WILLISTON BASIN / MANITOBA

SW Manitoba geology and hydrocarbon potential

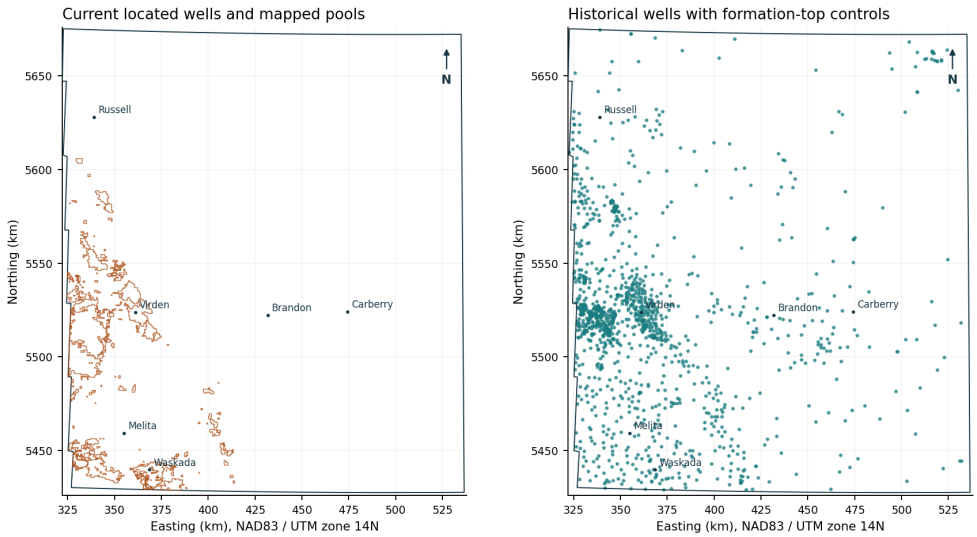
Formations, paleoenvironments, reservoir tests and a linked 3D / VR framework

A separate regional study covering the southwestern Manitoba petroleum province. Built from government geological models, formation tops, mapped pools, well records, production archives and selected original log/core data.

Base formation/reference surfaces	Mapped pool features	Located well licences
38	200	11,982

Plus a separately identified, bounded MES / sub-Mesozoic erosional-surface interpretation in this update.

Southwest Manitoba: coverage is concentrated around the oil province



Study area: 51,612 km², clipped to the provincial boundary. Current well inventory and historical model controls are separate datasets.
Town labels are approximate orientation points. Pool outlines do not delineate remaining mobile oil.

Derived from current Manitoba public petroleum GIS and historical TGI formation-top databases. Source dates and exclusions are documented in the study.

Updated 27 October 2026 with classified formation edges and erosional-surface guidance. Regional screening and evidence synthesis; no resources, reserves or drilling locations are assigned.

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Interpretive findings and how to use this study

The strongest starting points are several separate, proven petroleum systems with locally variable reservoir quality. The productive interval is not determined by thickness or proximity to an existing pool alone. Reservoir, seal, trap, charge, timing and water behavior must all agree at the same stratigraphic level.

Four settings deserve detailed local correlation

- Mississippian carbonate subcrops: test porous shelf, shoal and dolomitized intervals beneath a retained seal. Paleotopography and alteration can create traps, destroy pore space, or connect reservoirs to water [R05, R06, R07, R12].
- Lower Amaranth sand bodies: investigate sand continuity, mud baffles and cement along the buried Paleozoic landscape near Waskada, Pierson and Goodlands. A thick lower member does not establish connected net sand [R08, R09, R10].
- Bakken-Torquay around Daly-Sinclair: map preserved units, finer facies changes, oxidation and effective pores across erosional boundaries. Local salt-collapse remnants complicate simple blanket models [R03, R14, R16].
- Jurassic and multiformation pools around Manson: test the interaction of Reston/Melita facies, evaporite removal, fractures and older carbonate charge. Connectivity can produce oil or create water entry and leakage [R17, R18].

Deeper and younger alternatives

Winnipeg, Red River, Interlake and Devonian platform/buildup systems offer geological hypotheses that require independent charge and seal evidence. Younger Cretaceous and Paleocene units provide important cover, local sand systems and historical show context; they are not promoted to oil prospects solely because they are present. Every unit chapter identifies evidence and failure tests.

Read the visual evidence at the right scale

- Maps use a 2 km regional grid. A supported grid boundary may represent source coverage, truncation or a mapped unit limit; it is not automatically a reservoir pinchout or an oil-water contact [D01-D03].
- The paleogeographic diagrams are original conceptual reconstructions. Southwest is broadly basinward, but time-specific local shorefaces, channels and reefs require local facies and correlation evidence. No geographic ancient-shoreline line is invented.
- Pool polygons are source-defined outlines. Placing them on a compatible model top is a visualization, not a measured reservoir roof, base or fluid volume.
- Gross thickness can span composite or partially missing stratigraphy. It is not net reservoir, net sand or pay; composite intervals should not be added to their members.

