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Contents

Abstract

This is the first regional porosity/permeability study to incorporate petroleum industry laboratory core analyses submitted to the Ontario government and managed by Ontario's Oil Gas and Salt Resources Library. This study comprises 11,759 analyses for the Early Silurian Lockport Group of southwestern Ontario from 150 drill cores. The Lockport Group consists of a cyclic succession of dolostones and minor limestones comprising, in ascending order: Gasport, Goat Island, Eramosa, and Guelph formations. This stacked carbonate succession was deposited on an eastward-deepening carbonate ramp, extending from Michigan, through southwestern Ontario, to Ohio, Pennsylvania and New York. It is overlain disconformably by restricted marine carbonates, evaporites and mixed shales of the Salina Group, whereas unconformably underlain by one of four formations that include, the Lions Head (a stratigraphic equivalent of part of the Rochester), DeCew, Rochester and Irondequoit.

To ensure appropriate stratigraphic assignment of the laboratory test intervals, a quality assurance/quality control review on formational tops was carried out on the 150 cored wells that were tested. This regional subsurface work resulted in the reassignment of 846 formation tops that were verified by examination of drill core, drill cuttings, and geophysical well data including gamma-ray, neutron and density logs.

Core analysis datasets have been validated by summarizing laboratory protocols and standards and reconciling data fields in the core analysis database with auxiliary data, including geophysical logs, thin sections, and core examination. This auxiliary data was then used to identify data outliers to update the core analysis database. The measurements of porosity and permeability were then assigned a formation rank plotted on a subregional scale. Average porosity and permeability values have been divided into statistical populations for each formation assigned by three depositional realms.

The southwestern Ontario study area has been divided into three paleogeographic settings, based on distinctive lithofacies that correspond to different carbonate depositional regimes and regions of paleokarstification. From northwest to southeast, the lithofacies reflect an inner to outer carbonate ramp setting designated as area 1–3 from northwest to southeast. Area 1 is the inter-pinnacle karst region and includes some of the pinnacle structures within the Lockport Group. This region has the most significant paleokarstification of the upper Lockport Group (Guelph and Goat Island formations) and overlying Salina Group A-unit. Area 2 has rare pinnacle structures, where no porosity/permeability core analyses data are available. Area 3 is the middle to outer portion of the Lockport carbonate ramp, with local development of reef mound phases in the lower Goat Island and Gasport formations.

The porosity and permeability variability corresponds with areal distribution of paleokarstification and resulting diagenetic phases in Area 1, and lithofacies variations and temporal/spatial history of karstification in Area 3. Concentration of core data in oil and gas pools may introduce bias in the data set and consequent analysis. Higher porosity and permeability generally coincide with greater thicknesses of the oil and gas reservoirs within pinnacles in Area 1 and reef mound phases of the Lockport Group and lower Salina Group A-1 Carbonate in Area 3. Within inter-pinnacle karst regions in Area 1, average porosity for each formation is consistently high with little variations. In Area 3, a general increase of porosity and permeability towards the southeast corresponds with lithofacies ranging from restricted lagoonal/platform interior deposits to carbonate bank deposits with local development of reef mound phases in the Gasport and Goat Island formations. There has been significant erosion and karstification within and at the tops of pinnacles in Area 1, resulting in higher porosity and permeability of the Guelph and upper Goat Island formations, and the overlying Salina Group A-1 unit. Paleokarstic events have enhanced various porosity types, including intercrystalline, moldic, irregular and fenestral vugs, and cavities.

1. Introduction

Insights into the porosity and permeability variations of the subsurface is of critical interest for a range of applications that include petroleum exploration, production and storage, waste disposal, mapping of regional aquifers and aquitards, and alternative energy usages. Until recently this data was only available in hardcopy format making data compilation and analysis costly and time consuming. The Oil, Gas and Salt Resources Library (OGSRL) recently digitized the paper reports as PDF files and transcribed the analyses into a database format that helped to facilitate this analysis (Clark et al. 2018).

The OGSRL in London, Ontario maintains an extensive collection of porosity and permeability analyses of drill core of the intermediate to deep Paleozoic bedrock of southern Ontario collected by the Ontario government from petroleum industry wells. A total of 28,839 core analyses are available from 491 wells, representing a cumulative cored interval of nearly 13,850 metres and 43 formations (Clark et al. 2018). For a study of Lockport Group and Salina Group A-1 Carbonate 150 wells and 11,759 sets of analyses were identified (Figure 1.1).

The Geological Survey of Canada (GSC), Ontario Geological Survey (OGS), and the OGSRL recently completed a revised 3-D lithostratigraphic model for the Paleozoic bedrock of southwestern Ontario (Carter et al. 2021b) and a 3-D hydrostratigraphic model (Carter et al. 2022). Although the Guelph - “Amabel” bedrock aquifer has been known as a source of potable groundwaters for many decades within the up-dip Niagara Cuesta (*see* references in MacRitchie et al. 1994; Singer et al. 1997), the regional understanding of the shallow stratigraphic and karst-conduit controlled flow systems has only recently been delineated by OGS subsurface mapping (*see* references and overview in Brunton and Brintnell 2020). In the deeper subsurface Carter et al. (2021a) have identified a regional aquifer in the Guelph Formation and uppermost Goat Island Formation with a transition from brackish to saline sulphur water at intermediate depths to a deep basinal brine. To explore some of the regional controls on the deeper groundwater, conventional petroleum industry drill core analyses of porosity and permeability in the Lockport Group and Salina Group A-1 Carbonate can provide important insights.

The carbonates of the Lockport Group form the prominent Niagara Escarpment and cuesta and are amongst the most economically significant sedimentary rocks in southwestern Ontario because they possess: 1) significant potable groundwater resources at shallow depths (<250 m); 2) deeper subsurface oil/gas resources and natural gas storage reservoirs; 3) attractive characteristics for the disposal of radioactive wastes and spent nuclear fuel. 4) significant chemical, dimension stone and aggregate resources; and 5) natural features making them a major tourist and agricultural attraction (e.g., wineries, agriculture, waterfalls, hiking, climbing, and camping), resulting in millions of investment dollars in southern Ontario.

1.1 Objectives

The main objectives of this study are to: 1) complete a first assessment on the core analysis dataset, 2) verify the location of core analyses at the formation level within the Lockport Group, and 3) characterize the regional stratigraphic and spatial distributions of the porosity and permeability variations within the Lockport Group formations. This work will support improved understanding and predictability of pathways and barriers of subsurface fluid flow in the Lockport Group. More specifically this report addresses the objectives through, data tables, isopach maps, stratigraphic sections, and reservoir cross-sections with integrated porosity and permeability analysis to:

1) reduce uncertainty in extent/geometry (thickness and occurrence) of Lockport Group bedrock formations by Quality Assurance and Quality Control (QA/QC) improvements to formation top picks;

2) map and statistically analyze the geographic and stratigraphic variations in porosity and permeability in the Lockport Group and A-1 Carbonate core data and their relationship to depositional and diagenetic facies.

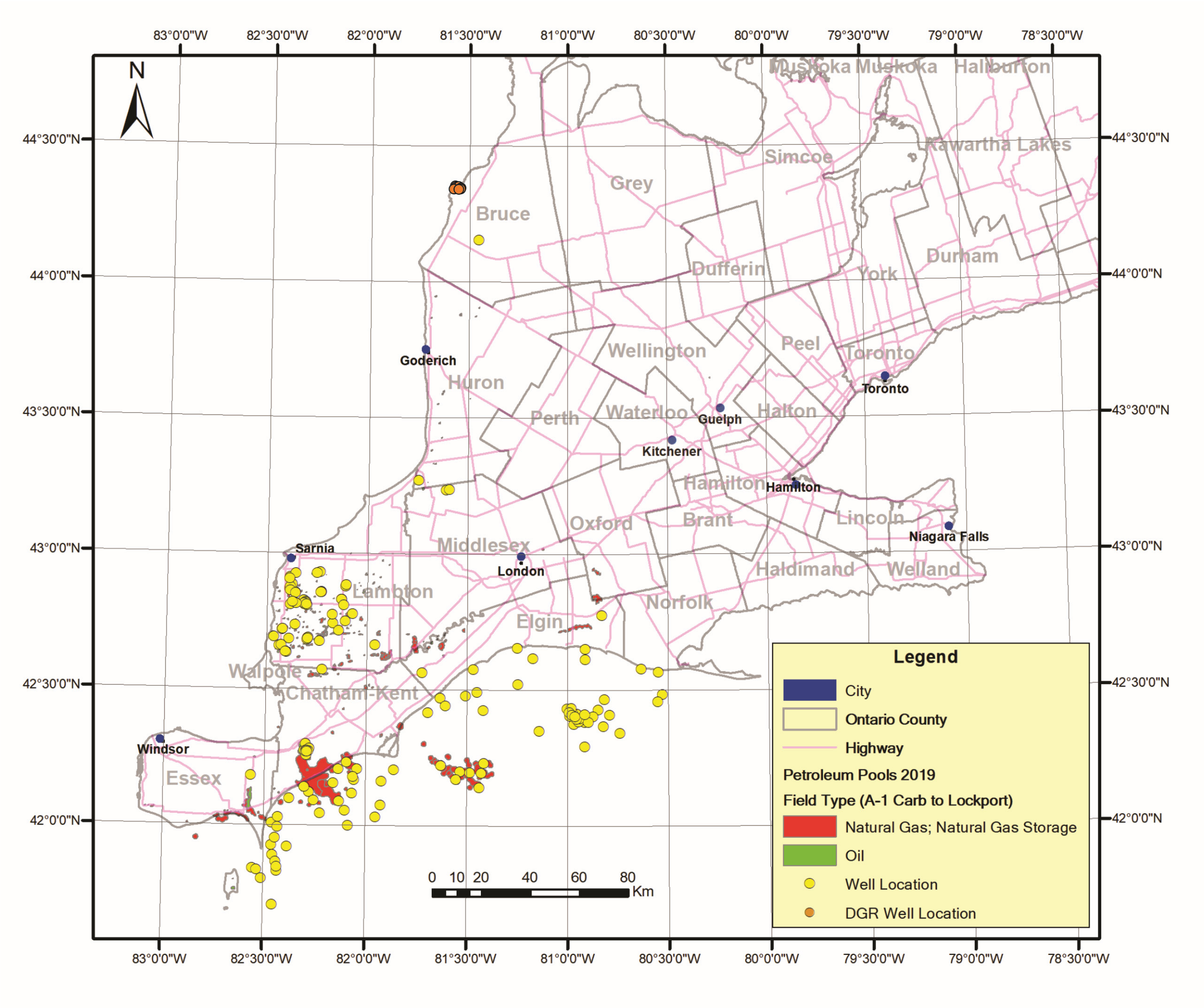


Figure 1.1 Well locations for core analyses utilized in the study. The study area covers the international frontier in Lake Erie to the southwest and the Wiarton-Guelph-Hamilton area to the northeast. Yellow dots represent the locations of the 150 oil and gas wells with petroleum industry porosity and permeability data for the Lockport Group. Orange dots represent the 4 deep cored boreholes at the Bruce nuclear site. (*See* Appendix A and B for details of well locations).

2 Geologic Setting

The study area straddles two Paleozoic sedimentary basins (Figure 2.1). The northwestern part of the study area includes the southeastern and north central parts of the Michigan (intracratonic) Structural Basin, whereas the southeastern part of the study area lies along the distal northwestern margin of the Alleghany sub-basin of the larger Appalachian Foreland Basin (Sanford et al. 1985). These structural basins are separated by a northeast- to southwest- trending broad region referred to as the Algonquin Arch (Quinlan and Beaumont 1984; Root and Onasch 1999; Ettensohn 1994, 2008). Recently it was interpreted as delineating the ephemeral position of the Appalachian Basin forebulge zone separating the Laurentian intracratonic regions and intermittent intracratonic far-field downwarping/upwarping events associated with tectophases within the Appalachian Foreland Basin (*see* discussion and references in Ettensohn 1994, 2008; Ettensohn and Brett 2002; Brunton et al. 2012; Brunton and Brintnell 2020). The northern and southern segments of this zone, named the Algonquin and Findlay arches respectively, are separated by a local, saddle-like structural low called the Chatham Sag (Johnson et al. 1992).

The Lockport Group includes the following formations in ascending order: Gasport, Goat Island, Eramosa and Guelph (Brunton 2008, 2009; Brunton et al. 2012; Brunton and Brintnell 2020). These stacked dolostones form the stepped Niagara Escarpment cuesta that extends from western New York State through southwestern Ontario and Manitoulin Island, and through the Upper Peninsula of Michigan to Wisconsin (Figure 2.1; Brunton et al. 2009; Carter et al. 2021a). Along much of the eroded cuesta edge (e.g., in Niagara area and the city of Hamilton), the cliffs comprise crinoidal dolostones of the Gasport and Goat Island formations. Near the city of Guelph and along the northern Bruce Peninsula, the Eramosa and Guelph formations form subdued cuesta steppes. The Lockport Group extends into the deeper subsurface across southwestern Ontario with an average dip of 3 to 12 m/km down the flanks of the Algonquin Arch into the Michigan and Appalachian basins (Armstrong and Carter 2010). The paleogeographic and tectonic setting of this Early Silurian carbonate succession has been recently summarized in Brunton and Brintnell (2020).

During deposition of the early Silurian (Wenlock) Lockport Group, the study area was largely covered by shallow subtropical epicontinental seas (Witzke 1990; Cocks and Torsvik 2011). Sedimentation in the Appalachian Basin was strongly influenced by events of tectonic uplift in the east that were accompanied by episodic shedding of siliciclastic detritus from the highlands into the foredeep; and carbonate production was largely restricted to the siliciclastic-starved western part of the foredeep (Brett et al. 1998). During Lockport Group depositional and erosional phases, the Michigan structural Basin and the Appalachian foreland Basin received relatively little siliciclastic sediment. Therefore, cyclic shallow marine through progressively restricted marine environmental conditions persisted, resulting in the accumulation of thick stacked predominantly carbonate units and growth of small microbial mounds and larger-scale decametre composite microbial-skeletal mounds, as well as more skeletal-rich crinoidal shoals and vast relatively muddy lagoonal environments on the western margin of Appalachian Basin (Brunton et al. 2012; Brunton and Brintnell 2020). These stacked, shallowing-upward carbonate-dominated successions possess numerous disconformities with associated lateral and vertical porosity and permeability variations within the Lockport Group (Brunton et al. 2012).

