PETROLEUM HYDROGEOLOGY OF THE HALFWAY FORMATION, NORTHEASTERN BRITISH COLUMBIA

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ABSTRACT

The petroleum hydrogeology of the Halfway Formation is one component of a detailed examination of British Columbia's existing Halfway Formation oil producers. Petroleum hydrodynamics provides insight on factors important for exploration and development such as formation fluid flow direction, connectivity of reservoirs, trapping mechanisms and oil-gas-water contacts. Pressure, depth and formation water salinity data from more than 500 wells with water-producing drillstem tests (DSTs) were examined. From among those more than 500 DSTs, only just over 200 of the best test results provided DST data to build a pressure-depth plot, salinity map and potentiometric surface map. A pressure-depth plot indicates a pervasive reservoir system, with most data points falling along a common gradient. The reservoir appears to be generally underpressured in relation to a hydrostatic gradient. Updip flow is indicated by the hydrodynamic gradient. Higher salinities generally coincide with the hydrocarbon reservoirs; fresher water occurs along and near the western disturbed belt and near the subcrop edge. A potentiometric surface map shows formation water generally flowing from west to east, except near the subcrop edge, where the direction reverses. Most oil accumulations appear to be within areas of relatively low hydrodynamic potential. Oil appears to be trapped as a result of downdip flow into areas of low potential.

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INTRODUCTION

This study of the petroleum hydrogeology of the Halfway Formation in British Columbia is intended as partial regional groundwork prior to detailed examinations of individual oil pools. An understanding of the way fluids move through the Halfway Formation might provide explorationists another perspective on British Columbia's most traditional and important oil-producing formation. It might explain in part the how and why of oil migration and entrapment within the Halfway Formation and potentially lead to new discoveries. In addition, this information might be important to the future use of depleted oil pools for water disposal or carbon sequestration.

Most Halfway Formation oil production in British Columbia occurs north of the Peace River (Fig. 1), north and northeast of the town of Fort St. John.

Petroleum hydrogeology (sometimes referred to as petroleum hydrodynamics) is fundamental for understanding how and where hydrocarbons accumulate. It can also be used to show

- whether a single reservoir exists under one pressure regime or a number of reservoirs exist at different pressures;
- flow direction of formation fluids and potential energy (potentiometric surface);
- where permeability barriers might exist, where flow is relatively unhindered or where static nonhydrodynamic conditions prevail;
- gas-oil-water contact elevations; and
- water chemistries where recharge/discharge might be occurring.

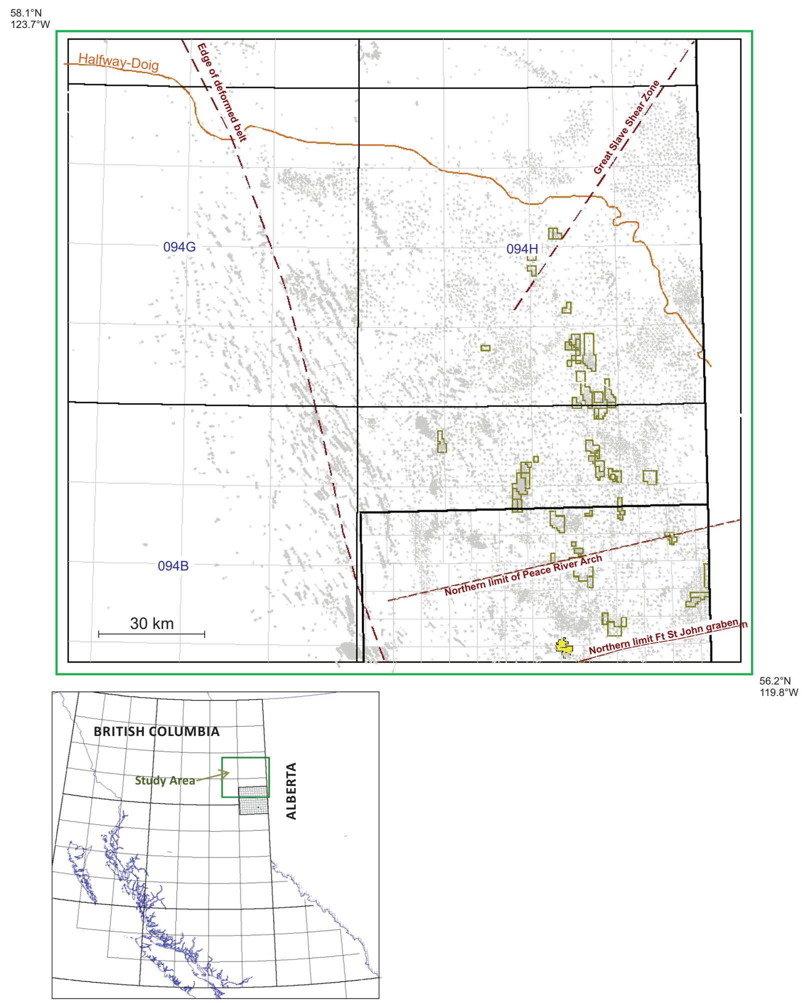

Figure 1. Study area: The Halfway Formation is constrained to the north-northeast by an erosional limit (brown line). To the west it thickens and the structure becomes more complex beyond the edge of the deformed belt. Green polygons represent the main oil-producing pools of the Halfway Formation; grey dots represent all wells within the study area.

With the current increase in drilling for unconventional gas in British Columbia's northeast and the resulting increase in the need for water disposal and water sources, the study of petroleum hydrogeology has found applications beyond its traditional uses. For example, it has been used to evaluate the practice of acid-gas disposal, which has been underway in northwest Alberta since 1990 and northeast British Columbia since 1996 (Buschkuehle and Michael, 2006). For safe disposal of waste fluids, it is important to understand the receiving aquifers to know where fluids might travel, if they will be contained and whether or not they are generally suitable for the purpose. Petroleum hydrogeology is also important for defining the extent and quality of potential water sources for fracking.

The study of petroleum hydrogeology depends on good-quality pressure data, provided mostly by drillstem tests (DSTs), which the Western Canada Sedimentary Basin has in abundance. For studying the behaviour of an aquifer associated with a productive formation, DSTs need to have been run where the formation is wet and therefore uneconomic. In the earlier days of exploration, this was done frequently in the hope that a wet formation might somehow be economic. Determining where oil and gas might contact the aquifer requires the inclusion of DSTs that recovered hydrocarbons. This is not the focus of this paper; the emphasis here is on DSTs with water recovery so that the aquifer can be characterized. Further hydrogeological work including DSTs with substantial hydrocarbon recoveries can be directed in the future to understand accumulations for individual oil pools.

Halfway Formation DSTs and water analysis data provided the basis for the main outcomes of this report, which include

- a potentiometric surface map,
- a pressure-elevation chart, and
- a formation water salinity map.

Geology

The Middle Triassic Halfway Formation (Fig. 2) was deposited as shallow marine parasequences (beds bounded by flooding surfaces) along the western margin of the North American craton in barrier island, shoreface and tidal inlet channel environments (National Energy Board, 2006). The Doig Formation

