SUBSURFACE AQUIFER STUDY TO SUPPORT UNCONVENTIONAL GAS AND OIL DEVELOPMENT, LIARD BASIN, NORTHEASTERN B.C.

Prepared for

Geoscience BC

August, 2013

Petrel Robertson

Petrel Robertson Consulting Ltd.

CERTIFICATE OF QUALIFICATION

BRAD J.R. HAYES, Ph.D., P.Geo.

I, Brad J.R. Hayes, Professional Geologist at Petrel Robertson Consulting Ltd., Suite 500, 736 – Eighth Avenue SW, Calgary, Alberta, Canada and author of a report dated May, 2013, do hereby certify that:

I am a professional geologist employed by Petrel Robertson Consulting Ltd., which Company did undertake a study entitled Subsurface Aquifer Study to Support Unconventional Gas and Oil Development, Liard Basin, Northeastern B.C. for Geoscience BC.

- I attended the University of Toronto, and that I graduated with a Bachelor of Science (Honours) Degree, Geology Specialist Program (1978), and obtained a Doctor of Philosophy Geology (1982) from the University of Alberta (Edmonton, Alberta); that I am a member of APEGA; that I have in excess of 29 years experience including geological studies relating to both Canadian and international oil and gas properties.
- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, any associate or affiliate of Geoscience BC.
- The evaluation was prepared based on information available in the public domain and/or from Geoscience BC.

PROFESSIONAL GEOSCIENTIST
PROVINCE OF BRITISH COLUMBIA
Dr. B. J. R. HAYES
#30134
SEPT 13 2013

Brad J.R. Hayes, Ph.D., P.Geo. (B.C.)

TABLE OF CONTENTS

Appendices

LIST OF FIGURES

Regional Stratigraphic Cross-Sections

INTRODUCTION

Liard Basin in northeastern British Columbia is highly prospective for unconventional gas and oil development (Fig. 1). Stacked, regionally extensive reservoirs have great potential for long-term development, which will eventually encompass large, continuous areas. Validation of this potential occurred in 2012, when both Apache Corporation and Paramount Resources Ltd. announced major shale discoveries (Adams, 2013; Macedo, 2012).

Some of the most prospective unconventional reservoirs include:

- Chinchaga / Dunedin / Nahanni (tight carbonates);
- Muskwa / Horn River (shales);
- Exshaw (shales);
- Mattson (tight sands and shales);
- Toad/Grayling (tight sands and silts);
- Chinkeh (tight sandstones);
- Fort St. John (shales).

Industry has had great success in developing unconventional reservoirs elsewhere in northeastern B.C. using horizontal wells stimulated by multiple hydraulic frac jobs. Each frac requires large amounts of water, depending upon the particular frac design. Stimulated reservoirs eventually flow back much of the frac fluid, contaminated by various chemicals used in the frac process and by naturally-occurring materials from the reservoir. Companies developing unconventional hydrocarbon resources thus require water sources capable of delivering large water volumes at high rates, and water disposal zones capable of accepting comparable volumes and rates.

Although surface water or shallow aquifers may be suitable locally for source water, deeper aquifers with brackish or saline waters offer options to avoid conflicts with other water consumers and possible negative environmental impacts. In addition, only deep subsurface aquifers are suitable for water disposal, to avoid contamination of potable water supplies at surface or in shallow aquifers.

Petrel Robertson Consulting Ltd. (PRCL) has undertaken a comprehensive study of deep subsurface aquifers in Liard Basin for Geoscience BC, in support of systematic sourcing and disposal of frac waters for unconventional hydrocarbon development. PRCL has extensive experience in such stratigraphic / hydrogeological projects, having completed similar aquifer studies, jointly with Canadian Discovery Ltd., in the Horn River Basin and Montney play areas.

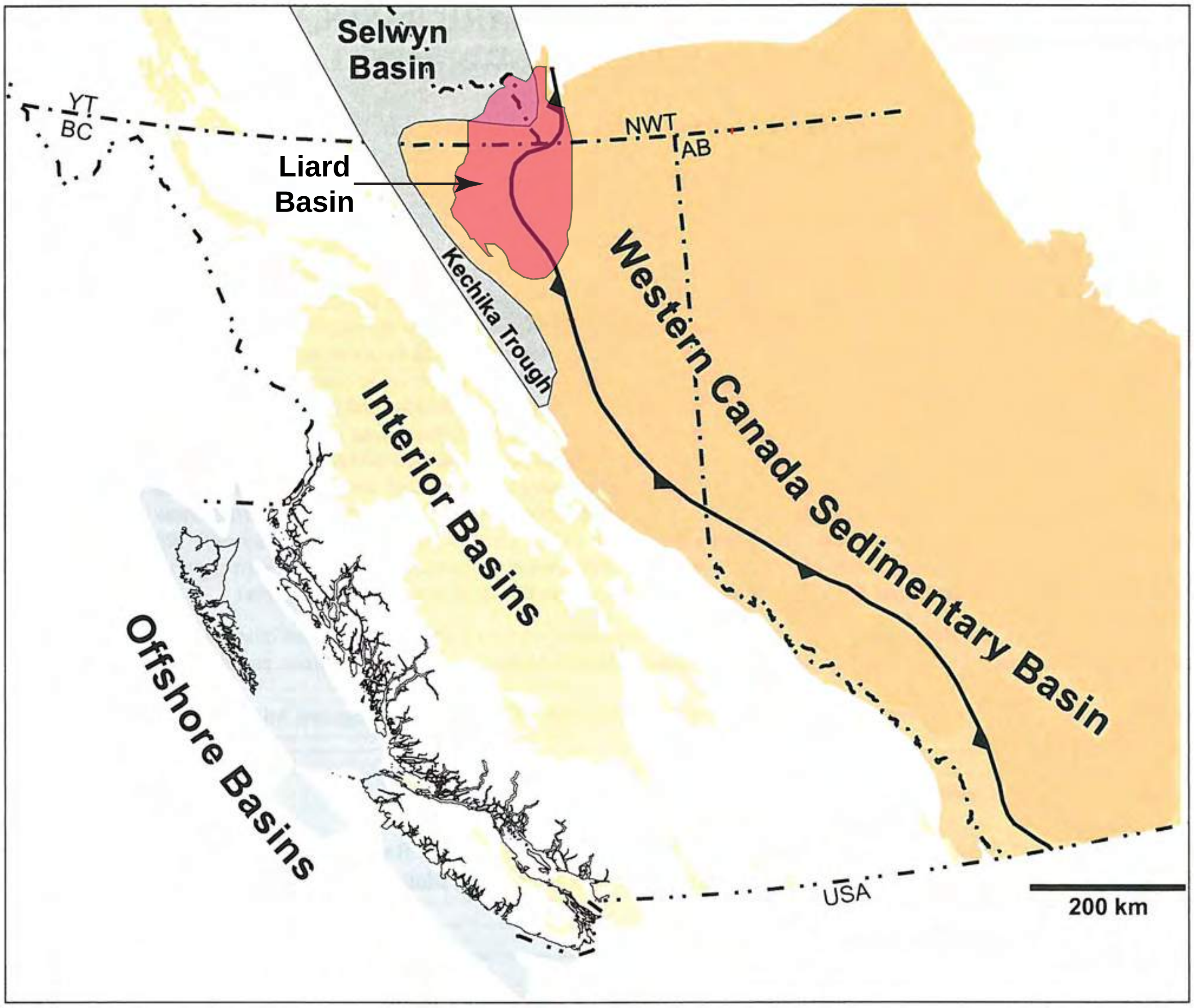


Figure 1. Location Map, Liard Basin (from Ferri et al., 2011).

STUDY METHODOLOGY

In order to map and characterize each prospective aquifer unit, the following tasks have been completed:

1. **Stratigraphy / Reservoir Characterization**

   - Collected relevant well data across aquifer intervals, from public and proprietary sources.
     - As well data are scarce in Liard Basin, particularly in pre-Cretaceous units, we have used all available well data.
     - Project participants have been asked to contribute information from new wells, still on confidential status.
   - Well control has been supplemented where possible with regional geological mapping straddling the basin, and with information from outcrop. Useful work has been published on Cretaceous sandstones in outcrop within the Liard Basin, and on the Mattson Formation in outcrop to the northwest in Yukon. Regional Debolt mapping from Geoscience BC's Horn River Basin study has also been employed.
   - Characterized reservoir quality and distribution for each regional aquifer.
     - Established consistent regional correlations by constructing a grid of regional stratigraphic cross-sections. Stratigraphic tops for all wells have been tabulated in Appendix 1.
     - Reviewed relevant literature and other available reports for regional context and existing characterizations.
       - Built upon this knowledge using well log, core, and sample cuttings data to create a stratigraphic database summarizing reservoir intervals and parameters.
       - Integrated lithological information – existing core and sample cuttings descriptions from PRCL's databases and public sources have been used. In addition, selected sample cuttings have been logged by petrographer John Clow.
     - Produced maps of each aquifer unit to illustrate reservoir characteristics. Total isopach and net porous reservoir isopach maps were prepared where sufficient information exists.
     - More advanced mapping, such as average porosity, porosity-thickness, and fluid volumetrics was considered. However, we judged

that given the small quantities and widespread distribution of high-quality data, it was not possible to produce meaningful maps of these types.

2. Hydrogeological Characterization

- Collected all pressure and fluid chemistry data from public sources. We used no proprietary test data for this study.
  - The total test database comprised 256 tests from 157 well entities.

- Integrated hydrogeologic data with stratigraphic mapping.
  - Correlated test data to aquifer units, and ensured each test was assigned to the correct unit.

- Characterized reservoir quality and hydrogeology for each regional aquifer, as permitted by data quality and distribution.
  - DST's with Hydro-Fax quality codes A to G (G's are commonly misruns) were reviewed, but only DSTs with a quality code of A through D had useable pressures and could be plotted on a Pressure-Elevation plot.
  - Based on subjective qualitative permeability, permeability ranges were estimated as follows:
    - Excellent: >50 mD;
    - High: 20 - 50 mD;
    - Relatively High: 10 - 20 mD;
    - Average: 2 - 10 mD;
    - Relatively Low: 0.1 - 2 mD;
    - Low: 0.01 - 0.01 mD;
    - Virtually None/Very Low: <0.01 mD;
  - Converted corrected formation pressures into hydraulic head (potentiometric surface values), and interpreted head distribution and groundwater flow regime for each regional aquifer.
    - If more than one valid potentiometric surface value for any formation can be calculated in a single wellbore, a number of criteria were used to select the value which was used in mapping:

- Highest quality code test;
- Test with largest water recovery and/or smallest hydrocarbon recovery;
- Highest value (m).

- Three PE plots were constructed: a plot with test data from the relatively shallow Dunvegan, Scatter and Chinkeh formations; a plot using Fantasque, Mattson and Rundle formation data; and a plot of the deep Chinchaga Formation DSTs.
  - Hydrocarbon columns have not been represented on the PE Plots to enhance clarity, consistent with our methodology in the Geoscience BC Horn River Basin study (PRCL, 2010). Discussion will be included as to the style of hydrocarbon trapping in each formation.

- Characterized formation water chemistry for each regional aquifer unit.
  - 875 water analyses were available in public datasets, taken from 204 wells.
  - Applied filtering criteria (detailed in Appendix 7), which resulted in 457 analyses with sampling interval tabulated that could be analyzed.
  - Calculated MEQ/l values for each cation/anion, as well as the cation/anion imbalance. 169 of the 457 water analyses were judged to be invalid, as there cation/anion imbalance was >10%.

- Created aquifer maps by integrating hydrogeological interpretation with regional stratigraphic mapping.

3. Report Preparation

- Prepared this report, summarizing geological and hydrogeological characteristics of each suitable aquifer unit, and recommending additional work to identify specific water source and disposal targets.

REGIONAL SETTING

Liard Basin is a structurally-bounded segment of the Western Canada Sedimentary Basin, lying in northeastern British Columbia and adjacent Yukon Territory (Fig. 1). It hosts a relatively-undeformed sedimentary section measuring several thousand metres thick (Fig. 2). Morrow and Shinduke (2003) described Liard Basin as a late Paleozoic and Cretaceous depocentre, bounded on the east by the Bovie Fault Zone, along which several stages of movement have occurred. Extensional faulting during Carboniferous and Early Cretaceous time provided accommodation space for abrupt westward thickening of the Upper Carboniferous (Mattson Formation) and Cretaceous sections (Fig. 2). Morrow and Shinduke (2003) also noted at least two episodes of contraction, during the late Paleozoic and also during the latest Cretaceous Laramide Orogeny, both of which contributed to structural complexity and conventional hydrocarbon trapping opportunities in the Bovie Fault Zone. Structural elevations drop a thousand metres or more from east to west across the highly-complex Bovie Fault Zone, which cannot be adequately characterized without detailed seismic control (McLean and Morrow, 2004).

For the purposes of this study, we have adopted the basin definition of Mossop *et al.* (2004), which mapped the deformed front of Paleozoic strata in the northern Rocky Mountain Fold and Thrust Belt to be the western margin of the prospective Liard Basin (Fig. 3).

Figures 4a and 4b are stratigraphic columns for the Liard Basin; we have highlighted both prospective hydrocarbon-bearing shales and water-bearing regional aquifer units. Potential shale reservoirs occur at several stratigraphic levels:

- Westward and northward of the Slave Point / Sulphur Point / Keg River carbonate platform margins, siliceous, organic-rich shales of the Horn River Formation form the basal part of a thick Mississippian – Devonian shale section (BC MEM / NEB, 2011).

- Siliceous shales of the Prophet and Besa River formations lie basinward (northwest) of stacked carbonate ramps/platforms of the Mississippian Rundle Group and Debolt Formation (Richards, 1989; Richards *et al.*, 1993; Ferri *et al.*, 2011; Adams, 2013).

- Cretaceous Buckinghorse shales lie unconformably on Mississippian and younger strata, or transgress basal Cretaceous Chinkeh sandstones (Chalmers and Bustin, 2008).

Prospective aquifers are discussed in the next chapter.

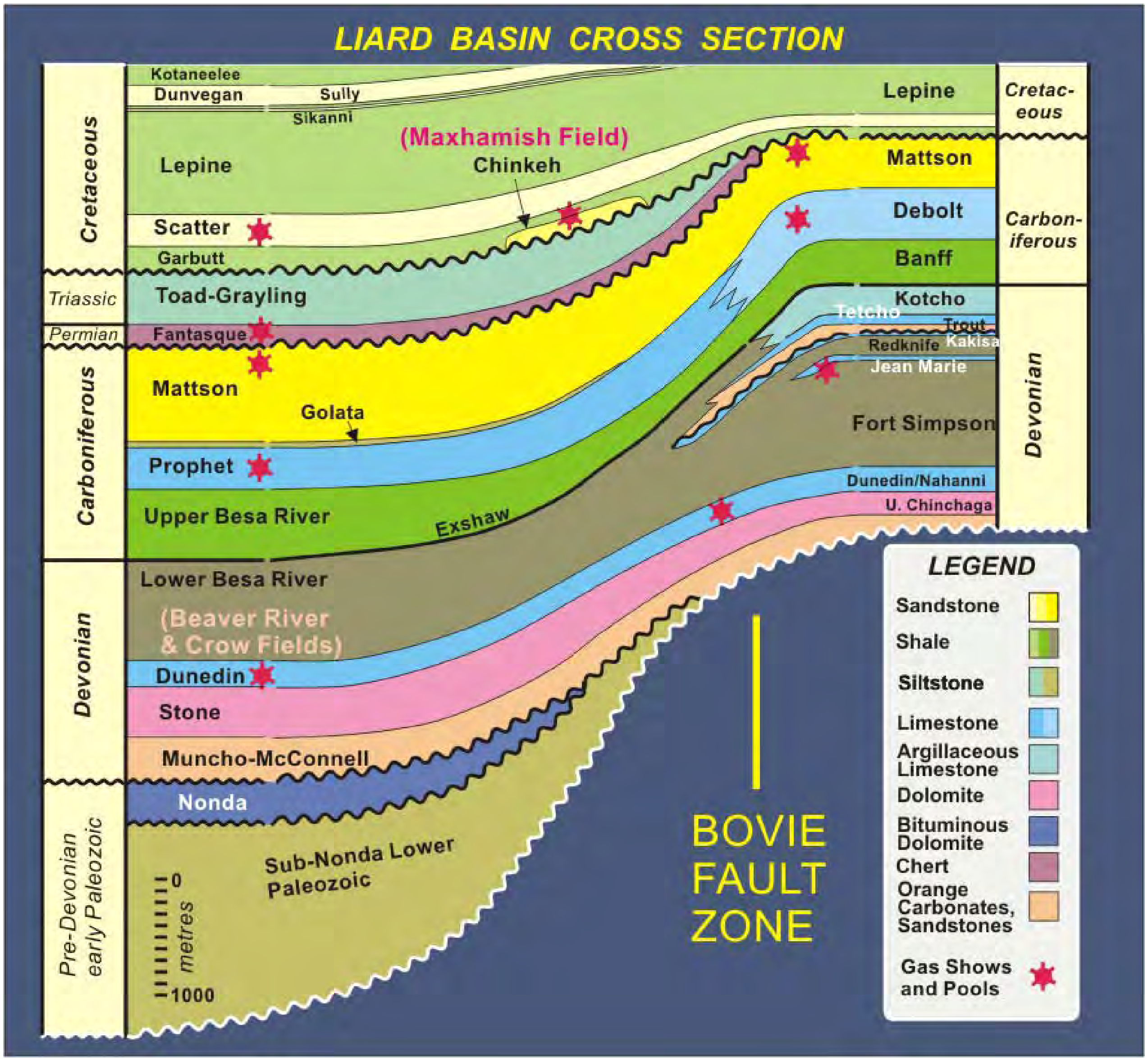


Figure 2. Schematic west-east cross-section, Liard Basin (from Morrow and Shinduke, 2003).