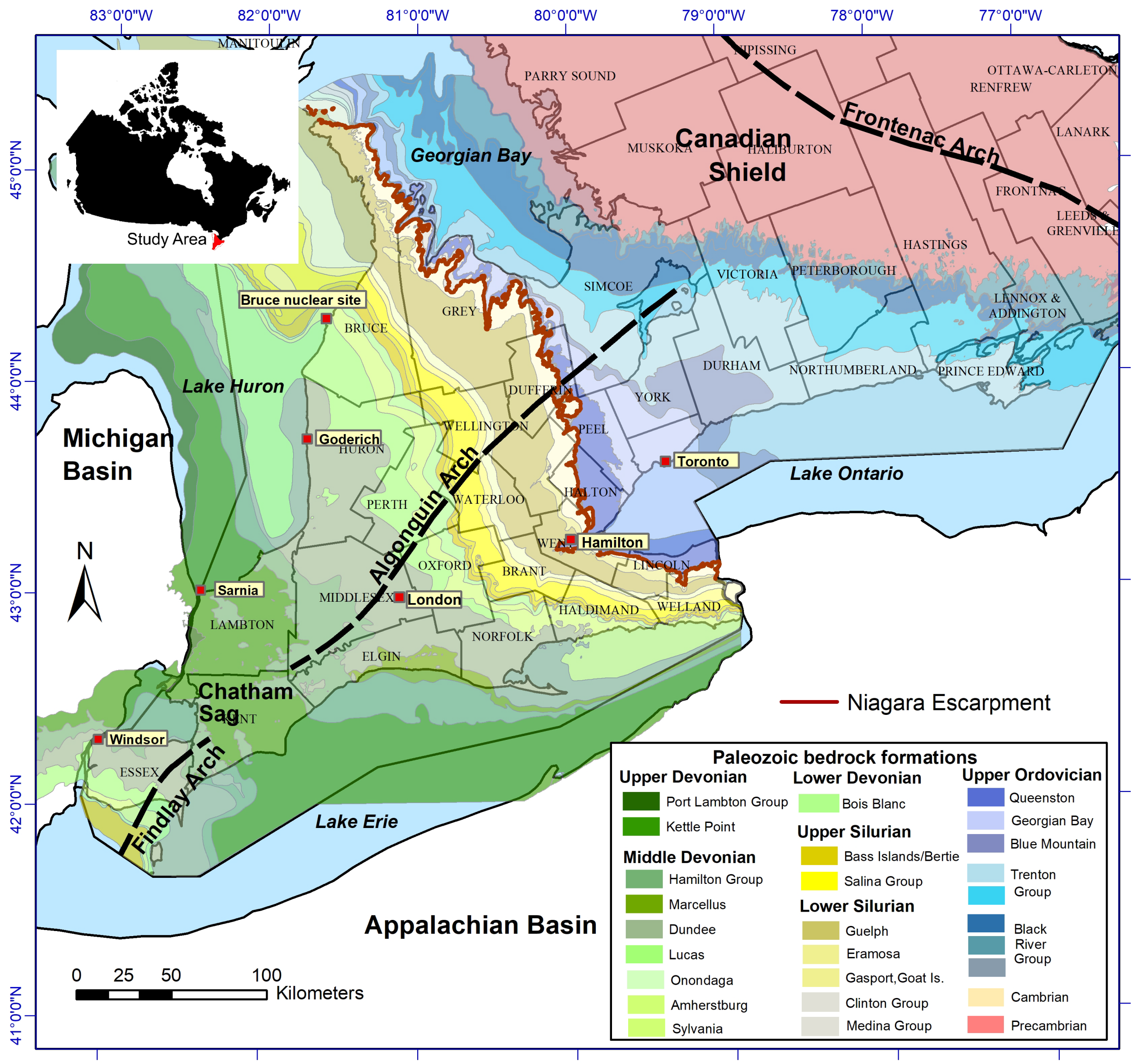


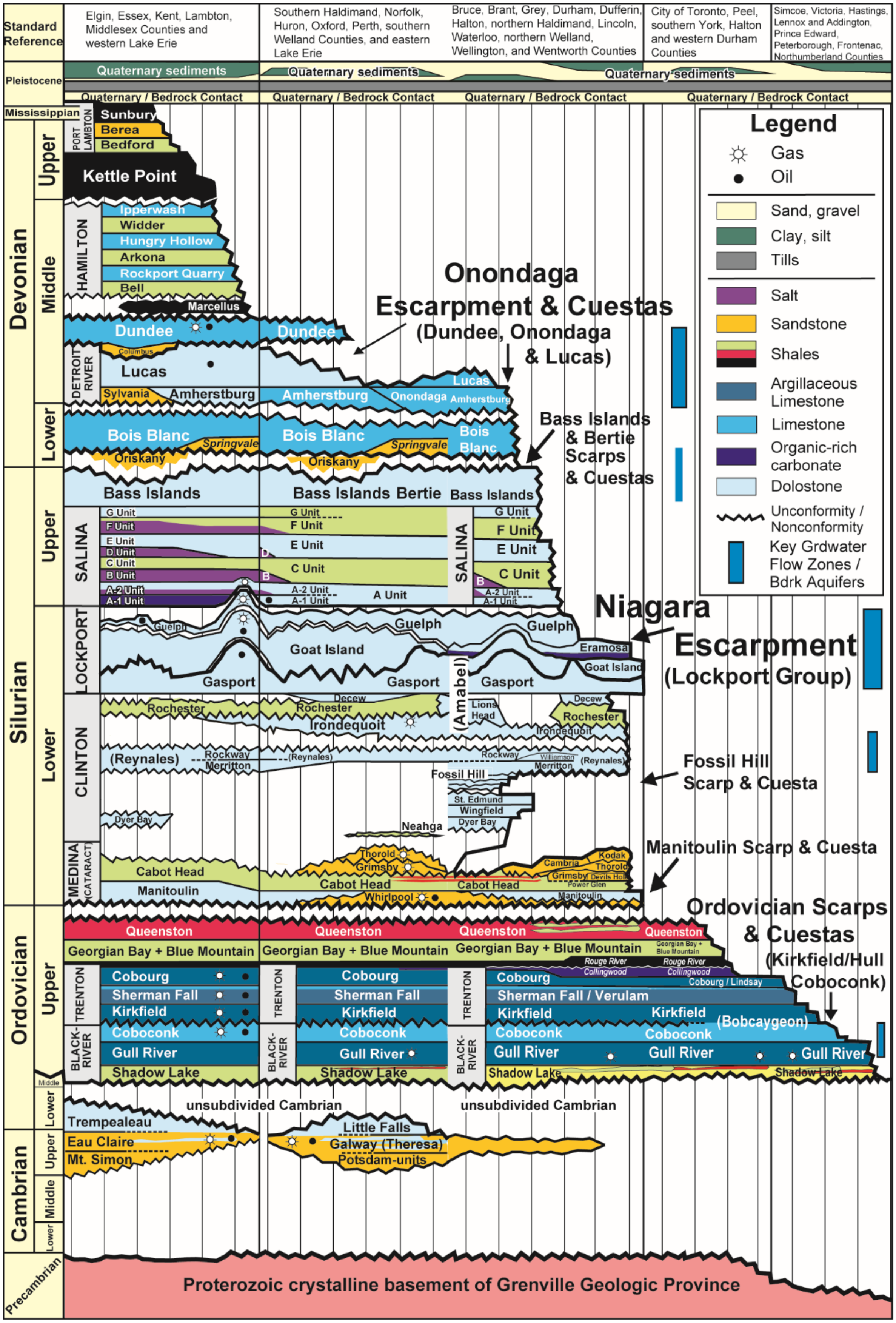
Figure 2.1 Bedrock geology of southern Ontario, showing bedrock formations and groups, structural arches and lowlands, and basins. This study area straddles the Algonquin and Findlay arches, which separate the Michigan and Appalachian basins (*adapted* from Carter et al. 2021).

2.1 Stratigraphy of the Silurian Lockport Group and Salina A-units

The Lockport Group consists of resistant reefal and crinoidal shoal dolostones and minor limestones of the basal Gasport and Goat Island formations. The overlying karst-prone Eramosa and Guelph formations consist of mixed shale to clean, shallow marine skeletal dolostones with intermittent biostromal and biohermal reef complexes (Figure 2.2; Brunton et al. 2012).

The Lockport Group is disconformably underlain by one of four formations that include, the Lions Head (a stratigraphic equivalent of part of the Rochester), DeCew, Rochester and Irondequoit. The Lockport Group is disconformably overlain by the basal microbial carbonates, mixed evaporites and shales of the Salina Group. This variably thick succession comprises up to 9 formational rank units (Landes 1945; Evans

1950; Sanford and Howie 1957; Gill 1977). Armstrong and Carter (2010) recognize 9 units in the Salina Group: A-0 Unit through to G Unit (Figure 2.2). The microlaminated limestone or



Standard Reference
Elgin, Essex, Kent, Lambton, Middlesex Counties and western Lake Erie
Southern Haldimand, Norfolk, Huron, Oxford, Perth, southern Welland Counties, and eastern Lake Erie
Bruce, Brant, Grey, Durham, Dufferin, Halton, northern Haldimand, Lincoln, Waterloo, northern Welland, Wellington, and Wentworth Counties
City of Toronto, Peel, southern York, Halton and western Durham Counties
Simcoe, Victoria, Hastings, Lennox and Addington, Prince Edward, Peterborough, Frontenac, Northumberland Counties
Pleistocene
Quaternary sediments
Quaternary / Bedrock Contact
Mississippian
Devonian
Silurian
Ordovician
Cambrian
Precambrian
Upper
Middle
Lower
PORT LAMBTON
Sunbury
Berea
Bedford
Kettle Point
HAMILTON
Ipperwash
Widder
Hungry Hollow
Arkona
Rockport Quarry
Bell
Marcellus
Dundee
Columbus
DETROIT RIVER
Lucas
Sylvania
Amherstburg
Onondaga
Bois Blanc
Springvale
Oriskany
Bass Islands
Bass Islands Bertie
SALINA
G Unit
F Unit
E Unit
D Unit
C Unit
B Unit
A-2 Unit
A-1 Unit
A Unit
LOCKPORT
Guelph
Goat Island
Gasport
Eramosa
(Amabel)
CLINTON
Rochester
Decew
Irondequoit
Lions Head
(Reynales)
Rockway
Merritton
Williamson
Fossil Hill
St. Edmund
Wingfield
Dyer Bay
Neahga
MEDINA (CATARACT)
Cabot Head
Manitoulin
Thorold
Grimsby
Whirlpool
Cambria
Kodak
Devils Hole
Power Glen
Queenston
Georgian Bay + Blue Mountain
Rouge River
Collingwood
Cobourg / Lindsay
TRENTON
Cobourg
Sherman Fall
Sherman Fall / Verulam
Kirkfield
(Bobcaygeon)
BLACK-RIVER
Coboconk
Gull River
Shadow Lake
unsubdivided Cambrian
Trempealeau
Eau Claire
Mt. Simon
Little Falls
Galway (Theresa)
Potsdam-units
Proterozoic crystalline basement of Grenville Geologic Province
Onondaga Escarpment & Cuestas (Dundee, Onondaga & Lucas)
Bass Islands & Bertie Scarps & Cuestas
Niagara Escarpment (Lockport Group)
Fossil Hill Scarp & Cuesta
Manitoulin Scarp & Cuesta
Ordovician Scarps & Cuestas (Kirkfield/Hull Coboconk)
Legend
Gas
Oil
Sand, gravel
Clay, silt
Tills
Salt
Sandstone
Shales
Argillaceous Limestone
Limestone
Organic-rich carbonate
Dolostone
Unconformity / Nonconformity
Key Grdwater Flow Zones / Bdrk Aquifers

Figure 2.2 Revised terminology of Paleozoic strata for south-central and southwestern Ontario (*modified after* Winder 1961; Beards 1967; Winder and Sanford 1972; Armstrong and Carter 2010; Brunton et al. 2017; Carter et al. 2017; Brunton and Brintnell 2020). The A-0 Carbonate of the basal Salina Group is not shown because of its localized distribution and thickness in southwestern Ontario and southeastern Michigan and the fact that it has been placed within the Salina Group A-1 Unit (*see* discussion in Gill 1973, p.41, p.133). Group names are in capital letters, members in italics, and abandoned formation names (e.g., Amabel) or regionally restricted but valid names (e.g., Reynales) that have been miscorrelated in past studies are in parentheses (*see discussions in* Brunton and Brintnell 2011; Brunton et al. 2012). The Phanerozoic bedrock topography is depicted by the erosional line (thickened black zig-zag line), from lower right to upper left, of stepped karstic carbonate-capped cuestas from Lake Simcoe–Frontenac Arch area to Windsor area (northeast to southwest; *see* geographic regions at top of figure). The line thicknesses signify inferred missing time. Oil- and gas-bearing units (deeper subsurface) and the main potable-water zones (upper 250 m) in carbonate cuesta successions are highlighted: the blue vertical boxes depict main stratigraphic intervals of potable-water zones, with the relative widths and sizes of boxes graphically depicting the significance of regional to subregional groundwater-flow zones (aquifers). The Niagara Escarpment stacked dolostone succession represents the most significant regional bedrock groundwater-flow zone system in southern Ontario. The relative thicknesses of rock units are not to scale.

dolostone of A-0 Carbonate overlies the highly karstic Guelph Formation in the subsurface of Essex, Kent, Lambton, Bruce, Oxford and Huron counties. In other parts of the subsurface of Ontario, the microlaminated or stromatolitic dolostones of the A-1 Carbonate directly overly the top of the Guelph Formation unconformably.

The Silurian Lockport Group displays a complex but predictable stratigraphic architecture in southwestern Ontario, influenced by periods of erosion and karstification during episodes of subaerial exposure in the geologic past (paleokarst) and at the present-day subcrop surface (Brunton and Brintnell 2020). The regional changes in the stacking patterns of carbonate-dominated rock units of the Lockport Group have resulted in the development of hydrogeologic units that are defined by mapping the karst-conduit disconformities corresponding with sequence boundaries and variations in carbonate lithofacies and paleokarstic features. More detailed descriptions of each geologic unit and the regional variations in the stratigraphic architecture are summarized in Brintnell (2012) and Brunton and Brintnell (2020).

2.2 Depositional Facies Distributions and Paleoenvironments

The stratigraphic position and thickness of lithofacies in the Lockport Group vary locally and regionally reflecting different depositional regimes in the geologic past when southwestern Ontario was largely covered by shallow, well circulated subtropical epicontinental seas with periodic stratification (Brunton et al. 2012; *see* Appendix 7 in Brunton and Brintnell 2020). In the Appalachian Foreland Basin system, the deposition of the Lockport Group is influenced by the collisional tectonics in the east along the Appalachian Orogeny Belt (Brett et al. 1998; Ettensohn and Brett 2002; Ettensohn 2008). Carbonate production was restricted to the distal part of the Appalachian Foreland Basin system where siliciclastic influx was minor (Brett et al. 1998). In contrast to the Appalachian Basin region, the subtropical intracratonic Michigan Basin in the interior of the Laurentia Continent received relatively little siliciclastic sediments during early Silurian. Therefore, shallow marine through more restricted marine environments persisted in what is today Michigan and southwestern Ontario. Various carbonate lithofacies in each formation of the Lockport Group formed in response to basin geometry, subsidence rates and regional sea level changes. The carbonate depositional environments are accompanied by the growth of small microbial mounds and decametre-scale composite microbial-skeletal mounds, as well as more skeletal-rich shoals and vast relatively muddy lagoonal environments (Copper and Brunton 1991; Brunton et al. 1998; Brunton et al. 2012). Numerous disconformities are present in these stacked carbonate-dominated rock successions. Using the distribution of each lithofacies and continuation of the disconformities, a regional stratigraphic framework can be established displaying temporal and spatial sub-divisions of the depositional system.

The traditional view on the depositional model of the Silurian Lockport Group in southwestern Ontario was based on the presumption that the slowly subsiding Michigan Basin became rimmed by pinnacle and barrier reefs that restricted basinal water circulation from the open ocean resulting in increasing salinity towards the Michigan Basin centre where deep-water evaporite minerals were deposited (Sanford 1969; Pearson 1980; Bailey 1986, 2000; Huh et al. 1977; Petta 1980; Gill 1985; Carter et al. 1994, 1996; Shaver 1996). Historically, the so-called "pinnacle reefs" of the Guelph Formation have been interpreted as biogenic buildups close to the basin slope where there is accommodation related to inferred higher subsidence rates. Paleogeographic reconstructions by Carter et al. (1994) and Coniglio et al. (2003) combined the patch reef (reef banks) and barrier reef belts of Sanford (1969) and the inner and middle platforms of Bailey (1986) to form the 'Ontario Platform' and retained the pinnacle reef belt (Sanford 1969) rimming the Michigan Basin. Carter et al. (2021) renamed "pinnacle reef belt" as "pinnacle belt & inter-pinnacle karst", identified a regional Guelph karst to the west (Brintnell 2012; Brunton et al. 2012), and identified carbonate banks/reefs within a carbonate platform to the east to represent areas where the Guelph Formation is thickened (Figure 2.3).