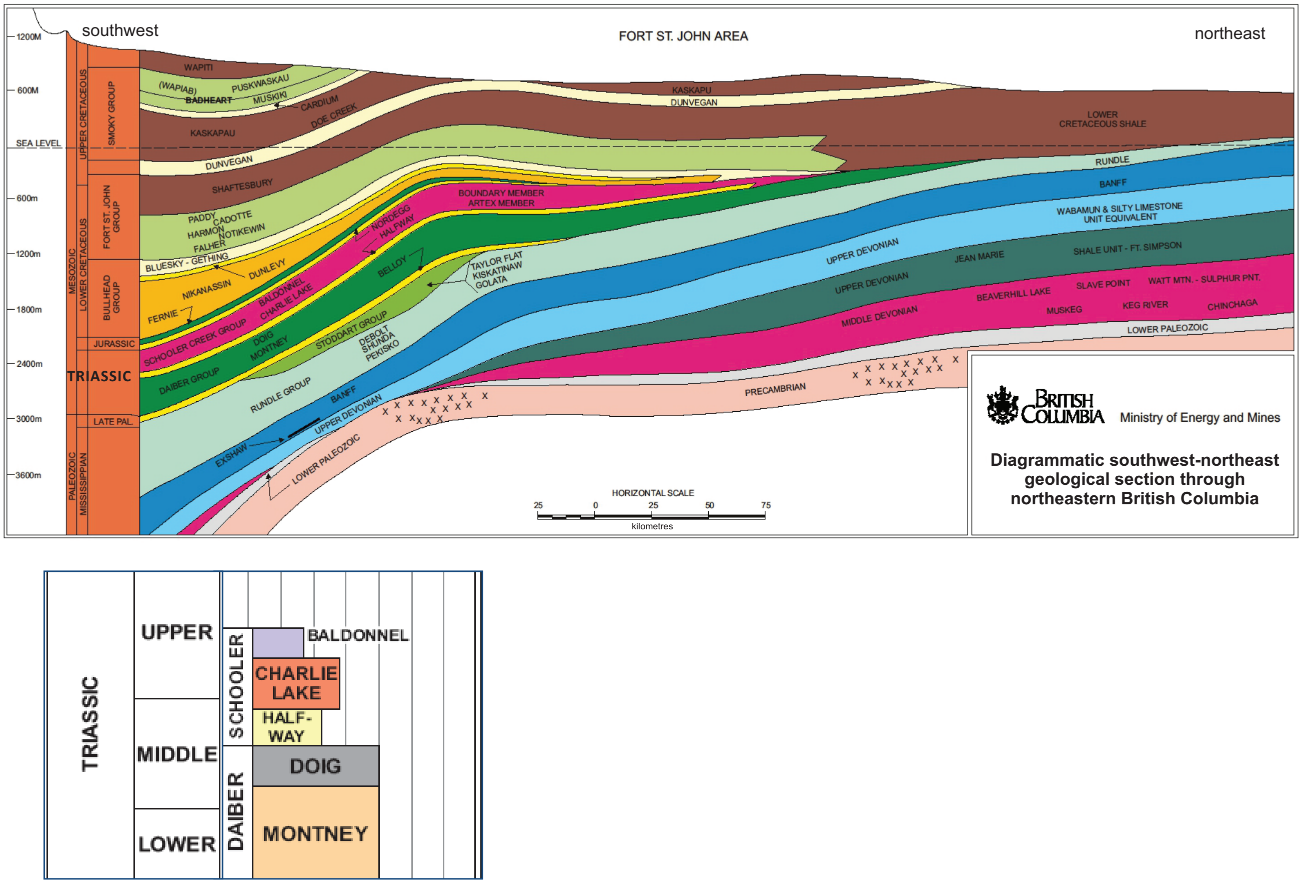

Figure 2. Schematic cross-section and Triassic stratigraphic chart for northeastern British Columbia. The Halfway Formation is shown as a thin yellow layer from the Middle Triassic, tapering off to the northeast. An unconformity follows Jurassic deposition and this limits the Jurassic–Triassic section to the northeast.

underlies the Halfway Formation and is difficult to differentiate lithologically in places. In the western part of the study area, the Halfway is more massively bedded and the contact with the Doig Formation is conformable, suggesting a continuum of deposition; to the east, over the Peace River Arch (Fig. 1) it might be unconformable in places (Hunt and Ratcliffe, 1959; O'Connell, 1994). For the purpose of this study, the two formations will be considered as one because they are assumed to be in communication. An extensive permeability barrier does not appear to exist between them (Fig. 3), although the degree of communication can vary from place to place.

Halfway Formation sandstones are primarily quartz arenites and sub-litharenites with local bioclastic (shell debris) sandstones and coquinas. Grain size varies from very fine to fine. Much of the sand is aeolian, having been blown in from the North American craton, where desert-like conditions prevailed during the Triassic. The best reservoir facies occur updip where the Halfway Formation is relatively thin and where channel-fill cuts into barrier islands. Downdip, where the Halfway Formation is more continuous, reservoir quality is generally less favourable, although localized secondary processes have acted to enhance porosity in places.

In the eastern part of the study area, the Halfway Formation is preserved discontinuously as barrier islands or shoreface sands cut by tidal channels. As a result, hydrocarbon trapping is largely stratigraphic due to rapid changes in facies. To the west-southwest, the Halfway Formation transitions to more continuous shelf sandstones. The eastern-northeastern pre-Jurassic–pre-Cretaceous erosional limit cuts down into the Triassic section, with deeper erosion occurring to the north, so that more of the Triassic is preserved in

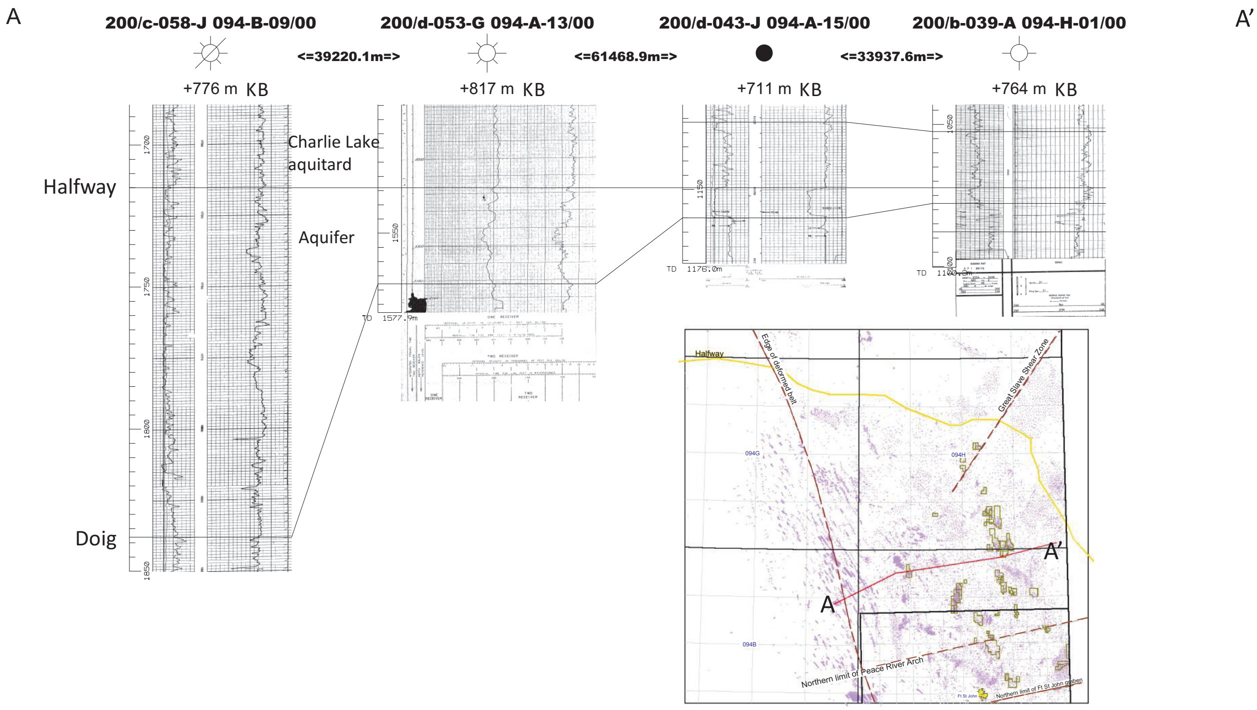

Figure 3. Stratigraphic cross-section A–A': The datum is the top of the Halfway Formation. This cross-section passes through the heart of Halfway Formation oil production. The Halfway Formation thickens considerably and is massively bedded to the west. It thins to the northeast and is bounded by relatively distinct flooding surfaces. The underlying Doig Formation cannot always be readily distinguished from the Halfway Formation. On this cross-section the picks are fairly clear. The Doig Formation tends to be finer grained than the Halfway Formation. The Halfway-Doig section, which contains porous sandstones and siltstones, is considered an aquifer unit, whereas the overlying Charlie Lake Formation, which is predominantly shaly/silty, is considered an aquitard.

the south and only the lowermost Montney Formation remains at the northeastern edge (Gibson and Edwards, 1990).

Doig Formation sandstones are generally finer grained than sandstones from the Halfway Formation because deposition results from a rapid transgression over an eroded surface. They are well-sorted, very fine to fine-grained sub-litharenites to quartz arenites, deposited along shelf margins as lowstand shoreface sands or transgressive barrier sands (National Energy Board, 2006).

The Triassic section, which includes the Halfway and Doig formations, dips more or less uniformly to the southwest (Fig. 2) until it encounters the edge of the deformed belt, where the structure abruptly becomes more complex. At the southeast corner of the study area (Fig. 1), the picture is complicated by reactivation of deep-seated faulting over the Fort St. John graben during the mid- to late Triassic (Barclay et al., 1990; Caplan and Moslow, 1997; Norgard, 1997). The Fort St. John graben was initiated during the Paleozoic and eventually filled in by Carboniferous–Permian sediment. During the Middle Triassic, deep-seated faulting was reactivated by a series of north-south– and east-west–trending normal faults forming horsts and grabens. Reservoir rock was preserved in grabens and eroded on horsts. These are small displacement faults and do not appear to propagate through the Triassic, so their effect on structural elevation appears muted at the interval used to contour the Halfway Formation's structural elevation in Figure 4. Faulting at a deeper level, however, might have produced enough relief to influence facies development and porosity distribution in the central part of the study area. The Peace River Arch, which passes through the southern part of the study area, is another deep-seated structural feature that likely influenced sedimentation.