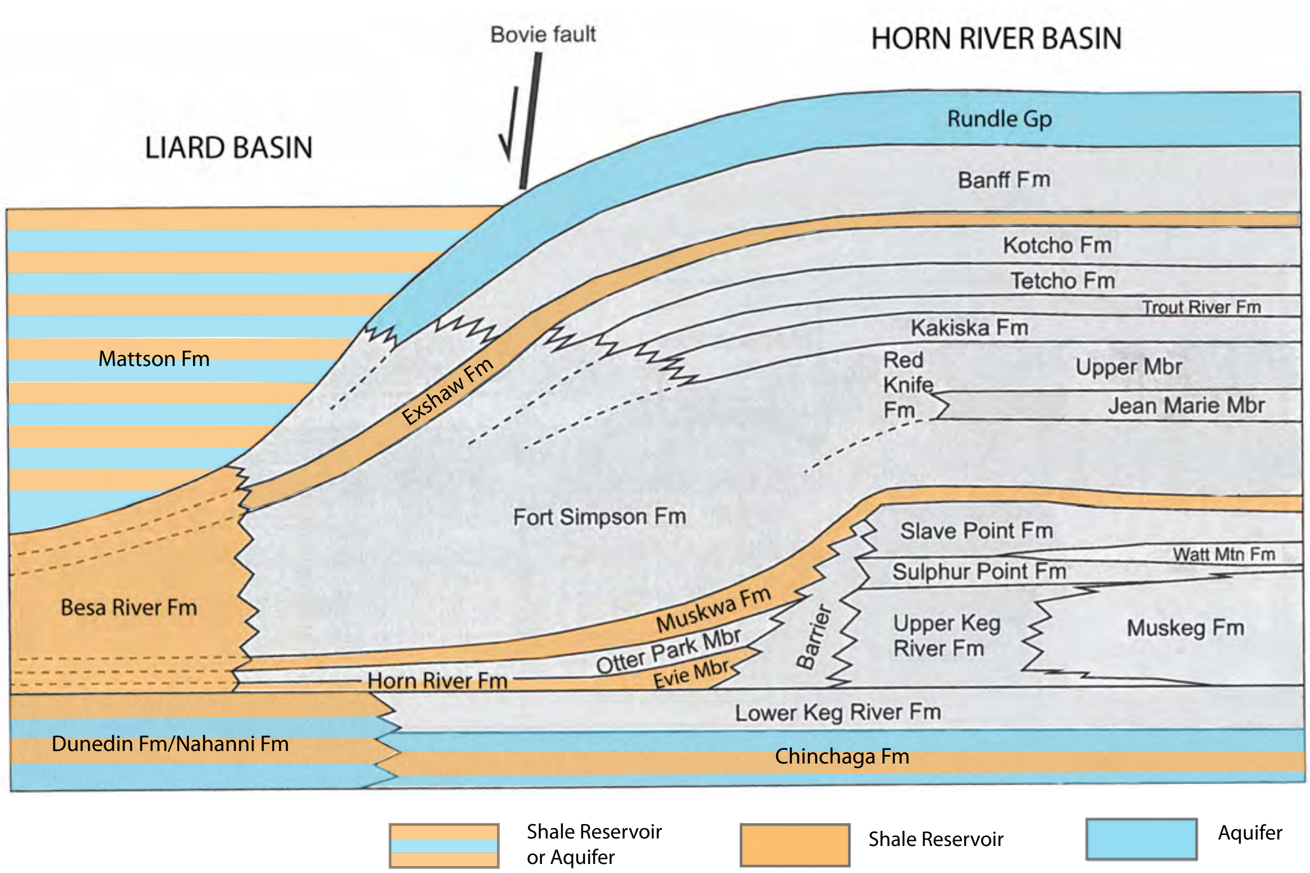


Figure 4a. Stratigraphic column, Devonian through Mississippian, Liard Basin (from Ferri et al., 2011).

System/Series	Formation and Thickness (m)		Lithology	AQUIFER	SHALE RESERVOIR
Upper Cretaceous	Wapiti (60)		conglomerate, sandstone, carbonaceous shale and coal		
	Kotaneelee (180)		dark shale		
	unconformity				
	Dunvegan (150-200)		massive conglomerate, sandstone and carbonaceous shale		
Lower Cretaceous	Fort St. John Group	upper Ft. St. John Group (~800)	primarily dark grey shale; in western part of Liard Basin, can be differentiated into (in ascending order) Lepine Shale, Sikanni sandstone and Sully Shale		
		Scatter (60-300)	very fine to fine glauconitic sandstone and shale		
		Garbutt (3-270)	black sideritic shale, minor sandstone		
		Chinkeh (0-40)	glauconitic siltstone overlying sandstone, glauconitic in part		
	unconformity				
Triassic	Toad (0-350)		grey to light grey calcareous siltstone and sandstone and light to dark grey shales		
	Grayling (0-250)		light grey, green, red and brown shales, minor sandstone, dark shales in southwesternmost wells		
	Unconformity				
Upper Permian	Fantasque (0-175)		dark chert, in part glauconitic, minor sandstone and siltstone		
Lower Permian	Unconformity				
	Middle-Upper Kindle (0-190)		calcareous sandstone, western liard basinonly		
	Unconformity				
Pennsylvanian	Lower Kindle (0-58)		siltstone, glauconitic, calcareous, phosphatic		
	Unconformity				
Mississippian	Mattson (125-600)		fine to medium sandstone, with siltstone, shale, dolomite and coal		
	Golata (6-72)		black shales		
	Prophet in western Liard Basin (0-375)	Debolt (0-270)	*Prophet* ; spiculite, spicular-rich limestone and shale / *Debolt* ; bioclastic limestone with dolomite, chert, and calcareous shale		
		Shunda (0-160)	*Shunda* ; argillaceous limestone and calcareous shale		
		Pekisko (0-35)	*Pekisko* ; bioclastic limestone and calcareous shale		
	Banff (375-525)		calcareous shale and argillaceous limestone		
Upper Devonian	Exshaw (15-150)		dark shale and silty limestone		
	Unconformity				
	Kotcho, Tetcho and underlying shales (lower part of Besa River Fm)		shales and argillaceous limestone		

Figure 4b. Stratigraphic column, Upper Devonian through Cretaceous, Liard Basin (from Monahan, 1999).

GEOLOGY AND HYDROGEOLOGY OF AQUIFER UNITS

Based on our current knowledge, there are four major aquifer intervals to be investigated in Liard Basin (Fig. 4a, b). From oldest to youngest, these are:

- Mississippian platform carbonates: The Debolt Formation and Rundle Group host a key subsurface aquifer in the Horn River Basin to the east, which is being utilized for water sourcing and disposal in the Horn River Basin shale play. Weathered and dolomitized strata immediately beneath the pre-Cretaceous unconformity exhibit the best reservoir quality, capacity and continuity.

- Mattson Formation sandstones: Thick, high-quality Mattson sandstones crop out on the northwestern flank of the basin in Yukon Territory, and exhibit excellent reservoir quality in conventional gas pools along the Bovie Fault Zone on the eastern margin. Their extent, continuity, and quality toward the basin centre will be a focus of this study.

- Lower Cretaceous sandstones, including:
  - Basal Cretaceous Chinkeh sandstones generally exhibit modest reservoir quality and host substantial hydrocarbons in Maxhamish Field, but may be prospective for water in other areas.
  - Lower Cretaceous Scatter sandstones exhibit poor aquifer capacity in the Horn River Basin, but are thicker and more prospective westward in the Liard Basin, toward their Cordilleran source areas.

- Upper Cretaceous Dunvegan Formation sandstones and conglomerates occur at very shallow depths in parts of Liard Basin. They may offer substantial local non-saline water sources, but are too shallow to offer disposal zone potential.

We will also review briefly the Permian Fantasque Formation and the Devonian Chinchaga Formation, both of which can be mapped across large areas. The Fantasque exhibits aquifer potential generally only where fractured, but it lies directly above the Mattson and can easily be assessed along with that unit. There are few penetrations of the Chinchaga, and drill depths are generally too deep for serious consideration of aquifer potential.

Upper Cretaceous Sikanni sandstones were not addressed in this study because of their shallow depths (less than 100 m below the Dunvegan) and limited apparent aquifer potential, according to regional descriptions by Stott (1982). However, one recent wellbore at Patry is injecting limited water volumes into the Sikanni, indicating that there may be some potential for the unit.

Geological mapping in the Liard Basin is constrained by scarce and irregularly-distributed well control (Fig. 5). Regional stratigraphic cross-sections demonstrate that major stratigraphic units can be carried across the basin, but that finer-scale subdivisions are difficult to correlate between widely-spaced wells. Abrupt thinning of the entire section at the eastern margin of the basin near the Bovie Fault Zone makes correlations challenging in that area, even though well control is generally denser (e.g., Cross-sections B-B', C-C').

CHINCHAGA FORMATION

Middle and Upper Devonian reefal carbonates of the Western Canada Sedimentary Basin shale out northward and westward, and in Liard Basin, only the Middle Devonian Chinchaga Formation remains in carbonate facies (Fig. 4a). It comprises deposits associated with a regional marine transgression that overstepped the Cold Lake evaporite basin. The Chinchaga contains a wide variety of lithofacies – including fine and coarse clastics, dense very fine crystalline anhydrite and dolomite cycles, marine intertidal laminites, stromatolites, very fine-grained peloidal wackestones and packstones, pebble breccias, and desiccation features (PRCL, 2005). PRCL mapped shallow carbonate shelf facies across Liard Basin, flanked on the northwest by a possible shoal or bank trend, with outer shelf facies in the far northwest. Moore (1993) included this as part of his MacDonald Platform, part of a broad shelfal western margin of the North American Craton.

Fewer than 30 wells penetrate the Chinchaga in and near the Liard Basin; they demonstrate burial depths around 4000 metres near the Bovie Fault Zone, up to 5000 metres in the basin centre, and shallower in the west where structurally deformed (Fig. Cc1). Even fewer wells are complete penetrations, but they suggest total thicknesses increasing from around 150 metres in the southeast to more than 300 metres on the Beaver River structure in the northwest (Fig. Cc2).

Cores from the Chinchaga were logged at a-90-I/94-O-6. A variety of dolomitized fabrics show limited porosity development, although permeability is associated with vugs and fractures in some intervals. A porosity-permeability crossplot using core from 18 wellbores (Fig. Cc3) shows generally low porosities (most <5%) and a huge spread of permeability data; we interpret this to indicate that much of the permeability is associated with fractures.

Given the scant well control, limited log suites in older wells, abundance of fracturing and great burial depths, no other formation evaluation work was attempted in the Chinchaga.

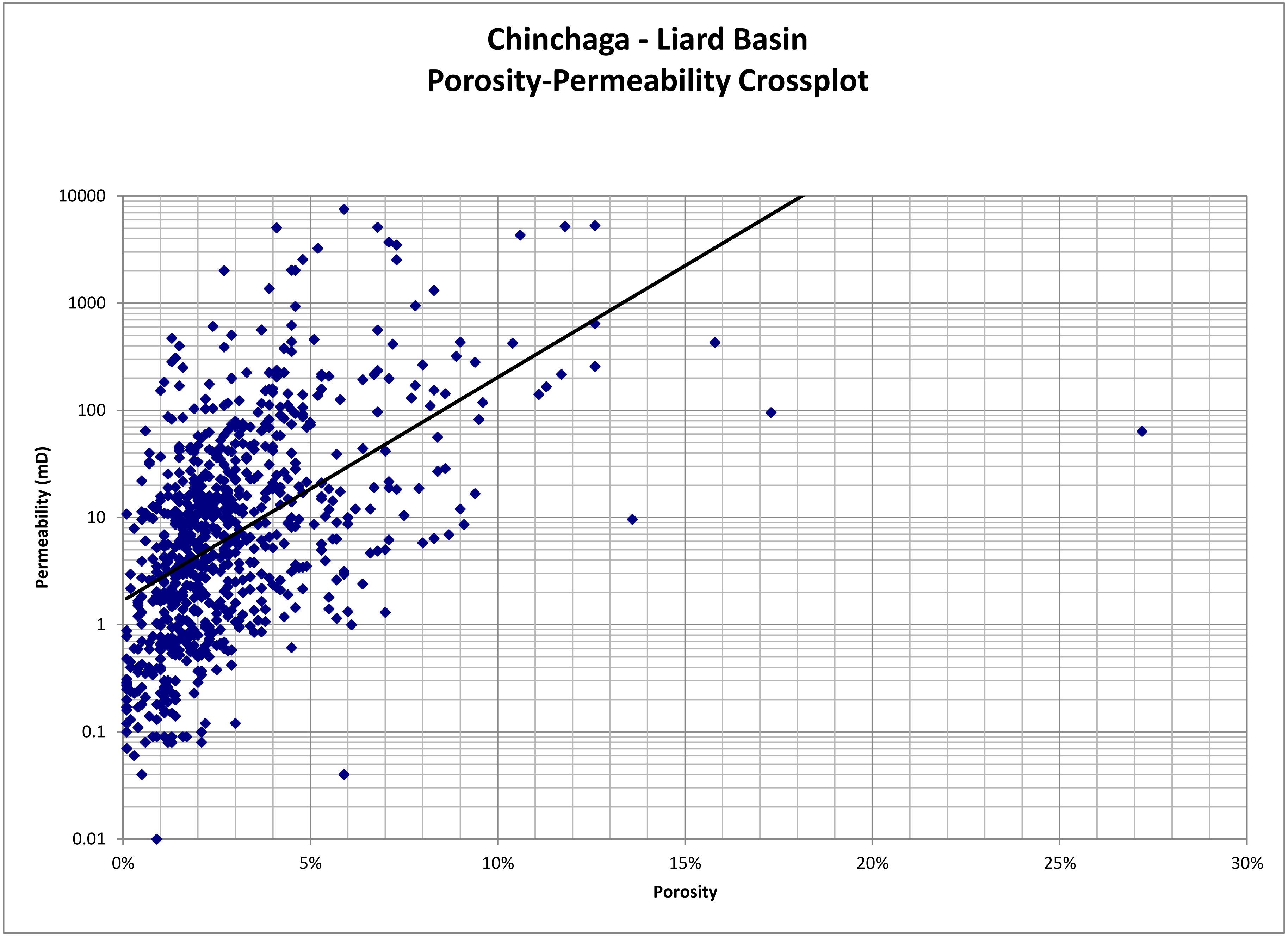


Figure Cc3. Porosity-permeability crossplot from core analysis data, Chinchaga Formation.

Hydrogeology – Chinchaga Formation

Forty-four drillstem tests have been conducted in the Chinchaga Formation in 15 wells, mostly drilled along the Bovie Fault Zone, presumably with structural trap objectives (Fig. Cc4, Appendix 5). Of the 44 tests, 11 have useable pressures and can be plotted on a Pressure-Elevation plot. Pressure gradients for valid tests range from 10.15 to 11.51 kPa/m (0.449 to 0.509 psi/ft). Pressure gradients for water tests only have the same range. Qualitative permeability is generally poor; most tests are relatively low (0.1 - 2 mD) or worse. Most of the tests reported mud recovery, sometimes with co-produced gas. However, 10 of the 44 tests reported water on recovery.

The Chinchaga produces gas from conventionally trapped pools at Crow River (94-N-15, Nahanni-Headless A pool) and Beaver River (94-N-16, Nahanni A pool) (Appendix 6). Water cuts are extremely high, with WGRs (bbl/MMCF) reaching up to the 1000's and 10,000's.

There is a very large elevation range on the Chinchaga Pressure-Elevation plot – approximately -5000 to -9300 ft subsea (1525 – 2835m subsea) (Fig. Cc5). There appears to be little pressure and fluid communication between wells; the only wells which share a common water gradient are b-021-G/94-O-06 and c-15-I/94-O-06. In general, there appears to be a trend of increasing pressure with depth. Where multiple tests are available in a single wellbore, they show fluid and pressure communication – specifically a-69-J/94-J-12, d-73-K/94-N-16, b-97-A/94-O-3, and c-15-I/94-O-6. Of particular note is a-69-J/94-J-12, which has a test in the upper and lower Chinchaga. These tests plot on the same water gradient and are in pressure and fluid communication.

Formation water salinities are highly variable, ranging from 33,639 to 115,769 mg/l TDS (Appendix 7). Salinity increases moving northward along the Bovie Fault Zone; however, this trend is not consistent with deepening structure of the unit.

Fluid gradients utilized in PE plotting were based on formation water samples. For example, the water column for a-69-J/94-J-12 has a gradient of 0.447 psi/ft (10.11 psi/ft), corresponding to a formation water salinity of approximately 36,000 mg/l. The 94-O-6 water column is plotted with a fluid gradient of 0.464 psi/ft (10.5 kPa/m), corresponding to formation water salinity of approximately 97,000 mg/l.

With respect to potentiometric surface calculations, a fluid gradient of 0.460 psi/ft (10.4 kPa/m) was utilized for all water tests, corresponding to a formation water salinity of approximately 82,000 mg/l. Potentiometric surface values can be calculated for six tests in seven wells, and are sparsely distributed along the Bovie Fault Zone, extending as far south as 94-J-12 (Fig. Cc4).

Potentiometric surface values suggest flow may be occurring from south to north within the Bovie Fault Zone, with a relatively high gradient observed in 94-J-12. This may suggest the presence of a barrier to flow. Extremely low gradients are observed in

94-O-3 and 94-O-6, suggesting minimal to no flow. The possibility of south to north flow is supported by increasing formation water salinity along this trend.

RUNDLE GROUP

Strata assigned to the Rundle Group (for the purposes of this study) make up the lower portion of the Mississippian carbonate ramp/platform succession, between the Banff Formation below and the Debolt Formation above (Fig. 4a, b). Shunda and Elkton subdivisions recognized further south and surface-derived stratigraphy from the Yukon/NWT cannot be carried with confidence into Horn River or Liard Basins. PRCL (2010) subdivided the Rundle in Horn River Basin using log markers that could be carried across the basin, and that appeared to have significance as depositional units. However, confidence in these correlations decrease to the west, and the Rundle (including Debolt equivalents) was mapped as an undifferentiated unit at the western margin of Horn River Basin (eastern edge of the undifferentiated Rundle from the Horn River Basin study is indicated on Fig. R1 and R2).