A reservoir idea must survive six independent tests

Requirement	Observe	Interpret	Test against
Reservoir	Core texture + plug permeability + corrected logs	Connected effective pores	Cemented or isolated pores
Seal	Lithology + continuity + capillary test	Oil column retained	Absent cap or throughgoing fracture
Trap	Depth-corrected picks + restored section + seismic	Closure/pinchout at reservoir level	Artifact or open updip pathway
Charge	Produced oil + biomarker/fluid match	Migration access	Stain only or incompatible gas
Timing	Crosscutting relations + burial history	Trap before charge	Late breach or reservoir destroyed
Water	DST/pressure + salinity + normalized production	Bounded mobile-oil interval	Connected aquifer/water-only test

Analytical workflow proposed for this study, grounded in the local examples [R03, R06, R08, R17, R19].

Observations, interpretations and disproof are kept separate. No numerical prospect chance is assigned without local data.

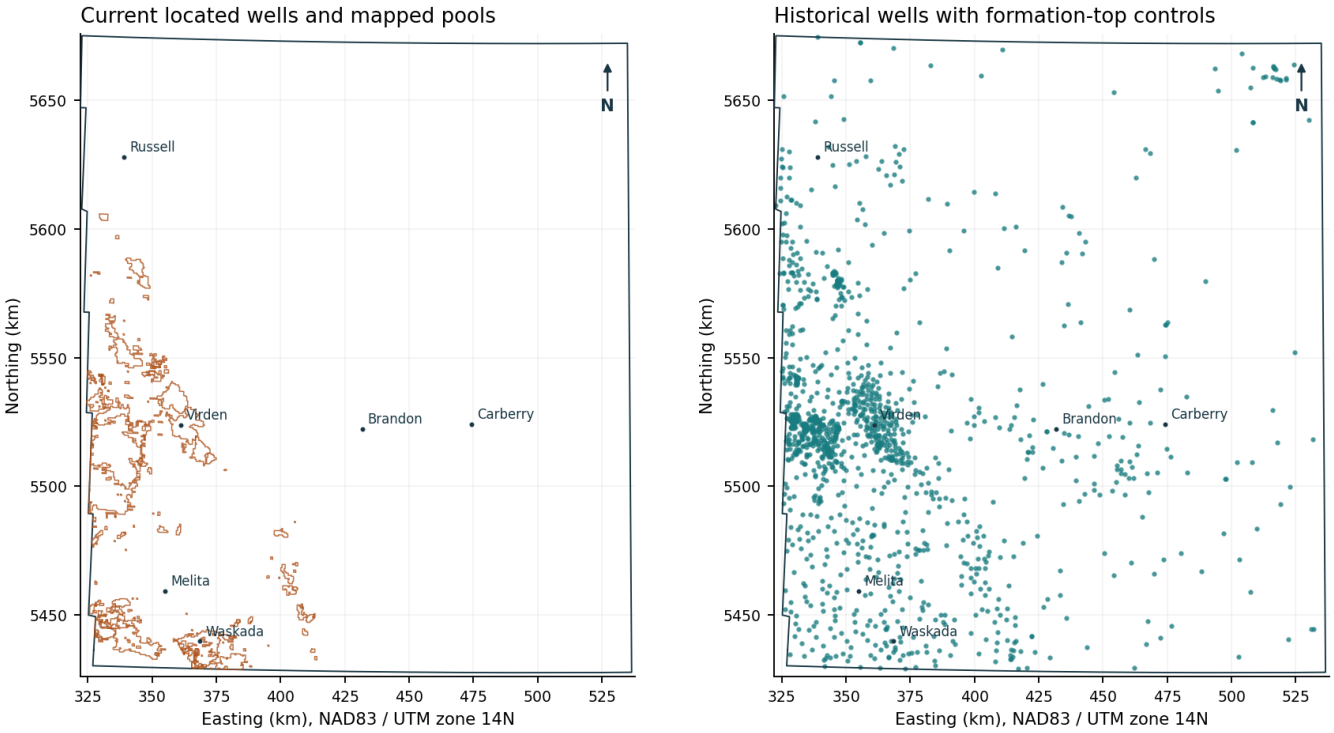
Data coverage, chronology and evidence limits

