. Local top seals do vary according to the presence and quality of the black, fissile shale commonly found at the interface between the top of the McMurray and the overlying basal Wabiskaw. Where present the shale sits immediately below the first appearance of Wabiskaw glauconite (ref. core work from this study). This zone probably is related to a ravinement surface representing the initial transgression of the Wabiskaw Sea. The fact that Basal Wabiskaw gas is not common indicates that the top seal likely lies deeper in the section in many wells. Hence, mapping the top of the Basal Wabiskaw does not yield simple closures that represent all of the gas traps.

Although there is a strong relationship between closed, very low amplitude highs and gas traps (and conversely the lack thereof in closed lows), most pools contain a thicker gas column than can be supported from structure alone. Clearly, lateral seals related to stratigraphic features (facies changes) have a high degree of control on the final trap geometry and location. Moreover, in areas of low well density it is clear that important stratigraphic details are often lacking. In such areas, channel sandstones in adjacent wells often appear connected from log correlations but may be found to be in different pools based on engineering data.

Cross sections through all of the pools modeled in the simulation and some from the buffer zones, using results traces (GR, PhiE, and Sw), are presented as **Figures G-36** (end) to **G-92** (end). These pool cross-sections often clearly show stratigraphic barriers between producing wells.

2.1.8 Mapping

The required maps for simulation at Surmont consist of a top structure map (top of Basal Wabiskaw), gross thickness, net-to-gross ratio (reservoir), average PhiE, and average k maps. These final maps were prepared using PETREL software. Some preliminary maps and others not required for simulation were prepared in SURFER. Final hardcopy maps, digital maps, and the project file itself are all archived in PETREL format and submitted as a part of this report, as **Appendix G-3.**

Final cutoffs determined from the petrophysical study were used to create summations of average properties for each mapped reservoir layer. These values were mapped using a 50 m x 50 m grid. Interpolated and extrapolated areas populated by average values that fell below the PhiE cutoffs were nulled in the final grids. The geological grid was then upscaled to a 402.34 m x 402.34 m simulation grid, which is one grid cell per legal subdivision (LSD).

The mapped data are based on net reservoir not net pay calculations. The net reservoir values include Vshale, PhiE, and k cutoffs (in this case 40%, 14%, and .5 md respectively). No water saturation cutoff was used.

The maps generated for the simulation model should be used judiciously when predicting reservoir properties in sparsely drilled areas. This is because the continuity of the channel complexes at the macro-scale, as implied by maps such as **Figure G-T10** (above), can be deceiving. The areas that appear most uniform are exactly those areas with the sparsest well control. In particular, the width of many shale channels is less than the distance between wells at a density of one well per section. Likewise, the sand channel complexes are not likely to be as uniform as indicated in those same sparsely controlled areas.

2.1.8.1 Top Structure Map

The top structure map was constructed utilizing the 45 m x 45 m 2D seismic interpretation grid from ConocoPhillips combined with the top of the Basal Wabiskaw pick (top of Layer 1) from this study. The first pass was produced by using a basic krigging function in SURFER on a 50 x 50 m grid. These results were then further modified using PETREL's convergence gridding function.

Although the input data from the 2D seismic grid is assumed to have an accuracy of ± 3 m at P_{50}, the more important issue involved providing shape to the structural contours in areas with low well density. Dipmeters were reviewed to see if they were useful in contouring in areas of sparse control. However, the dipmeter data itself (at the top of the Basal Wabiskaw) is somewhat sparse and non-definitive because of extremely low dips. The final top of structure map is presented as **Figure G-93** (end).

2.1.8.2 Gross Thickness Maps

Gross thickness maps were produced for the six model layers. These maps are successively subtracted from the overlying structure map beginning with the top of structure map discussed above to generate the structural grid in the simulator. The final gross thickness maps are provided at the end of this report as **Figures G-94 to G-99.**

2.1.8.3 Net-to-Gross Reservoir Thickness Maps

The net-to-gross maps data are derived from net reservoir summations from petrophysics. The cutoffs utilized were PhiE = 14%, Vsh = 40%, and k=0.5 mD. The layer maps for this parameter are found at the end of the report as **Figures G-100 to G-105.**

2.1.8.4 Average Effective Porosity Maps

The average PhiE maps were created using summation results for net reservoir (without a Sw cutoff). The layer maps for this parameter are found at the end of the report as **Figures G-106 to G-111.**

2.1.8.5 Average Permeability Maps

The average k maps were created using summation results for net reservoir (without a Sw cutoff). The layer maps for this parameter are found at the end of the report as **Figures G-112 to G-117.**

2.1.8.6 Other Maps

A few other maps were constructed for purposes other than simulation to advance understanding of the overall geology of Surmont. For example, a map of the gas column was constructed from point data, even though the data properly contoured are isolated as separated pools. This smearing of the data by interpolation was useful to view quickly where the gas volumes are distributed. From this work, one can see that the gas is heavily weighted to locations in the southeast of the study area at the edge of and east of the basal bitumen-water contact.

Finally, as stated above, HPV maps were generated in order to identify the basal bitumen-water contact zone for each reservoir layer. Maps of this type are qualitative but useful conceptual tools for use in understanding migration history.

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