In Liard Basin, the top of the Rundle lies at depths varying from 500 metres along the Bovie Fault Zone to more than 3200 metres in the centre of the basin (Fig. R1). Very scant well control west of Maxhamish area makes burial depth uncertain over most of the basin, particularly as several wells were not drilled as deep as the Rundle. Important control points will be added when shale gas wells drilled in 2012 and later come off confidential status. The upper contact of the Rundle ranges from more or less conformable over much of Liard Basin, where overlain by marine shales of the Upper Mississippian Golata Formation, to unconformable where overlain by Pennsylvanian / Permian Kindle and Fantasque formations, to highly unconformable east of the Bovie Fault Zone, where Rundle carbonates are succeeded by Lower Cretaceous strata. The base of the Rundle is picked at the lowest occurrence of clean carbonates above the Banff Formation, a contact which climbs stratigraphically as the formation shales out westward.

Regionally, the Rundle is recognized as the product of stacked transgressive/regressive cycles, with deposition occurring in outer ramp through marine shelf to intertidal environments (Richards *et al.*, 1994; Richards, 1989; PRCL, 2000). Each cycle prograded northward and westward toward the Besa River shale basin (Fig. 4a). To the south, PRCL (2000) documented cycles culminating in open marine to restricted facies, while to the north, Richards (1989) interpreted more distal slope to shelfal facies through most of the succession. In Horn River Basin, the Rundle package appears to become cleaner and more proximal upward – thick shale intervals and pronounced cyclicity are evident in the lower Rundle, while the upper Rundle is dominated by cleaner carbonates with little evidence of well-developed transgressive surfaces. In Liard Basin, shallowing-upward cyclicity can be seen at the eastern margin (e.g., well c-51-B/94-O-14, Cross-section A-A'), but deeper-water, shale-dominated facies predominate to the west, and shallowing-upward cyclicity is not apparent (e.g., well d-36-H/94-N-15, Cross-section AA-AA' (deep)). In western outcrops, Rundle carbonates are no longer recognized within the Besa River Shale package (Fig. R1).

Figure R2, a gross isopach map of the Rundle Group, shows thicknesses on the order of 500 metres or more in the Bovie Fault Zone, along the eastern margin of Liard Basin. An anomalously thick value at d-71-J/94-O-6 was ignored in contouring, as the well is deviated and likely encountered faults in the Rundle section, as indicated by major lost circulation events. While data points to the west are scant, it is clear that the formation generally thins westward as clean carbonates pass westward to basinal shales.

Reservoir Quality

No cored sections of the Rundle Group were available in or adjacent to Liard Basin. Sample cuttings were logged across the Rundle in a number of wells, mostly along the eastern flank of the basin (Fig. R2; Appendix 3). Very fine crystalline cherty limestones and carbonate muds dominate the succession, and feature very low porosity and poor permeability. Intercrystalline porosity is developed in isolated sections (e.g., 1093-1097m in well b-97-A/94-O-3), although porosities are generally <5% and permeabilities <1 mD. A thick dolomitic section is present in b-96-E/94-O-10, and dolomitic streaks were logged in d-83-L/94-O-7 (730-750m), with porosity/permeability values comparable to the porous limestone intervals noted above. PRCL (2010) speculated that such dolomites might be the product of dolomitizing fluids introduced along local, deep-seated faults. Dominance of muddy facies, lack of clean shallow-water facies, and scarcity of dolomites appear consistent with the regional picture of more basinward distal marine settings in Liard Basin, compared to more proximal carbonate ramp deposits documented to the east and southeast.

There are few modern well log suites across the Rundle Group in Liard Basin, although more should become available when shale gas wells drilled in 2012 and later are released. Using available well logs, however, we observed little or no evidence of porous rock in the Rundle succession. We therefore have not attempted to construct a net porous reservoir map for the Rundle Group.

"Detrital" Zone

Sample cuttings and limited core illustrate the widespread presence of an intensively leached and dolomitized zone ("detrital zone") at or near the top of the Mississippian carbonate platform in Horn River Basin (PRCL, 2010). Development of a detrital zone associated with a profound unconformity on carbonate substrate is common in the subsurface of western North America. However, in Liard Basin, the Mississippian carbonate succession is succeeded nearly conformably in most places by marine shales of the Golata Formation, and thus there is no profound unconformity beneath which a detrital zone would form.

Little evidence of a well-developed detrital zone was observed in samples. There is a thick cherty-rich interval correlated with the top Rundle at d-57-D/94-O-12, but its stratigraphic assignment is unclear, and reservoir quality is poor (see sample cuttings log, Appendix 3).

Hydrogeology – Rundle Group

Thirty DSTs were conducted in the Rundle Group in 24 wells distributed across the basin (Fig. R3, Appendix 5). Of the 30 tests, 17 have useable pressures and can be plotted on a Pressure-Elevation plot. Pressure gradients for valid tests range from 7.54 to 13.16 kPa/m (0.333 to 0.582 psi/ft), and pressure gradients for water tests only have the same range. Tests show variable permeability, with several tests ranging from relatively high (10-20 mD) to excellent (>50 mD). Permeability values generally decrease toward the central portion of the basin; the highest permeability tests are situated near to the Bovie Fault Zone, and close to the Tattoo Field. Compared to other formations, there are a relatively high proportion of water tests (10) to other fluid types.

Rundle Group reservoirs produce gas from conventional structural traps along the Bovie Fault Zone in Tattoo Field, located in 94-O-10 (Debolt, Debolt A, and Mattson C pools) (Appendix 6). These wells water out with time, with water-gas ratios increasing to >5 bbl/MMCF (into the 10's of bbl/MMCF).

Three formation water analyses were identified in the Rundle, with TDS values ranging from 15,206 – 25,207 mg/l (Appendix 7).

The Fantasque, Mattson and Rundle formations appear to be in hydraulic communication. Three water systems have been identified in the study area, which we have named the High Pressure Permian/Mississippian Water System, Medium Pressure Permian/Mississippian Water System, and Low Pressure Permian/Mississippian Water System (Fig. R4). A fluid gradient of 0.44 psi/ft (10 kPa/m) was utilized for PE plotting for all three formations.

The High Pressure Permian/Mississippian Water System is located in the northwest, near to Mattson and Fantasque outcrop (94-N-11, 12, 14 and 15). Four Mattson and two Fantasque DSTs plot on the High Pressure Permian/Mississippian Water System. Pressure and fluid communication is evident within the water system from approximately 200 to -3300 ft subsea (+60 to -1010 m) (Fig. R4). By extrapolating the water system fluid gradient to 100 kPa pressure (approximately atmospheric pressure), a recharge elevation of approximately 750m was calculated. The Crow and Grayling Rivers are at or near this elevation within areas of Mattson and Fantasque outcrop, suggesting that they are a source of recharge to the aquifer.

The Medium Pressure Permian/Mississippian Water System is defined by six Mattson tests, and is located east of the High Pressure Permian/Mississippian Water System, and west of the Low Pressure Permian/Mississippian Water System. Pressure and fluid communication are observed in the water system from approximately -4350 to -6250 ft subsea (-1325 to -1900m).

The Low Pressure Permian/Mississippian Water System is coincident with the Mattson Water System identified in the Horn River Basin aquifer study, and is situated generally over the Bovie Fault Zone, and as far west as Blocks J and K/94-O-14. The water system is defined by the majority of the DSTs in these three formations: seven Fantasque tests, 34 Mattson tests, and 13 Rundle tests. Referring to the PE plot, pressure and fluid communication within the Low Pressure Permian/Mississippian Water System is noted from approximately 500 to -4500 feet (+150 to -1370m).

Three Mattson tests with valid pressures are noted in a-96-J/94-O-14. Two of these tests plot on the Low Pressure Permian/Mississippian Water System (DSTs #2 and 5), but a third DST (#3) taken at a lower interval within the formation plots on the Medium Pressure Permian/Mississippian Water System. At this location, lower and upper Mattson intervals appear to be in different pressure regimes, suggesting a lack of vertical hydraulic communication.

One Fantasque test (DST #4, a-96-G/94-O-13) in the central portion of the basin plots significantly underpressured with respect to all identified water systems and is isolated.

Two high-pressured, isolated Rundle tests are situated in one well in the distal part of the basin (c-10-E/94-N-7, DSTs #6 and 7). Rasters were not available to confirm the validity of these tests. High-pressured, isolated Rundle tests are also observed near the Bovie Fault Zone: DST #7 b-94-L/94-J-11, and DST #3 a-45-E/94-O-10. Rasters were reviewed by PRCL for both of these tests and their pressures and elevations were deemed valid. These intervals/tests may have been isolated from the regional Low Pressure Permian/Mississippian Water System by fault displacement.

All potentiometric surface values calculated from Rundle, Mattson, and Fantasque tests were combined and posted to a common potentiometric surface map (Fig. R5). These include values from seven Rundle tests in six wells. They suggest that flow is occurring from the western and southern portion of the basin, through a combined Fantasque/Mattson/ Rundle flow unit, towards the Bovie Fault Zone.

MATTSON FORMATION

The Mattson was originally described in outcrop, and surface exposures were correlated over an area of southeastern Yukon, southwestern Northwest Territories, and northernmost B.C., in a series of Geological Survey of Canada reports in the 1950's and 1960's. Within the Liard Basin study area, about 300 feet of Mattson sandstone crops out in the Bovie Anticline, on the eastern margin of the Bovie Fault Zone, but was not described in detail (Fig. 3, M1) (Taylor and Stott, 1968). Mattson outcrops also occur on the northwestern flank of Liard Basin; Bamber *et al.* (1968) mentioned the presence of the Mattson but did not describe the sections (Fig. 3). Little subsurface work on the

Mattson has been published with the exception of Monahan (1999), who presented a series of well-log cross-sections in Liard Basin, and a brief discussion. Hayes and Stewart (*in review*) characterized the Mattson in the Liard Basin in adjacent Northwest Territories.

In Liard Basin, the top of the Mattson lies at depths varying from less than 500 metres along the Bovie Fault Zone to more than 3000 metres near the basin centre (Fig. M1). Subsurface distribution in the west is complicated by structural elements, and the Mattson appears to be at or near surface in d-57-K/94-N-2 and c-10-E/94-N-7. Very scant well control west of Maxhamish area makes burial depth uncertain over most of the basin, although important control points will be added when shale gas wells drilled in 2012 and later come off confidential status.

The Mattson grades upward from marine shales of the Golata Formation below, and is overlain unconformably by the Kindle/Fantasque succession or younger rocks (see west-east regional cross-sections A-A', B-B' and C-C').

At the type section at Jackfish Gap (Fig. M2), the Mattson consists of coarsening- and sandier-upward prodeltaic fine clastics, overlain by deltaic to fluvial and floodplain strata. Richards *et al.* (1993) interpreted the Mattson to have been deposited as fluvially-dominated, wave- and tide-influenced deltas of lobate form. In the east and north, thick braided stream sandstones occur interbedded with finer-grained and coaly delta plain deposits. Southward, the Mattson grades to a fully deltaic section and, in the Liard Basin of northeastern B.C., passes into prodelta clastics and equivalent basinal shales (Fig. M3).

Figure M4, a gross isopach map of the Mattson, shows it to thicken abruptly westward from an eastern zero edge and into the Bovie Fault Zone. Northwestward, toward the deltaic depocentre in Yukon/NWT, it thickens to more than 800 metres. Southward and away from the source area, it thins to an apparent zero edge in southern Liard Basin. Presence of the Mattson in two wells in 94-K-9 is rather problematic; these sections are difficult to correlate, and may relate more to time-equivalent Stoddart Group deposition to the south. If this is the case, there may be little real Mattson rock south of 94-O-4 and 94-N-1.

Well control is not sufficient to break out clear subunits or depositional trends within the Mattson, but clean, thick, reservoir-quality sandstones are common in many wells (e.g., core log d-87-A/94-O-11). Sandstones are generally very fine- to fine-grained, massive to low-angle cross-bedded in metre-scale sets, broken by thin grey to green shale beds (Fig. M5). Mud clasts and shell debris (or moldic porosity after shell fragments) are locally common, and minor burrowing suggests some marine / deltaic influence (Fig. M6).

Mattson sandstones are typically quartzarenites; minor framework components include chert, phosphate, and detrital carbonate grains. Silica is the primary cement, mostly in the form of quartz overgrowths. Carbonate cements are highly variable, ranging from

Figure M2. Type section, Mattson Formation, Jackfish Gap, Northwest Territories.

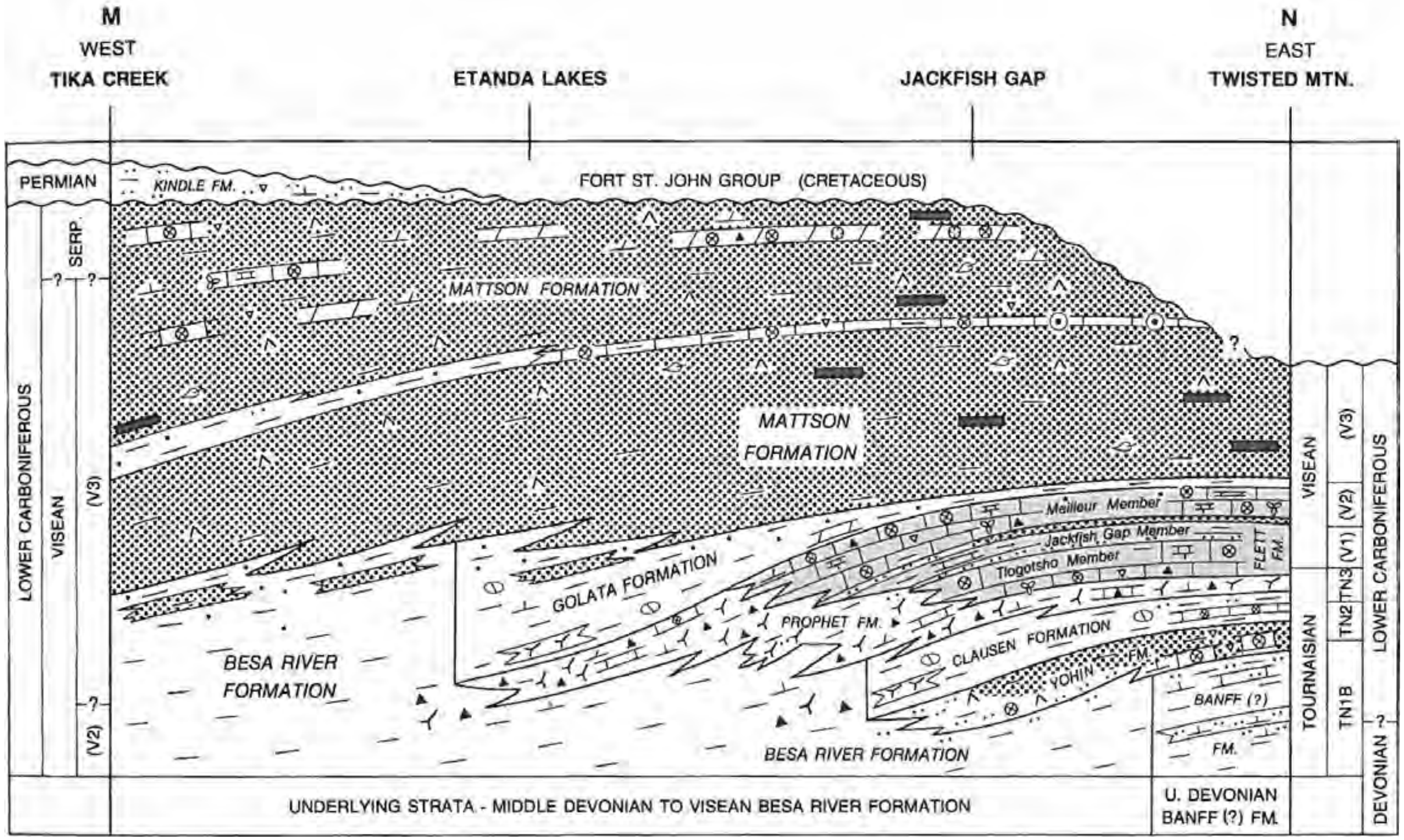


Figure M3. Schematic stratigraphic cross-section, illustrating deposition of Mattson Formation on the western margin of the cratonic platform (from Richards et al., 1993).

Figure M5. Fine-grained, massive to planar-bedded Mattson sandstones with platy green-grey shale bed. Hess Aquitaine et al. Windflower d 67 A/94 O 11.

Figure M6. Very fine-grained sandstone with large vertical Diplocraterion burrow.
Aquitaine et al. Tattoo a 78 L/94 O 10, 2470 ft.

absent to porosity-occlusive (e.g., core log c-37-G/94-O-6). Kaolinite cement is common in finer (silt-sized) rock. PRCL (2010) noted local concentrations of pyrobitumen. Where fossil fragments are heavily concentrated, sandstones may take on a bioclastic texture (Fig. M7).

Reservoir Quality

Reservoir quality ranges from very poor in very fine-grained rocks and tightly-cemented sandstones to excellent in well-sorted quartz sandstones (Fig. M8). Porosities locally exceed 20%, and permeabilities range into the hundreds of millidarcies (see core analysis plots on core logs, Appendix 2). Most porosity is primarily intergranular, augmented by secondary solution of chert and carbonate grains. In the Windflower gas field, BC Oil & Gas Commission listed average porosity of the Mattson at 15%.

Sample cuttings logs in the east (e.g., c-66-E/94-O-10, b-96-E/94-O-10, a-27-L/94-O-10) document longer sand-dominated, variably-cemented Mattson sections. To the west, samples at d-57-D/94-O-12 indicate a much poorer-quality Mattson reservoir. Natural fracturing was observed, particularly in more tightly-cemented intervals, and is likely related to tectonic activity along the Bovie Fault Zone (e.g., d-67-A/94-O-11).

