Summary
The Cardium Pembina Field was discovered in the 1950’s and yet it continues to be exploited as technologies increase the recovery efficiency of the approximately 95% oil remaining in place. Therefore, a detailed geological reservoir characterization and resource evaluation of the Southern Pembina Field in township 47 and range 7 was conducted. We interpreted regional cross-sections, core descriptions and analysis, structure and net sand map, and production decline analysis to interpret the reservoir architecture and production trends. An assessment of the original oil in place and estimate of remaining oil reserves was also completed. From the resource evaluation there is still lots of opportunity to produce additional oil in this area. Horizontal multistage hydraulic fractured wells have the potential to add reserves as a method of enhanced oil recovery within water flooded areas in the Cardium Pembina Field.

Introduction
The Pembina Field is a prolific oil producing formation in west-central Alberta. It was discovered in the 1950’s but due to dominant solution gas drive oil recovery rates remain low, no more than 20% (Mossop & Shetsen, 1994). The Cardium is a stratigraphic trap with a conventional sandstone reservoir. The rocks themselves were deposited in the late Cretaceous (Turonian) as a north-eastward prograding shoreface (Figure 1). The reservoir is an upward coarsening clastic wedge that sits on top of the muddy bioturbated Blackstone Formation and is capped by over 300m of marine mudstone. The Cardium Formation in the study area is a stack of bioturbated siltstones, interbedded sand and mudstones to very fine to fine grained shoreface sandstones capped by...
transgressive conglomerate lags. We conducted a detailed geological reservoir characterization and resource evaluation for a study area in the southern part of the Cardium Pembina Field.

Theory and/or Method
To begin the analysis of the study area in Cardium Formation cores, well logs and production data were integrated. Over the study area six cores were logged and analyzed. This resulted in the subdivision of five main facies consisting of bioturbated siltstone, sandstone, interbedded sand and mudstone, conglomerate, and mudstones. The core was then correlated with well log data (GR, resistivity, and neutron/density) across the study area. By examining the well logs five main surfaces were identified. These include the top of the Cardium (E7), a flooding surface (E6), top of the reservoir (T5), and the base of the reservoir. Using core analysis for each of the five facies cross plots of porosity and permeability were created. The trends of each individual facies was analyzed and reservoir potential within each was considered.

Various types of maps were created after determining the facies, surfaces, cut-offs (75API), and reservoir properties. Isopach, structural, net reservoir, and net pay maps based on the surfaces were produced and contoured allowing a visual interpretation of the prograding shoreface depositional environment. The maps are tied together with stratigraphic cross-sections. These maps were then overlain with the cumulative and first 36 month production data of the study area to integrate the reservoir architecture and production trends. The volumetric OOIP estimation and production decline analysis were also conducted to add depth to our interpretation.

Examples
Well 100/16-06-47-7W5/00 illustrates a typical Cardium succession in this study area. The clean sand unit has a gamma ray cut-off at 75 API in figure 2. The Cardium includes a coarsening upward sequence with resistivity log showing oil saturation from the base of the formation to the top of the sand reservoir. The total sand thickness in this well is 15 m. Interbedded mud separates the sand into two main packages.

Figure 2: 100/16-06-47-7W5/00 well log with highlighted sand at 75 API cut-off.
From core analysis, five distinct facies were identified in the Cardium. The contact between the facies can be observed in Fig 3.

**Facies 1**  Thinly laminated dark mudstone  
**Facies 2**  Clast-supported, poorly sorted conglomerate containing well-rounded pebble-sized chert, with some feldspathic and lithic grains  
**Facies 3a**  Fine grained sandstone A is the thinner sand unit with small-scale grading and hummocky cross-bedding  
**Facies 3b**  Fine grained sandstone B is the thicker sand unit with planar to low-angle cross-bedding  
**Facies 4**  Interbedded unit with wavy bedding of thin mud layers in sand, this unit separates sandstone A and B  
**Facies 5**  Highly bioturbated siltstone gradationally underlies sand B and contains high clay content with abundant sand-filled vertical and horizontal burrows  

![Figure 3: Complete core of well 100/16-06-47-7W5/00 showing facies changes.](image)

**Conclusions**  
Reservoir characterization and resource evaluation were completed in the Southern Pembina Field in township 47 and range 7. A regional cross section showed laterally pinching units creating stratigraphic traps for oil and gas to accumulate. Examining the core, the Cardium Formation is subdivided into 5 facies consisting of a thinly laminated mudstone, a pebble chert conglomerate, clean sandstone, interbedded mud and sand, and a highly bioturbated siltstone. The depositional
setting is widely debated, but is interpreted to represent a series of parasequences that prograde northeastward and are bounded by an erosional surface (Walker & Eyles, 2013).

Using porosity and permeability cross plots, three main producing intervals were identified including the conglomerate, and two sand packages (A and B) which are separated by the interbedded facies. The conglomerate is located at the top of the reservoir, with a thickness ranging from 0.2-2.4m. The second producing interval Sand A consists of cleaner sand represented from the low gamma response, with the overall thickness ranging from 2-5m. The third producing interval Sand B represents a dirty sand with high spikes in gamma shown but is a much thicker interval ranging from 3-6m. Core analysis data was analyzed to determine the porosity and permeability of each reservoir unit. The conglomerate was characterized to have high permeability ~16mD but a lower porosity of 4-12%. The sandstone units were found to have high porosity values ranging from 15-25% with an average permeability of 10mD. Finally, the petroleum system is capped by a mudstone unit which has low porosity and permeability preventing the migration of petroleum out of the system.

Further investigation using production data is needed to estimate the original oil in place (OOIP) and determine the efficiency of enhanced oil recovery techniques such as horizontal multi-stage hydraulic fractured wells.

Acknowledgements

The authors wish to thank Dr. Per Pedersen, Marco Venieri, Henry Galvis Portilla, and Sochi Iwuoha for enthusiastically teaching and guiding us through the steps of reservoir characterization and resource evaluation as part of the 2018 senior undergraduate course GLGY 581 Advanced Petroleum Geology at the University of Calgary.

References