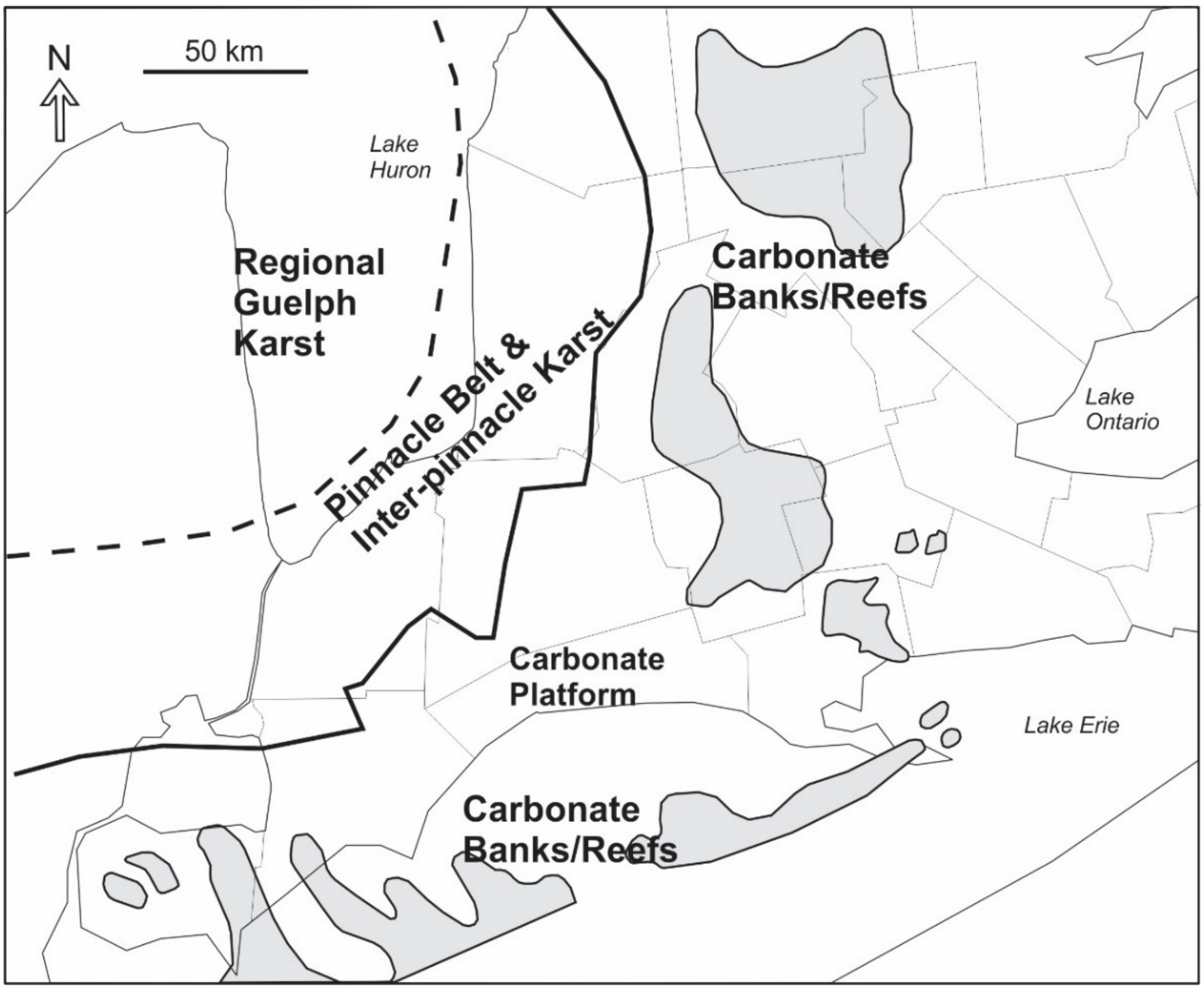


Figure 2.3 A revised depositional model of the Lockport Group. Depositional areas include a pinnacle belt and inter-pinnacle karst, and carbonate platform including reef bank complexes (*Modifired* from Brunton et al. 2012; Carter et al. 2021a). Within the Regional Guelph Karst belt, and in inter-pinnacle locations in the Pinnacle Belt, all primary

depositional features in the Guelph Formation have been destroyed by karstic dissolution leaving a karstic paleosol rubble unit a few metres in thickness.

In contrast to the biogenic reefal interpretations of the Guelph Formation, studies by Alling and Briggs (1961), Pounder (1962); Brunton (2009) and Brunton and Brintnell (2020) suggest a non-reef origin of the Guelph Formation pinnacles in SW Ontario. Recent outcrop and subsurface mapping reveal that the lower Guelph possesses crinoidal, stromatoporoid-coral microbial mounds in basal transgressive parts of the Guelph carbonate ramp in the deeper areas to east and southeast (Guelph, Cambridge through Fergus and Elora areas; Figure 2.4). Only in select areas along the carbonate ramp belt were basal reef mound phases of the Guelph Formation discerned. The pinnacles in Lambton County region do not possess this reef mound phase according to Brunton and Brintnell (2020). Sedimentologic and stratigraphic evidence supports that the depositional setting during early Silurian was an easterly deepening carbonate ramp with shoals and episodes of paleokarstification (Figure 2.4), and with no central deeper water Michigan Basin (Brunton et al. 2012; Brintnell 2012; *see* Appendix 7 in Brunton and Brintnell 2020).

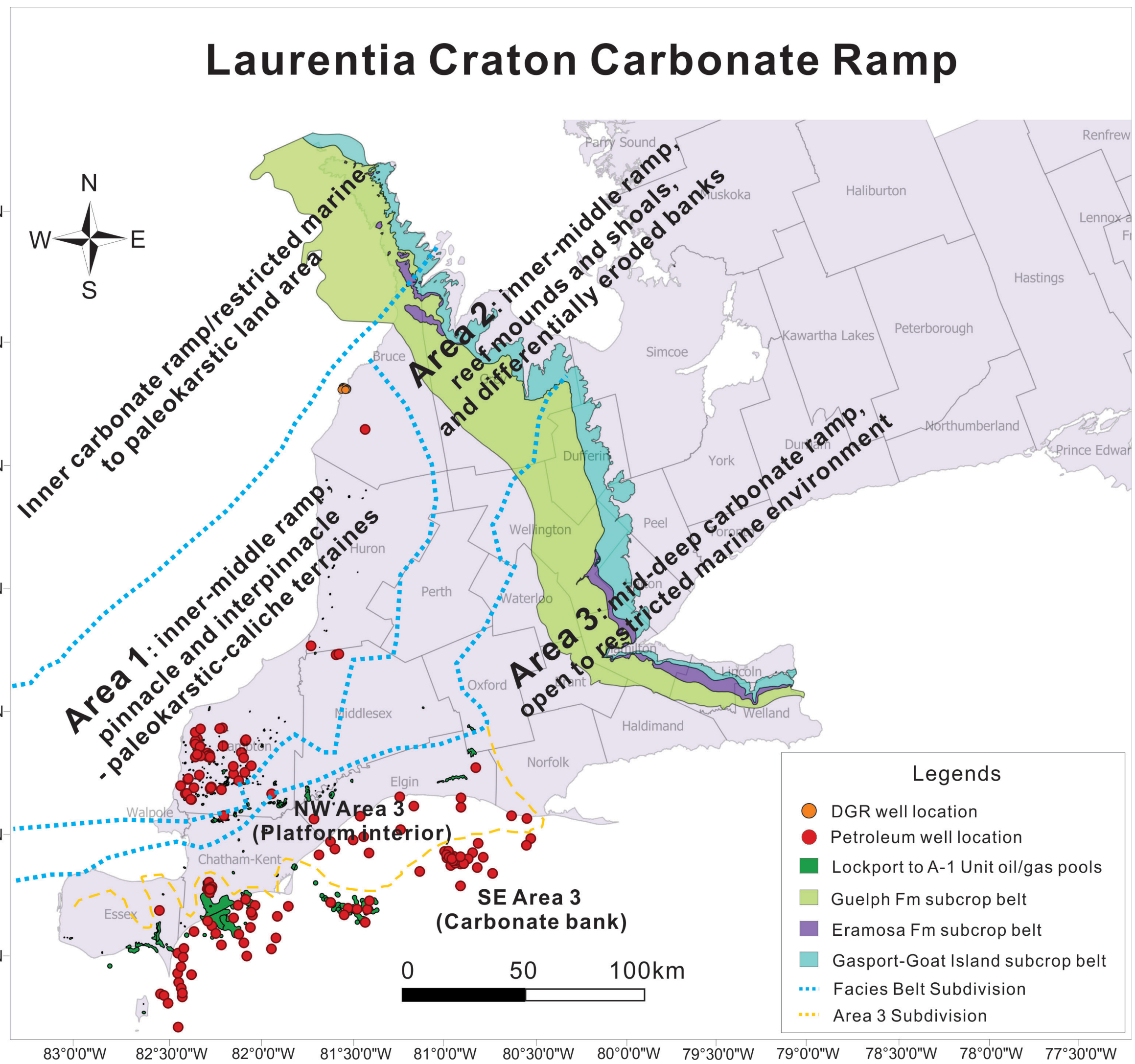


Figure 2.4 Subdivisions of the study area. Area 1 includes cored petroleum wells and the boreholes at the Bruce nuclear site. This area covers the inner ramp of the Lockport Group. Area 2 is the inner-middle ramp of the Lockport Group where no pinnacle structures developed. Area 3 is inferred in this study as the middle-outer ramp of the Lockport Group. Cored wells in Area 3 are concentrated near western and central Lake Erie. Yellow dashed line indicates transitional change of lithofacies belt from restricted interior platform (NW Area 3) southeasterly to carbonate bank/platform edge (SE Area 3).

Three lithofacies belts (Brintnell 2012; Brunton et al. 2012; Appendix 7 of Brunton and Brintnell 2020) have been delineated reflecting different carbonate depositional regimes and degrees of karstification of the Guelph Formation and general Lockport Group that differ from classic studies of the Silurian paleogeographic reconstructions (*see* Sanford 1969; Burgess and Benson 1969; Bailey 1986; Carter et al. 2016; *see* Figure 2.4). Area 1 corresponds with the “Regional Guelph Karst” and the “Pinnacle Belt & Inter-Pinnacle Karst” proposed by Carter et al. (2021). Area 2 has rare pinnacle structures, where no porosity/permeability core analyses data are available. Area 3 is predominantly in Lake Erie and the Lockport Group subcrop belt. The rarely karstic lithofacies of the Lockport Group in Area 3 corresponds to the traditional patch reef and barrier reef complex (Sanford 1969; Bailey 2000) or “Carbonate Platform” (Carter et al. 2021a) and southeastern Area 3 corresponds to “Carbonate Bank/Reefs” (Carter et al. 2021a).

2.3 Lockport Pinnacle Structures

The Lockport pinnacle structures have basal areas of up to 2.02 km^2 with structural height up to 128 m above the regional Guelph surface (*see* Pounder 1962; Sanford 1969; Carter et al. 1994) (Figure 2.5 and 2.6). The inter-pinnacle area consists of dolostone paleokarst-paleosol rubble 4 to 10 m thick, and in some areas the underlying Goat Island and Gasport formations thin to a combined thickness of less than 20 m. This unique stratigraphic architecture has contributed to form oil and gas reservoirs in the pinnacles capped by the impermeable A-2 Evaporite of the Salina Group (Figure 2.6).

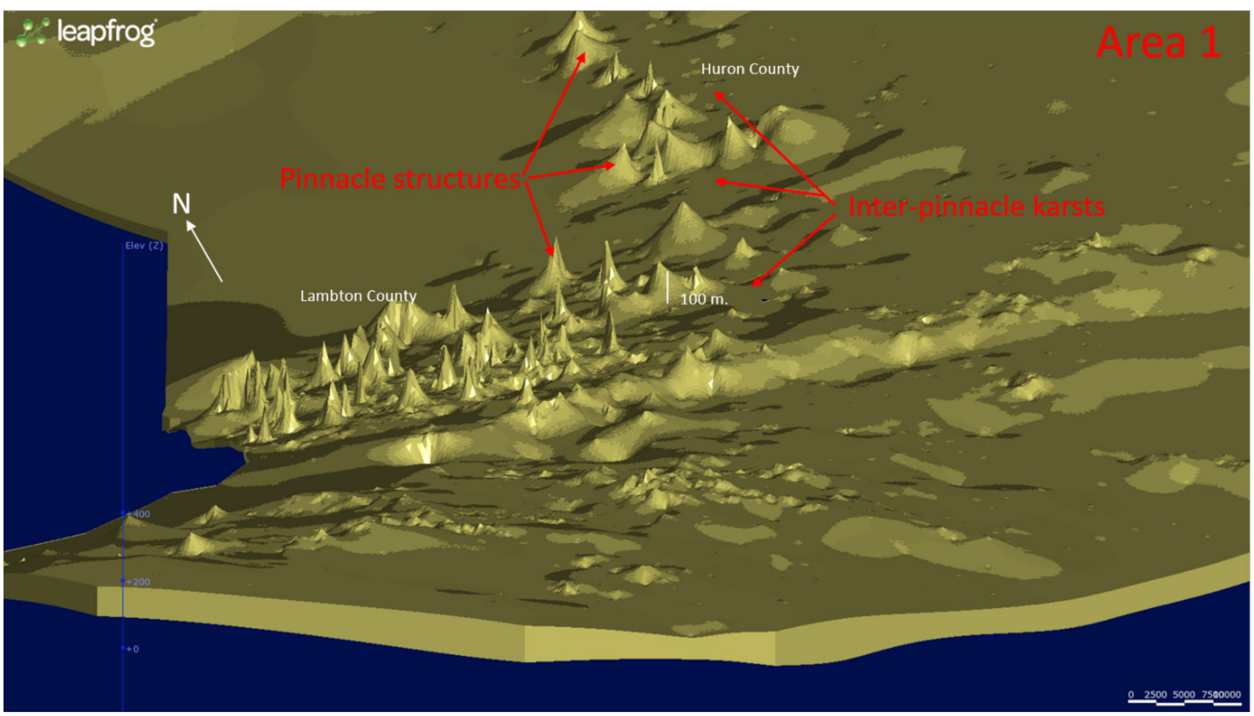


Figure 2.5 A 3-D lithostratigraphic model of the Lockport pinnacle structures and inter-pinnacle karst areas. Adapted from Carter et al (2021b). Height of the pinnacle structures have been exaggrated.

Several hypotheses have been proposed to explain the formation of the mound-like to pinnacle-like features first described in Silurian carbonates of the Michigan Basin, most of which support a reefal origin (Pounder 1962; Mesolella et al. 1974; Huh et al. 1977; Sears and Lucia 1979; Charbonneau 1990; Bailey 2000; Figure 2.6 A-G). Several studies have suggested, at least on a local scale, a strong temporal association between some 'pinnacle reefs' and events of subaerial erosion and/or karst development (e.g., Gill 1977; Charbonneau 1990, 1991; Carter et al. 1994; Bailey 2000). Brunton et al. (2012), Brintnell (2012) and Brunton and Brintnell (2020) proposed that the Lockport Group is characterized by a series of transgressive-regressive (T-R) carbonate-dominated or stacked cyclic dolostones that generally display progressive shallowing and more pervasive regional karstification from east to west moving toward the inferred central Michigan Basin. They proposed that the remnant stacked carbonate structures (Guelph pinnacles) represent a complex mosaic of paleokarsted predominantly Goat Island and Guelph Formation paleo-highs capped by variably karsted Guelph Formation and Salina A-group carbonates and evaporites – karst towers adjacent to Early Silurian scarps in an overall karst basin terrain.