Reviewing both DST data and the porosity-permeability crossplot from available core analysis data, a porosity of 10% (equivalent to about 3 mD permeability) was selected as the net porous sandstone cutoff value (Fig. M9). While this permeability value is relatively low for aquifer assessment, the dataset is small, and there are some coarser-grained sandstones showing permeabilities of >10 mD at 10% porosity. We therefore took the approach of being more, rather than less inclusive. Net porous sandstone values were calculated from all wells with adequate logs, using a clean gamma ray cutoff of 60 API units and the 10% porosity value on sandstone density logs (or an equivalent value on sonic logs). A net porous sandstone isopach map (Fig. M10) was constructed, which shows total values ranging up to 18 m thick. The most consistent porosity development is in the relatively shallow sections along the Bovie Fault Zone, although several wells on the Beaver River structure and southward exhibit substantial porous sections as well. Wells in the central and southern parts of the basin exhibit limited or no net porous sandstone.

Hydrogeology – Mattson Formation

Seventy-nine drillstem tests have been conducted in the Mattson Formation in 41 wells, four of these straddling other formations (Fig. M11, Appendix 5). Tests are focused along the Bovie Fault Zone, where many Mattson tests have been drilled pursuing structural trap objectives. Of the 79 tests, 49 have useable pressures and can be plotted on a Pressure-Elevation plot. Pressure gradients range from 5.90 to 13.29 kPa/m (0.261 to 0.587 psi/ft). Pressure gradients for water tests only range from 7.44 to 10.80 kPa/m (0.329 to 0.477 psi/ft). Twenty-one valid water tests in 16 wells were identified, and relatively high or greater permeabilities are common (Appendix 5).

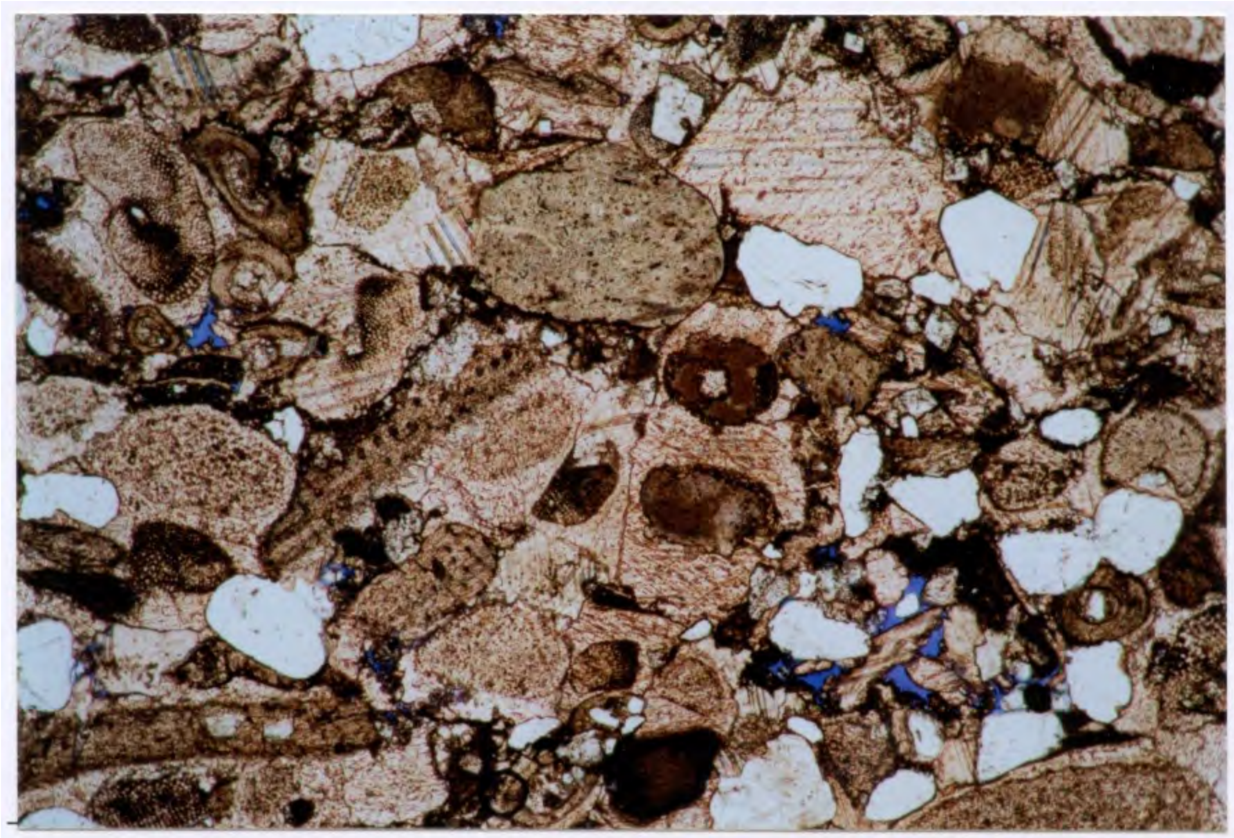


Figure M7. Thin section showing sandy limestone – originally bioclastic grainstone with minor quartzose sand. Bioclasts include abundant echinoderms and brachiopod shell fragments. Ammin Aquitaine et al. Windflower d 6 H/94 O 11, 1417.7 ft.

Well:	d-6-H/94-O-11	Depth:	1581.0 ft.	Magnification:	50x	Polarization:	PL

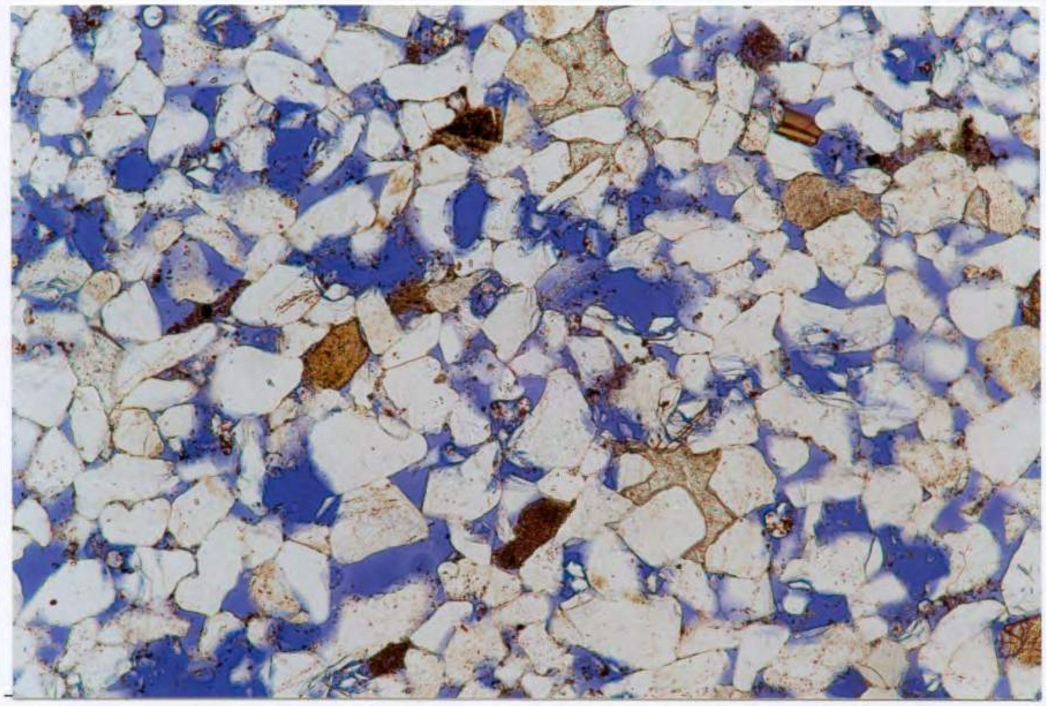


Figure M8. Moderately-sorted quartzarenite with minor dolomite cement. Excellent reservoir quality (Φ~25%). Ammin Aquitaine et al Windflower d 6 H/94 O 11, 1581 ft.

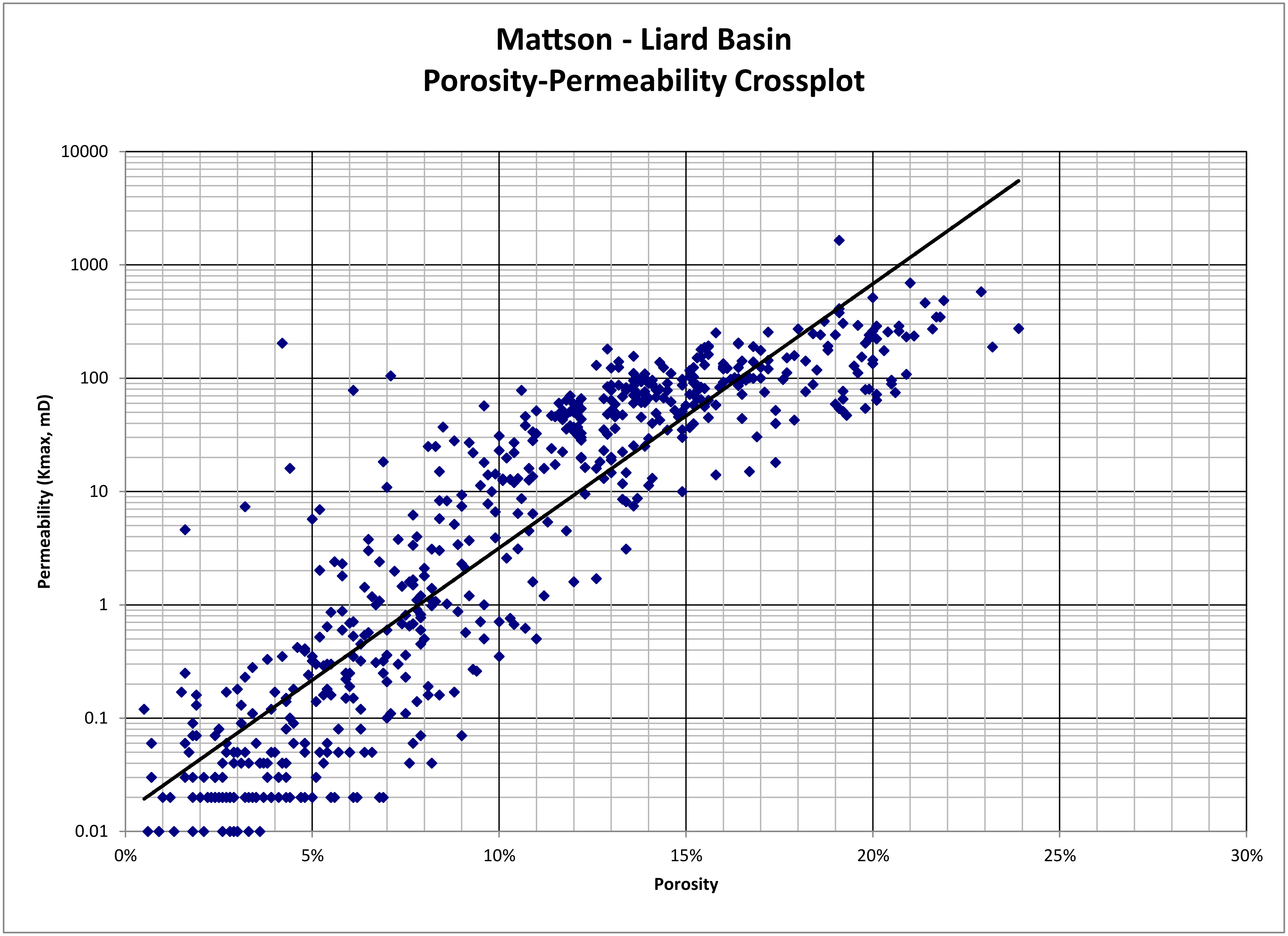


Figure M9. Porosity-permeability crossplot from core analysis data, Mattson Formation.

The Mattson produces gas from a number of areally-small, conventionally-trapped structural closures associated with the Bovie Fault Zone (Fig. M12). These have been assigned to the Maxhamish Lake, Tattoo, and Windflower fields. Most of the wells co-produce formation water, with water-gas ratios > 5 bbl/MMCF and up to the 10's of bbl/MMCF.

The Mattson is in hydraulic communication with the Fantasque and Rundle. Water systems and the Pressure-Elevation plot are discussed under Rundle Group hydrogeology.

True formation water is found within a relatively consistent range, from 12,497 - 34,095 mg/l. A representative fluid gradient of 0.44 psi/ft (10 kPa/m), roughly corresponding to a salinity of ~21,075 mg/l TDS, was utilized in PE plotting and calculation of the potentiometric surface. This is consistent with the fluid gradient utilized in the Horn River Basin aquifer study. An anomalously high TDS sample (71,687 mg/l) with the characteristics of formation water was noted at a-79-B/94-O-11. The DST for this sample shows little to no water inflow, and reports the recovery water to have a salinity of 17,500 ppm (field estimate). The 71,687 mg/l sample may be either mud filtrate or an error in the Fluids Analysis database in geoSCOUT. This value has not been included in the interpretation and does not appear in the report table.

Potentiometric surface mapping for the Rundle/Mattson/Fantasque aquifer is discussed under Rundle Group hydrogeology. Two notes specific to the Mattson:

- There are three valid water tests in d-64-K/94-N-16. Potentiometric surface values are highest in the uppermost test (758m), and lowest in the deepest test (729m), suggesting that flow may be occurring downward within the formation.

- Conversely, b-83-K/94-O-14 has two valid water tests. Potentiometric surface values are higher in the lower test (557m) and lower in the upper test (490m), suggesting that flow may be occurring upwards within the formation.

KINDLE AND FANTASQUE FORMATIONS

Permian rocks in Liard Basin, unconformably overlying the Mattson and in turn overlain by Triassic siltstones, have been assigned to the Kindle and Fantasque formations (Fig. 4b). Henderson *et al.* (1993) described the Kindle as "basinal to shallow-neritic siliciclastics and silty carbonates", recording "the establishment of moderately deep marine environments during the initial Permian transgression". Fantasque strata overlie a regional intra-Permian disconformity capping the Kindle, and consist of a regolith of partly chertified, brecciated sandstone with minor shale and siltstone laminae; the proportion of siliciclastics increases westward as the Fantasque grades into basinal mudstone (Henderson *et al.*, 1993).

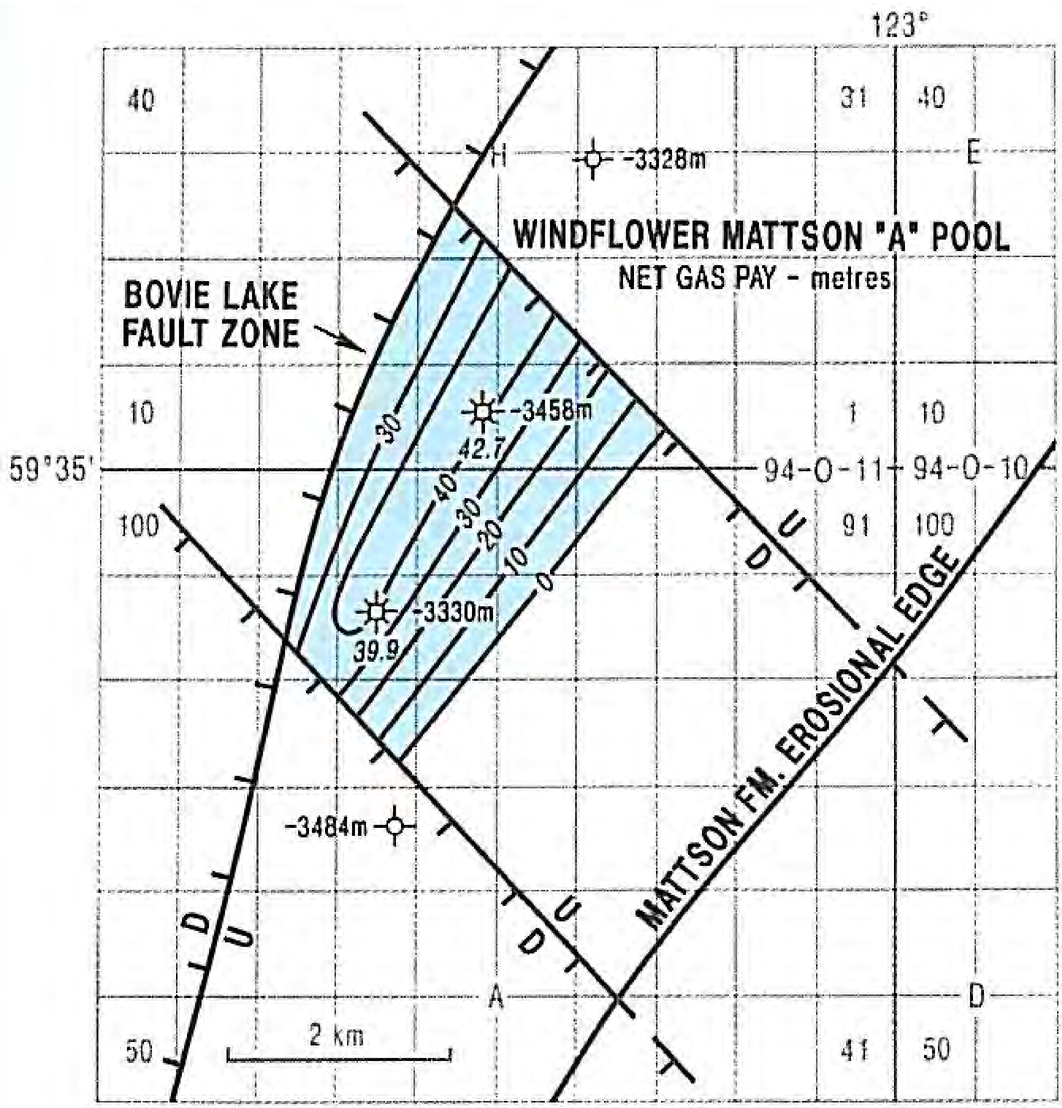


Figure M12. Mattson gas pool at Windflower – note small structural closure associated with Bovie Fault Zone (from Barclay et al., 1997).

In Liard Basin subsurface, regional cross-sections show the Kindle/Fantasque interval to be characterized primarily by its stratigraphic position between the distinctive and well-defined Triassic and Mattson units. Log signatures are highly variable; one or more "hot" gamma kicks are seen in many wells, probably indicative of mineralization associated with bounding and intra-Permian unconformities. We have referenced these sections simply as the Fantasque, as we cannot reliably distinguish the two units. Limited core and sample control shows little continuous reservoir-quality sandstone. Most of the cores are in the lower part of the succession, and consist of transgressive, burrowed fine clastics lying unconformably on the Mattson (which was probably the actual target for the core) (e.g.,c-37-G/94-O-6).