Dataset	Coverage used	Meaning / limitation
Regional surfaces	38 supported horizons; 51,612 km²; 2 km grid	37 published TGI surfaces plus a separately bounded Lower Amaranth interpretation. Five wider-basin source horizons have no supported local nodes.
Historical formation tops	1,311 wells; 22,400 selected positive picks	Model controls are separate from the modern inventory; zero is not treated as a picked top.
Current well inventory	11,982 located licence records	Preserves available UWI completions, mapped traces, public source links and missing data. Current snapshots are not real-time.
Oil/petroleum pool GIS	200 source features; 22 reservoir categories	Some pools span formations. Two Manson code conflicts remain flagged rather than forcibly joined.
Production archives	574,906 annual rows with 12 monthly values; 9,555 licences	Rows 1951-2026; latest positive oil/water month 2026-08. Licence totals span reported completions.
Physical core/cuttings catalogues	8,153 core entries /3,268 licences; 5,582 cuttings entries /4,264 licences	Entire provincial catalogues. Viewer joins only exact mapped licence IDs. Availability is not evidence of personal sample examination.
Original detailed well examples	Manson licence 9990; Hartney licence 2612	Selected original files checked. This study has not reinterpreted every public log or downloaded every technical file.

Source dates

The principal well GIS ZIP is a 26 August 2026 snapshot. Weekly UWI and physical sample catalogues were available through 9 October 2026. Pool outlines are published as pools_2025. The regional model and historical picks are older TGI products. Retrieval took place on 27 October 2026 [D01-D07].

Southwest Manitoba: coverage is concentrated around the oil province



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Town labels are approximate orientation points. Pool outlines do not delineate remaining mobile oil.

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What “all available well data” means here

The package collects the accessible bulk inventory, available mapped horizontal paths, public weekly completion identifiers/statuses, selected formation-top databases, monthly production histories, and physical-sample availability. Records without a reliable coordinate remain in a separate unlocated table. Public technical and log access links support further well-specific investigation. Unretrieved log reports and private or paid datasets are not represented as analyzed.

TD and survey rules

A measured 3D trajectory requires depth-indexed survey stations. The mapped horizontal polylines supply plan geometry only. Without a survey, a labelled vertical display uses verified TVD where available, otherwise reported MD as an explicit vertical assumption. With neither, the well keeps its surface symbol and plan trace and no depth column is fabricated. KB is used only where independently supported; lack of a datum is not converted to a false subsea elevation. Reported TD formation, completion interval and any model inference are distinct [D03, D09-D11].

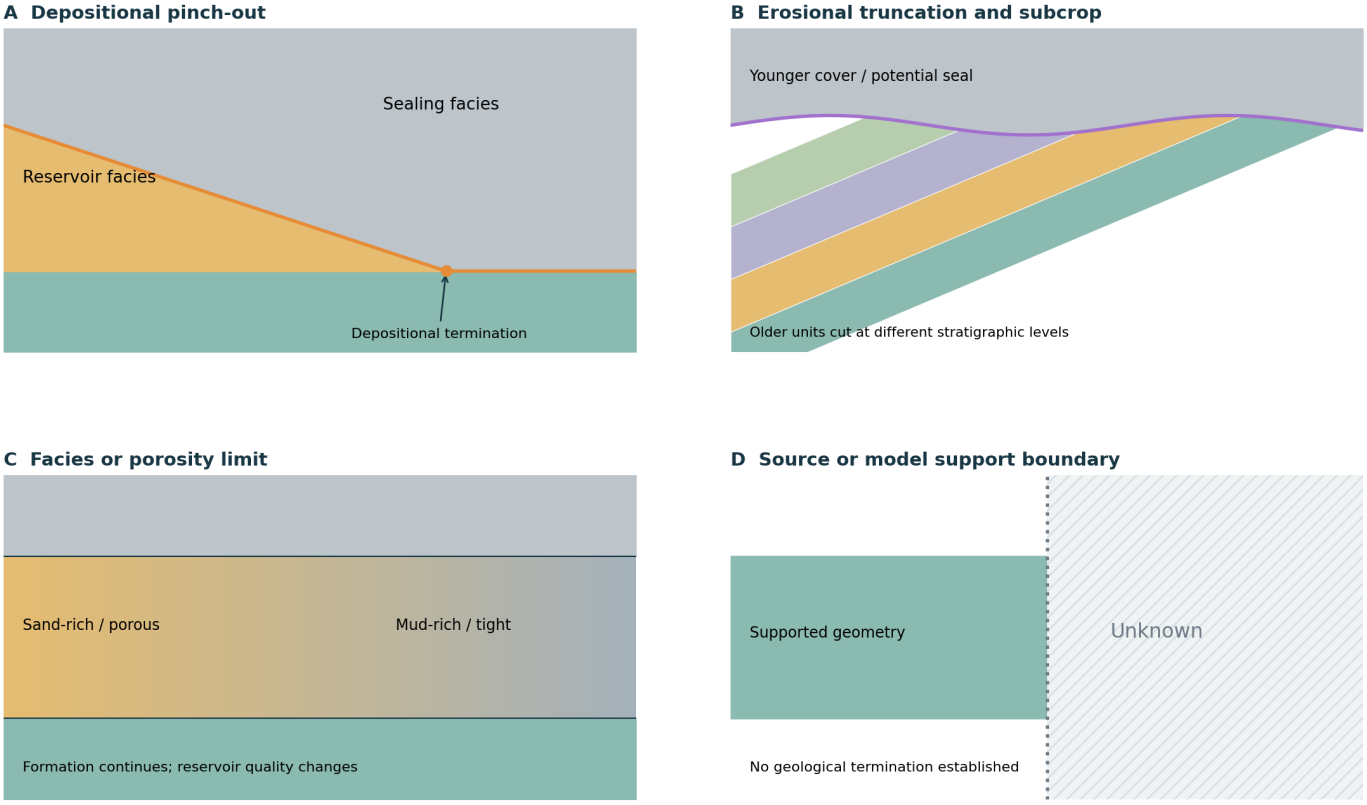
Formation edges, pinch-outs and erosional surfaces