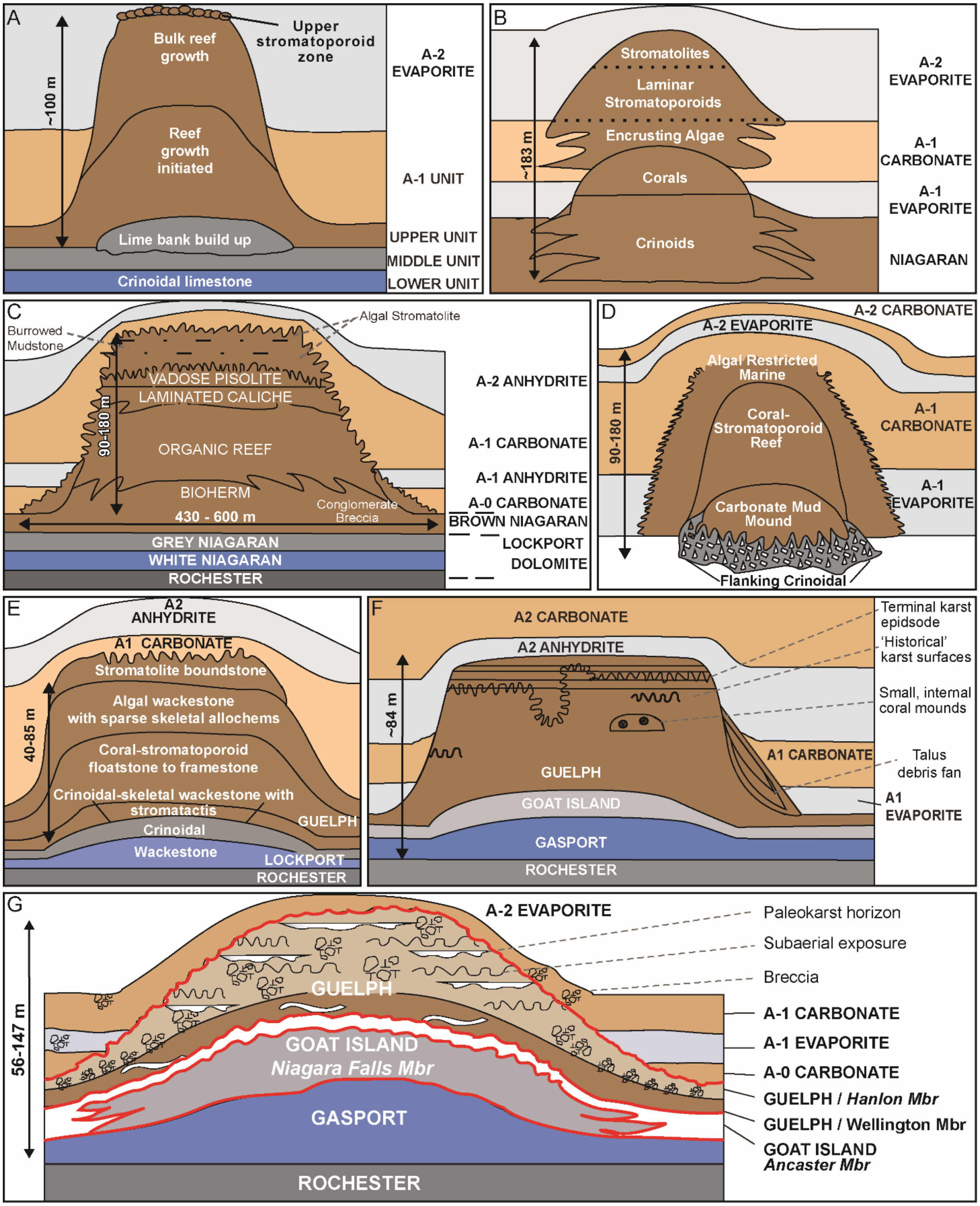


Figure 2.6 Comparison of historic Niagaran/Guelph/Lockport 'Pinnacle Reef' models to the proposed *karst tower* model (*from* Brintnell 2012; Brunton et al. 2012). Below is a brief description of select models and nomenclature used relative to updated terminology adopted in this study:

A: Pounder (1962; Ontario) recognized: (i) the 'Guelph-Lockport' is composed of three units; (ii) the 'pinnacle reef' growth began in the Middle Unit (= Niagara Falls Member, Goat Island Formation); (iii) and the presence of unconformities. He also suggested that the ‘Guelph-Lockport’ paleogeography does not fit the bull’s eye shape of the Michigan Basin.

B: Mesolella et al. (1974; Michigan) recognized: (i) a subaerial exposure event following deposition of their ‘coral-reef’ phase; (ii) a short hiatus between Niagaran and Cayugan time (Salina Group). They suggested that ‘reef’ development took place in a ‘quasi-contemporaneous depositional setting’, the first carbonate and the second evaporitic.

C: Huh et al. (1977; Michigan) recognized evidence for exposure in the entire uppermost portion of the ‘pinnacle reef’, including vadose sediments, caliche crusts, solution leaching, erosional surfaces, iron oxides, flat-pebble conglomerates. They also discussed a Guelph-Salina unconformity.

D: Sears and Lucia (1979; Michigan) recognized that the ‘pinnacle reef’ buildup reflects increasing salinity. They suggested continuous reef growth and only one subaerial exposure event – post-Niagaran deposition.

E: Charbonneau (1990; Ontario; and Leigh Smith and students) recognized: (i) several episodes of subaerial exposure; and (ii) the correlation of two separate, possibly regional, exposure surfaces – a lower surface, top of Lockport (= Goat Island Formation, Niagara Falls Member), and an upper surface (top of Guelph Formation).

F: Bailey (2000; Ontario) first acknowledged that these carbonate structures are actually mud mounds and not ‘reefs’.

G: The proposed karst tower model (modified from Brintnell 2012 and Brunton et al. 2012). Sequence boundaries and associated paleokarst horizons highlighted at red lines. The karst tower or remnant bank is a carbonate-dominated 3D structure with variable disconformities separating the Gasport and Goat Island formations and displays the most significant erosional episodes during Lockport Group deposition/erosional time – especially Eramosa (which is absent or poorly delineated in most subsurface cores of southwestern Ontario and southeastern Michigan) and Guelph and post-Guelph depositional phases and stratigraphic relationships (see more detailed discussion of karst tower model in Brintnell (2012) and Brunton et al. (2012)).

3. Datasets

Core analysis data for this study include 150 cored wells from the OGSRL (Clark et al. 2018) and 4 deep boreholes drilled at the Bruce nuclear electrical generating site on Lake Huron, southern Bruce County (Sterling et al. 2011).

3.1 Petroleum Well Core Analysis Database

Petroleum well data for Ontario are reported to the Ministry of Northern Development, Mines, Natural Resources and Forestry (NDMNRF). Core analysis data are collected under the authority of S.13.6.1 of the Provincial Standards and become part of the public record after expiry of a confidentiality period. The submission of drill core analyses has been a legal requirement in Ontario since at least 1954 (*see* Table 3.1 and Figure 3.1 for year range of tested data). All physical data are stored at the OGSRL in London and digital data are part of the Ontario Petroleum Data System (OPDS) relational database. The database is owned and operated by the NDMNRF with public access and QA/QC managed by OGSRL.

There are records for nearly 27,000 wells in OPDS. The well records include details on well history, construction, location, stratigraphy, oil, gas, and water-bearing intervals. Included in well records are well licence number, well name, operator's name, drilling and TD time, well location, drill rig type, geological formation top picks by operator and/or NDMNRF, geophysical logs, core analyses and chemical analyses of subsurface fluid samples. The OGSRL houses hard copies of the source documents, drill cutting samples from over 13,000 wells, and nearly 1100 drill cores. The NDMNRF formation top picks are those reviewed by qualified geologists (i.e. registered PGeo, GIT and university professors) with formation top pick criteria listed in Armstrong and Carter (2010). In this database, a total of 28,839 conventional core analyses are available from 491 wells (Clark et al. 2018). Data entry and QA/QC protocols for digitizing the core analysis database are provided in Appendix F.

Data used in this study comprises 11,759 porosity and vertical and horizontal permeability tests from 150 cored wells within the Lockport Group and the basal Salina Group (A-0 Carbonate, A-1 Evaporite and A-1 Carbonate). The range of thicknesses of cored intervals are summarized in Figure 3.2. Well locations are scattered across southwestern Ontario but are concentrated within oil and gas reservoirs within pinnacles and carbonate ramp in the deeper subsurface in Area 1 and Area 3 (Figure 1.1 and 2.1). Appendix A and B provide a list of the 150 cored wells with geographically plotted locations. This may result in an unequal representation and characterization of the properties of the Lockport Group.

Drill core acquired by petroleum well operators has been analysed at one of ten commercial laboratories (Table 3.1). The commercial analyses for this study were completed over a 46-year period between 1954 and 1999. Core Laboratories contributes results for 43 of the 46 years, and Maness Petroleum Laboratories and AGAT Laboratories for 8 and 9 respectively. The remainder of the labs provided results for less than 3 years with 5 labs providing results for only one year. Reports from Core Laboratories, Agat Laboratories, Chemical & Geological Laboratories Inc and Geotech Core Services confirm that analytical protocols followed the conventional or full diameter core analysis procedures of the American Petroleum Institute (1960, 1998; *see* Appendix G for details), representing 95 % of the 150 cored boreholes and 73.7% of the analysis. Summarization of techniques is provided in Appendix G. No attempt to correct data from different laboratories (level) has been completed, though some absolute differences in analytical values may exist between laboratories, and not recognized.

Data in the core analysis database can be assigned to three categories a) location metadata, b) core analysis laboratory, c) tested values from laboratory and measured core or borehole information. Core analysis data includes measurements of porosity, vertical permeability, horizontal permeability, depth interval, geological formation, date analyzed, well licence number, oil saturation, water saturation, bulk density, and grain density (Table 3.2). Each dataset is measured on full-diameter core or core plugs (Appendix G.2).

Table 3.1 List of the 10 core labs and number of analysis, time period, and formation assignment.

Laboratory	Analyses # (%)	Interval years	Time period	Analysis per formation			
				Salina A Unit	Guelph	Goat Island	Gasport
AGAT Laboratories	1,133 (9.6)	9	1990-1999	163	925	44	1
Core Laboratories	7,176 (61.0)	43	1954-1997	1515	4708	537	416
Maness Petroleum Laboratories	2,927 (24.9)	8	1965-1973	427	2170	254	76
Clearbeach Resources Inc.	22 (0.2)	1	1964	22	0	0	0
Chemical & Geological Laboratories Inc.	88 (0.7)	2	1994-1996	16	72	0	0
Geo-Engineering Laboratories Inc	5 (0.1)	1	1972	5	0	0	0
Robertson Research Canada Limited	29 (0.2)	1	1987	12	17	0	0
Hycalog, Inc.	69 (0.6)	1	1959	0	0	0	69
Geotech Core Services	266 (2.3)	3	1988-1991	28	161	36	41
Northwest Labs	44 (0.4)	1	1999	21	23	0	0
Total: # (%)	11,759			2,209 (18.8)	8,076 (68.7)	871 (7.4)	603 (5.1)

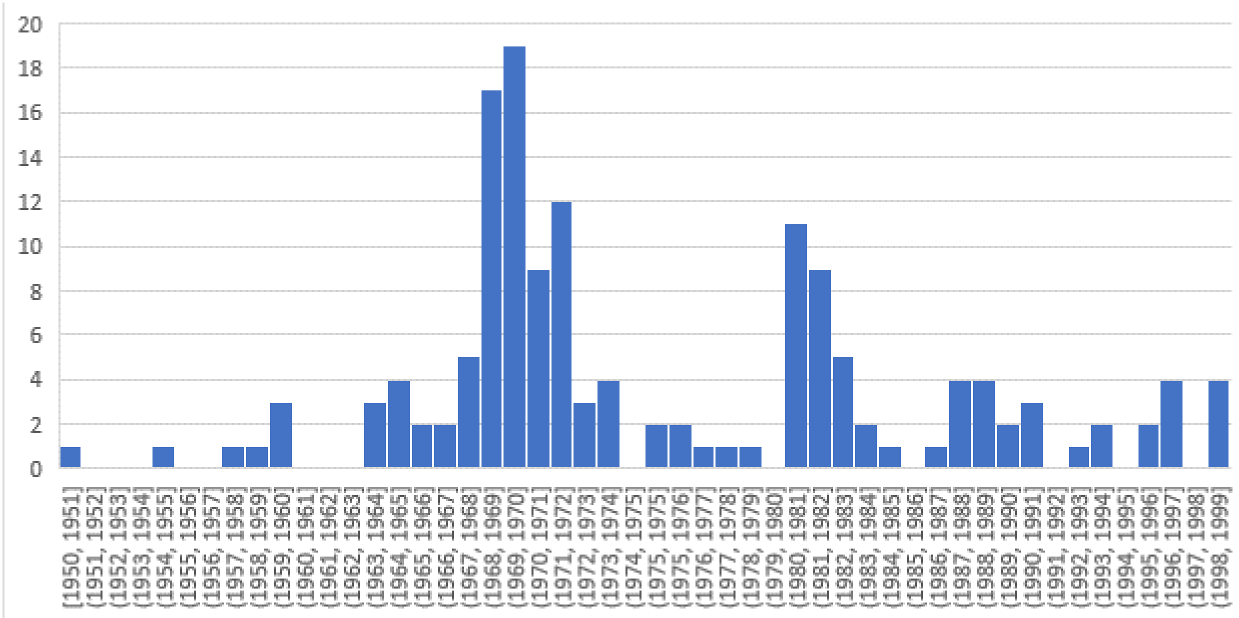


Figure 3.1 Core analysis dates aggregated by boreholes and grouped by one-year intervals. N = 150

The core analysis data has been reviewed to remove inconsistencies in reporting standards of the laboratories and create normalized data fields. Review methods include: 1) summarize laboratory protocols and standards; 2) reconcile data fields in core analysis database with auxiliary data: geophysics, thin sections and core logging, then use this auxiliary data to identify data outliers for correcting the core analysis database.

Table 3.2 Parameters in the core analysis database

Parameter	Explanation
Location	
Thickness (m)	Vertical thickness of the analyzed cored interval in metres
Thickness (ft)	Vertical thickness of the analyzed cored interval in feet
Core Laboratory	
Company Name	Company responsible for core analysis
Date of Analysis	Date core analysis was completed
remarks	Additional descriptions from the core analysis company, commonly referencing geology of the core
Analysis parameters	
perm_horizontal	Maximum measured horizontal permeability
perm_horizontal_90	90 degrees to the perm_horizontal measurement in horizontal plane

perm_vert	Maximium vertical permeability
perm_units	All units in millidarcy
horiz_perm_length	Diameter of the tested sample
vert_perm_length	Length of the tested sample
KH	Horizontal permeability
KV	Vertical permeability
Porosity_Percent	measured porosity of the sample interval
Porosity_length	Indicates the storage capacity of the reservoir for the length of the analysis interval
Bulk_Density	Measured by Caliper/Archimedes/Sanding
Grain_Density	Calculated from the measured dry weight divided by the grain volume of a core sample. Used to confirm the mineralogy of the core
sat_oil	Oil saturation: Defines the presence and quantity of hydrocarbons within a reservoir (fraction of pore space occupied by oil)
sat_water	Water saturation: Defines the presence and quantity of hydrocarbons within a reservoir (fraction of pore space occupied by water)
probable_production	Oil, gas or nil

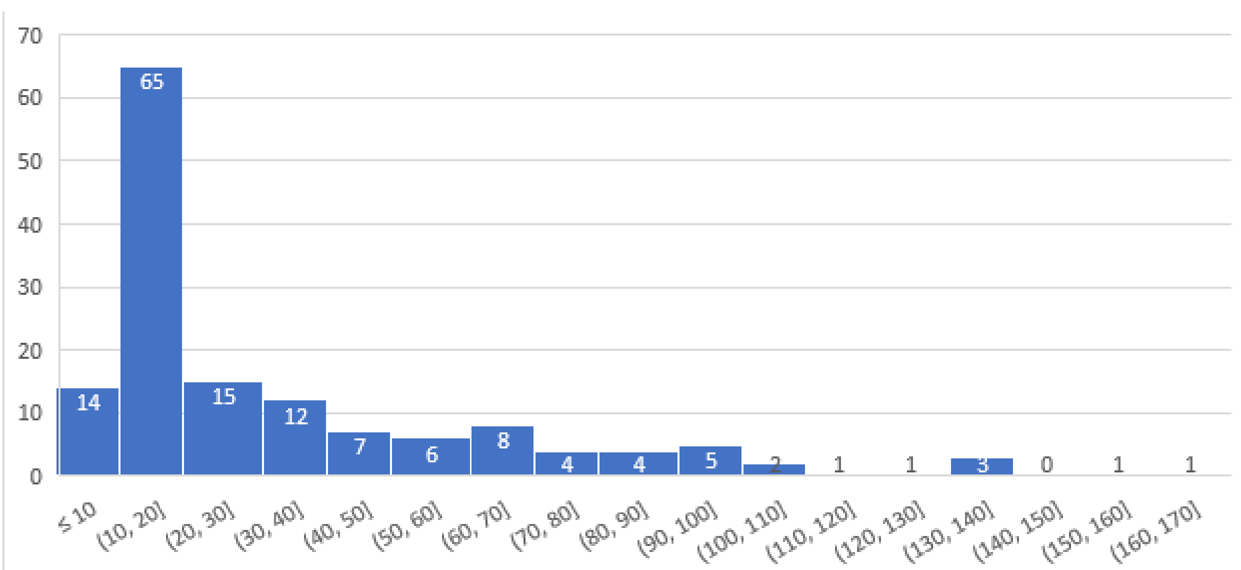


Figure 3.2 Histogram of thickness of cored interval for 150 wells within the Lockport Group. Note that ~40% of the cored data are of 10-20 m thickness. *See* Appendix A for individual wells, cored interval, and thickness.