Fantasque rocks crop out on the northwestern flank of Liard Basin and along the Beaver River Anticline in 94-N-16 (Fig. F1). Depth of burial ranges from less than 500 metres in the Bovie Fault Zone to more than 3000 metres at basin centre. Subsurface distribution in the west is complicated by structural elements, and the Fantasque appears to be at or near surface in d-57-K/94-N-2 and c-10-E/94-N-7. The regional isopach map shows the Fantasque to thicken northwestward to a maximum of more than 200 metres in the Beaver River area (Fig. F2). The presence of another thick in 94-O-6 and 11 and the irregular contour patterns in general suggests there is stratigraphic complexity in this interval that we do not understand.

With our poor regional understanding of Kindle/Fantasque lithologies, and the apparent lack of good reservoir rock, we have not attempted to characterize reservoir quality. As suggested below, formation tests indicate some aquifer potential, but it appears likely that this would be associated at least in part with fracturing of brittle, siliceous lithologies.

Hydrogeology – Fantasque Formation

Seventeen drillstem tests have been conducted in the Fantasque in 13 wells (Fig. F3, Appendix 5). Of the 16 tests, 10 have useable pressures and can be plotted on a Pressure-Elevation plot. Four valid tests reported water recoveries of >150m. Gas is locally present in the formation, and was produced on seven tests. Pressure gradients for valid tests range from 7.10 to 11.55 kPa/m (0.314 to 0.510 psi/ft), and pressure gradients for valid water tests only have the same range. Permeabilities are variable, ranging from virtually nil to excellent. Relatively high (10-20 mD) to excellent (>50 mD) permeability was measured in two tests in the west, and locally within the Bovie Fault Zone. In general, tests in the central region of the basin show low to virtually nil permeability and do not have valid pressures.

Three hydrocarbon producers were identified, one of which is commingled with the Mattson formation (Appendix 6). Gas is produced from the Tattoo field (Mattson A pool) and the Maxhamish Lake field (Fantasque pool). All of the producers have significant water co-production and are conventionally trapped.

The Fantasque is in hydraulic communication with the Mattson and Rundle. Water systems and the Pressure-Elevation plot are discussed under Rundle Group hydrogeology.

There are two formation water analyses from DSTs in the Fantasque, with salinities of 22,240 mg/l and 11,557 mg/l (Appendix 7). This salinity range coincides with the formation water salinity ranges noted in the Mattson and Rundle formations. A fluid gradient of 0.44 psi/ft (10 kPa/m) was utilized in potentiometric surface calculations.

Potentiometric surface mapping for the Rundle/Mattson/Fantasque aquifer is discussed under Rundle Group hydrogeology. Potentiometric surface values were calculated from Fantasque tests in four wells.

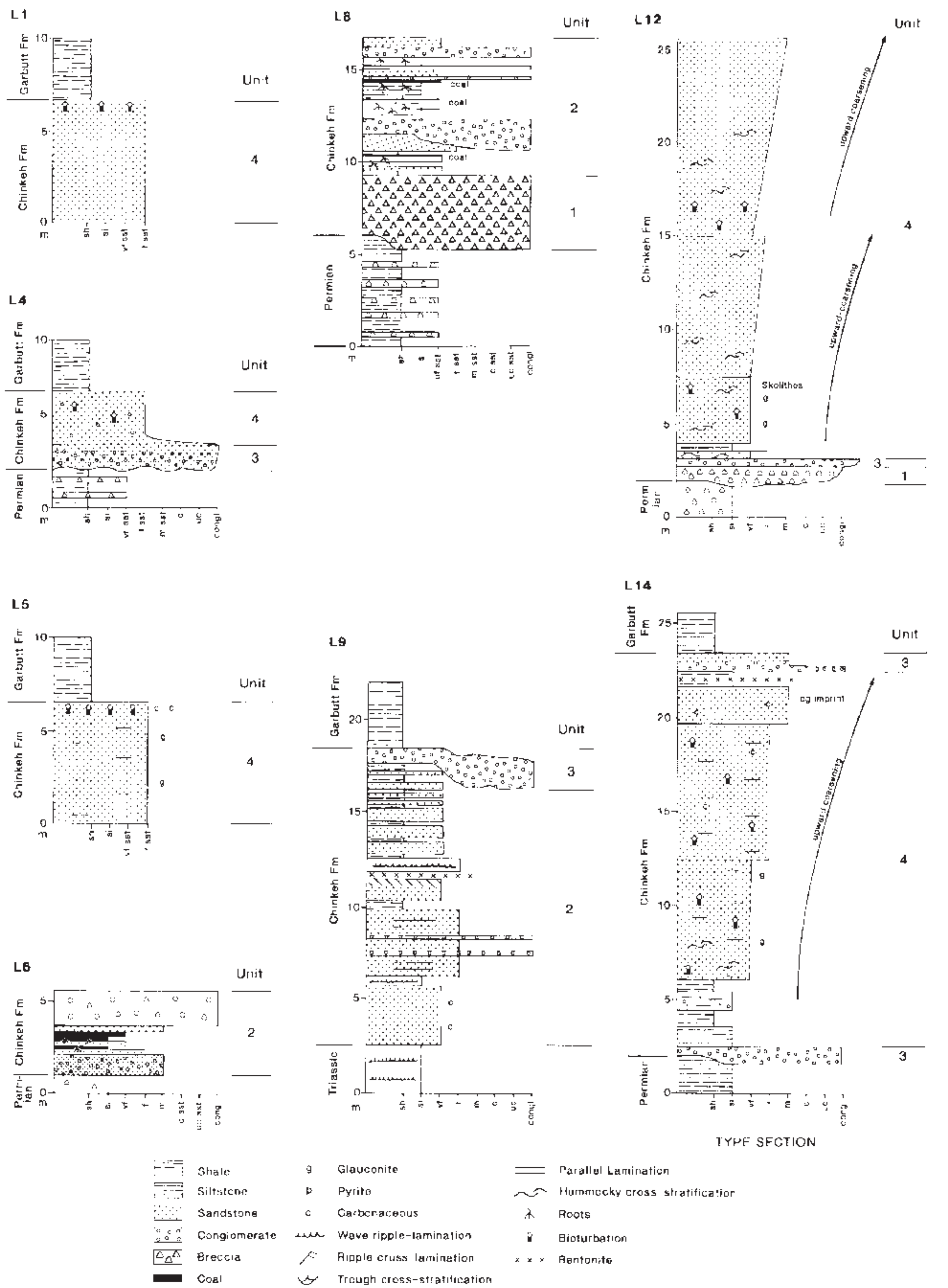
CHINKEH FORMATION

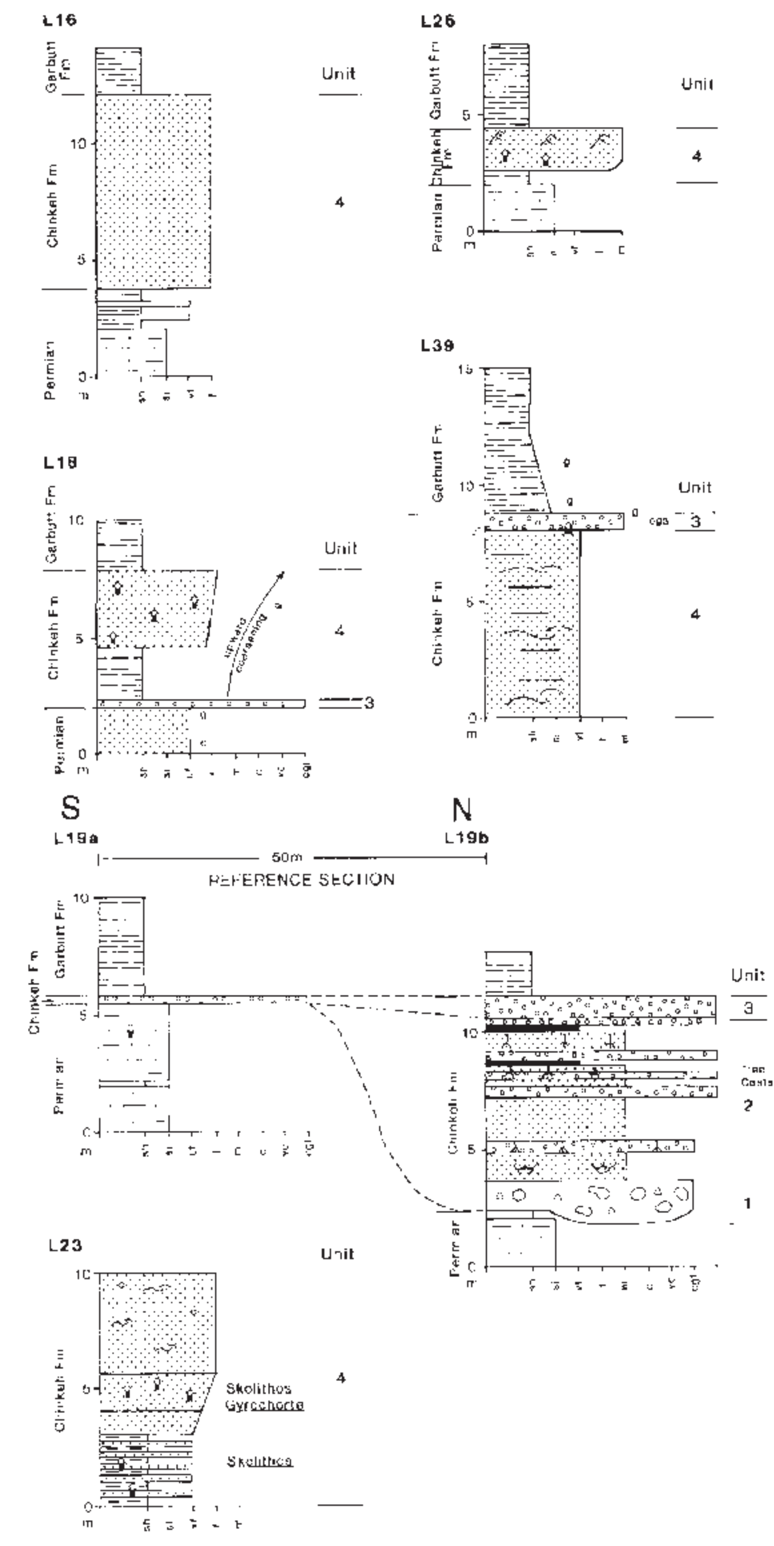
Sandstones and finer-grained clastics of the Chinkeh Formation were described and mapped in the Liard Basin and northward by Leckie *et al.* (1991) and Frank *et al.* (1999, 2000). Hayes and Stewart (*in review*) characterized the Chinkeh in the Liard Basin in adjacent Northwest Territories.

Chinkeh deposition was confined to Liard Basin, as the formation reaches a zero edge west of or within the Bovie Fault Zone. It lies at depths varying from about 1100 metres at the eastern edge to more than 2100 metres near the basin centre (Fig. C1). On the depth to formation map, we have posted Triassic outcrop to indicate the limits of Chinkeh burial, as the Chinkeh itself has not been mapped regionally at surface in western Liard Basin. Very scant well control west of Maxhamish area makes burial depth uncertain over most of the basin, although important control points will be added when shale gas wells drilled in 2012 and later come off confidential status. The Chinkeh lies on the pre-Cretaceous unconformity, which cuts strata ranging from Mississippian carbonates in the east to Triassic siltstones over most of the basin (see regional cross-sections). It is transgressed more or less conformably by marine shales of the Garbutt Formation.

Chinkeh deposition took place in a variety of non-marine to marine settings, but the best reservoir quality appears to be in shoreface sandstones that are the primary reservoir in the Maxhamish Field, running north-south through the centre of 94-O-11 and 94-O-14 (Frank *et al.*, 2000). Cores logged by Frank *et al.* (1999) at d-76-J/94-O-11 and b-4-K/94-O-11 exhibit these clean sands and fair to good reservoir quality, as do cores logged by PRCL at b-98-A/94-O-5 and 02/b-71-K/94-O-6 (Appendix 2). Most other core logs and outcrop logs by Leckie *et al.* (1991) show greater sedimentological variability, including a variety of breccias and conglomerates in channelized settings, and generally poorer-quality sands (Fig. C2).

The Chinkeh ranges up to 60 metres thick in Liard Basin, but is 20 metres or less in most areas (Fig. C3). Well control is too scanty to make a definitive map, but two





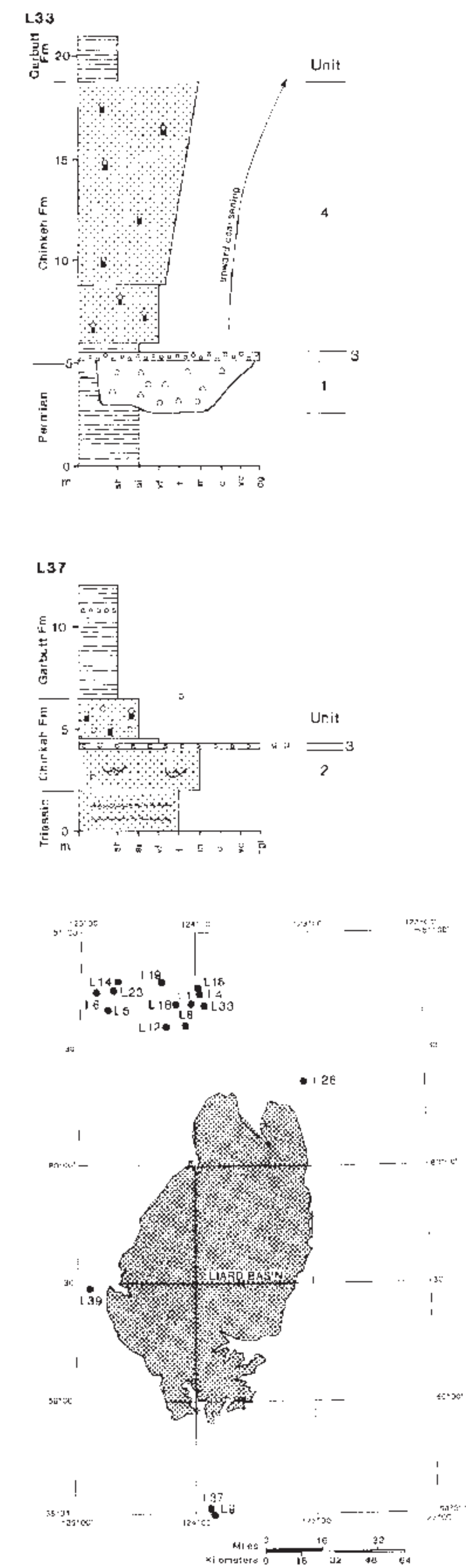


Figure C2. Graphic logs from outcrop sections of the Chinkeh Formation (from Leckie et al., 1991).

L1 N67260 E4485;	L16 N67348 E4375;
L4 N67337 E4463;	L18 N67348 E4458;
L5 N67211 E4043;	L19 N67423 E4287;
L6 N67336 E3994;	L23 N67338 E4078;
L8 N671715 E4394;	L26 N66895 E4965;
L9 N64825 E4460;	L33 N67256 E4494;
L12 N67177 E4316;	L37 N64899 E4429;
L14 N67395 E4106;	L39 N65931 E3944.

parallel NNE-SSW thicks have been interpreted. A thick, clean, porous sandstone succession ("basal Cretaceous sandstone") penetrated by several wells in I/94-O-14 and F, K, L/94-O-15 has been included in our mapping with the Chinkeh, although we believe some operators have assigned it to the Mattson. These sands are found in a structurally-disturbed area in the Bovie Fault Zone, immediately offsetting local surface exposures of the Mattson and Flett/Debolt (Fig. C3). We considered the Mattson interpretation, but settled upon including this sandstone with the Chinkeh because:

- Stratigraphic position is consistent with the Chinkeh – overlying the pre-Cretaceous unconformity
- Stratigraphic position is not consistent with the Mattson – lies on the Fantasque (and regional Mattson) in d-87-I/94-O-14, and directly on the Debolt (no intervening Golata) in c-20-K/94-O-15
- The sandstone section appears very similar on logs from well to well, and ranges from 24 to 85 metres thick. The (typical) Mattson section at a-57-L/94-O-15, drilled very close to the Mattson outcrops, is more than 500 metres thick.
- Clean, porous, quartz-rich sandstones, logged in sample cuttings at b-100-F/94-O-15 are consistent with Chinkeh shoreface sandstones (but could also be from the Mattson).

Reservoir Quality

Chinkeh sandstones were described by Leckie *et al.* (1991) as: "fine- to medium-grained, well-sorted, slightly glauconitic, matrix-poor, moderately porous sublitharenite to quartzarenite. The majority of the sandstone is mineralogically very mature and texturally mature". Frank *et al.* (1999) noted porosities of 15-20% and permeabilities of 5-80 mD in the Maxhamish gas field. However, regional cross-sections and core logs through the Chinkeh in this study also demonstrate a high proportion of argillaceous, fine-grained, non-reservoir rock (e.g., b-98-A/94-O-5, 02/b-71-K/94-O-6).

Quartz overgrowths are the dominant cement in the Chinkeh, particularly in the most quartzose sandstones (Leckie *et al.*, 1991). Pyrobitumen, calcite, and clays were also noted, but are volumetrically less important.

Core analysis data from the Chinkeh show relatively low-permeability sandstones; the best-fit line in the porosity-permeability crossplot does not attain 10 mD until porosity values reach 21% (Fig. C4). Given these low permeability values, and the fact that most of the better-quality sandstone in the Chinkeh is hydrocarbon-charged in the Maxhamish Field, we decided it would not be productive to pick net porous sandstone values for the Chinkeh, as it exhibits very little rock with the aquifer characteristics needed to support unconventional resource development.