A formation can end through nondeposition, erosion, dissolution or a change in correlation. A reservoir can end within a formation that continues. A data model can end while the geology remains unknown. This update therefore assigns an evidence class to every displayed line and keeps the physical mechanism separate from the geometry.

A zero edge is an observation or map interpretation; pinch-out and erosion are explanations. The explanation must come from stratigraphic relationships, samples, logs or the source map - not from the mere presence of a boundary.

Class	What it establishes	What it does not establish
Published formation zero edge	The source maps a limit at which the named preserved interval is absent or approaches zero.	Depositional origin, exact subcrop position, a reservoir seal or a fluid contact.
Depositional pinch-out	The bed or facies body terminates through its original accumulation pattern, supported by correlation/facies evidence.	That the enclosing formation disappears, or that hydrocarbons are present.
Erosional truncation / subcrop	A younger surface removes older strata; the affected older unit meets that surface.	Original shoreline direction or preserved reservoir quality.
Reservoir facies / porosity limit	Connected sand, dolomite porosity or another effective reservoir property changes laterally.	A zero edge of the entire formation.
Model-derived thin interval	A positive low-thickness contour from the specified supported top/base interval.	Zero thickness or proof of either deposition or erosion.
Support limit / map clipping	The available model, data or project domain ends.	Geological absence. It is retained as an uncertainty boundary.
Salt-dissolution front	Evidence suggests removal of soluble strata and associated modification of the overburden.	An erosional land surface or a reliably sealed petroleum trap.

Four edges that must remain different in maps and 3D



CONCEPTUAL - NOT TO SCALE. A published zero edge identifies a limit of preserved occurrence; its origin requires additional evidence.
Only A is a depositional pinch-out. B records removal. C is a reservoir-property change. D records an evidence limit.

Original conceptual cross-sections. They explain classification, not mapped positions or local closure. A zero-thickness line does not alone identify its cause.

What has been added to the Manitoba maps

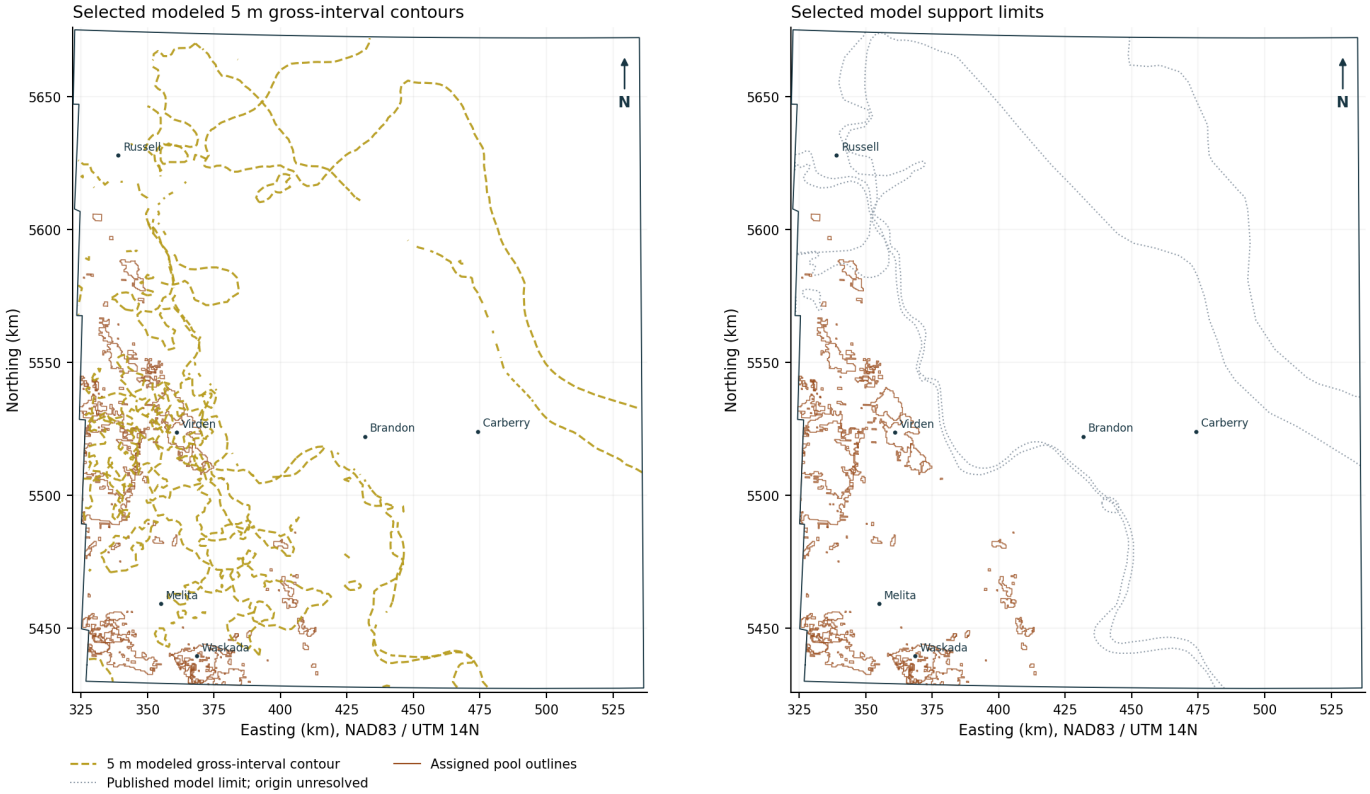
Vector class in this release	Feature records
published model limit	96
model thinning indicator	643
mapped bedrock contact	93