The first phase of data validation was to verify that the digitized core analysis data match the information and values in the original hardcopy report. The second round of data validation included a quality assurance and quality control (QA/QC) assessment of the core analysis data to eliminate any errors or discrepancies in the database. Protocols have been provided in Appendix F. The verified data includes measurements of the following: porosity, vertical permeability (KV) horizontal permeability (KH 90°), geological formation, oil saturation/water saturation, bulk density and grain density. Procedures for data validation for each of the 150 cored wells are as follows:

- Depth profiles of porosity, vertical permeability, horizontal permeability (KH and KH 90°), geological formation, bulk density, and grain density;
- Compared the plotted data with the available geophysical well logs (gamma-ray, neutron porosity, density, density porosity and PE) or the re-run of gamma-ray logs by core processing labs to check if there are any discrepancies in formation assignment;
- Any extreme high or low data were confirmed or questioned by lithofacies observation in core; the discrepancies include permeability values less than 0.1, negative, > 1,000 Md; porosity values > 20%; bulk density is larger than grain density;
- Verified the causes for data discrepancies: they may come from broken core samples; vertical fracture or unreadable hard copy records;
- Remarks recorded in the source files.

Conventional core data, including porosity, density, permeability, and residual saturation measurements, are collected at room pressure. Therefore, the compressibility of rock is not considered. In the core analysis database, documentation of implementation of the Klinkenberg formula is incomplete. Therefore, no Klinkenberg correction was carried out. A total of 223 unreliable analyses have been eliminated by comparing reported data to cored wells and geophysical logs.

3.2 Cored Wells at the Bruce Nuclear Site

At the Bruce nuclear site (Figure 3.3), four vertical continuously cored boreholes (DGR-1, DGR-3, DGR-4 and DGR-8) were drilled between 2006 and 2010 (Geofirma Engineering Ltd. 2012) and have drill core intersections of Lockport Group and A-1 Carbonate (Table 3.3).

Data available for the cored intervals include: 1) well locations; 2) stratigraphic, sedimentological and structural discontinuity logging notes; 3) geophysical well logs (gamma-ray, near and far neutron, focused density, resistivity, fluid temperature, acoustic and optical televiewer); 4) laboratory tests on fluid saturations, total porosity, bulk density and permeability; and 5) borehole hydraulic conductivity tests. Total and liquid porosity have been reported for DGR-3 and DGR-4 (Intera Engineering Ltd. 2010a; b; Hobbs et al. 2011 and Geofirma Engineering Ltd. 2011a; b) that were drilled and cored from the top of bedrock to the top of the Cambrian sandstone at depths of approximately 869 and 857 m BGS, respectively (Sterling et al. 2011).

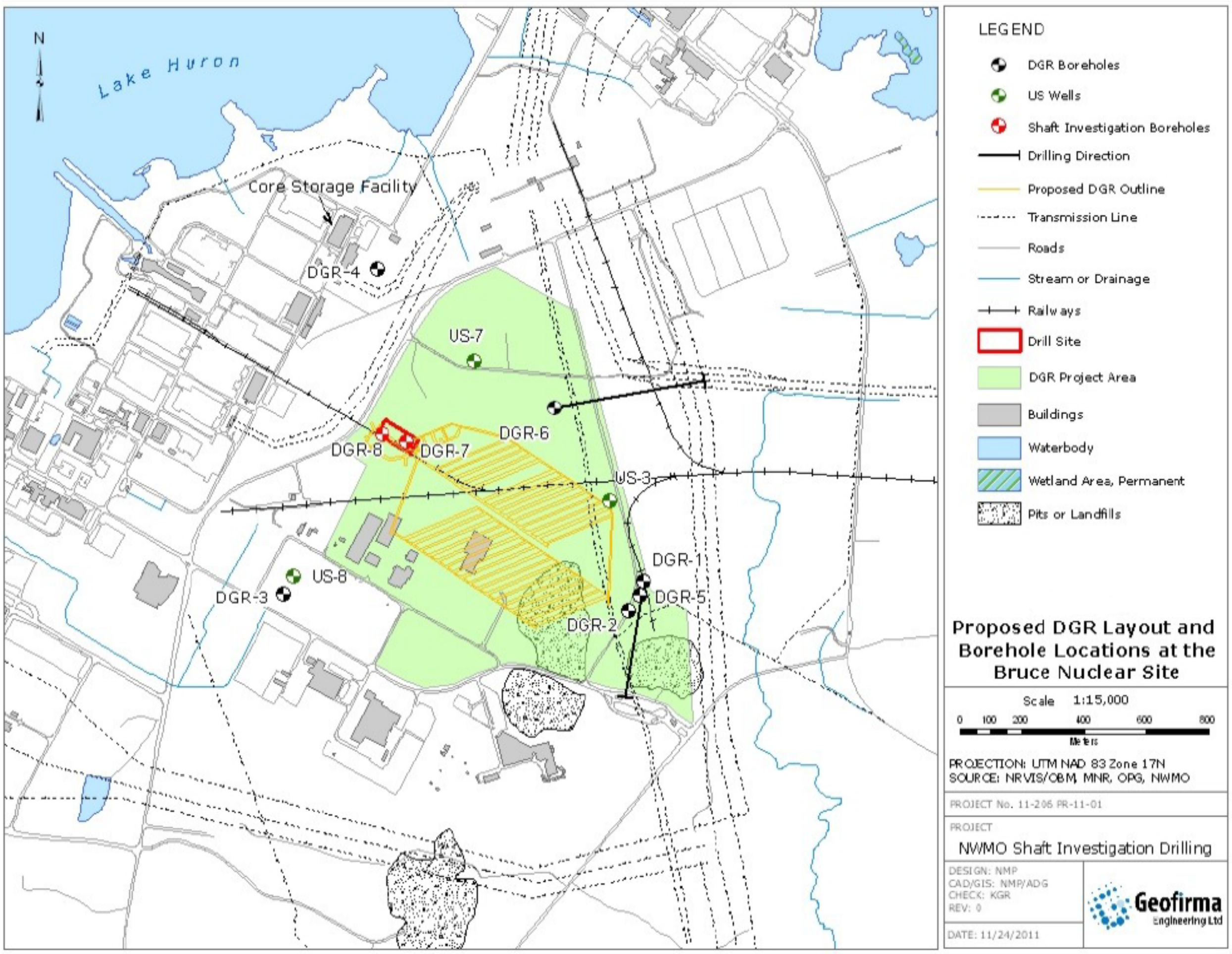


Figure 3.3 Well locations at the Bruce nuclear site (Geofirma Engineering Ltd. 2012)

Three types of porosity are tested on the core 1) total porosity, 2) liquid porosity, and 3) water-loss porosity by differentiating the type of fluid occupying the void space. Total porosity is the sample volume not occupied by mineral grains (i.e., total volume of voids) divided by the volume of the sample, and comprises the cumulative total volume of water, oil and gas filled pore spaces. Liquid porosity is the volume of the voids occupied by liquid (pure water plus dissolved solutes and liquid petroleum such as oil and gas) divided by the total volume of the sample. Water-loss porosity is the volume of the voids occupied by pure water divided by the total volume of the sample. Total porosity should equal liquid porosity plus porosity occupied by any gas phase.

Total porosity of the wells has been measured by Core Laboratories and University of Bern as part of petrophysical, diffusion and porewater testing programs (Table 3.4; Sterling et al. 2011). Laboratory tests on cores of DGR-1 through to DGR-6 were conducted at the Core Laboratories, Houston, Texas. In labs of the University of Bern, samples were analysed for both total porosity and water-loss porosity for DGR-3 and DGR-4. Each porosity measurement was completed on different sub-samples taken from the same preserved core sample. Total porosity sub-samples were 4-5 g plugs and liquid porosity subsamples were 60-420 g segments (edges chipped off sample). In Core Laboratories, samples were analysed for total porosity and water saturation on the same ~150 g core plug (horizontal and vertical). Total porosity measured by Boyle's gas law expansion (He) on "clean and dried" samples under a confining stress of 34 kPa/m (DGR-3 and DGR-4) to replicate the depth-specific hydrostatic in-situ stress. Core Labs measured total porosity and liquid porosity using Dean Stark methods and using Nuclear Magnetic Resonance (NMR)/He gas expansion methods on the same cores (Sterling et al. 2011).

Table 3.3 Boreholes at the Bruce site with porosity and permeability data.

UTM (NAD83)		Well_name	Well licence	County	Logs	Status	Vertical
Northing	Easting						
454240.11	4907753.95	DGR-1	T011582	Bruce	Neutron, Resistivity, Temperature, Caliper, Sonic, Image	STR-ACT	Y
453080.82	4907738.84	DGR-3	T011811	Bruce	Gamma Ray, Neutron, Resistivity, Temperature, Caliper, Sonic, Image	STR-ACT	Y
453378.62	4908742.94	DGR-4	T011812	Bruce	SP, Gamma Ray, Neutron, Resistivity, Temperature, Caliper, Sonic, Image	STR-ACT	Y
453397.59	4908234.21	DGR-8	T012102	Bruce	Gamma Ray Neutron, Neutron, Resistivity, Temperature, Caliper, Sonic, Density, Image	STR-ACT	Y

For the DGR core the distribution of total and liquid porosity are summarized in Table 3.5, Figure 3.4 and 3.5, respectively (Sterling et al. 2011). The highest measurements of both total and liquid porosity occur in the Guelph Formation, with a formational average of approximately 7.5% and 13.1%, respectively. Where liquid porosity exceeds total porosity tis inversion has been attributed by Sterling et al. (2011) to mineralogical aspects of core intervals, for example the presence of gypsum and /or release of bound water. The total porosity values for Guelph Formation show a moderate variation, ranging from 1% near the bottom to 10.7% near the top. Low average values of total porosity occur in the Goat Island Formation, lower A-1 Carbonate, A-0 Carbonate, with formational averages of approximately 2.9%, 5.4% and 2.1%, respectively.

Table 3.4 Summary of Porosity Measurements for DGR Core Samples (Sterling et al. 2011)

Test Element	University of Bern	Core Labs
Measurements	total porosity, liquid porosity	total porosity, water saturation
Methods	Bulk dry/grain density calculation using Archimedes Principle (paraffin displacement)	Boyles Law gas expansion, Dean Stark fluid saturations
Sample Size	~4-5 g plug (total)	~150 g plug
Drying Temperature	40°C and 105°C	105°C
Drying Time (days) range and (average)	48-135 (99) @ 40°C 12-174 (92) @ 105°C	2 to 7 vacuum oven

Porosity data have been discussed in Sterling et al. (2011). Some samples exhibit a liquid porosity greater than the corresponding total porosity for the same core sample. This can be caused by hydration water release from gypsum during heating and drying or different labs using different methods on different subsamples that are subject to different handling and sample preparation techniques. Because no liquid porosity data are incorporated in the core analysis database for this study, the total porosity values measured on DGR wells are used in this report for comparison and regional correlation.

Table 3.5 Summary of total and liquid porosity (%) by formation in DGR boreholes (Sterling et al. 2011)

Formation	(# Liq > Tot) / (# Tot & Liq)	Total Porosity		Liquid Porosity	
		Mean (%)	Count	Mean (%)	Count
upper Salina A-1 Carbonate	NA	null	null	6.3	6
lower Salina A-1 Carbonate	0/1 = 0%	2.9	1	4.0	13
lower Salina A-1 Evaporite	1/2 = 50%	1.2	2	1.1	5
Salina A-0 Carbonate	0/3 = 0%	5.4	3	2.7	7
Guelph	0/1 = 0%	7.5	1	13.1	5
Goat Island	0/3 = 0%	2.1	3	2.8	16
Gasport	NA	null	null	1.9	3
Lions Head	NA	null	null	8.3	2

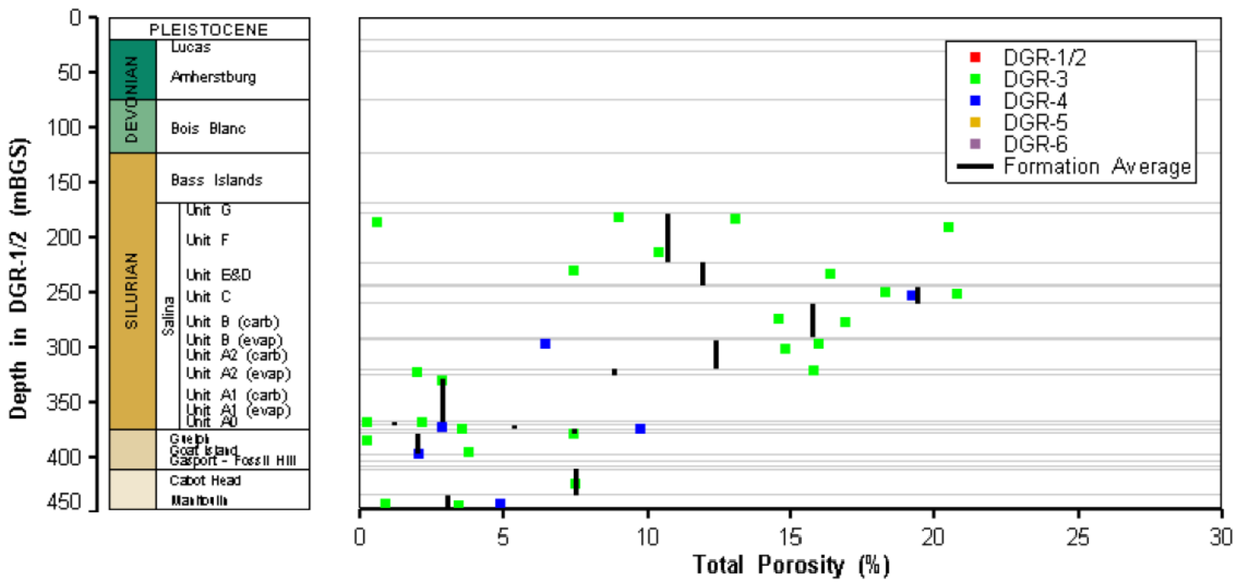


Figure 3.4 Depth profile of total porosity measurements from DGR Cores (Sterling et al. 2011)

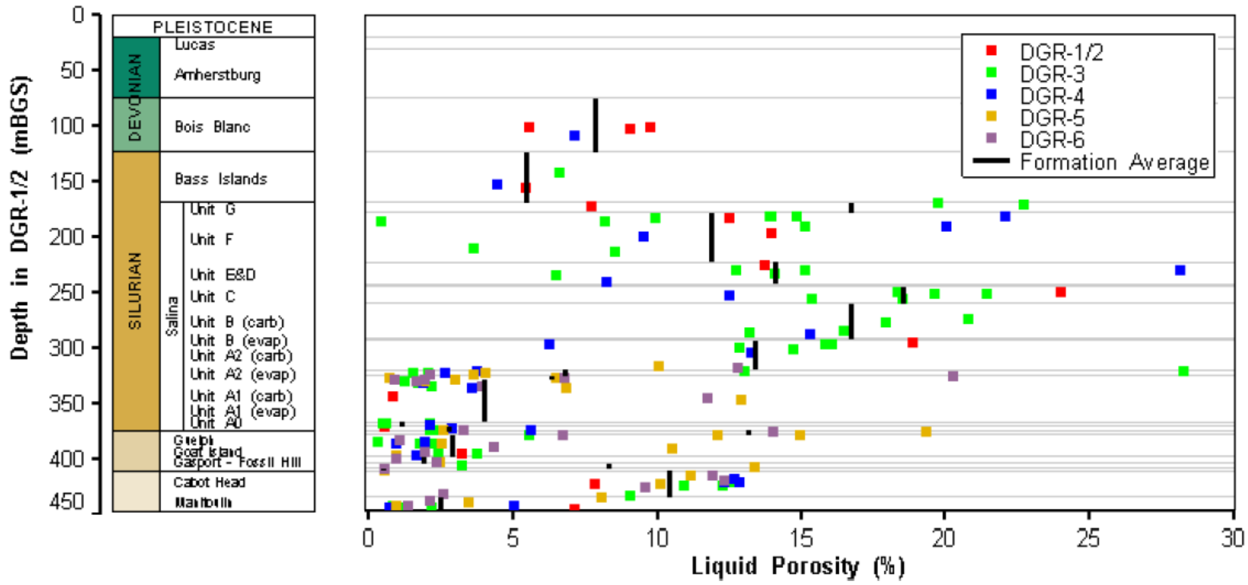


Figure 3.5 Depth profile of Liquid porosity measurements from DGR Cores (Sterling et al. 2011)

4. Geology QA/QC

To ensure accurate correlation of the core analysis data to geological formations and lithofacies the formation top picks for cored wells with core analysis data for the Lockport Group have been reviewed and confirmed. Formation tops reviewed include, in ascending order, Rochester, Lions Head, DeCew, Gasport, Goat Island, Eramosa, Guelph, A-0 Carbonate, A-1 Evaporite and A-1 Carbonate. Data used to review and examine geological formation tops include petroleum well files (driller reports, Ministry Form 7 reports), drill cuttings, drill cores and geophysical logs (gamma-ray, neutron and density logs) stored at the OGSRL. A total of 1950 formation top picks have been reviewed for 150 wells resulting in updates of 942 formation top picks (*see* Appendix A and B for well list and locations).