Well logs indicate considerably better reservoir quality in the basal Cretaceous sandstone section in the northeast, although in a number of sections it is fully or partially

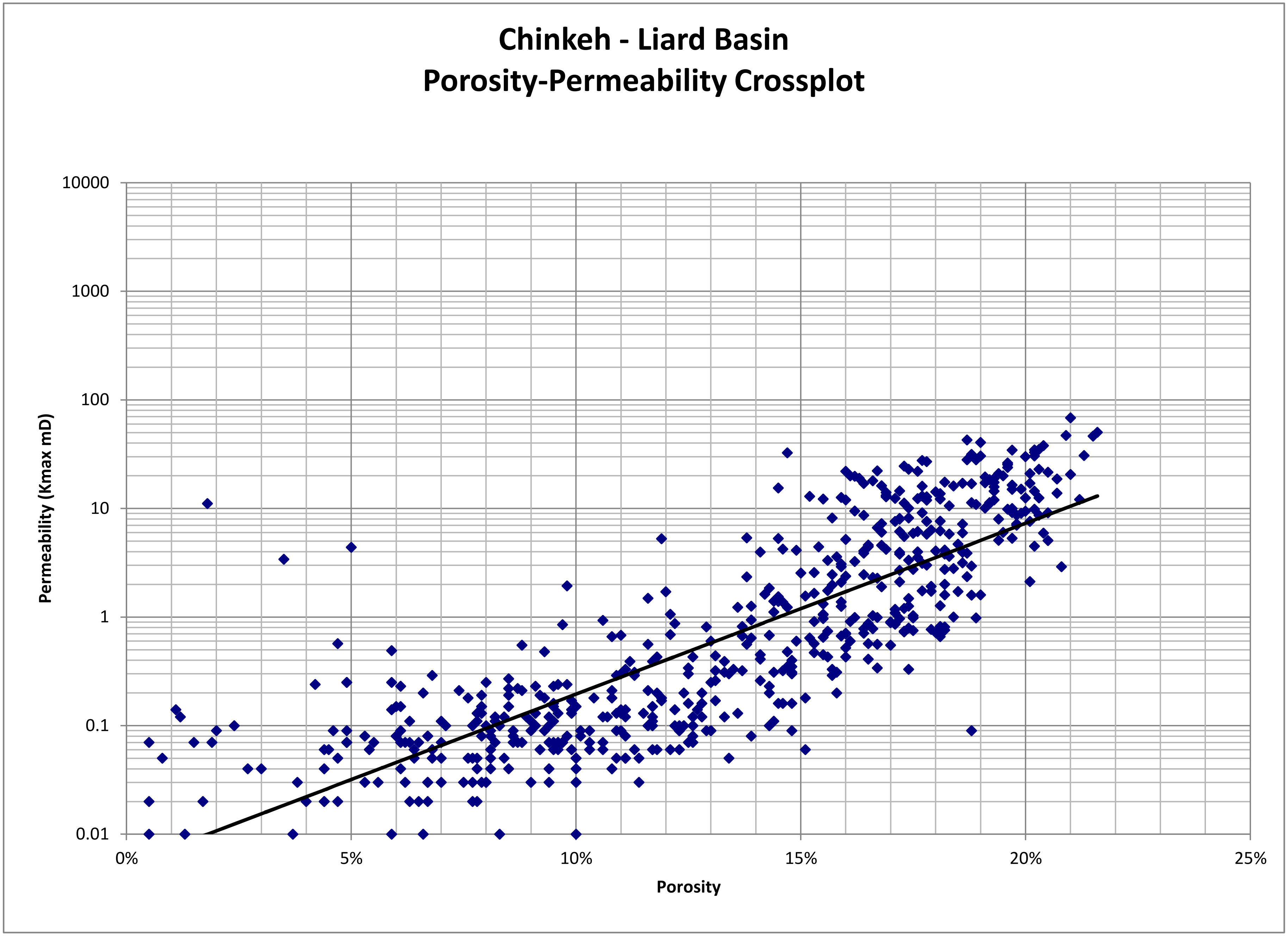


Figure C4. Porosity-permeability crossplot from core analysis data, Chinkeh Formation.

behind surface casing, and hence is not logged with a full suite of tools. As this unit is outside Liard Basin proper, and has little or no core or test data, we have not attempted a quantitative interpretation.

Hydrogeology – Chinkeh Formation

Thirteen DSTs conducted in the Chinkeh Formation in 13 wells have been reviewed, most within or flanking the Maxhamish Lake Chinkeh 'A' Pool (Fig. C5, Appendix 5). There are additional tests in field wells not used in our mapping, but these were judged not to offer significant additional information. Of the thirteen tests, six have useable pressures and can be plotted on a Pressure-Elevation plot. Pressure gradients for valid tests range from 5.69 to 8.23 kPa/m (0.251 to 0.364 psi/ft). Most tests show relatively low (0.1 - 2 mD) to very low/virtually no (<0.01 mD) qualitative permeability, and only two tests (both in B/94-O-14) are rated relatively high (10-20 mD) and high (20-50 mD). All of the tests recovered mud or gas, and no tests reported any water recovery.

The Chinkeh produces gas in the Maxhamish Lake Chinkeh A Pool, located in 94-O-6, 94-O-11 and 94-O-14, west of the Bovie Fault Zone (Fig. C5, Appendix 6). Very little water is co-produced from this pool, which appears to have a down-dip oil leg in 94-O-11. A preliminary Pressure-Elevation plot was not useful in delineating a regional aquifer, as there are no water tests, and we conclude that there is no evidence for a regional Chinkeh aquifer. These observations suggest that the Chinkeh is in a Deep Basin (hydrocarbon-saturated) regime. Chinkeh tests are plotted on a composite Pressure-Elevation plot, which also includes Scatter and Dunvegan tests (Fig. C6).

One valid formation water analysis is available for the Chinkeh Formation at a-96-J/94-O-14, which yielded a salinity of 16,873 mg/l TDS (Appendix 7).

No potentiometric surface values could be calculated for the Chinkeh in the absence of valid water tests.

SCATTER FORMATION

The Scatter Formation was deposited in shallow marine shelf to shoreline settings in Liard Basin, and is encased by marine shales of the Garbutt Formation below and the Lepine Formation above (Fig. S1). Two sandstone members, the Tussock and Bulwell, are recognized in outcrop, but generally are not distinguished in the subsurface. Stott (1982) mapped the Scatter in outcrop; Leckie and Potocki (1998) provided a detailed sedimentological and petrographic analysis in outcrop and the subsurface of Liard Basin (Fig. S2). On regional cross-sections, the Scatter interval appears as a thick and homogeneous interval between prominent log markers in the regional shales above and below.

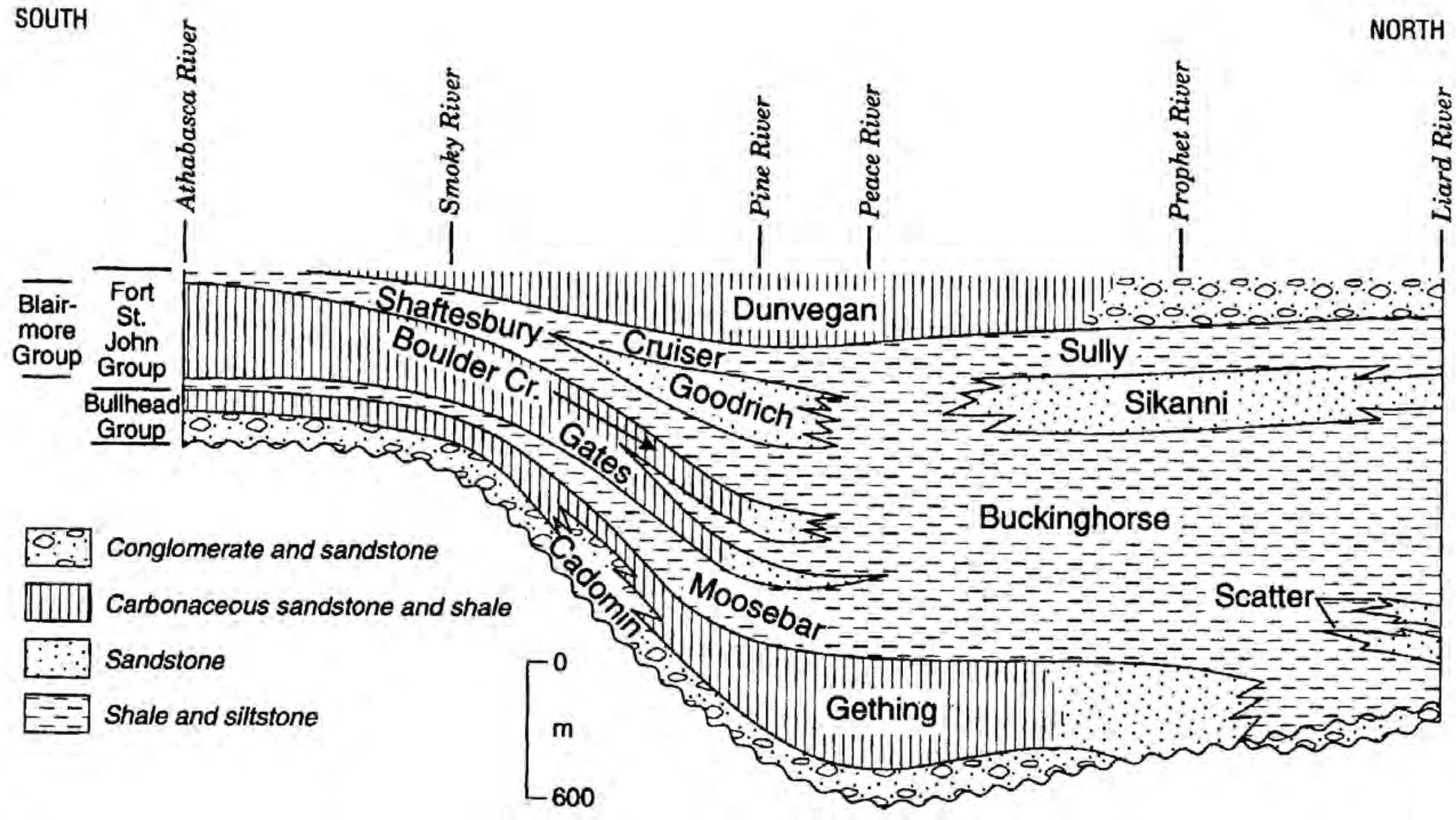
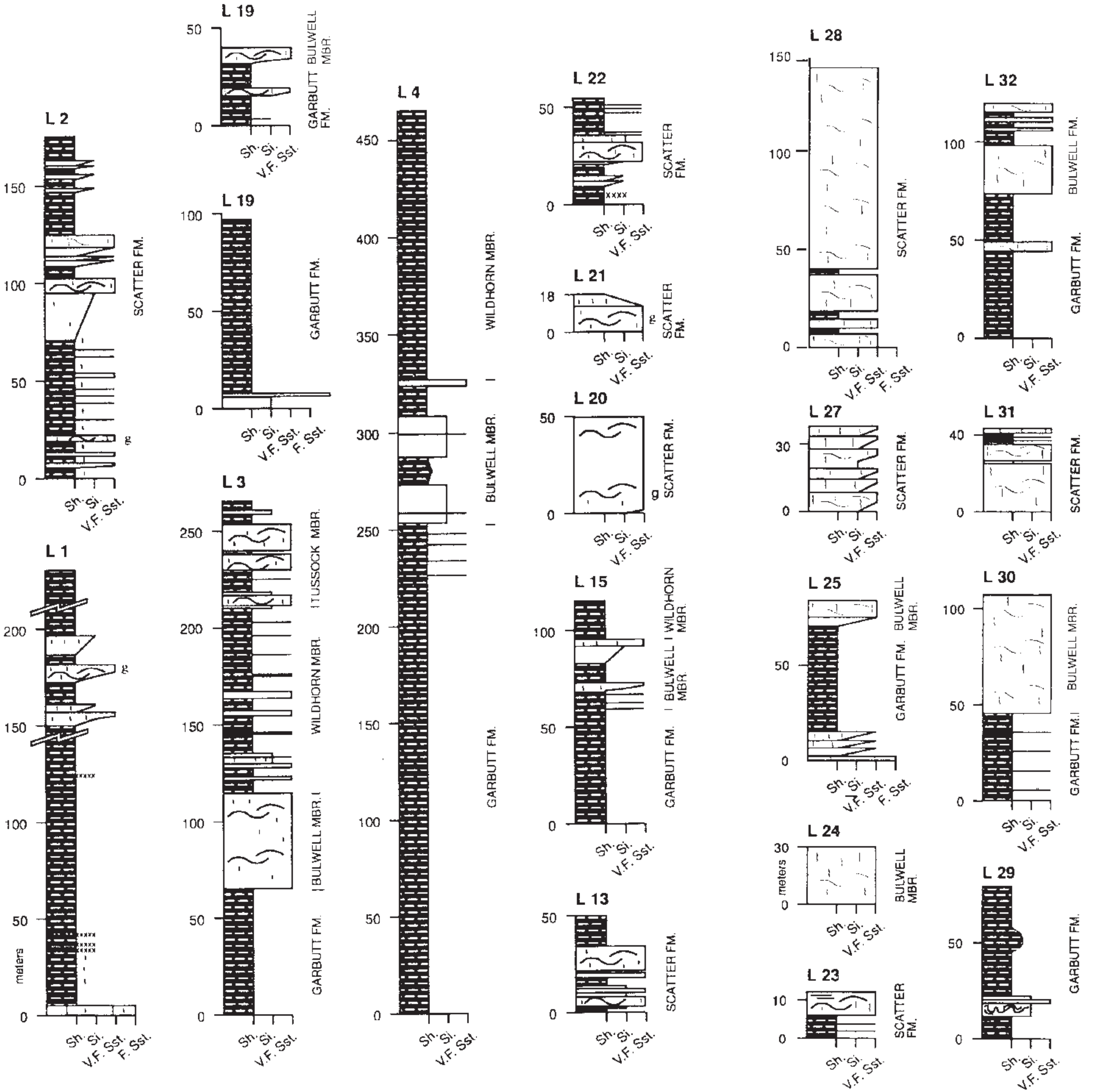


Figure S1. Schematic stratigraphic cross-section, Fort St. John Group, northeastern B.C. Scatter sandstones are limited to the Liard Basin (from Leckie and Potocki, 1998).



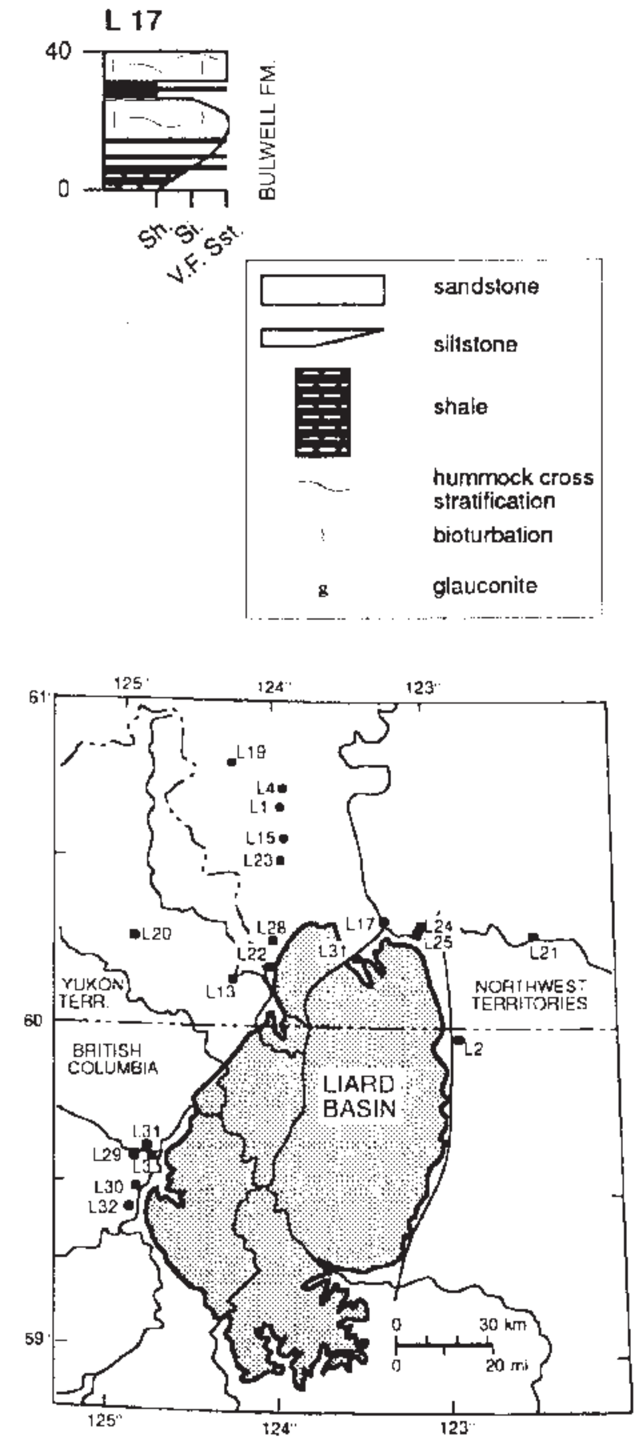


Figure S2. Outcrop measured sections, Scatter Formation, Liard Basin (from Leckie and Potocki, 1998).

Scatter sandstones occur throughout the Liard Basin subsurface, and crop out along the western margin (Fig. S3). Outcrop is posted only in the west and extreme south, as the Scatter is not broken out in surface mapping in between. Depth of burial ranges from just over 200 metres along the eastern flank of the basin to more than 1700 metres at the basin centre (Fig. S3); shallowing at the western edge of the basin likely occurs much more abruptly than indicated on the regional map, but well control is scarce and outcrop is not mapped in the southwest. Gross thickness increases from zero along the eastern margin of Liard Basin to more than 400 metres in the west (Fig. S4). From isopach and net sandstone distributions, Leckie and Potocki (1998) interpreted major depocentres to the west and southwest of Liard Basin.