The numerical formation plates retain the existing supported TGI surfaces and their separately defined gross intervals. The thinning indicators are derived from supported gross-interval grids; published-model limits are extracted from the original source meshes with the study clipping edge excluded. They are not promoted to independently mapped geological zero edges.

This release contains no independently digitized Manitoba deep formation zero-edge vectors and no confirmed depositional pinch-out polylines. The separate published-model limits must not be presented as either. Published Manitoba erosion/subcrop maps provide geological context and verification targets. Where an independently georeferenced formation-edge vector has not been obtained, the line is not traced by eye onto the regional map. Source maps remain cited so that a future controlled digitization can preserve map scale, legend meaning and uncertainty.

A mapped present bedrock contact also has a different meaning from the older sub-Mesozoic surface. The age of the erosional event and the surface being represented must accompany the line. Multiple unconformities can intersect or overprint the same modern map area.

Southwest Manitoba: thinning and data support are different evidence



Selected intervals: Bakken, Lodgepole, Lower Amaranth, Reston and Upper Melita markers. Lines are derived from the existing 2 km model. They do not establish zero thickness, an original shoreline, a reservoir seal or a precise erosional-subcrop position.

Model-derived overview. No geological genesis is assigned solely from these contours. See each formation plate and the evidence register.

Erosional settings worth testing locally

The table identifies geological relationships to investigate around established reservoir settings. It does not assign new prospect boundaries or quantify hydrocarbons. The published formation chapters provide the detailed source evidence and local examples.

Interval / setting	Evidence-based interpretation	Local test and reservoir implication
Interlake and pre-Devonian surface	An erosional break separates parts of the older carbonate succession from Devonian deposits [R01, R04].	Correlate omitted units and alteration independently. Weathering can create pores or fill them; test preserved seal and charge.
Torquay, Big Valley and Lower Bakken	Erosion and localized preservation in collapse lows affect which units contact Middle Bakken [R03].	Map the surviving unit, rather than extending a regional average. Different preserved subunits and sealing arrangements can change reservoir behavior.
Lodgepole, Mission Canyon and Charles beneath Mesozoic cover	Post-Mississippian erosion cuts the succession and creates buried relief [R01, R05-R07].	Compare regional subcrop maps with penetrating wells. Test porous alteration below the surface, lateral seal and whether later erosion breached the accumulation.
Lower Amaranth above older relief	The member fills paleolows and contains heterogeneous sand/silt/mud bodies [R08-R10].	Separate inherited relief from sand distribution. A gross isopach high can be muddy or water-bearing; a model support edge is not a sand pinch-out.
Reston, Melita and Waskada beneath Cretaceous cover	Onlap and later incision/truncation can both affect Jurassic preservation [R02].	Correlate sub-Cretaceous substrate, erosional bases and preserved members. Do not label every missing member as original nondeposition.
Manson evaporite/structural modification	The published local interpretation combines missing evaporite, brecciation and structural/dissolution effects [R17].	Examine residues, fractures and cross-formation connections. The interpretation remains local; removal of seal can aid migration or cause leakage.