Each formation top depth pick in OPDS has a QA code assigned that represents the level of certainty of the pick (Table 4.1). An example of high certainty is a pick made using reliable geophysical logs and/or good quality cores. An uncertain formation top pick may be the result of geophysical logs and/or cuttings/cores of poor quality or when the interval being analyzed does not show obvious characteristics for its identification. Geology QA/QC protocol is summarized in Appendix C and the revised formation top pick criteria in Appendix D. The newly updated geology QA/QC results are presented in Appendix E.

Common corrections include digital data entry typographical errors, incorrect formation tops assignment using outdated pick criteria, imperial to metric unit conversion errors, and missing formation top picks.

Table 4.1 OPDS quality assurance (QA) codes for formation top picks recorded in the well database

CODE	PICK CONFIDENCE	SOURCE	DESCRIPTION

2.0	Confirmed	MNRF P. Geo	The reviewer had good data—rock cuttings, geophysical logs, or rock cores—and is confident in confirming the pick.
1.9		P. Geo	
1.8		OGSRL Geologist in Training or Graduate	
1.7		OGSRL Geology Student	
1.5	Reviewed	MNRF P. Geo	The reviewer made the best possible pick based on the data available: rock cuttings, geophysical logs, or rock cores; however, more data or review should be considered.
1.4		P. Geo	
1.3		OGSRL Geologist in Training or Graduate	
1.2		OGSRL Geology Student	
1.0	Not Anomalous	MNRF well records	No geological review but does not cause anomalies in 3-D model
NULL	Not Evaluated	MNRF well records	Default value for unedited well records submitted by well operators. No subsequent geological review.
-1.0	Anomaly, requires review	Any	Causing local anomalies when used in 3-D mapping and requires review.
-2.0	Anomaly, unresolvable	Any	Causing local anomalies when used in 3-D mapping but could not be confirmed or corrected because of an absence of data (rock cuttings, geophysical logs, or rock cores).

Table 4.2 Summary of formation top pick changes per geological formation post geology QAQC.

	Picks Added			Picks Revised			Picks Confirmed			Total
	Area 1 (pinnacle structure)	Area 1 (inter-pinnacle)	Area 3	Area 1 (pinnacle structure)	Area 1 (inter-pinnacle)	Area 3	Area 1 (pinnacle structure)	Area 1 (inter-pinnacle)	Area 3	#, (%)
A-2 Shale	3	0	87	2	0	0	50	0	0	142, (15.1)
A-2 Salt	1	0	0	0	0	0	16	0	0	17, (1.8)
A-2 Anhydrite	2	0	7	3	1	88	39	1	5	146, (15.5)
A-1 Carbonate	15	0	10	33	0	68	7	2	11	146, (15.5)
A-1 Evaporite	0	0	3	0	0	13	12	0	0	28, (3.0)
A-0 Carbonate	10	3	0	0	0	0	0	0	0	13, (1.4)
Guelph	1	0	3	37	0	83	17	2	6	149, (15.8)
Eramosa	0	0	0	0	0	4	0	0	0	4, (0.4)
Goat Island	4	0	42	21	0	24	8	2	1	102, (10.8)
Gasport	10	0	29	11	0	28	12	2	2	94, (10.0)
Lions Head	1	0	0	0	0	0	0	0	0	1, (0.1)
DeCew	0	0	15	0	0	5	0	0	0	20, (2.1)
Rochester	1	0	2	3	0	18	20	0	36	80, (8.5)
Total #,(%)	48, (5.1)	3, (0.3)	198, (21.0)	110, (11.7)	1, (0.1)	331, (35.1)	181, (19.2)	9, (1)	61, (6.5)	

Challenges for the geology QA/QC procedures are listed below.

1) **Nomenclature change.**
   Many wells in OPDS only have recorded formation picks for the Guelph Formation as industry drillers did not make picks for the Goat Island and Gasport formations.
2) **Lithological similarity of adjacent formations.**
   a. The top picks of Guelph Formation recorded in OPDS are usually placed too high in western Lake Erie because of the similar lithology present in the overlying lower A-1 Carbonate Formation;
   b. Reef mound facies of the Goat Island Formation may have been mistakenly included in the Guelph Formation;
   c. Niagara Falls Member of the Goat Island Formation may have been mistakenly identified as crinoidal grainstone facies of the Gasport Formation;
   d. Eramosa Formation may have been included with the basal Guelph Formation because of its various carbonate lithofacies;
   e. Lateral variations in carbonate lithofacies in the Goat Island and Gasport formations;
   f. Similarities in lithology and geophysical expression of Guelph, Goat Island and Gasport formations and overlying A-1 Carbonate Formation within pinnacles and carbonate mounds. New observations on the lithofacies changes along the outcrop-subcrop belt has established criteria to better distinguish and identify these formations.
3) **Unit Thickness.**
   The underlying DeCew Formation - where it is present in Area 3 - has not been systematically picked because it is usually less than 1m thick and a reliable criterion for identification in drill cuttings has proven difficult, due to mixing of overlying Gasport Formation lithofacies.

Updates to the geology QA/QC results are summarized in Table 4.2. Picks are added where no picks were recorded in OPDS. Picks are revised when the formation top picks are placed incorrectly based on the newly updated criteria (*see* Appendix D). Picks identified as confirmed indicate the recorded picks are reliable thus no change has been made.

Results of the newly picked formation tops have been used to create and update isopach maps of each formation within the Lockport Group (*see* Appendix I, J, K, and L).

5. Regional Porosity and Permeability Variations

On the basis of previous mapping of facies belts, the study area is divided into three geographic sectors which delineate the different carbonate depositional regimes and changes of thickness of the Lockport Group (Figure 2.4). Area 1 covers most of Lambton County and the northwestern portion of the following counties: Kent, Middlesex, Huron and Bruce. Area 2 is situated in the western regions of the Lockport outcrop-subcrop belt and covers parts of Middlesex, Waterloo, Perth, Wellington, Grey and northern Bruce counties. Area 3 includes all of Lake Erie and neighbouring counties, north into Dufferin, Wellington, Oxford, and Brant. Area 3 has a NW to SE transition from an interior ramp of restricted lagoonal dolostones in the NW, and more open marine mid-ramp dolostones within localized reef mound phase to the SE (seaward region)s.

In Area 1, 13 of the wells are from the inter-pinnacle karstic areas and 44 from the pinnacle structures (Table 5.1). In Area 3, 16 wells are from the restricted platform interior (NW Area 3) and 77 from the platform edge (SE Area 3). Data are grouped by formation and each formation is treated as a single lithological unit that is not subdivided into members or lithofacies. For Area 1 the data within respective formations are assigned to one of two architectural relationships, pinnacles and inter-pinnacles.

Table 5.1 Number of wells, conventional core analysis by facies belt area

	Area 1: Inter-Pinnacle	Area 1: Pinnacle Structure	NW Area 3 (Carbonate Ramp)	SE Area 3 (Reef mounds)	Total # samples
Number of wells	13	44	16	77	
A-1 Carbonate	217	939	49	956	2161
A-1 Evaporite	16	0	0	0	16
A-0 Carbonate	32	0	0	0	32
Guelph	98	3096	441	4441	8076
Goat Is	26	351	173	321	871
Gasport	127	418	31	27	603
Total #, (%)	516, (4.4)	4804, (40.9)	694, (5.9)	5745, (48.9)	11759

The stratigraphic distribution of porosity and permeability data in each well have been divided into statistical populations for each formation. Porosity is a scalar property of a porous medium that may be described by a normal probability density function (Dagan 1989) (*see examples in* Appendix H). Thus, the porosity value (Φ) at formation level is calculated as the arithmetic average of the measured values for that formation multiplied by the thickness of sampled interval. In cases of sampled interval thickness not being provided, a thickness of one foot being assigned by default.

Permeability of sedimentary rocks is best characterized by a lognormal frequency distribution (Baker et al. 2015). When applying the lognormal distribution for permeability, the best estimate of the representative value of horizontal permeability (Kmax) at the formation scale is the geometric average and similarly for the vertical permeability (Kv) (*see examples in* Appendix H). It is important to note that the vertical permeability is generally lower than the horizontal permeability, sometimes by up to several orders of magnitude.

To characterize porous and permeable horizons at the regional scale, a scaling-up process has been used. The measurements of porosity and permeability were scaled up first on the formation level, and then the well-scale values were scaled up to the regional scale in each areal subdivision.

As noted by Bachu and Undershultz (1992) any scaling-up process inherently involves loss of detailed information from the lower scale, retaining only the main characteristics at the larger scale. The variability produced by factors having a smaller characteristic length is lost as information is passed up to larger scales. Given the loss of details through the scaling-up process, regional relations and trends detected in scaled-up data should not be used to make predictions of property values at smaller scales. After the scaling-up process, the 3-D distribution of porosity and permeability data was transformed into a series of 2-D distributions by formation-scale permeability and porosity values for geographic distribution pattern recognition or correlation with 3D structures (*see* Appendix I, J, K and L).

Using linear regression analysis, sets of correlated values, the correlation between log(Km) and Φ was consistently the highest, although the R^2 of this correlation varied between 0.0005 to 0.96. Porosity-permeability values scaled up for four individual formations resulted in 244 values each, unevenly distributed both areally and with depth. The results of the analysis of regional scale variability are presented by individual formation in Appendix I to L. The variation in porosity for each formation is high, ranging from 0.1% to 44% (*see* Table I.1, J.1, K.1 and L.1). It presents the statistical characteristics of the maximum porosity (Φ _Max), minimum porosity (Φ _Min), arithmetic average porosity (Φ) for each formation and the standard variance (Φ_Var).

The maximum horizontal permeability variation (Kmax = 0.01 mD to 10240 mD) spans several orders of magnitude. This high variability is indicated by high variances of the ln (Kmax) distribution. In Appendix I to L, also presented are the statistical characterization of maximum horizontal permeability (Kmax_Max), minimum horizontal permeability (Kmax_Min) and average horizontal permeability (Kmax_Ave). For better regional correlation, logarithmic average horizontal permeability (ln (Kmax_Ave)) and logarithmic standard deviation of horizontal permeability (ln(Kmax)Var) are also given. Information for the vertical permeability (Kv) is presented similar to the information format of the maximum horizontal permeability. For the same unit, there are fewer data for Kv than for Kmax. The lowest permeability value is 0.01 mD, which indicates the measurement limit. The minimum value is most likely lower.

In several cases, a high correlation coefficient (R^2) suggests a linear relationship between Kv and Kmax (Appendix I to L), indicating a consistent anisotropy for the respective units. In many cases, however, no such relationship exists, indicating a random variability in the anisotropy ratio. The high R^2 should be interpreted with care because it is possible that the high R^2 is produced by a few points outside a cluster. The controlling factors for such relationships will be explored in the second phase of this research.

Appendix I to L also present the coefficients of the relation,

$$\log(\mathrm{Kmax}) = a\,\Phi + b$$

In Area 1 most wells have higher R^2 and in Area 3 the correlation of log(Kmax) and Φ is lower. When linked to the lithology and diagenesis, it is obvious that the higher permeability and porosity are better correlated than those units with low porosity-permeability values.

5.1 Porosity and Permeability Variations across Major Oil and Gas Fields

Most of the data are from oil and gas fields in Lambton, Kent and Elgin counties and western and west-central Lake Erie. A wide range of small fields and exploration sites in other counties only have scattered data or are not represented in the data (e.g., Huron, Bruce, Middlesex and Oxford counties). The major oil and gas pools are presented in Appendix A. Isopach maps for A-1 Carbonate, Guelph, Goat Island and Gasport formations are created using formation thicknesses recorded in OPDS (Appendix I to L; Figure 5.1 is illustrative of these plots).

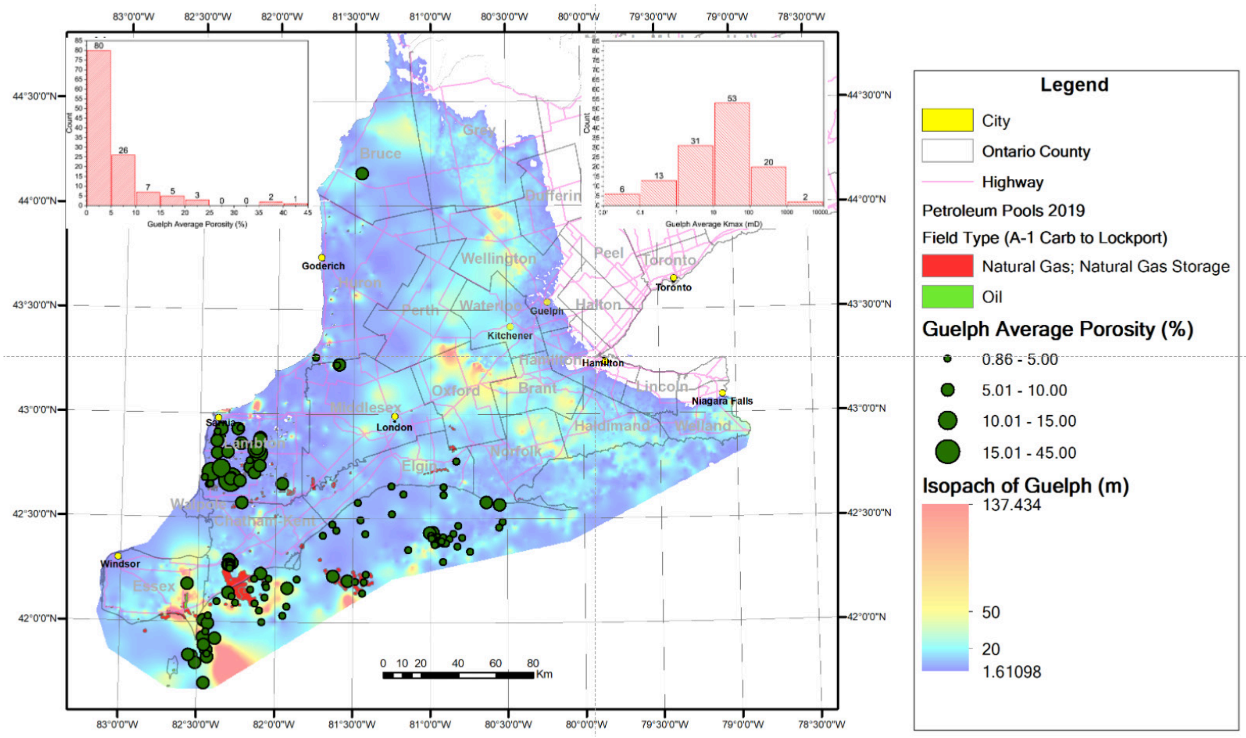


Figure 5.1 Isopach map of Guelph Fm and the average porosity (%) of key wells with core analysis data, southern Ontario. Histograms of the distribution of the average porosity (left) and permeability (right) ranges of Guelph Fm, southern Ontario.