Petroleum production

Hydrocarbons were first discovered in the Halfway

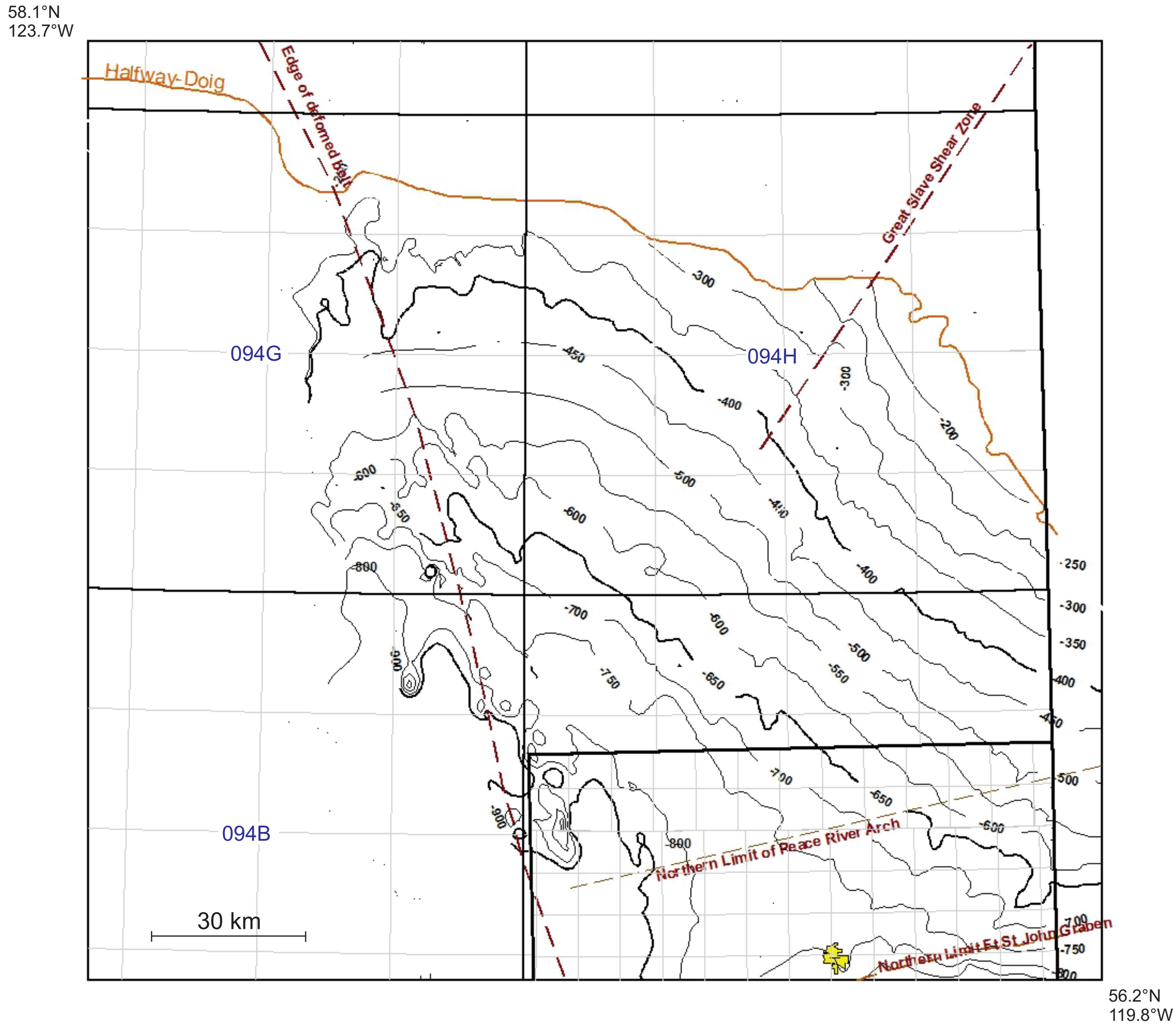

Figure 4. Structural elevation top of the Halfway Formation (contour interval 50 m): The Halfway Formation dips more or less uniformly to the southwest until the deformed belt, where the structure becomes more complex. The influence of deep-seated faulting might be evident by deviations from the general trend near the Fort St. John graben in the southeast.

Formation in the late 1950s. This followed the success of British Columbia's first oil production from the Boundary Lake member (Charlie Lake Formation) in 1956 (Janicki, 2008a, b). Since then, approximately 2000 wells have produced oil and/or gas from the Halfway or Doig formations.

Most Halfway Formation oil is produced from pools located within the east-central portion of the study area (Fig. 4). These pools appear to align along strike in two or three subparallel northwest trends. Gas production follows the same trends but also forms long linear trends further west along the edge of the disturbed belt and in irregularly shaped groupings of various orientations. Some hydrocarbon accumulations can result from structural position and some might be influenced more by porosity distribution (Janicki, 2008a, b); however, as is discussed later, hydrodynamics might have been a determining factor in where some of the oil pooled.

During the past few decades, the Halfway Formation has been used extensively for water disposal because it offers many depleted reservoirs and available boreholes and is generally receptive to large quantities of disposal waters, at least for the short term. Faults originating at greater depths do not appear to propagate through the formation (Norgard, 1997; Buschkuehle and Michael, 2006), which would provide migration pathways.

Study methods

Hundreds of wells in the region have Halfway or Doig formation DSTs, so there is an abundance of pressure and salinity data from which to draw maps. A major task is culling the data so only the most reliable are used. Because this study is primarily concerned with the behaviour of the Halfway-Doig aquifer system, the focus here is on DSTs that recovered water. Consequently, DSTs that recovered significant amounts of oil or gas were not used. If the water recovery was large, a small hydrocarbon recovery was acceptable. More than 500 DSTs were examined; of those, more than 200 were used to supply data for a pressure-elevation chart and potentiometric surface map. These data are summarized in Appendix A.

The DSTs were selected on the basis of three criteria: a significant water recovery indicating good permeability; rapid buildup and stabilization of pressures on shut-in intervals; and the pressure recorder being within the interval tested. In each case, the DST pressure-versus-time chart was examined to ensure the test was mechanically successful and to qualitatively evaluate permeability. In cases where the DST demonstrated very good permeability by a substantial water recovery and rapid stabilization of shut-ins, it was included despite having an outside recorder. Where initial and final shut-in pressures differed, the higher of the two was used, assuming they did not differ significantly; if they did, the DST was not used. Extrapolations to original reservoir pressure, as provided by a data vendor (geoSCOUT®) or the service company, were used when available. Horner plots to achieve the most accurate original reservoir pressure possible were not created for tests lacking pressure extrapolations; however, because only DSTs with pressure readings near or at stabilization were used, they could be expected to be within a few percent of an extrapolated value. For the purpose of potentiometric mapping, a small deviation from total precision should not impair the general result significantly because of the broad contour interval used.

A discussion of how DST charts are interpreted can often be found in the wellfile report supplied by the service company. A very thorough discussion of the use of DST data and petroleum hydrogeology in general is provided in Dahlberg (1995).

RESULTS AND DISCUSSION

Potentiometric surface

Figure 5 shows the potentiometric surface, also known as the hydraulic head, of the Halfway-Doig formations. It represents the height to which a column of water would rise in a wellbore open to the Halfway Formation. It is often considered as the potential energy (not to be confused with hydrocarbon production potential) of the aquifer at that point. Each data point is calculated using the formula

Potentiometric surface = static reservoir pressure / static pressure gradient + elevation

where static reservoir pressure is taken either from a stabilized or an extrapolated shut-in pressure on a DST; the static pressure gradient is the change in pressure over depth of a column of formation water, as determined by the salinity of water samples; and elevation is the height in relation to sea level of the pressure recorder. Because salinity is highly variable, even within a formation at one location, many authors, including Dahlberg (1995), recommend the use of a common static freshwater gradient of 9.7 kPa/m. This is what was done for this study. Although this approach yields different absolute values along the potentiometric surface, in practice the differences are averaged over a region and broad contour intervals (typically 100 m) are not significantly affected.

Potentiometric surface maps can reveal much about an aquifer. Formation water will move from high to low potential energy. Widely spaced contours suggest little change in permeability and low flow rates, whereas closely spaced contours indicate rapid changes or possibly a permeability barrier. Under near-static conditions, structural closure is needed for hydrocarbons to accumulate. Without structural closure