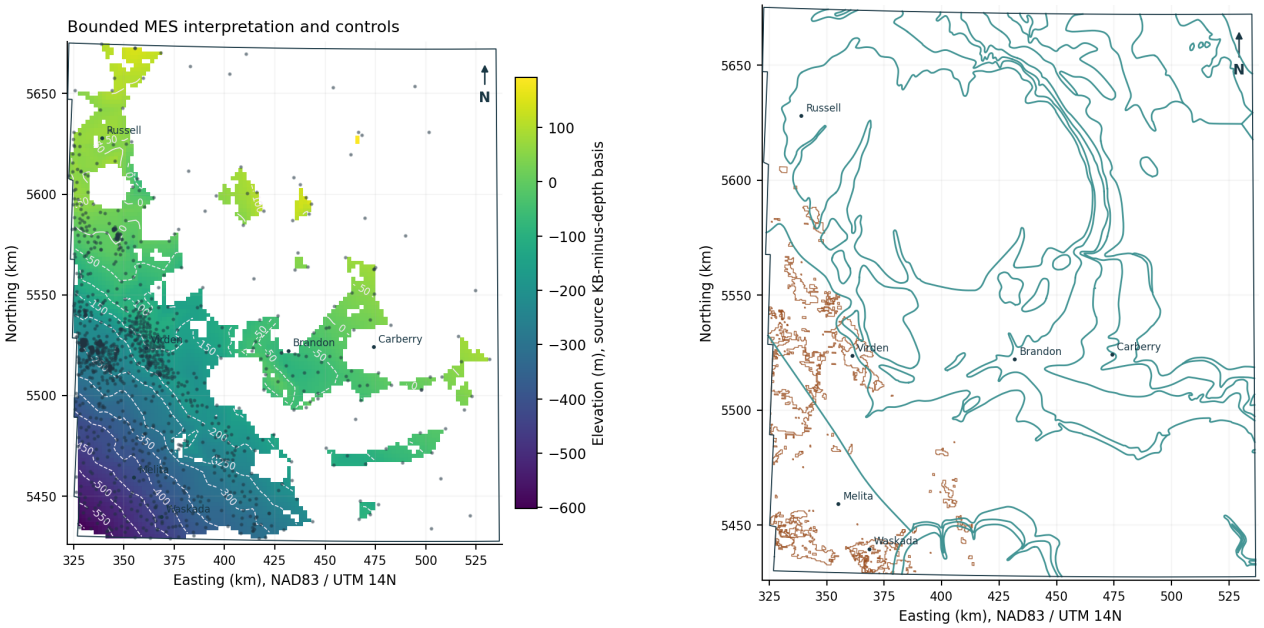
Where erosion can help and where it can destroy a trap

- Removal can expose porous rock to alteration and juxtapose it against a younger seal. A retained porous remnant can become a reservoir only if charge, closure or lateral sealing, and preservation also work.
- The same event can remove the reservoir, breach its seal, introduce water or leave disconnected pores. A mapped subcrop is therefore an exploration condition, not a positive hydrocarbon test.
- A formation-wide zero edge is usually much broader than an internal reservoir facies or net-pay limit. Map gross formation preservation and reservoir quality separately.

A bounded reconstruction of the sub-Mesozoic surface

Two different surfaces: buried sub-Mesozoic and modern bedrock

Do not interpret a modern contact as a deep subcrop or an original depositional shoreline.



MES: 1,173 accepted vertical-classified records; 1,163 unique locations; 4,202 supported 2 km nodes. 50 m contours.
No extrapolation: within control hull, 7.5 km of a control, maximum 20 km triangle edge. Five-fold holdout MAE 5.965 m; RMSE 10.002 m.
38 conflicting display nodes masked; source picks retained. Holdout is not independent pick validation; full surveys/datum conversion unverified.
Sources: MGS TGI historical MES records; Manitoba mapped bedrock contacts; existing pool inventory. Erosional relief is not a mapped trap.

The interpolation retains 1,173 vertical-classified historical MES records at 1,163 unique locations. It samples 4,202 valid nodes on the existing 2 km grid. Support is limited to the control convex hull, 7.5 km from a control and a maximum 20 km triangle edge. No extrapolation or smoothing is applied.

A separate order check masks 38 display nodes where MES lies more than 5 m above the independently modeled regional or Lower Amaranth top. This is a display-support exclusion, not clamping: source picks and the younger surfaces remain unchanged. The conflict audit is included with the data.