The average porosity of wells within oil and gas fields in pinnacle structures and in SE Area 3 is consistently high. Within pinnacle structures in Lambton County, the average porosity of A-1 Carbonate ranges from 1.109% to 15.613%, and that of Guelph ranges from 4.242% to 15.429%. In inter-pinnacle karst areas, the average porosity of A-1 Carbonate ranges from 2.133% to 4.197%, and that of Guelph ranges from 6.324% to 6.886%. In oil and gas fields in Kent County, the average porosity of A-1 Carbonate ranges from 2.471% to 6.92%, and that of Guelph ranges from 3.349% to 7.286%. In SE Area 3, within natural gas wells the average porosity of A-1 Carbonate ranges from 0.4% to 6.15%, and that of Guelph ranges from 0.9% to 5.501%. (*See* Appendix H for details).

Major A-1 Carbonate – Guelph oil and gas fields with higher average porosity are restricted within a limited depth range. In Lambton County the A-1 Carbonate to Lockport occurs at depths between 516.3m to 718.6m. In Kent County, they occur at depths of 311.6m to 547.8m.

Thickness of each formation is also positively related to the porosity variation. Higher porosity is in general associated with greater thickness of the oil and gas reservoir in lower A-1 Carbonate and the Guelph Formation. Positive thickness-porosity correlation is also consistent with the fact that the Tec. Dow 7 well in the Moore 3-21-XII Pool has the greatest thickness of A-1 Carbonate and Guelph Formation and the highest average porosities. Exceptions occur in wells in western Lake Erie, where there is only poor correlation of thickness with average porosity regionally. This is probably caused by variations in depositional lithofacies formed in the open marine environment on an outer carbonate ramp, where the carbonate production rate was relatively lower and cementation is highly advanced compared to that in the inner to middle ramp.

The permeability distribution in A-1 Carbonate to Gasport formations also exhibits a division into areas of generally high and low values. The overall distribution of permeability as a function of porosity was examined by plotting log(Kmax_Ave) versus Por_Ave for all wells. Although these two parameters correlate well in a linear relationship, wells in different fields show distinct ranges and differing degrees of correlation of their average values indicated by R^2 (Appendix I to L). The similar overall trends of porosity-permeability correlation throughout the data are indicative of overall similarity in the pore systems between the different locations and depths included in this compilation. The similar overall trends of porosity and permeability throughout the study area is indicative of overall similarity in the pore systems between the different locations and depths.

5.2 Geographic Trends by Formation

To characterize the geographic trends for each formation, arithmetic means were computed, and porosity and permeability data were analyzed using percentiles and boxplots (Table 5.2 to 5.5; Figure 5.2A-H). Boxplots are derived from the 90th, 75th, 50th, 25th and 10th percentiles with median values and confidence bands displayed. Data outliers (<10th and >90th) are also illustrated as indicator of presence of extremely porous or dense intervals.

5.2.1 Gasport Formation

For the basal Gasport Formation dolostones, porosity and permeability from 603 samples are very variable. Most data are from wells in Lambton County and offshore wells in Elgin and Norfolk counties, and only portions of the Gasport have been sampled for conventional core analysis. Average arithmetic porosity on conventional core samples ranges from 0.76 to 9.4%, and average Kmax ranges from 0.121 to 150.58 mD (Figure 5.2A and 5.2B).

Within the pinnacle structures in Area 1, the 10-20m thick Gasport is dominated by crinoidal grainstone with deeply penetrated karstification surfaces. Relatively high average permeability value of 150.58 mD (hi-K) occurs in wells in Bickford Pool in Lambton County (Figure I.3). Within inter-pinnacle karst region in Area 1 core analysis data are available for only one petroleum well (T002477) and shows average porosity of 0.76% and low average Kmax of 0.206 mD.

In Area 3 data from two wells show average porosity of 2.46 to 5.39% and average Kmax of 0.665 to 0.729 mD (Figure I.2 and I.3; Table I.1). The Gasport Formation in these wells is comprised of crinoidal grainstone, with rare karstification or biohermal facies.

The relatively higher porosity and permeability values in Area 1 may be controlled by karstic intervals in the pinnacle structures in Area 1. Geographic trends for porosity and permeability of the Gasport Formation are not well established in Area 3, due to the limited amount of data. The relatively more fossiliferous crinoidal grainstone have been better bioturbated and cemented with rare paleokarstic features, possibly resulting in relatively low porosity and permeability.

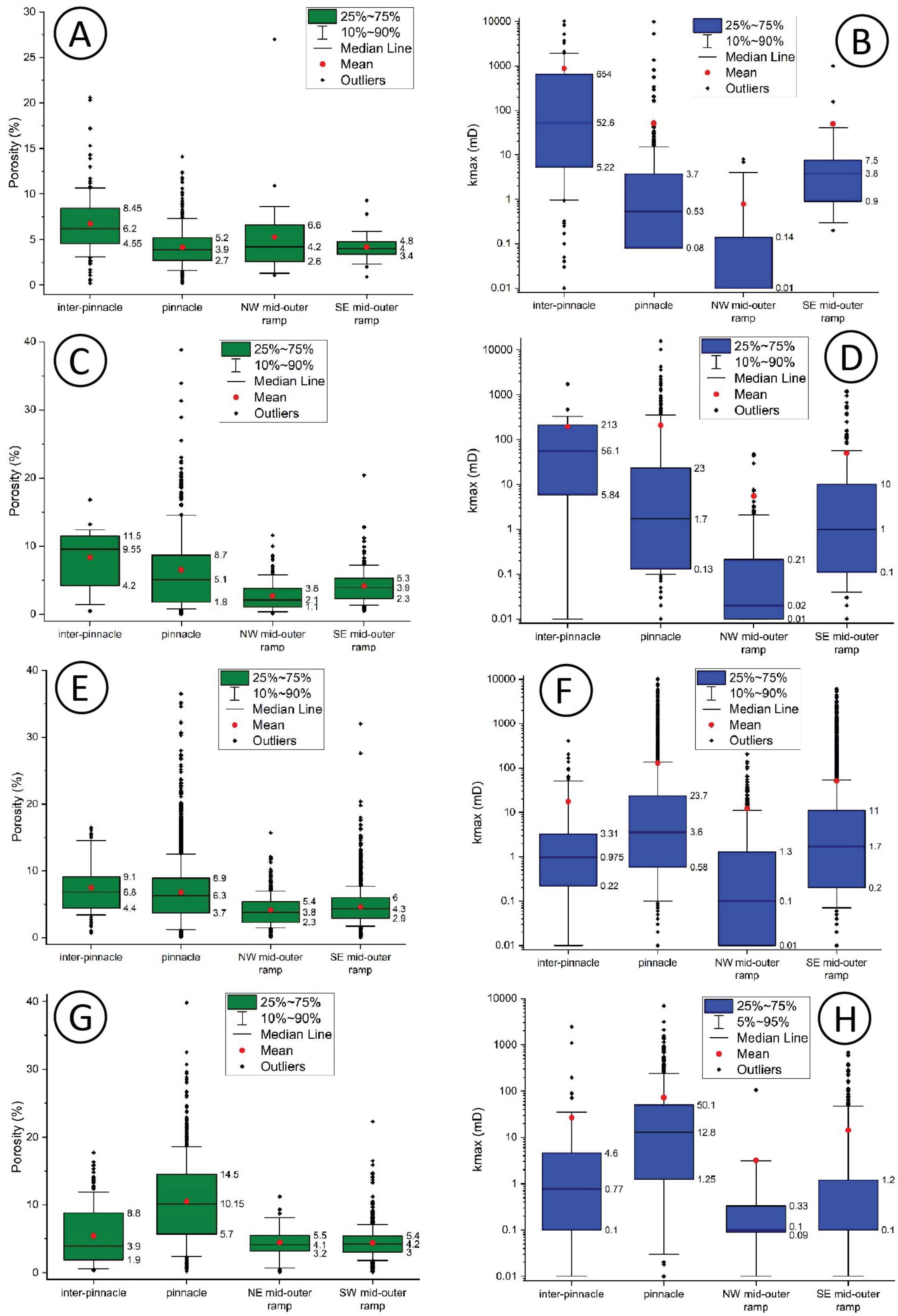


Figure 5.2 Box plots of porosity and permeability data by areas for: A&B) Gasport Fm; C&D) Goat Island Fm; E&F) Guelph Fm; and G&H) A-1 Carbonate. Number of samples per geographic region are in Table 5.2 to 5.5.

Table 5.2 Porosity and permeability percentile distribution for Gasport Formation in each subdivided area

Area	Parameter	No. of Cases	Mean	Min.	Percentile 10th	25th	50th	75th	90th	Max.
Inter-pinnacle	Φ (%)	120	6.74	0.20	3.18	4.58	6.20	8.43	10.61	20.60
	Kmax (mD)	119	881.35	0.01	1.00	5.60	52.60	652.00	1696.00	10240.00
	Kv (mD)	119	11.35	0.01	0.01	0.11	0.91	4.12	17.36	368.00
Pinnacle	Φ (%)	412	4.16	0.20	1.61	2.70	3.90	5.20	7.29	14.10
	Kmax (mD)	402	51.23	0.01	0.01	0.08	0.53	3.70	14.90	9850.00
	Kv (mD)	265	2.87	0.01	0.01	0.01	0.01	0.75	3.06	192.00
NW Area 3	Φ (%)	27	5.28	1.10	1.78	2.80	4.20	6.20	8.00	27.00
	Kmax (mD)	27	0.78	0.01	0.01	0.01	0.01	0.14	2.10	8.02
	Kv (mD)	3	0.34	0.14	0.15	0.17	0.19	0.44	0.59	0.69
SE Area 3	Φ (%)	26	4.19	0.90	2.55	3.40	4.00	4.75	5.90	9.30
	Kmax (mD)	26	49.75	0.20	0.45	0.93	3.80	7.05	30.40	1000.00
	Kv (mD)	26	5.85	0.10	0.10	0.13	0.30	2.80	20.80	51.80

5.2.2 Goat Island Formation

The porosity and permeability in the Goat Island Formation correlates with lithofacies variations and diagenetic extents. In major Salina-Lockport oil and gas fields in Lambton in Area 1 and Chatham-Kent counties in SE Area 3, the upper Goat Island forms the lowermost zone of the reservoirs in pinnacle structures, where high porosity and permeability values occur (see Figure J.2 and J.3). In inter-pinnacle region in Area 1 and western Lake Erie in Norfolk County in NW Area 3, the Goat Island forms a relative dense zone with lower porosity and permeability values (Figure 5.2C and 5.2D).

In Area 1, average porosity ranges from 0.93 to 8.46 % and average Kmax ranges from less than 0.01 to 1277.79 mD (Table J.1). Within pinnacle structures, two members of the Goat Island Formation are both present. Porosity is strictly dependent on lithofacies and diagenetic extents in this area. The greatest porosity and permeability occur near the upper contact with the overlying Guelph Formation as well as in the karstic zones in the Ancaster Member of the upper Goat Island, whereas lower porosity and permeability values occur in the bioturbated, finely crystalline grainstone of the lower Goat Island Formation and the crinoidal grainstone of the Niagara Falls Member. Intercrystalline and moldic porosity are the dominate pore types. The pore sizes and permeability are related to crystal size and dissolved fossil sizes, therefore are variable. Within the inter-pinnacle areas, only the Ancaster Member is preserved, with low average porosity and Kmax ranges from 0.5 to 4% and 0.01 to 5.98 mD (Figure 5.2C and 5.2D; Table 5.3 and J.1). Only two wells with core analysis data locate in the inter-pinnacle area. The dense carbonate corresponds to the regionally uniform, highly bioturbated and well cemented nature. Due to the limited data recovery, no regional geographic trends are established.

In Area 3, porosity and permeability of the Goat Island Formation is strongly facies related. In oil and gas pools in Elgin County in SE Area 3, average porosity ranges from 4.12 to 6.36%, whereas average Kmax ranges from 2.371 to 432.15 mD (Table 5.3 and J.1; Figure 5.2C and 5.2D). Higher porosity and permeability occur in the reef mounding facies near the top of Goat Island Formation. Intercrystalline and cavities among reef mound builders (stromatoporoids-rugose corals) are dominant pore types. The oil and gas reservoirs extend into the lower reef mound facies where porosity is higher. A general vertical decrease in porosity and permeability into the lower Goat Island Formation where lithofacies is dominated by coral-lenticular stromatoporoid wackestone to mudstone. In Chatham-Kent and Essex counties of NE Area 3, a general southwestward decrease of porosity and permeability is present following the deepening basinward trend as lithofacies changes from restricted lagoonal deposits of platform interior into the open marine carbonate bank deposits.

Tracing northward into the Elgin and Norfolk counties, the Goat Island Formation thins and becomes denser. Where no reef mounding facies occur, the average porosity ranges from 1.05 to 7.1%, whereas average Kmax ranges from 0.012 to 7.537 mD (Figure J.2 and J.3; Table 5.3 and J.1). This locally dense zone of the Goat Island Formation corresponds to the well-cemented and rare karstic nature of the carbonate.

Table 5.3 Porosity and permeability percentile distribution for Goat Island Formation in each subdivided area

					Percentile					
Area	Parameter	No. of Cases	Mean	Min.	10th	25th	50th	75th	90th	Max.
Inter-pinnacle	Φ (%)	22	8.32727	0.5	1.46	4.625	9.55	11.45	12.36	16.8
	Kmax (mD)	21	195.031	0.01	0.01	5.84	56.1	213	326	1740
	Kv (mD)	17	76.4059	0.03	1.498	5.08	33.3	69.9	147	578
Pinnacle	Φ (%)	346	6.54855	0	0.8	1.8	5.1	8.675	14.2	38.8
	Kmax (mD)	337	208.587	0.01	0.1	0.13	1.7	23	330.2	15700
	Kv (mD)	241	65.5892	0.01	0.01	0.01	0.39	4.2	140	2380
NW Area 3	Φ (%)	150	2.68067	0.1	0.4	1.1	2.1	3.8	5.64	11.6
	Kmax (mD)	149	5.51228	0.01	0.01	0.01	0.02	0.21	1.94	633
	Kv (mD)	104	0.44442	0.01	0.01	0.01	0.01	0.01	0.01	44.13
SE Area 3	Φ (%)	312	4.13269	0.5	1.3	2.3	3.9	5.3	7.17	20.4
	Kmax (mD)	309	50.2968	0.01	0.064	0.11	1	10.1	56.24	1209
	Kv (mD)	210	4.59395	0.01	0.01	0.01	0.1	1.3	15	69.2

5.2.3 Guelph Formation

The Guelph Formation is the principal host rock of oil and gas reservoirs in the Silurian carbonates of southern Ontario (Carter et al. 2016). It is also a regional sulphur water-brine aquifer in the intermediate to deep subsurface (Carter and Fortner 2012, Sharpe et al. 2014, Carter et al. 2021a). A total of 126 out of the 150 wells have conventional core analysis datasets that sample the complete or upper Guelph Formation. The heterogeneous porosity and permeability variations are dependant on variable lithofacies and diagenetic features. Regional karstification has shaped the irregular topography of the Guelph Formation and consequently influence the porosity zones. In general, the average porosity ranges from 0.9 to 15.43% and the average Kmax ranges from 0.01 to 1250.688 mD (Figure 5.2E and 5.2F; Table 5.4 and K.1). The highest values occur in the pinnacle structures in Lambton County of Area 1 within major oil and gas fields, and the lowest variations occur on the rarely karstic carbonate in central Lake Erie, Norfolk County of NW Area 3 (*see* Figure K.2 and K.3; Table K.1). The porosity and permeability variations are positively related to the formation thickness. In pinnacle structures where the Guelph Formation reaches 60 to 80 m thickness, the average porosity and permeability are generally high (values) and formed oil and gas reservoirs in the deep subsurface sealed by basal Salina Group, whereas in inter-pinnacle areas, the thin (<10m), highly karstic dolostones of the Guelph Formation have reduced porosity and permeability values relative to the pinnacles. On the mid-outer ramp depositional settings in Area 3, there is a general thinning of the Guelph Formation from northwest to southeast with a corresponding regional decrease of the average porosity and permeability values (Table 5.4; *see* Figure K.2 and K.3).