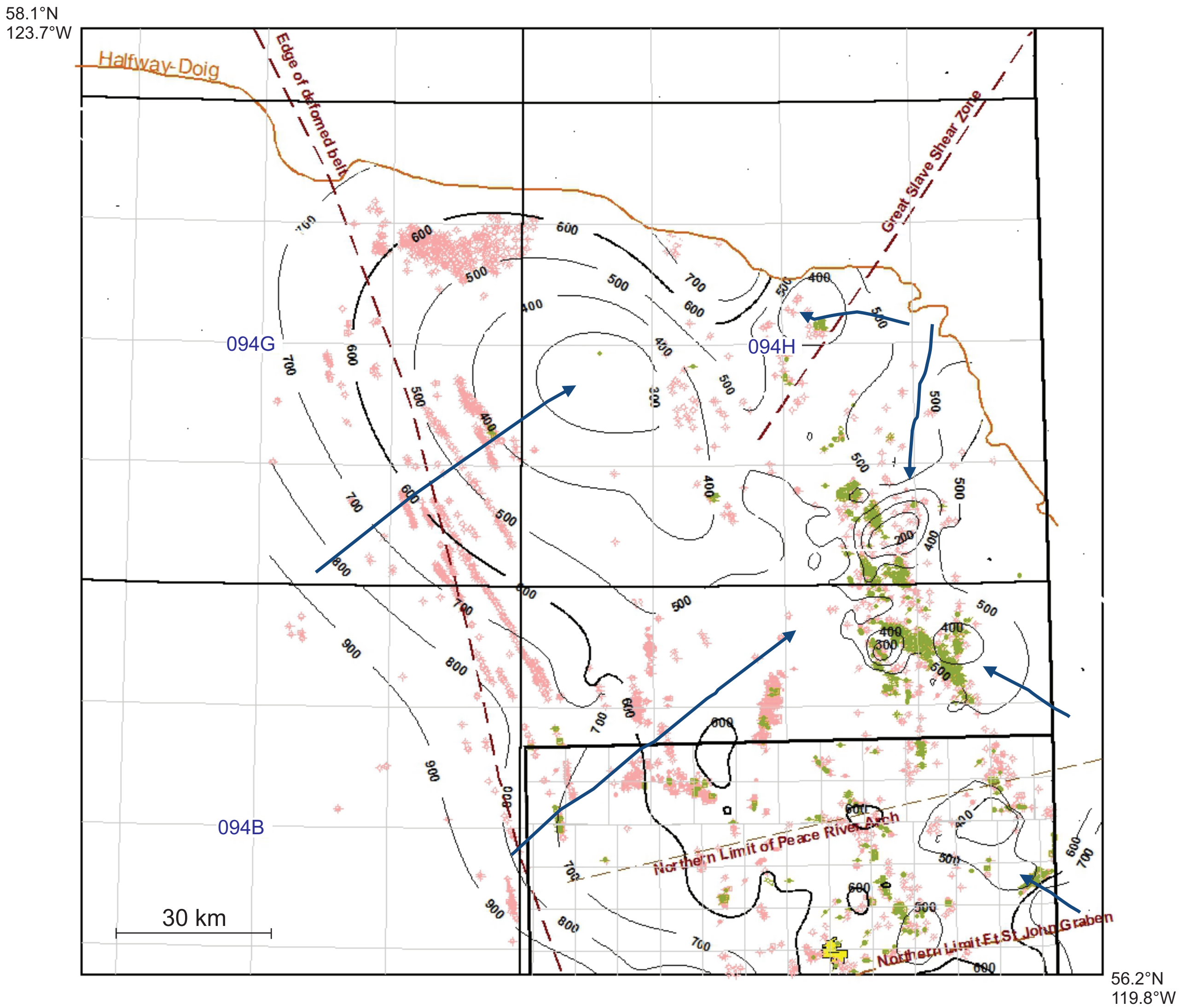

Figure 5. The potentiometric surface (contour interval 100 m) is the height to which formation fluid would rise in a wellbore. Flow is generally from west to east except for apparent reversals from the edge of the Halfway Formation into the centre. Widely spaced contours in the central region indicate small potential differences and little tendency for flow, except for some centres of low potential highlighted by closely spaced concentric contours. Many oil producers (green dots) appear to be clustered near those potentiometric lows. Gas producers (pink dots) tend to be in areas of higher potential. A common water gradient of 9.7 kPa/m was assumed. Inferred flow directions are indicated by blue arrows.

or facies change, trapping can occur hydrodynamically because of different densities (buoyancy) for oil, gas and water. It also depends on whether flow is updip or downdip. Downdip is favourable for oil; updip might allow gas to be trapped under certain conditions. Knowledge of the hydrodynamic situation can explain why in some cases trapping of hydrocarbons can occur in suboptimal structural situations. Under flowing conditions, gas, oil and water will settle into traps suitable for their density. This is why oil, gas and water are separated in both vertical and lateral space (Dahlberg, 1995).

Formation fluid flow in the map area is generally from west to east, except for some apparent reversal occurring from the Halfway Formation edge back into the central area occupied by the oil pools. This confirms generally with established theories (e.g., Toth, 1963) that say aquifer flow conforms largely to topography: water moves from high land to lower land. This seems to hold true here, at least in a general sense, because the ground elevations rise abruptly near the edge of the deformed belt (Fig. 6). Relatively high

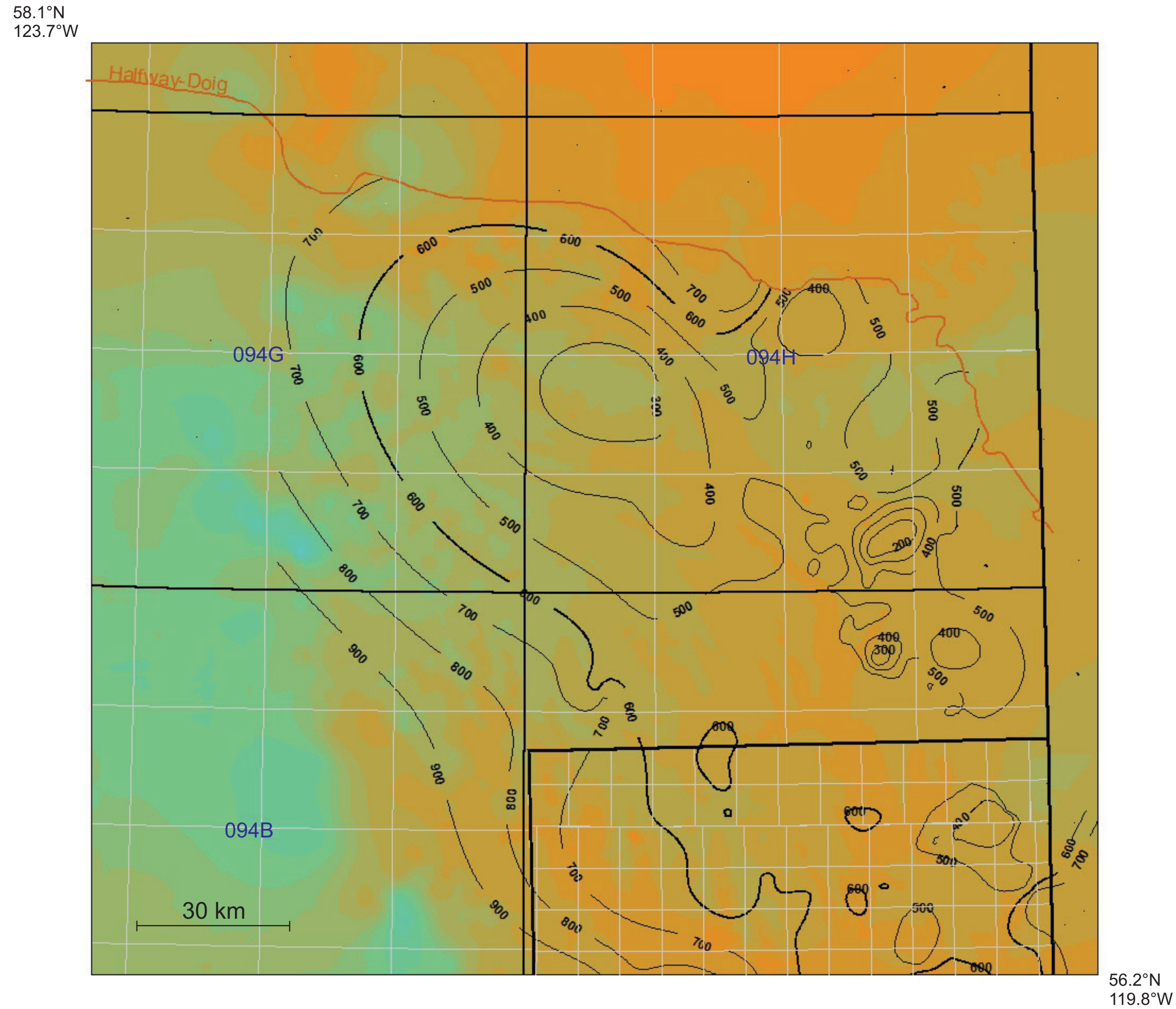

Figure 6. Topography and potentiometric surface: The shading represents topography, based on ground elevations surveyed at more than 18 000 well sites. Green areas are highlands; browns are lowlands. Land rises to the west, flattens in the central region and rises again somewhat to the northwest and northeast. Topography generally conforms to hydrodynamic flow, which goes from the highlands to the west into a central low, and also to some extent from the vicinity of the Halfway-Doig section edge westward back into the centre.

topography also exists east of the Halfway Formation edge and this would be consistent with a change in flow direction. Most Halfway Formation oil pools fall within a region of relatively level and low topography, which also generally conforms to the areas of low potential energy. As a general principle, hydrocarbons will come to rest in an area of low potential energy (Hubbert, 1953).

As well as high potential over the topographically higher land to the west, an area of high potential is present along the northwestern part of the Halfway Formation edge, where it is intersected by the deformed belt. This might be due to some infiltration of the overlying Cretaceous aquifer, which is under relatively higher pressure than the Triassic aquifer (Buschkuehle and Michael, 2006). Where overlying Jurassic aquitards are thin, the Cretaceous might come into contact along the edge. Over most of the study area, the intervening Charlie Lake Formation provides a barrier between aquifers. Another pocket of apparent high potential is present in the southeast corner. There is no ready explanation for that, except perhaps that it falls within an area of known faulting east of Fort St. John, and that environment might introduce other pressure regimes. Topography also rises up slightly in the southeast. Figure 7 illustrates schematically how the Halfway-Doig aquifer comes up against the pre-Cretaceous unconformity and unconformably underlies possible Cretaceous aquifer rock. The Fernie Group, which acts as an effective barrier (aquitard) between aquifers, does not extend to the edge of the Triassic. Overlying aquitards of the Fernie Formation present to the west are absent, approaching the Halfway Formation edge. To the west, the Halfway Formation might be overlain by several hundred metres of Triassic or Jurassic rock; near the eastern edge of the Formation, the Triassic section might be less than 100 m thick. As a result, recharge or infiltration could be occurring in proximity to the Halfway Formation edge where aquitards are thin or absent; it might also be occurring near the edge of the disturbed belt, where structural dislocation might have brought different aquifers into contact with each other or possibly in contact with the surface.