Reservoir Quality

Scatter sandstones are silty to very fine-grained, moderately- to well-sorted, matrix-rich, moderately to poorly porous, glauconitic and lithic. Much of the clay matrix is pseudomatrix, produced by ductile deformation of labile framework grains. Compaction has thus greatly reduced porosity and permeability; in addition, locally abundant calcite cement has further reduced reservoir quality. On logs, the Scatter is characterized by a serrated or "ratty" gamma log signature, indicating much of the section consists of interbedded sandstones and finer-grained rocks (see regional cross-sections).

Core analyses from two cored sections show poor reservoir quality, with the best values reaching just over 14% porosity and 2-3 mD permeability (Fig. S5). Given the heterolithic nature of the formation, vertical permeabilities on a large scale are likely to be substantially lower. Leckie and Potocki (1998) measured porosity values of 0 to 11% from outcrop samples, but noted no potential for coarser rocks with better reservoir quality.

We did not attempt to pick net porous sandstone values from logs, given the poor quality of the rock. Leckie and Potocki (1998) measured "net sandstone" thicknesses of greater than 100 metres over the western part of Liard Basin, but these values were picked with tight gas sandstones as the reservoir model.

Hydrogeology – Scatter Formation

Twenty-one drillstem tests have been conducted in the Scatter Formation in 16 wells scattered throughout the basin (Fig. S4, Appendix 5). However, five tests are misruns, and only three tests (all from the same well) have useable pressures. Pressure gradients for the three valid tests range from 9.31 to 9.92 kPa/m (0.411 to 0.438 psi/ft). Permeability of the formation is extremely poor – 13 of 16 valid tests have very low to virtually no perm (<0.01 mD). Water was recovered on only one test in well a-98-D/94-O-13.

Gas production from the Scatter has been recorded in only one well in the Maxhamish Field – d-80-J/94-O-6 produced 24 e^3m^3 (850 MCF).

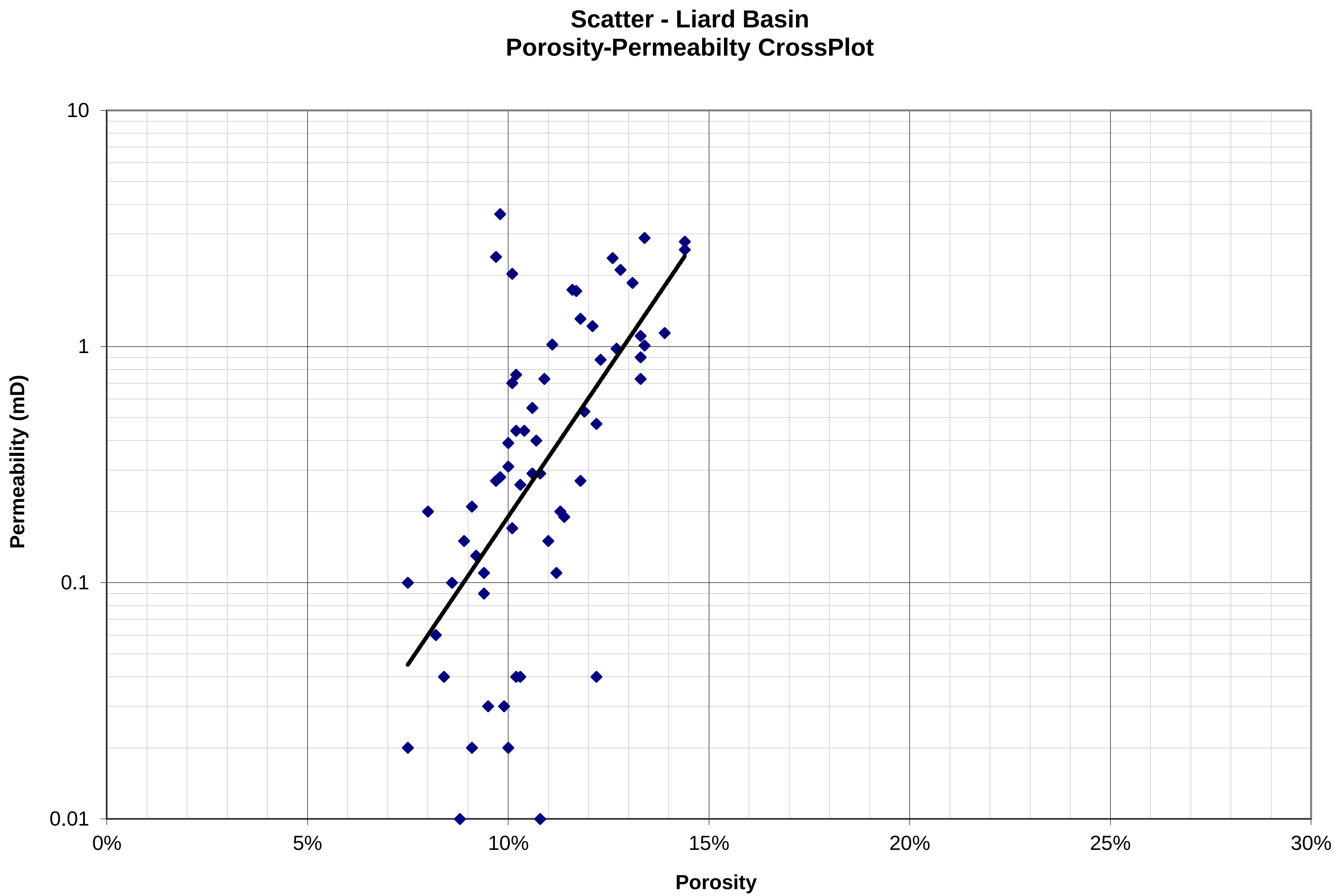


Figure S5. Porosity-permeability crossplot from core analysis data, Scatter Formation.

Referring to the Pressure-Elevation plot (Fig. C6), there is data scatter within the only well with valid DSTs (b-55-E/94-O-13), suggesting poor vertical continuity within the formation.

One formation water analysis is available for the Scatter Formation at d-35-G/94-O-4, with a salinity of 24,346 mg/l TDS.

No potentiometric surface values could be calculated for the Scatter with only one valid water test.

DUNVEGAN FORMATION

Upper Cretaceous (Cenomanian) Dunvegan deposition and stratigraphy have been studied extensively in outcrop and in the subsurface in west-central Alberta and the Peace River region of northeastern B.C. (Riddell, 2012). Further north, the Dunvegan is known primarily from GSC field mapping. Stott (1982) compiled numerous earlier reports in describing the Dunvegan in outcrop and subsurface throughout northeastern B.C. and northward into NWT. In Liard Basin, he mapped extensive Dunvegan outcrop, and measured a number of sections along river valleys and in major cliff exposures.

Dunvegan strata crop out within Liard Basin, and occur in the subsurface only in the northern part of the basin (Fig. D1). Depth to top of the formation ranges up to 750 metres, although it is much shallower in most wells. Where it does exist, part or all of the formation is behind surface casing in wellbores, and thus is not completely logged (Fig. D1).

Stott (1982) showed the Dunvegan to pass from interbedded sandstones and shales in the south to a conglomerate-dominated section in Liard Basin (Fig. D2), where it generally comprises a basal sandstone grading up from underlying shales, passing into "thick units of coarse-grained conglomeratic sandstone and conglomerate separated by units of carbonaceous mudstone with minor amounts of fine-grained sandstone and siltstone" (Stott, 1982) (Fig. D3). The succession ranges up to just over 200 m thick, although many outcrop exposures are only partly preserved and are thus incomplete (Fig. D4). Stott interpreted Dunvegan deposition to have taken place in a broad high-relief alluvial setting, adjacent to western uplands that experienced a pulse of renewed tectonism around Cenomanian time.

Reservoir Quality

Stott (1982) noted that conglomerates and sandstones are composed primarily of chert and quartz, with small proportions of rock fragments, feldspars, and other non-resistant components. Coarser conglomerates appear to be clast-supported, although sandstone matrix is present in places.

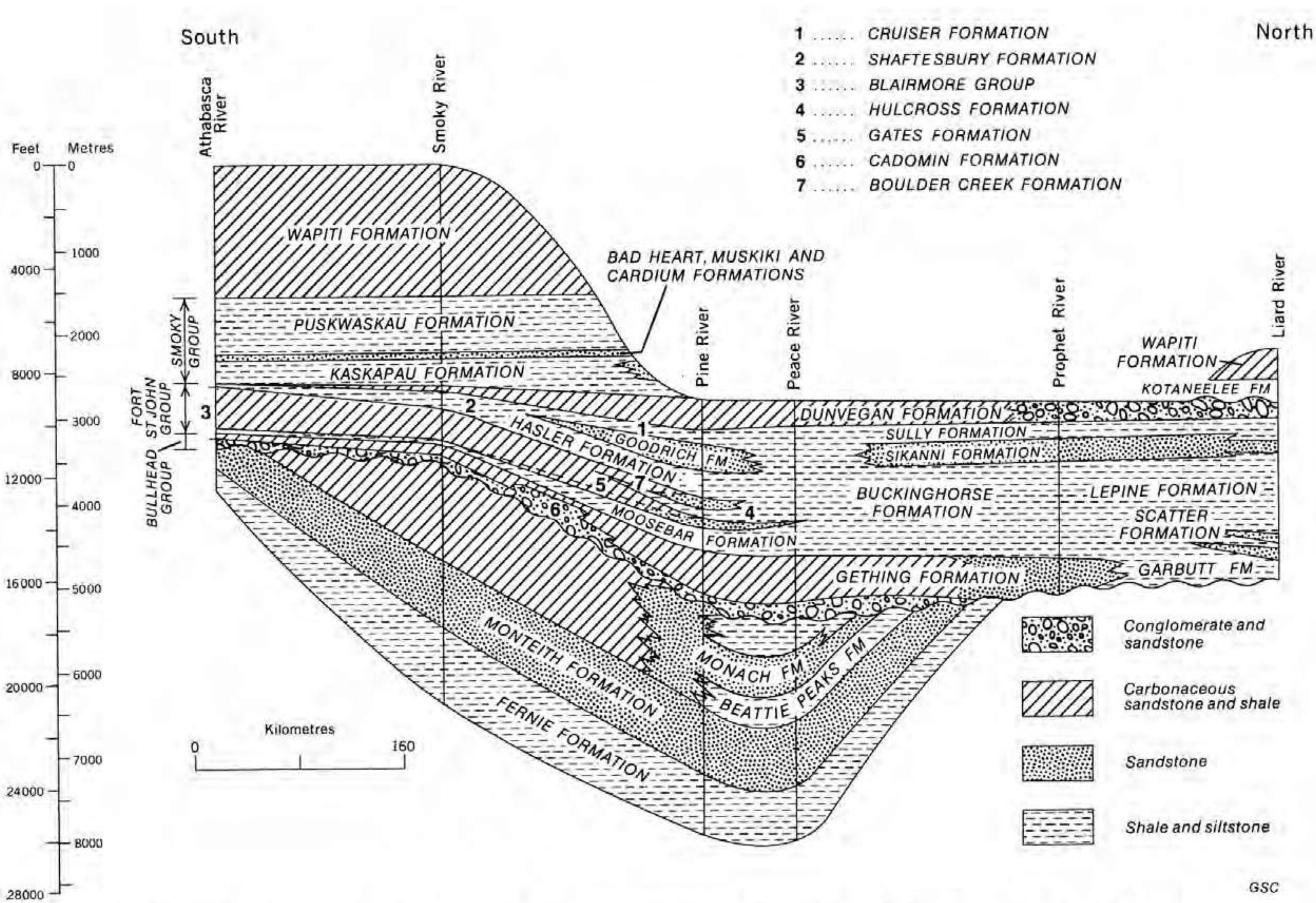


Figure D2. Schematic stratigraphic diagram for Jurassic and Cretaceous strata of NEBC (from Stott, 1982).

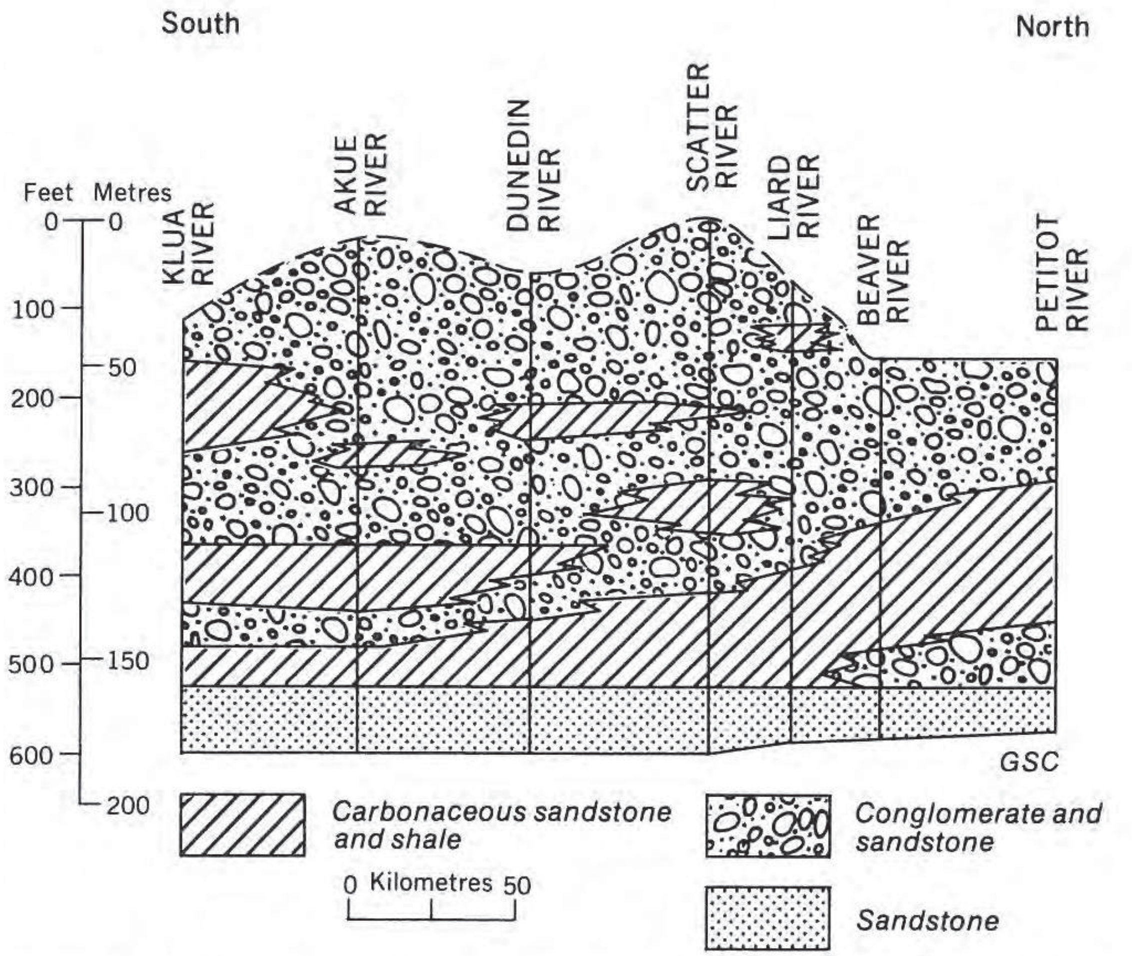


Figure D3. Schematic diagram illustrating facies and approximate thicknesses of Dunvegan Formation (from Stott, 1982).

Core analysis data from the one available core in Liard Basin at 03/b-71-K/94-O-6 shows excellent reservoir quality (Fig. D5). Sample cuttings show excellent reservoir at c-66-I/94-N-9 (porosities to 20%, permeabilities to 50+ mD), and more moderate reservoir quality at a-77-D/94-O-11 (porosities to 14-16%, permeabilities from <1 mD to 10-50+ mD).

We did not attempt to pick or map net porous sandstone values for the Dunvegan, as there is very limited porosity log coverage. However, as gamma log coverage is somewhat more complete, we did create a net clean sandstone isopach map using a 60 API gamma cutoff (Fig. D6). Given the very good reservoir quality observed in core, samples and outcrop, we expect that a high proportion of the clean sandstones would also make the cutoff for net porous sandstones. Every Dunvegan section shows a substantial component of net clean sandstone, with thicknesses ranging from about 40 to 140 metres.

Hydrogeology – Dunvegan Formation

Five drillstem tests have been conducted in the Dunvegan Formation in three wells (Fig. D4, Appendix 5). Of the five tests, four have useable pressures and can be plotted on a Pressure-Elevation plot (Fig. C6) Tests in 202/a-67-D/94-O-13 (DSTs #3 and 4) confirm vertical hydraulic communication; however, no pressure or fluid communication was observed between wells. Pressure gradients for valid tests (all fluid types) range from 5.32 to 10.46 kPa/m (0.238 to 0.462 psi/ft). Pressure gradients for valid water tests have the same range. Three out of the four valid tests exhibit high permeability (10-20 mD), and the fourth test has relatively low permeability (0.1-2 mD).

There is no hydrocarbon production from the Dunvegan, and no valid formation water analyses.

No potentiometric surface values could be calculated for the Dunvegan with only two valid water tests.