Within pinnacle structures in Area 1, average porosity ranges from 4.34 to 15.43% and average Kmax ranges from 0.827 to 1250.688 mD (Table 5.4 and K.1). They are largest in major oil and gas fields where the Guelph Formation is dominated by intercrystalline and moldic porosity types. In the upper Guelph Formation, moldic porosity of gastropods and the dissolution of anhydrite may have enhanced the overall porosity. In lower Guelph Formation, intercrystalline porosity in corals and shelly fossil fragments have been enhanced by the deeply penetrated karstification surfaces. Intervals with the highest porosity and permeability are usually 1 to 5.5 metres thick and cut across karstic surfaces, especially near the City of Sarnia. Within inter-pinnacle areas, only three wells have complete datasets from the Guelph Formation. The average porosity is uniformly near 6.5 %, ranging from 6.32 to 6.89%, and the average permeability is 2.198 to 2.569 mD (Table 5.4 and K.1). The low variation comes from the uniform highly karstic nature of the Guelph Formation in inter-pinnacle areas. At the Bruce nuclear site average porosity of the interpinnacle Guelph Formation is 13.1% (Intera 2011).

Table 5.4 Porosity and permeability percentile distribution for Guelph Formation in each subdivided area

					Percentile					
Area	Parameter	No. of Cases	Mean	Min.	10th	25th	50th	75th	90th	Max.
Inter-pinnacle	Φ (%)	94	7.49149	0.7	3.52	4.425	6.8	9.075	14.32	16.5
	Kmax (mD)	94	17.5117	0.01	0.01	0.22	0.975	3.308	49.63	412
	Kv (mD)	60	19.0188	0.01	0.01	0.01	0.665	2.833	53.31	365
Pinnacle	Φ (%)	2761	8.8019	0	1.2	3.7	6.3	8.9	12.5	2948
	Kmax (mD)	2735	133.989	0.01	0.1	0.586	3.6	23.78	136	10200
	Kv (mD)	2073	65.9928	0	0.01	0.07	0.4	4.4	30.562	11007
NW Area 3	Φ (%)	237	4.14407	0.1	1.5	2.3	3.8	5.4	7	15.7
	Kmax (mD)	234	12.2781	0.01	0.01	0.01	0.1	1.255	11	1911
	Kv (mD)	124	0.75774	0.01	0.01	0.01	0.01	0.1	0.296	122
SE Area 3	Φ (%)	4046	4.58947	0.01	1.7	2.9	4.3	6	7.68	32
	Kmax (mD)	3985	50.9952	0.01	0.07	0.2	1.7	11	53.52	6000
	Kv (mD)	2746	10.2348	0.01	0.01	0.01	0.1	0.6	3.32	4030

In Area 3 where karstic features are rare, there is a general decrease of porosity and permeability from northwest to southeast basinward to the mid-outer ramp. The porosity and permeability are controlled by both lithofacies and diagenetic alteration. In major oil and gas fields in Chatham-Kent County of SE Area 3, the average porosity ranges from 2.34 to 7.29%, and the average Kmax ranges from 0.205 to 410.97 mD (Table 5.4; Figure 5.2E and 5.2F). Overlying the reef mound facies of the Goat Island Formation and the Guelph Formation is dominated by intercrystalline and moldic porosity of skeletal grains. Dissolution of anhydrite occurs locally and appears to have enhanced the overall porosity. Higher permeability occurs for given porosity values locally that surrounds the major oil and gas fields (Figure K.2 and K.3; Table K.1). To the southeast, the Guelph Formation shows a subtle thinning to less than 20 m. In this area of Elgin and Norfolk counties of NW Area 3, the porosity and permeability are relatively low due to a lack of karstic features and presence of finely crystalline carbonate. The average porosity ranges from 1.46 to 5.5 %, and the average Kmax ranges from 0.017 to 81.885 mD (Table 5.4 and K.1).

In general, the regional porosity and permeability variations are mainly controlled by diagenetic features in Area 1 and both lithofacies distributions and early diagenesis in Area 3. The variations are positively related to formation thickness that both follow a decreasing pattern from inner to mid-outer ramp basinward into the southwest. Regional karstification plays an important role in Area 1, where the karstified pinnacle structures show significant porous and permeable zones in the Guelph Formation corresponding to karstic zones, and the interpinnacle Guelph is a porous regional karst rubble or caliche.

5.2.4 A-1 Carbonate

The porosity and permeability variations of the A-1 Carbonate are heterogeneous and are closely related to formation thickness. The overall average porosity ranges from 1.09 to 18.08 %, and the average Kmax ranges from less than 0.1 to 1520.31 mD (Figure 5.2G and 5.2H; Table 5.5 and L.1).

The A-1 Carbonate on top of thick Guelph Formation within pinnacles is generally much thinner than that overlying the regional inter-pinnacle karst. Intense karstification occurs within the A-1 Carbonate overlying pinnacle structures in Area 1, which gives the A-1 Carbonate a generally higher porosity and permeability which commonly forms the upper part of the oil and gas reservoirs in pinnacles. In the pinnacle structure area of Area 1, the average porosity is 1.11 to 18.08 % and the average Kmax ranges from 0.454 to 1250.688 mD (Figure 5.2G and 5.2H; Table 5.5 and L.1). The zones of highest porosity and permeability occur in major oil and gas fields, particularly in pinnacles, where the A-1 Carbonate is entirely dominated by moldic porosity of skeletal grains and anhydrite.

Table 5.5 Porosity and permeability percentile distribution for A-1 Carbonate in each subdivided area

Area	Parameter	No. of Cases	Mean	Min.	Percentile					Max.
					10th	25th	50th	75th	90th	
Inter-pinnacle	Φ (%)	179	5.4419	0.3	0.6	1.95	3.9	8.7	11.74	17.7
	Kmax (mD)	178	26.8624	0.01	0.02	0.1	0.77	4.555	24.25	2430
	Kv (mD)	92	5.5788	0.01	0.01	0.01	0.06	1.51	14.27	139
Pinnacle	Φ (%)	856	10.5302	0.2	2.45	5.7	10.15	14.5	18.6	39.8
	Kmax (mD)	858	73.25	0.01	0.1	1.253	12.8	50.08	140.9	6890
	Kv (mD)	646	33.9492	0.006	0.01	0.04	0.715	11.4	40.4	6120
NW Area 3	Φ (%)	37	4.46757	0.1	0.76	3.2	4.1	5.5	8.1	11.2
	Kmax (mD)	36	3.21361	0.01	0.05	0.09	0.1	0.325	0.565	106
	Kv (mD)	14	0.11429	0.01	0.01	0.01	0.01	0.01	0.163	1.2
SE Area 3	Φ (%)	832	4.39772	0.1	1.8	3	4.2	5.425	7.09	22.3
	Kmax (mD)	956	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Kv (mD)	665	26.2512	0.01	0.01	0.01	0.1	0.1	1.66	5607

Within the inter-pinnacle areas, the A-1 Carbonate and the Guelph Formation are separated by the A-1 Evaporite and A-0 Carbonate. The A-0 Carbonate is generally 2 to 5 m thick, crinkly laminated dolostone or limestone. The A-1 Evaporite is dominated by nodular anhydrite that is dense and impermeable. These two units form an impermeable zone that separate the A-1 Carbonate from the Guelph Formation in terms of fluid conductivity. The A-1 Carbonate in inter-pinnacle area is 35 to 45 m thick and dominated by lime/dolomudstone and microbialites. The average porosity ranges from 2.13 to 4.19 % and average Kmax ranges from 0.918 to 1.938 mD (Figure 5.2G and 5.2H; Table 5.5 and L.1). Exceptions occur at the Bruce site where a karstic zone with irregular vugs occurs below the upper contact with the A-2 Anhydrite, which gives the uppermost 3 to 4 metres of the A-1 Carbonate a high porosity and permeability. Saline water with interpreted cold-climate stable isotope signatures was recovered from this interval (Intera 2011). Petroleum well data indicates the continuity of this subregional paleokarst aquifer 25 km to the northeast to the subcrop belt (Carter et al 2021a).

In Area 3, the average porosity ranges from 0.4 to 6.74 % and the average Kmax ranges from less than 0.1 to 51.792 mD. The regional variation pattern is similar to the Guelph Formation – representing a general thinning from northwest to southeast into the relatively deeper water of the mid-outer ramp possessing rare karstic features and less anhydrite and lower porosities and permeabilities (Figure 5.2G and 5.2H; L.2 and L.3).

5.3 Discussion

A general constraint of this study is the vertical and lateral distribution of the dataset when considering regionals porosity and permeability measurements in the Lockport Group. The porosity and permeability data from core data are concentrated in petroleum pools and are not evenly distributed throughout the various formations of the Lockport Group. Therefore the data are most appropriate for characterization of a limited range of geographic and stratigraphic settings of the Lockport Group for southern Ontario.

In general, porosity and permeability for all formations are relatively higher within the pinnacle structures and SE Area 3 in oil and gas pools than in inter-pinnacle paleokarst region and NW Area 3. Within inter-pinnacle structures, higher porosity and permeability correlated with the highly karstic nature of Guelph Formation. In Area 1, the porosity and permeability in the A-1 Carbonate and Guelph formations have low variability in the inter-pinnacle karst areas compared to pinnacle structures. In inter-pinnacle karst areas, the average porosity of the Guelph Formation is consistently 5% - 6.8%. In each pinnacle structure, porosity and permeability are greatest in the northwest part of Lambton County of Area 1. They gradually decrease southwestwards and are distinctly less northwestwards. The permeability distribution in the four formations exhibits a division into areas of generally high and low values. These areas are easily identified as pinnacle structures in Area 1 by the Kv and Kmax values. The relative position of the areas of high and low permeability varies throughout the four successions. Within the pinnacle structures, lower A-1 Carbonate and Guelph formations have pockets of high permeability, while the Goat Island and Gasport show a variable distribution of highly permeable intervals. In the regional inter-pinnacle karst areas, the relative permeability of A-1 Carbonate through to Gasport is low.

In Area 3, the Guelph Formation exhibited a general trend of increasing porosity from northwest towards the southeast accordingly that corresponds to lithofacies change from restricted lagoonal deposits into relatively open marine depositional environment. Near Elgin County and the adjacent portions of Lake Erie of SW Area 3, the A-1 Carbonate, Guelph Formation and the reef mounding facies in the upper Goat Island Formation show relatively high permeability and locally host natural gas pools, while the Gasport is relatively impermeable. Northeastwards, the four formations show relatively lower porosity-permeability values.

Isopach maps show a general correlation of elevated porosity with greater thicknesses of the oil and gas reservoir within pinnacles and reef mound phases of Lockport Group and lower Salina Group A-1 Carbonate (*see* Appendix I, J, K, L).

A number of factors should be considered to account for the wide range of average formation porosity. The average porosity and permeability of the A-1 Carbonate and Guelph Formation are positively associated. Porous A-1 Carbonate commonly occurs overlying the highly karstic and porous Guelph Formation, as observed in wells within major oil and gas fields (e.g., T007457 and T007460 in Enniskillen Pool). The crests of large fields are sites of positive anomalies. The flank areas of hydrocarbon fields, however, are not always associated with lower porosity distributions. It is likely that the porosity variation is controlled by not only the depositional thickness, but also the diagenetic karstification that enhanced the matrix porosity in flank areas. In Area 3, the general thinning of the Guelph Formation northeastwards corresponds to a general reduction of porosity. In this area karstification features are rare and the porosity and permeability are largely facies controlled. The open-marine, wackestone-packstone facies to the northeast usually featured dense matrix and undissolved skeletal grains, whereas the gastropod-dominated, restricted marine facies to the southwest contain more argillaceous materials and skeletal grains are partly dissolved.

6. Summary and Conclusions

To advance understanding of the porosity and permeability variability in the Silurian Lockport Group and overlying Salina A-1 Carbonate Unit, both stratigraphically and geographically, a study utilizing the petroleum industry core analysis database of the Oil, Gas and Salt Resources Library has been completed. This study is based on 11,759 sets of porosity and vertical/horizontal permeability analyses from 150 cored wells in the deeper subsurface of the Early Silurian Lockport Group, southwestern Ontario. It provides the first comprehensive analysis of this legacy data.

Study methods involved placing the core analysis data and lithofacies characteristics within a stratigraphic framework. Prior to the data analysis, both the geological formation tops and the conventional core analysis data have been verified. Quality assurance (QA) review of the formation top picks in the Lockport Group has been conducted using geophysical well logs, drill cuttings and core logging. A total of 846 formation tops have been re-picked/confirmed and updated in the Ontario Petroleum Data System (OPDS). Each formation top depth pick in OPDS has a QA code assigned to it, which represents the level of certainty of the pick.

Conventional full diameter core analyses or core plugs from 150 wells were completed between 1956 to 1999 at 10 different laboratories. Data validation of the parameters of effective porosity, grain/bulk density and permeability (horizontal and vertical) were completed to improve data quality by applying knowledge from laboratories reports and auxiliary data (geophysical well logs and duplicate cores. The validated core analyses are displayed with each porosity/permeability parameter plotted vertically within stratigraphic logs for defining permeable and impermeable zones.

The study area is divided into three geographic sectors within an easterly-dipping carbonate ramp, based on distinctive facies motifs corresponding to different carbonate depositional regimes and degrees of karstification of the Lockport Group, as influenced by paleogeographic setting. Area 1 includes the regional inter-pinnacle karst and the pinnacle structures within the A-1 Carbonate and Lockport Group. Area 2 comprises an inner-middle carbonate ramp, where pinnacle structures are rarely developed. No core analysis data are available for this area as it does not have any discovered hydrocarbon resources. Area 3 comprises the southeastern part of the study area with available drill core located largely in Kent and Elgin counties and central and western Lake Erie. This area corresponds to the middle-outer portion of the regional Lockport carbonate ramp.

Stratigraphic logs in major individual oil and gas fields have been constructed for correlation of porosity and permeability values within specific intervals (e.g., similar lithofacies). These intervals have been contoured to create isopach maps of each formation to show lateral thickness changes and pinch outs. Datasets from the 150 cored wells with average porosity and average permeability in each formation have been compiled according to depth, thickness and well locations to create a 2D surface for permeable and impermeable zones. Petrology data are not included in this study, but regional lithofacies from earlier studies have been summarized in representative fields to provide a basis for interpretation for regional correlation.

The main geographic trend corresponds with the lithofacies variations and temporal/spatial history of karstification. Higher porosity and permeability are in general associated with greater thicknesses of the oil and gas reservoir in lower A-1 Carbonate and the Lockport Group. Several highly permeable intervals occur in the pinnacle structures in Area 1 and reef mound facies in Area 3. Within the inter-pinnacle karst region of Area 1 and western Lake Erie, porosity in both the A-1 Carbonate and Lockport Group show relatively reduced values towards the northeast, where no major oil and gas fields have been discovered.

It should be emphasised that most of the available core analysis data, except for the interpinnacle karst, is from petroleum wells within oil and gas reservoirs in pinnacles and reef mounds and consequently constitutes a biased sample. There is also no comparable data from Area 2 of this study or from the outcropping equivalents of these formations in Area 3.

In general, porosity and permeability in the studied formations are largely controlled by variations in carbonate lithofacies, diagenetic destruction and enhancement, and existence of paleokarst. Key findings include the following:

1. The inter-pinnacle facies within the Guelph Formation is widely distributed and regionally continuous with relatively high porosity (0.5% - 16.8 %, average of 7.49%) and widely varying horizontal permeability (0.01 mD – 412 mD, average of 17.51 mD) due to its paleokarstic nature.

2. Within pinnacle structures in the, the high porosity and permeability of the A-1 Carbonate, the Guelph Formation and the upper Goat Island Formation have formed either oil and natural gas reservoirs or saline water-bearing zones. There has been significant erosion and karstification of the A-1 Carbonate Unit and Lockport Group within and at the tops of the pinnacles. Porosity types include intercrystalline and moldic to irregular vugs and cavities that have been enhanced by paleokarstic events.

3. In western and central Lake Erie, both the karstic top of the Guelph Formation and the overlying A-1 Carbonate are variably porous and permeable. Reef mounds in the Guelph or Goat Island formations contribute to the relatively higher intercrystalline porosity and form major gas pools in Kent County and beneath Lake Erie. A general geographic trend of porosity-permeability values increasing southeasterly has been discovered that correspond with the lithofacies change from carbonate platform interior into the open marine carbonate bank in Area 3.

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Appendices

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