Pressure depth

Figure 8 shows pressure plotted against elevation. Most points plot along a common gradient of approximately 11.5 kPa/m, which means that for every metre of depth the pressure increases by 11.5 kPa due to the weight of overlying water. The freshwater gradient is approximately 9.7 kPa/m and water of the salinity normally expected for the Halfway Formation would be approximately 11.0 kPa/m. The gradient is somewhat higher (lower slope) than would normally be expected for water with salinities and densities typically found in the Halfway Formation. The gradient for a pressure-depth plot by Kirste et al. (1997) shows close agreement.

Dahlberg (1995) demonstrates that a less than hydrostatic slope is an indication of updip flow in the aquifer. Hitchon et al. (1990) explain that a less than hydrostatic slope, which is seen in Figure 8, indicates a vertical (upward) component to flow. The combined forces of gravity flow and buoyancy effects on waters of varying density create a deviation from normal hydrostatic. An alternative explanation—or perhaps an adjunct—is the possibility of a leaking aquifer. This would produce a gradient different from one caused only by the density of water. Some leakage seems likely, particularly near the edges of the Halfway Formation, where overlying aquitards thin.

Despite the strong linear trend displayed in Figure 8, a number of points plot away from the gradient, either on the relatively underpressured (left) or overpressured (right) side. Figure 9 shows where these wells are located. As might be expected, those on the underpressured side fall within areas of low potential energy and those on the high-pressured side are mostly located along the high-potential rim near the deformed belt and the erosional edge, which might be indicative of recharge from the overlying Cretaceous aquifer.

If a normal saltwater gradient (11.0 kPa/m) is drawn from an elevation typical for the Peace River region (approximately 800 m above sea level) and is projected to depth, it plots to the right (higher pressure) side of the Halfway Formation gradient. This indicates that the Halfway Formation is at a lower pressure than would result from a static column of typical formation water. One possible explanation for this observation is that a pressure equilibrium was reached before the end of the Triassic, when the Halfway Formation and other Triassic horizons became well lithified and isolated from overlying influences. Pressures remained constant despite the erosional episodes that followed. Afterward, during the Cretaceous, more sediment was deposited than was previously eroded. As a result, the pressure observed today is a result of the preserving effects of early compaction and lithification, which would explain the lower than normal values expected for the thickness of overburden.

The reader might question the validity of much of these pressure data because the oil fields have been producing for decades from many wells and pressures must have been artificially lowered; however, a close examination of this dataset affirms its validity. Most DSTs used for this study recovered abundant water and for that reason did not produce any great quantities of formation fluids that would have altered formation pressures. This is also true for nearby offsets. In addition, the well density around most of the data points is actually not as high as might be suggested by the

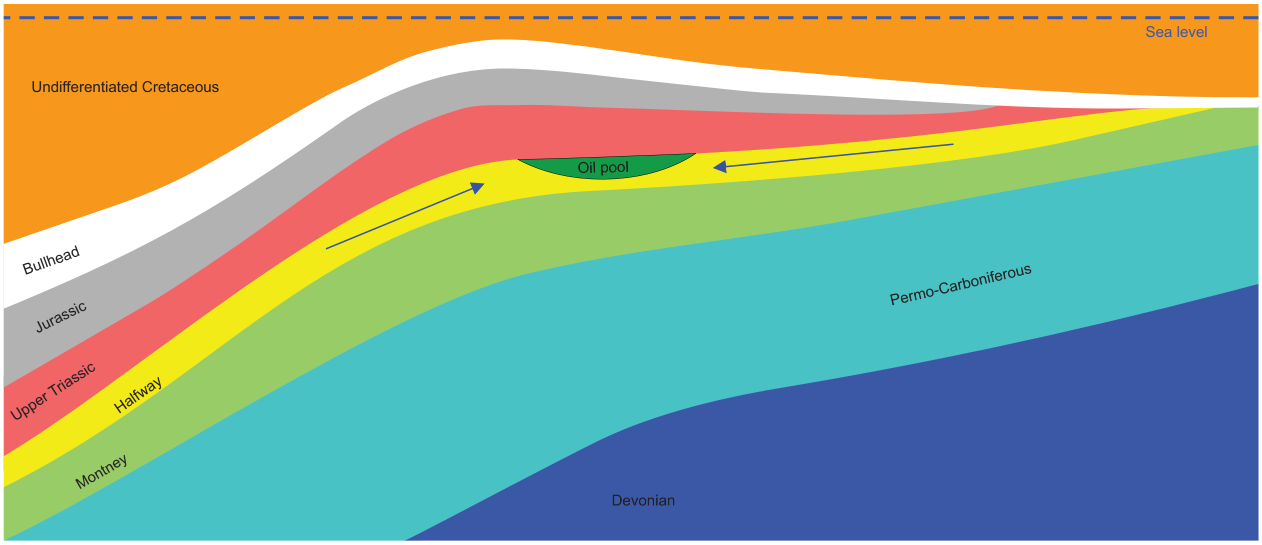

Figure 7. This schematic cross-section illustrates how the Halfway Formation comes up against the Bullhead aquifer to the east. Fresh recharge might take place along the edge. Hydrodynamic flow is mostly updip from west to east, except for a small reversal from the edge. The arrows show inferred direction of formation fluid flow and suggest a possible mechanism for oil entrapment approximately where flow is slowed in an area of lower potential.

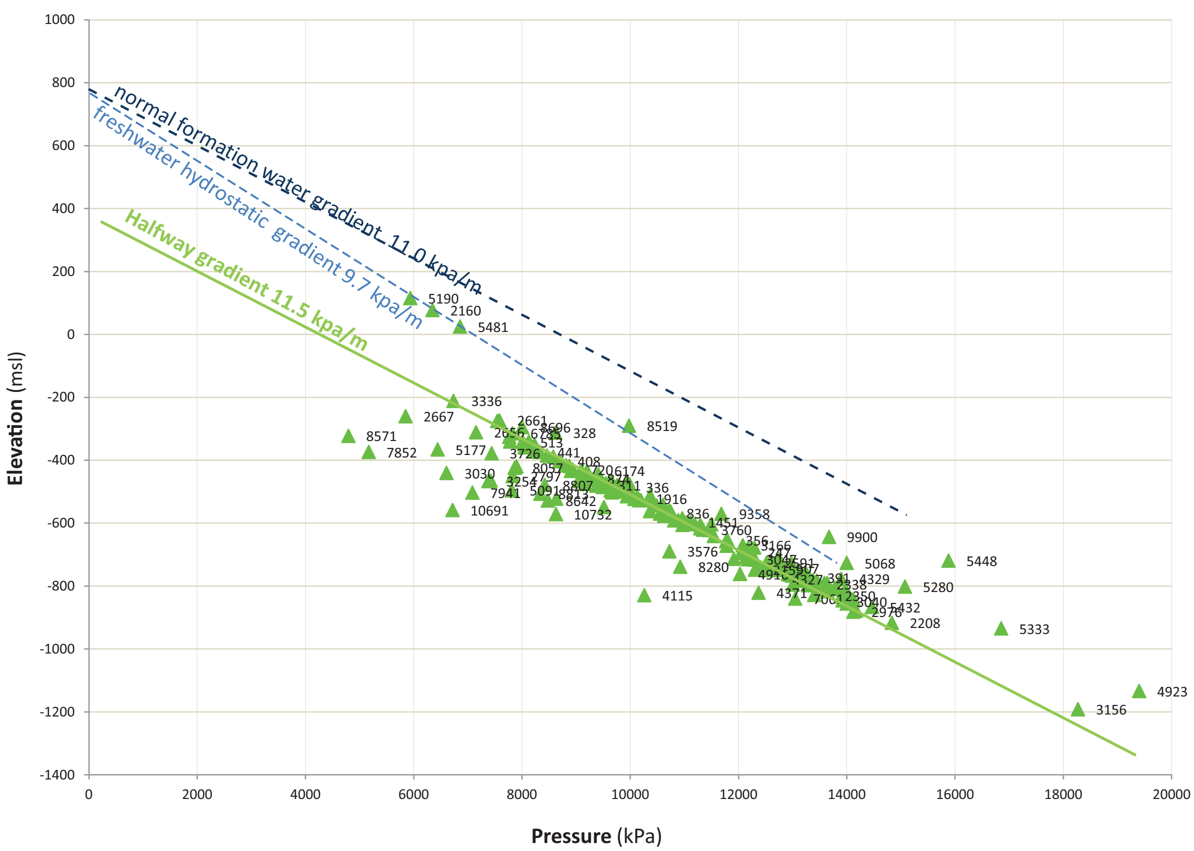

Figure 8. Pressure versus elevation (kPa vs. m elevation): Most data fall along a gradient of approximately 11.5 kPa/m. A freshwater gradient is 9.7 kPa/m and a normal saltwater gradient for the Halfway Formation (120 000 mg/L) is approximately 11.0 kPa/m. These water gradients are plotted assuming zero pressure at surface, which occurs at an elevation of approximately 800 m. The Halfway Formation pressure regime is lower than the water gradients. Locations on the higher pressure side (right) tend to be in areas of higher potential (see Fig. 5) and those on the lower pressure side (left) of the gradient tend to be in areas of low potential. Data points are labelled with well authority (WA) numbers. Due to space limitations not all points are labelled.