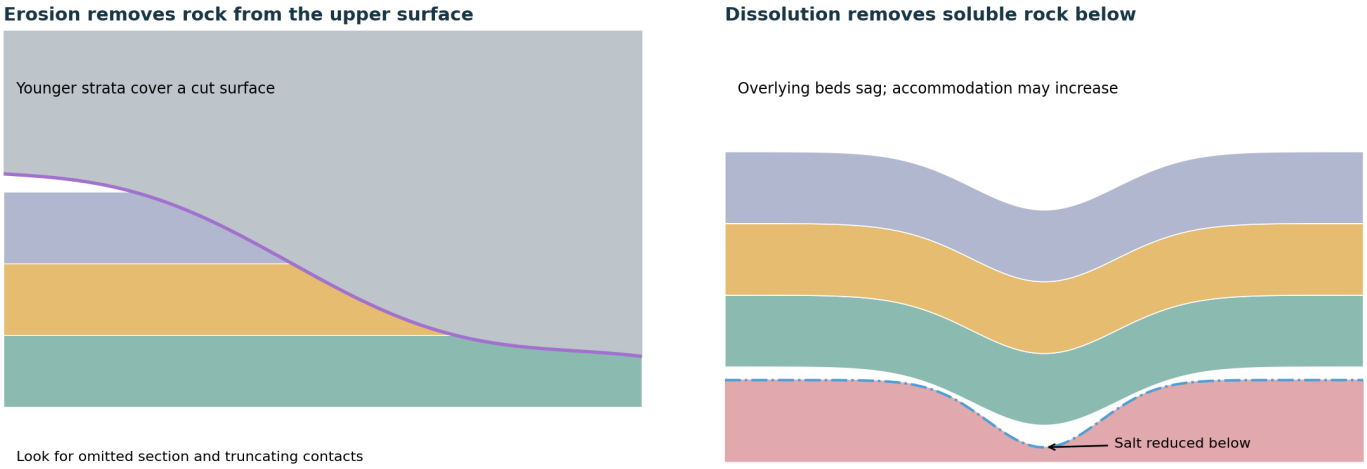
Five-fold internal holdout gives MAE 5.965 m and RMSE 10.002 m over 1,014 supported held-out controls. The maximum absolute residual is 97.47 m. These statistics test interpolation consistency, not the correctness of historical picks or a geodetic datum. They are not a universal local uncertainty envelope.

This supplemental surface interpolates documented historical unconformity picks inside its explicit support mask. It is separate from the original TGI formation-top surfaces and must not replace them. The local shape is a regional interpretation; a smooth surface does not resolve small valleys, fault repetition, karst or pool-scale closure.

The subcrop map identifies which older units meet the unconformity. The elevation model describes where the picked surface lies. These complementary datasets are not interchangeable. A younger marker flattened section is also not a restoration of the original erosional landscape.

Erosion, dissolution and uncertainty

A missing interval can have more than one geological cause



CONCEPTUAL - NOT TO SCALE. Both processes can modify thickness, structure and seals; they can also act at different times in the same area.
Compare multiple horizons, core fabrics, evaporite residues and the timing of overlying thickening before assigning a mechanism.
A fracture or collapse trend may enhance flow, compartmentalize it or breach a seal; it is not automatically a trap.

Original conceptual comparison. Manitoba examples include pre-Mesozoic truncation and the documented local Manson dissolution/structural interpretation. Sources R01-R03 and R17 in the main study.

Preserved thickness should be tested against more than one mechanism. In Manitoba the Three Forks succession and Manson examples show why later preservation, exposure and salt-related deformation matter [R03, R17]. The sequence of events must be reconstructed from cross-cutting relationships and successive isopachs. A salt-free interval is not automatically a paleovalley.

A practical log and sample test

- Correlate tops and bases through wells that actually penetrate the target; retain nonpenetration, uncertain picks and missing logs as separate statuses.
- Look for progressive omission of older markers below a younger contact, lag or reworked material, paleosol/karst fabrics and an erosive base. Test these observations against an alternative correlation.
- For depositional termination, seek lateral facies replacement, onlap/downlap or a consistent depositional geometry with no younger truncating contact. A single GR shape is not sufficient.
- Examine residues, breccia, cement and overlying sag/thickening when salt dissolution is plausible. Core fabrics and event timing can distinguish mechanisms that look similar in a regional isopach.
- Use well tests, completion intervals and fluid data to evaluate charge and seal. A dry well that never tested the target is not a negative reservoir test.