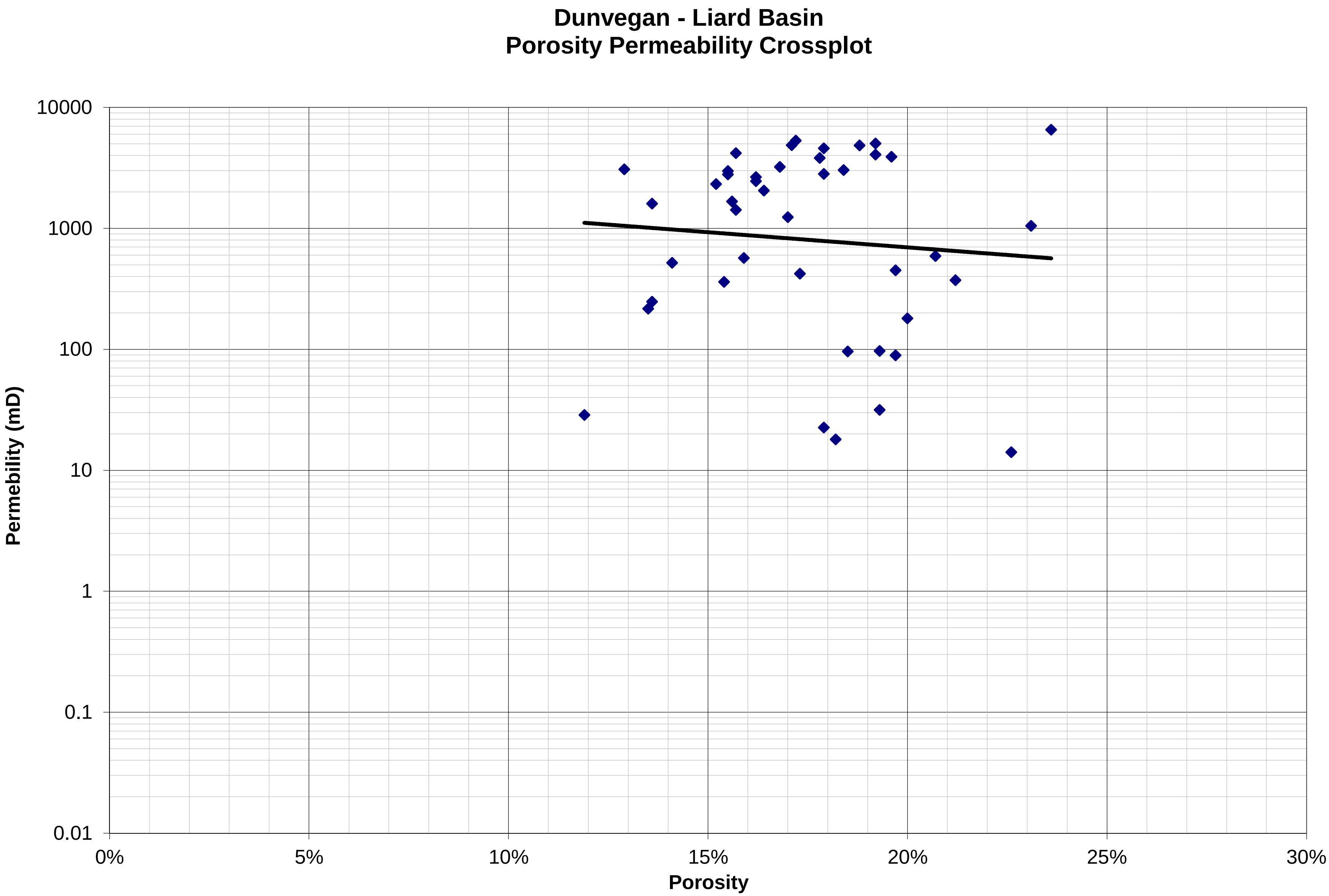


Figure D5. Porosity-permeability crossplot from core analysis data, Dunvegan Formation.

No water source wells in deep saline aquifers were identified in Liard Basin.

Eight water disposal zones in six wells were identified. Injection zones are: Rundle (2 zones), Mattson (3 zones), Fantasque/Mattson (2 zones), and Sikanni (1 zone) (Appendix 8).

Looking at these injectors on a zone-by-zone basis:

Transeuro Beaver River 202/b-19-K/94-N-16 (Mattson, Suspended Water Disposal)

- Cumulative injection = 336,832 m^3 water
- Average injection daily rates = 1.5 e^3m^3/d from April 1999 to January 2000, and 40 m^3/d from February to December 2000.
- Average injection monthly rates = 20 e^3m^3/month from April 1999 to January 2000, and 1.2 e^3m^3/month from February to December 2000. Maximum monthly rates were 5 e^3m^3/month.
- The well was later brought on production for two months in 2001 (March/April), at which time it produced 12 e^3m^3 of water at a maximum rate of 9.6 e^3m^3/month.

Transeuro Beaver River d-64-K/94-N-16/02 (Mattson, Abandoned Water Disposal (917.4-929.6m, 996.6-999.7m)

- Cumulative injection = 953,215 m^3 water
- Daily injection rates are not available for the injection period (1972-1978).
- Average injection monthly rates = 9 e^3m^3/month, sustained fairly consistently throughout injection life.

Transeuro Beaver River d-64-K/94-N-16/03 (Re-entry) (Mattson, Water Disposal (917.5 – 1138.1m)

- Cumulative injection = 150,698 m^3 water
- Well accepted 148 e^3m^3 water from 1990 to 1993, at maximum rates up to 1000 m^3/d (25 e^3m^3/month).
- Intermittent injection resumed in 2006, with rates averaging 120 m^3/d from 2011 to 2013.

EOG Tattoo b-35-E/94-O-10 (Rundle, Water Disposal)

- Cumulative injection = 131,113 m^3 water, beginning October 2010
- Injection rates average 400 m^3/d, or 4 e^3m^3/month
- Entire Debolt section perfed and acidized; wellsite sample description indicate abundant dolomite through upper 150 metres

Tervita Maxhamish a-95-H/94-O-11 (Fantasque/Mattson, Water Disposal)

- Cumulative injection = 18,049 m^3 water, beginning July 2012
- Average injection rates are about 600 m^3/d.
- Initially tested for gas production from the Fantasque, converted to water disposal, frac'd across Fantasque and upper Mattson sands

Tervita Maxhamish a-95-H/94-O-11/02 (Re-entry) (Fantasque/Mattson, Water Disposal)

- Second event in this wellbore appears to reflect addition of perfs in upper Mattson interval, after attempt to produce gas from Fantasque
- Injection rates were 630 m^3/d for May/June 2012, for a total of 7.4 e^3m^3 .

Apache Patry 202/c-30-A/94-O-12 (Sikanni, Water Disposal)

- Cumulative injection = 6,359 m^3 water
- Injection has occurred sporadically since April 2009, at average injection rates of ~25 m^3/d, or 200 m^3/month.
- Sikanni sandstone lies about 80 metres beneath a thick Dunvegan conglomerate at this location, separated by Sully Formation shales. The entire 20 metre Sikanni section was perfed and acid squeezed to establish disposal capacity.

EOG Maxhamish c-20-K/94-O-15 (Rundle, Suspended Water Disposal)

- Cumulative injection = 35,236 m^3 water
- This well was on injection from January 2010 to February 2011, at average injection rates of 100 m^3/d, or 2 e^3m^3/month.
- Two intervals, 7 and 8 metres thick, in the middle to lower Rundle were acid frac'd. The intervals appear clean and reasonably porous on logs, but not anomalously so; they may have been identified on samples or drilling records.

Analyzing water well performance using only injection statistics entails some uncertainty, as injection rates and volumes are likely controlled by volumes available, and not by the capacity of the zone being injected. However, we can make the following observations:

- Thick, sand-rich Mattson sections at Beaver River are capable of accepting high water volumes and rates; these waters are probably produced from high-WGR wells in the Beaver River Field.

- The Rundle can accept more modest water volumes in the Bovie Fault Zone area with appropriate stimulation. At least some of the water capacity appears related to matrix porosity development in dolomites.

- The Sikanni, although not addressed in this study, has some local water disposal capacity at Patry. We speculate that Apache needed this capacity to handle produced waters from its new shale play wells in the area. We find it interesting that injection was allowed at such a shallow depth (470 m) into a formation that could be relatively continuous laterally.

SUMMARY AND CONCLUSIONS

Conclusions regarding subsurface aquifer potential in Liard Basin are tempered by the limited distribution of wellbore data, particularly as many of the wells in more remote parts of the basin were drilled as exploratory tests several decades ago. However, with the support of a good regional geological framework, we summarize with the following points:

1. Mattson Formation sandstones offer very good to excellent water source and disposal zone potential in the northern and northeastern portions of Liard Basin.

    a. Porous wet sandstone sections, tens of metres thick, exhibit good reservoir quality and only limited hydrocarbon charge in defined structural traps. Reservoir quality decreases southward, away from the northerly source area, but well control is too poor in the middle of the basin to quantify this trend well.

    b. Injection well performance at Beaver River appears very good, indicating the potential for at least 1000 m^3/d capacity.

    c. Depth of burial is quite shallow in the Bovie Fault Zone, but increases rapidly southward and westward.

    d. Water salinities are modestly saline.

    e. Cross-formational connectivity of Mattson tests with Rundle and Fantasque tests indicates very large potential aquifer volumes.

2. Dunvegan sandstones and conglomerates may offer very good to excellent water source potential in the north-central part of the basin.

    a. Thick, very coarse-grained rocks appear to have very good reservoir quality from well logs, sample cuttings, and outcrop descriptions, but our dataset is limited. Distribution of the unit is defined by an outcrop belt within the basin.

    b. Depth of burial is very shallow, making water sourcing attractive but likely precluding any water disposal potential.

    c. Water salinity data were not available, but we expect the waters would be non-saline, and experiencing recharge from nearby outcrops.

3. Rundle and Fantasque rocks exhibit moderate reservoir potential in some wellbores, but reservoir quality appears to be substantially poorer than in the Mattson.

    a. Tighter, more brittle rocks dominate both sections – carbonates in the Rundle and siliceous sediments in the Fantasque, with relatively isolated better reservoir in dolomitized intervals, sandstones, and probably fractured intervals.

    b. Rundle carbonates are present beyond the eastern margin of the basin, but their reservoir quality degrades rapidly west of the Bovie Fault Zone.

    c. Injection well performance is moderate, at up to 100-400m^3/d.

    d. Depth of burial is reasonably shallow along the Bovie Fault but increases rapidly westward.

    e. Common pressure systems with the Mattson and similar water salinities indicate potential for large effective aquifer volumes.

4. Chinkeh Formation sandstones exhibit moderate to poor aquifer potential.

    a. Rock properties and test results show limited reservoir potential, and the Chinkeh is within a regional (Deep Basin?) gas trap in the eastern part of the basin.

    b. To the northeast, just east of the Bovie Fault Zone, a thick basal Cretaceous sandstone package appears on logs to have very good reservoir quality and water saturations. However, rock and test data are lacking. Combined with the substantial Mattson potential, this area may have the best subsurface water source and disposal potential in the region.

5. Chinchaga Formation has limited potential as a deep disposal zone.

    a. While limited permeability is indicated on some tests, Chinchaga carbonates and evaporites are generally tight, and most permeability is likely associated with fracturing. Reservoir volumes and continuity are thus questionable.

    b. Extreme burial depths and high water salinities make the Chinchaga unattractive as a water source interval.

    c. Water disposal may be viable where the Chinchaga is relatively shallow, reservoir permeability has been established, and a high degree of confidence is required that disposed fluids are safely isolated.

6. Scatter Formation sandstones have very limited aquifer potential.
    a. The Scatter has the rock properties of a tight gas sandstone reservoir, and exhibits no substantial aquifer properties.

REFERENCES

Adams, C., 2013. Summary of shale gas activity in northeast British Columbia 2012. *In:* Oil & Gas Reports 2013, British Columbia Ministry of Natural Gas Development, p. 1-27.

Badgley, P.C., 1952. Notes on the subsurface stratigraphy and oil and gas geology of the Lower Cretaceous series in central Alberta. Geological Survey of Canada Paper 52-11.

Bamber, E.W., and B.L. Mamet, 1978. Carboniferous biostratigraphy and correlation, northeastern British Columbia and southwestern District of Mackenzie. Geological Survey of Canada Bulletin 266.

Bamber, E.W., G.C. Taylor, and R.M. Proctor, 1968. Carboniferous and Permian stratigraphy of northeastern British Columbia. Geological Survey of Canada Paper 68-15.

Barclay, J.E., G.D. Holmstrom, P.J. Lee, R.I. Campbell, and G.E. Reinson, 1997. Carboniferous and Permian gas resources of the Western Canada Sedimentary Basin, Interior Plains. Geological Survey of Canada Bulletin 515.

B.C. Ministry of Energy and Mines and National Energy Board, 2011. Ultimate potential for unconventional natural gas in northeastern British Columbia's Horn River Basin. Oil and Gas Reports 2011-1.

Chalmers, G.R.L. and R.M. Bustin, 2008. Lower Cretaceous gas shales in northeastern British Columbia, Part II: evaluation of regional potential gas resources. Bulletin of Canadian Petroleum Geology, v. 56, no. 1, p. 22-61.

Ferri, F., A.S. Hickin and D.H. Huntley, 2011. Besa River Formation, western Liard Basin, British Columbia (NTS 094N): geochemistry and regional correlations. *In* Geoscience Reports 2011, B.C. Ministry of Energy and Mines, p. 1-18.

Frank, J., K. Aulstead, M. Edmonds, and G. Pemberton, 1999. Stratigraphy and ichnology of the Lower Cretaceous Chinkeh Formation, Liard Basin, northeastern B.C. In: 1999 CSPG and Petroleum Society Joint Convention Core Conference Guidebook, Abstract 99-117C.

Frank, J.H., M.K. Gingras, S.G. Pemberton, K. Aulstead and M. Edmonds, 2000. A wave-dominated shoreface: the anatomy of a 400 BCF gas field, Maxhamish Lake, northeastern British Columbia. Proceedings, GeoCanada 2000 conference.

Hayes, B.J.R., and R. Stewart, *in review*. Deep subsurface saline aquifer characterization, Deh Cho area, Northwest Territories. Report for Northwest Territories Geoscience Office.

Henderson, C.M., E.W. Bamber, B.C. Richards, A.C. Higgins, and A. McGugan, 1993. Permian; Subchapter 4F in Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (ed.); Geological Survey of Canada, Geology of Canada, no. 5, p. 272-293.

Hopkins, J.C., 1999. Characterization of reservoir lithologies within subunconformity pools: Pekisko Formation, Medicine River Field, Alberta, Canada. Bulletin of the American Association of Petroleum Geologists, v. 83, no. 11, p. 1855-1870

Law, J., 1981. Mississippian correlations, northeastern British Columbia, and implications for oil and gas exploration. Bulletin of Canadian Petroleum Geology, v. 29, p. 378-398.

Leckie, D.A., and D.J. Potocki, 1998. Stratigraphy and petrography of marine shelf sandstones of the Cretaceous Scatter and Garbutt formations, Liard Basin, northern Canada. Bulletin of Canadian Petroleum Geology, v. 46, p. 30-50.

Leckie, D.A., D.J. Potocki, and K. Visser, 1991. The Lower Cretaceous Chinkeh Formation: a frontier type play in the Liard Basin of western Canada. Bulletin of the American Association of Petroleum Geologists, v. 75, p. 1324-1352.

Macedo, R., 2012. Apache validates new shale play in B.C.'s Liard Basin. Daily Oil Bulletin, June 14, 2012.

MacLean, B.C., and D.W. Morrow, 2004. Bovie Structure: its evolution and regional context. Bulletin of Canadian Petroleum Geology, v. 52, p. 302-324.

Massey, N.W.D., D.G. MacIntyre, P.J. Desjardins and R.T. Cooney, 2005. Digital geology map of British Columbia: Whole Province. B.C. Ministry of Energy and Mines, GeoFile 2005-1.

Monahan, P., 1999. Stratigraphy and potential hydrocarbon objectives of Mississippian to Lower Cretaceous strata in the eastern Liard Basin area. Report, British Columbia Ministry of Energy, Mines, and Mineral Resources.

Moore, P.F., 1993. Devonian; Subchapter 4D *in* Sedimentary Cover of the Craton in Canada, edited by D.F. Stott and J.D. Aitken, Geological Survey of Canada, Geology of Canada no. 5, p. 150-201.

Morrow, D.W., and R. Shinduke, 2003. Liard Basin, northeast British Columbia: an exploration frontier. Proceedings, Partners in a new Environments, CSPG/CSEG Join Convention.

Mossop, G.D., K.E. Wallace-Dudley, G.G. Smith, and J.C. Harrison (compilers), 2004. Sedimentary basins of Canada. Geological Survey of Canada Open File Map 4673.

Petrel Robertson Consulting Ltd., 2000. Exploration study of Mississippian and Cretaceous strata, Bivouac area, N.E. British Columbia and N.W. Alberta. Non-exclusive report.

Petrel Robertson Consulting Ltd., 2005. Exploration for deep Devonian reservoirs, northeastern British Columbia – new perspectives. Non-exclusive report.

Petrel Robertson Consulting Ltd., 2010. Horn River Basin aquifer characterization project geological report (NTS 94I, 94J, 94O & 94P). Geoscience BC Report 2010-11 http://www.geosciencebc.com/s/2010-011.asp

Richards, B.C., 1989. Uppermost Devonian and Lower Carboniferous stratigraphy, sedimentation, and diagenesis, southwestern District of Mackenzie and southeastern Yukon Territory. Geological Survey of Canada Bulletin 390.

Richards, B.C., E.W. Bamber, A.C. Higgins, and J. Utting, 1993. Carboniferous; Subchapter 4E in Sedimentary Cover of the Craton in Canada, D.F. Stott and J.D. Aitken (ed.); Geological Survey of Canada, Geology of Canada, no. 5, p. 202-271.

Richards, B.C., J.E. Barclay, D. Bryan, A. Hartling, C.M. Henderson and R.C. Hinds, 1994. Carboniferous strata of the Western Canada Sedimentary Basin. In: Geological Atlas of the Western Canada Sedimentary Basin, edited by G.D. Mossop and I. Shetsen. Canadian Society of Petroleum Geologists and Alberta Research Council, Calgary, Alberta, p. 221-250.

Riddell, J., 2012. Potential for freshwater bedrock aquifers in northeast British Columbia: regional distribution and lithology of surface and shallow subsurface bedrock units (NTS 093I, O, P; 094A, B, G, H, I, J, N, O, P). *In* Geoscience Reports 2012, British Columbia Ministry of Energy and Mines, p. 65-78.

Smith, D.G., 1994. Foreland Basin. In: Geological Atlas of the Western Canada Sedimentary Basin, edited by G.D. Mossop and I. Shetsen. Canadian Society of Petroleum Geologists and Alberta Research Council, Calgary, Alberta, p.317-334.

Stott, D.F., 1982. Lower Cretaceous Fort St. John Group and Upper Cretaceous Dunvegan Formation of the Foothills and Plains of Alberta, British Columbia, District of Mackenzie and Yukon Territory. Geological Survey of Canada Bulletin 328.

Taylor, G.C., and D.F. Stott, 1968. Maxhamish Lake, British Columbia (94-O). Geological Survey of Canada Paper 68-12.