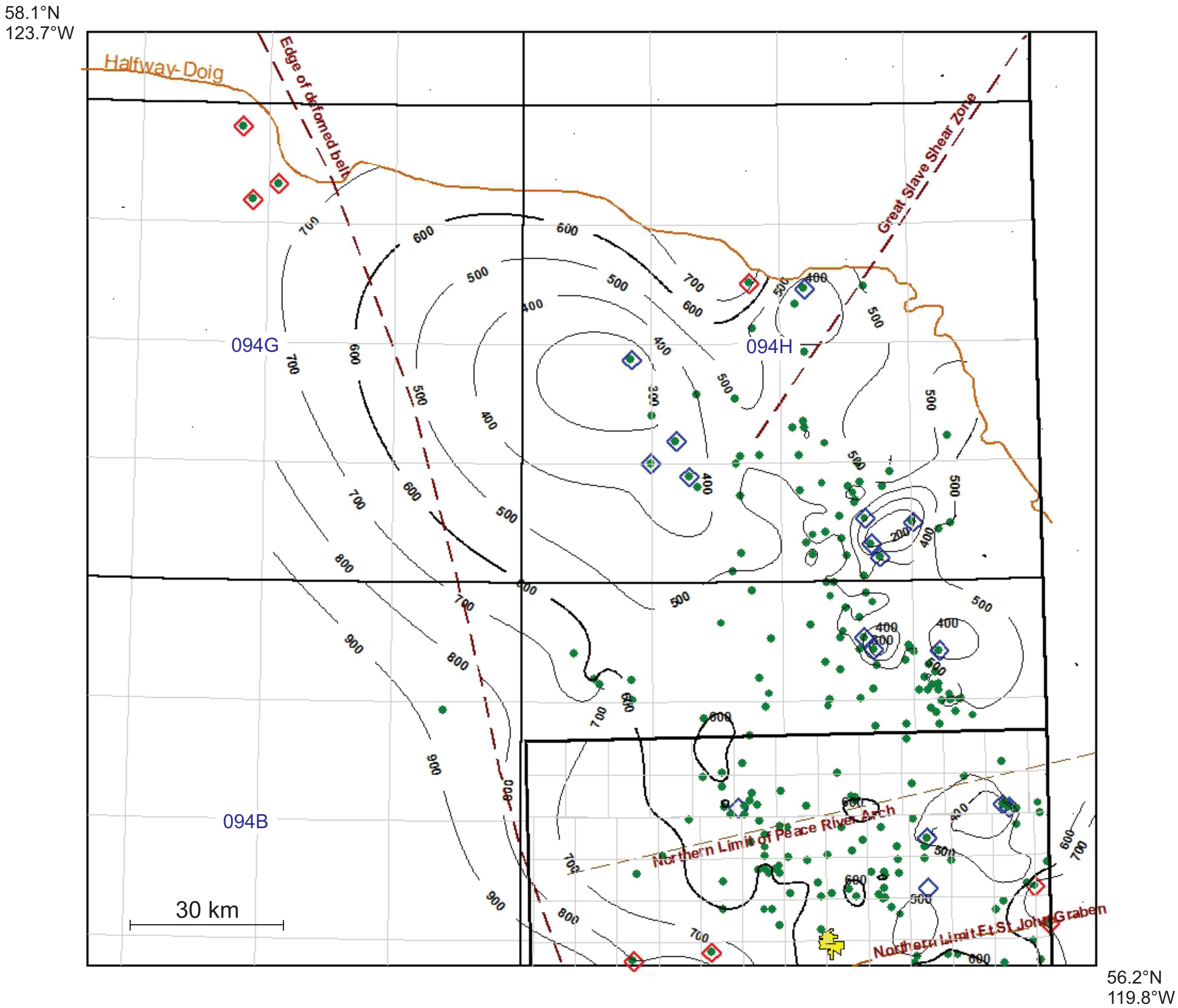

Figure 9. High and low pressures: The green dots represent data points used in this study. Blue diamonds highlight wells on the low pressure (left) side of the Halfway Formation gradient of Figure 8. They tend to fall within low-potential areas. Red diamonds indicate wells on the high-pressure (right) side of the gradient. They are generally in areas of higher potential. These wells with pressures on either side of the normal pressure-depth gradient may be within separate pressure regimes.

mapping; offsetting wells are generally more than 1 km away and likely outside the radius of influence.

Salinity

Figure 10 plots salinity (in mg/L) analyses from DSTs or production test water samples. Not all available water tests were used; standard culling procedures as outlined by Johnson (1991) were used to select values representative of the actual formation waters. The values displayed are generally from substantial water recoveries taken from the bottom of the water column (fresh and filtrate waters tend to be near the top). They have pH values in the range of 6–8 and an ionic composition consistent with formation waters for the area. 'Stiff' diagrams (Fig. 11) available in the wellfiles provide a qualitative check on the validity of a sample; a valid water sample should have an ionic composition that provides a characteristic shape. If a sample does not meet the aforementioned criteria, it is culled from the compilation of salinity data. In practice, more samples are culled than accepted.

Most salinities fall in the range of 90 000–150 000 mg/L, but vary widely over short distances.

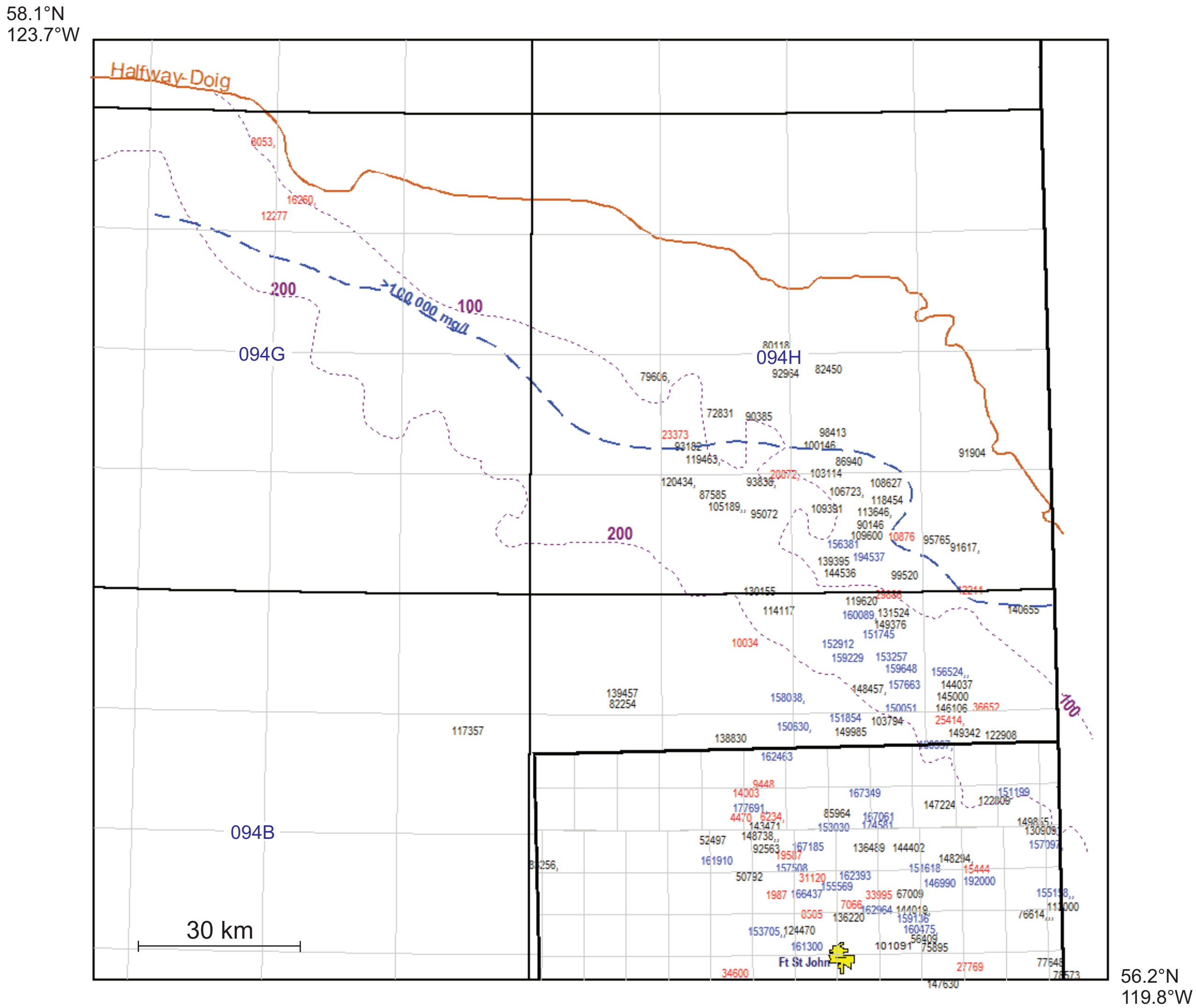

Figure 10. Halfway Formation water salinity map (mg/L): Red values represent water samples lower than 50 000 mg/L; the records suggest they are valid. Not all values are placed exactly adjacent to their well. Some valid salinities are not shown due to lack of space (refer to Appendix A for a complete list). Salinity is generally lower near the Halfway Formation edge. North of the blue dashed line, salinities are lower than 100 000 mg/L. Salinities greater than 150 000 mg/L occupy the central part of the study area and are shown in blue. The magenta dashed contours indicate the isopach (in metres) between the sub-Cretaceous unconformity and the Halfway Formation.

The practice of water sampling is historically far from standard. Over the decades, service companies and individual samplers have used different methods, so results can be difficult to compare. As well, each DST yields results particular to the formation at that location. Little precision can be attached to the results and care must be taken when making comparisons from well to well.

Nevertheless, if suspect analyses are culled so that only the most trustworthy analyses are used, salinities can be plotted and a few tentative observations can be made. For example, over the central part of the study area higher salinities of more than 150 000 mg/L tend to coincide, more or less, with Halfway Formation oil production. This might be evidence for a concentrating effect in the central region where flow slows. A number of anomalously low salinity values—verified as valid bottom-hole samples and representative stiff diagrams—seem to follow a northwest trend near the town of Fort St. John. Perhaps this could be related to some structural activity, parallel to the deformed belt, locally introducing fresher waters to the Halfway Formation. There are several apparently valid, but anomalous, low salinities at the northwest corner of a)

b)

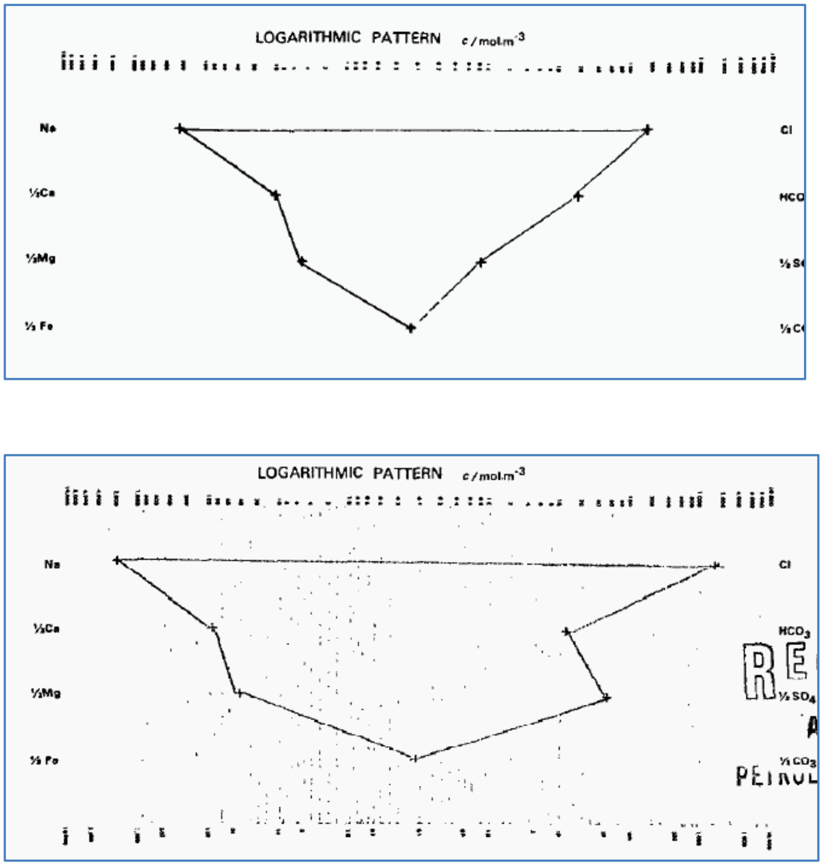

Figure 11. Stiff diagrams: a) Stiff diagram from location c-55-A-94-G-14, WA 5190, DST 1. This Halfway Formation sample was taken from the bottom. The stiff diagram shows readings similar to a typical Upper Cretaceous formation water. It is located near the Halfway Formation limit and west of the edge of the deformed belt. Salinity is 12 277 mg/L. b) Stiff diagram for location d-53-D-94-H-6, WA 5091, showing a typical shape for Halfway Formation water samples in the area. Salinity is 119 463 mg/L.

the map area, with characteristics similar to Upper Cretaceous waters. This would suggest recharge from Upper Cretaceous aquifers where Jurassic aquitards thin near the Halfway Formation edge. Alternatively, it could be due to structural dislocation along the edge of the deformed belt. Salinities are somewhat lower near the Halfway Formation edge, which could be a result of near-contact with the Cretaceous. Dashed lines in Figure 10 show an approximate isopach for the interval between the sub-Cretaceous unconformity and the top of the Halfway Formation. A clear connection between salinity and isopach is not evident, except that the line for salinity less than 100 000 mg/L and the 100 m isopach are subparallel. Also, the isopach is clearly very thin near the Halfway-Doig section edge in NTS 094G, where three low salinities are found.

SUMMARY AND CONCLUSIONS

Data from more than 200 DSTs were used to construct a pressure-elevation chart and potentiometric surface map for the Halfway Formation in northeastern British Columbia. Pressures for most wells fall along a common gradient. The gradient, or slope, is higher than normal hydrostatic, which is an indication that the flow of formation fluids is updip. Pressures located outside the common gradient generally fall along the edges of the study area near the erosional edge, the disturbed belt or in areas of lowest potential energy. The potentiometric surface map shows that formation fluid flow is generally to the northeast into a central low-potential area where most of the oil pools are located. Some reversal of flow direction appears to occur from the Halfway Formation edge westward into the centre. The coincidence of low potential with oil production seems to suggest that hydrodynamics is an important factor in the location of oil accumulations. Relatively high formation water salinities tend to occur in areas of low potential. Gas has accumulated largely in areas of higher potential. Lower salinities near the Halfway Formation edge might be due to infiltration of fresher water from the overlying Cretaceous aquifer.

When abundant DST data are available, as is the case for this study of the Halfway Formation in northeastern British Columbia, petroleum hydrogeology can be a valuable adjunct to other forms of geological examination such as stratigraphy, sedimentology and structure. It deals with the fundamental object of economic interest: the movement and resting place of hydrocarbons and other fluids within the target formation. It can provide clues about what would happen to fluids or gases under pressure (such as produced waters) and it can be used to point to new areas for exploration not necessarily revealed by seismic surveys or other methods of geological mapping.

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APPENDIX A

DATA USED TO DRAW THE POTENTIOMETRIC SURFACE AND SALINITY MAPS; WELLS ARE ARRANGED IN ORDER OF WELL AUTHORITY (WA) NUMBER.

WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m	WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m
311	a-31-k-94-a-15	Beatton	152 319	495	2828	d-98-g-94-h-2	Milligan	90 146	471
328	a-77-i-94-h-2	Hunter	103 642	575	2976	10-18-83-16w6	Two Rivers	147 630	575
336	b-23-d-94-a-16	Doig River	124 960	541	2999	6-22-86-20w6	W. Stoddart	19 587	572
408	d-39-k-94-h-2	W. Beatton	132 189	494	3009	10-8-87-20w6	W. Stoddart	4339	592
441	d-48-k-94-h-2	W. Beatton	107 083	485	3010	11-12-84-19w6	Ft St. John	18 986	578
513	d-40-j-94-h-2	Beatton	114 331	483	3030	a-67-i-94-h-5	Spangler	79 606	241
699	d-87-d-94-h-7	Beatton River	100 628	480	3040	11-27-84-21w6	Goose	44 987	602
720	b-70-b-94-h-2	Weasel	128 357	491	3047	11-35-85-17w6	Pluto	152 241	541
721	c-39-i-94-h-2	Alder	107 087	462	3055	7-31-86-16w6	Siphon	11 949	557
874	d-61-d-94-h-2	Donis	144 536	495	3068	11-2-87-14w6	Boundary	130 002	531
987	d-17-a-94-h-6	Pickell	28 872	485	3083	10-32-87-21w6	Teal	7007	593
1012	d-64-d-94-a-16	Buckthorn	137 846	512	3092	b-7-j-94-h-2	Beatton	89 300	488
1190	11-10-86-20w6	Stoddart	157 508	580	3141	b-48-f-94-h-1	Drake	37 500	503
1224	c-13-h-94-a-15	Peejay	80 000	554	3156	b-46-b-94-a-13	Inga	82 254	692
1300	d-11-e-94-h-2	Pure Donis	128 792	492	3159	c-99-g-94-a-14	Umbach	10 034	551
1401	a-27-f-94-h-2	Pure Donis	156 381	493	3166	6-9-86-16w6	Gopher	6364	575
1447	b-3-e-94-h-7	Eucalyptus	98 413	480	3197	7-30-86-19w6	Stoddart	2000	527
1451	10-9-87-14w6	N. Boundary	149 855	549	3218	11-27-84-17w6	Cecil	140 000	579
1599	d-2-f-94-h-2	Donis	194 537	493	3254	c-20-e-94-h-6	Martin	17 300	294
1763	d-33-i-94-a-10	Rigel	160 997	531	3278	d-39-a-94-h-11	Mercury	80 118	479
1859	d-68-k-94-a-9	Melanie	162 059	531	3336	a-69-c-94-h-8	Velma	91 904	483
1873	d-27-g-94-a-15	Wolf	89 178	511	3388	6-13-86-18w6	Oak	37 500	579
1880	d-15-d-94-h-7	Beatton	103 114	496	3399	6-13-84-20w6	Wilder	161 300	610
1911	d-97-k-94-a-15	Falcon	78 657	500	3564	6-17-86-20w6	Stoddart	9688	590
1915	d-73-c-94-a-15	Beavertail	148 457	542	3576	10-16-86-16w6	Siphon	119 000	416
1916	d-82-b-94-a-15	Wolf	157 663	525	3726	c-60-a-94-h-2	Weasel	82 100	390
1924	d-7-j-94-a-15	Grouse	84 168	503	3738	d-53-f-94-a-15	Raccoon	154 537	526
1951	6-6-86-18w6	Stoddart	162 393	579	3760	6-29-87-16w6	Rigel	147 224	549
1959	11-34-85-19w6	Stoddart	155 569	582	3770	11-15-85-21w6	Red	38 159	554
2032	b-26-d-94-a-16	Fox	146 106	527	3928	6-10-85-18w6	W. Eagle	162 964	603
2093	d-22-h-94-a-15	Peejay	127 000	466	3931	c-94-j-94-h-3	Pickell	96 000	491
2130	b-64-g-94-h-6	Bercli	90 385	505	3967	6-2-85-18w6	Eagle	27 578	607
2159	10-25-86-20w6	Stoddart	166 885	521	3972	d-13-j-94-h-3	S. Wargen	95 075	507
2160	c-97-d-94-g-15	Prophet	16 260	732	4005	6-11-86-17w6	Pluto	151 618	552
2208	16-21-85-23w6	Coplin	4905	613	4008	7-21-87-20w6	W. Stoddart	4500	567
2235	d-33-d-94-a-16	Currant	75 000	526	4091	c-97-c-94-a-15	Beavertail	151 621	518
2350	6-28-85-20w6	Mallard	7990	599	4128	16-6-85-19w6	Mallard	8505	611
2417	d-53-k-94-a-9	Osborn	122 908	513	4285	b-6-a-94-a-13	Fireweed	81 052	570
2507	10-5-85-17w6	Cecil	4408	573	4323	d-97-i-94-h-6	Redeye	92 964	498
2523	6-1-85-19w6	Badger	136 220	588	4327	7-33-86-20w6	W. Stoddart	92 563	546
2571	6-28-86-18w6	Montney	136 489	544	4329	b-24-f-94-a-13	Inga	145 390	656
2584	7-11-87-21w6	W. Stoddart	4470	603	4383	16-6-85-18w6	Eagle	7068	586
2591	11-8-88-20w6	Silverberry	9948	565	4408	11-33-85-16w6	Gopher	146 990	553
2656	d-73-l-94-h-7	Lapp	82 450	426	4426	6-27-85-20w6	Stoddart	2929	616
2661	b-44-g-94-h-10	Gutah	64 300	508	4429	11-33-88-20w6	Buick	148 000	590
2667	d-33-e-94-h-10	Lapp	65 313	343	4459	d-31-h-94-a-14	Maple	153 714	532

WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m	WA	Location	Field	Salinity (ppm)	Potentiometric surface (m) grad 9.7 kpa/m
2741	b-6-c-94-a-15	Rigel	151 854	525	4466	7-27-86-14w6	Boundary	157 097	560
2780	6-16-87-20w6	W. Stoddart	6234	570	4511	16-22-85-20w6	W. Stoddart	1987	612
2797	a-23-e-94-a-16	Peejay	16 569	357	4639	d-97-k-94-a-9	Currant	51 642	529
4730	10-35-86-22w6	N. Red	52 497	588	6981	6-32-84-14w6	Boundary	2209	575
4901	8-26-85-20w6	Stoddart	6132	591	7061	9-19-83-16w6	Two Rivers	37 849	505
4916	10-23-84-17w6	Flatrock	101 091	479	7107	10-18-83-13w6	Clayhurst	20 000	611
4921	d-55-k-94-11	Buick	138 830	599	7200	d-86-i-94-a-11	Buick	150 630	550
4923	c-74-k-94-b-9	Cameron	117 357	867	7412	11-21-85-17w6	N Pine	67 009	588
4962	6-2-88-21w6	Spirea	14 003	612	7419	c-58-b-94-a-13	Inga	139 457	598
4977	d-80-i-94-a-14	Prespatou	114 117	552	7686	d-58-a-94-a-14	Buick	11 000	582
5008	14-25-85-20w6	Stoddart	4209	588	7735	16-3-86-18w6	Oak	119 000	575
5028	6-11-87-19w6	Montney	153 030	577	7754	a-7-b-94-a-15	Rigel	103 794	545
5043	11-26-84-20w6	Tea	124 470	615	7762	c-75-l-94-a-9	Currant	147 055	521
5091	d-53-d-94-h-6	Wargen	120 365	309	7852	b-93-b-94-h-2	Weasel	104 900	159
5110	c-94-k-94-a-15	Kestrell	119 620	498	7941	d-23-g-94-a-15	Peejay	159 658	228
5136	d-13-a-94-h-6	Pickell	80 400	499	7995	c-96-k-94-a=9	Currant	32 471	470
5159	6-8-87-13w6	Boundary	109 600	525	8057	b-15-b-94-h-2	Weasel	29 886	387
5177	d-55-g-94-h-2	Milligan	9860	298	8403	b-9-c-94-a-16	Currant	25 414	494
5190	c-55-a-94-g-14	Prophet	12 277	728	8519	a-60-h-94-h-11	Mars	9031	738
5270	d-35-d-94-a-16	Buick	150 792	516	8571	c-50-e-94-h-1	Woodrush	96 765	171
5280	10-29-83-21w6	Monias	36 883	753	8642	c-36-k-94-h-3	Birley	20 000	346
5318	6-22-88-15w6	Cardinal	135 320	524	8663	a-72-f-94-a-15	Osprey	149 888	495
5333	6-21-83-23w6	Fox	20 458	803	8696	d-22-e-94-h-1	Drake	91 617	531
5370	c-25-b-94-h-3	Prespatou	130 155	507	8712	c-99-k-94-a-9	Currant	19 300	486
5392	d-86-d-94-a-16	Peejay	144 037	529	8807	c-55-g-94-a-15	Peejay	153 257	390
5409	6-9-85-17w6	Cecil	144 019	570	8813	d-69-k-94-h-3	Birley	87 585	354
5432	7-6-86-22w6	Bluejay	128 289	625	8891	1-4-88-18w6	Rigel	167 349	543
5448	6-24-87-19w6	Squirrel	85 964	918	8899	4-28-86-17w6	Oak	144 402	556
5481	a-49-i-94-g-14	Bunch	8053	732	9111	13-33-84-17w6	Flatrock	95 000	575
5491	6-9-88-14w6	N. Boundary	29 087	557	9164	2-6-86-19w6	Stoddart	31 120	580
5496	d-25-l-94-h-2	W. Beatton	109 391	497	9358	3-13-87-18w6	Muskrat	22 736	634
5518	d-47-c-94-h-7	Elm	86 940	484	9391	14-12-87-18w6	Oak	163 491	553
5720	d-93-a-94-a-15	Lynx	155 126	527	9421	11-13-87-18w6	Muskrat	174 581	578
5771	6-17-83-14w6	Alces	8338	584	9457	b-32-j-94-a-10	Rigel	18 000	545
5814	d-23-b-94-a-15	Beavertail	150 051	523	9515	10-36-83-14w6	Boundary	6000	598
5868	14-24-85-20w6	W Stoddart	141 705	586	9598	16-14-87-18w6	Muskrat	167 061	547
6134	7-21-85-17w6	Bison	119 000	605	9668	d-91-i-94-h-4	Nig	120 434	368
6174	d-43-j-94-a-15	Osprey	149 376	526	9829	d-54-h-94-a-14	Buick	12 700	540
6253	d-93-d-94-h-2	Big Arrow	139 395	511	9900	A8-12-85-14w6	Boundary	113 000	766
6303	d-65-j-94-a-15	Osprey	131 524	511	10 087	14-24-83-16w6	Two rivers	4385	631
6359	A6-26-87-21w6	W. Stoddart	177 691	591	10 227	d-77-d-94-h-6	Wargen	93 182	300
6364	8-33-87-15W6	Alberta Lagarde	122 809	545	10 352	d-64-l-94-a-9	Currant	140 000	515
6501	a-92-e-94-a-15	Bluebird	152 912	538	10 377	16-30-88-16w6	Rigel	123 000	519
6616	d-87-k-94-a-10	Rigel	149 985	548	10 691	6-9-87-14w6	N. Boundary	98 000	134
6647	a-63-f-94-h-2	W Milligan	109 600	488	10 732	13-3-87-14w6	N Boundary	142 000	318
6690	a-66-k-94-a-15	Dede	160 089	526	11 187	12-27-84-20w6	Bear Flat	153 705	615
6716	15-19-85-17w6	N Pine	33 995	590	11 526	c-57-d-94-a-16	Currant	145 000	495
6739	7-1-87-21w6	W Stoddart	148 738	573	12 029	a-29-d-94-a-16	Rigel	150 000	524
6785	b-96-j-94-h-2	North Beatton	108 627	492	12 670	c-46-j-94-h-2	Beatton	118 454	475
6811	d-83-d-94-h-7	Elder	87 506	498	16 670	b-76-f-94-h-6	Martin	72 831	395
6921	10-23-85-17w6	W Flatrock	16 979	516	19 065	5-31-85-15w6	Paradise	192 000	545