Structure and thickness contours in the 3D / VR viewer

- Select the formation and choose structure or gross interval thickness. Structure contours describe an elevation surface; thickness contours describe a top/base difference, not an elevation. A thickness isoline displayed on a formation plane is still an attribute contour.
- Set a positive contour interval in metres. The offset selects the reference level for that sequence. For example, 50 m with zero offset gives ..., -100, -50, 0, 50, 100 ... for elevations; a 10 m thickness interval gives 0, 10, 20 ... only where supported values actually cross those levels.
- Contours are calculated from the same supported grid triangles used for the display. Null or unsupported triangles must not be bridged. A small interval produces more lines; it does not add well control, improve the 2 km source resolution or establish a smaller feature.
- Compare top and base structure, where a valid base is available, with gross thickness. Parallel structure and nearly constant thickness are different from converging top/base surfaces. Neither pattern alone determines geological cause.
- Use the classified-edge layer and source inspector separately from custom contours. A chosen 5 m contour is a thinning indicator, not an official zero edge. The absence of a 0 m contour does not prove the unit never terminates; the mapped values may end at a source-support limit.
- In VR, keep vertical exaggeration visible. Exaggeration alters the visual steepness of structures and apparent spacing in elevation. It does not change source metres, the chosen contour values or the horizontal position of the classified edge.
- The portable GLB downloads contain fixed 50 m structure contours. Adjustable intervals and offsets are controls in the live browser / VR viewer. Edge segments without supported formation elevation remain separately named reference context at 0 m in the portable package; that reference height is not a geological depth.

Fixed atlas maps and adjustable viewer contours

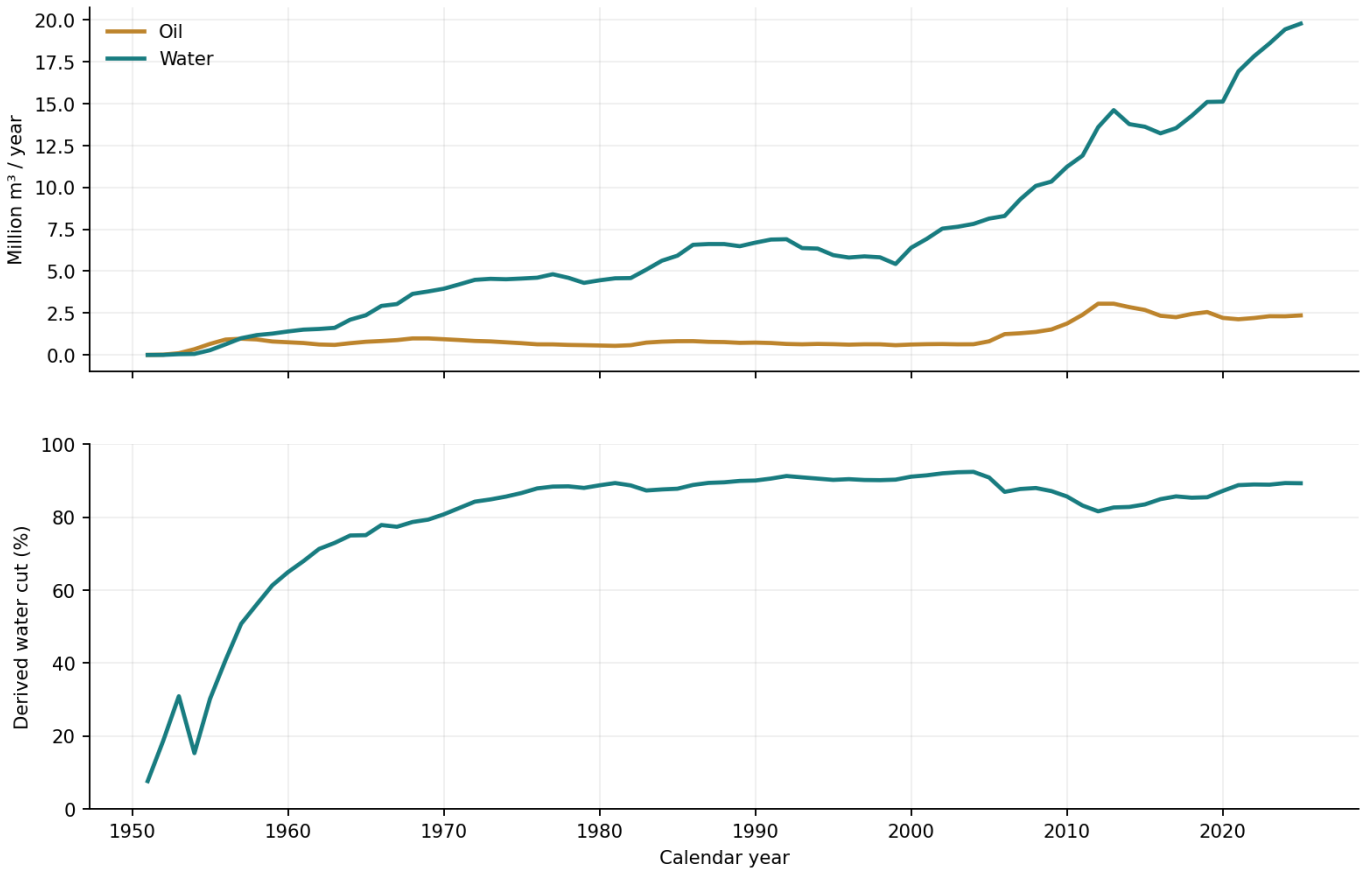
The atlas provides a reproducible default view. Interactive contour choices are display settings over the documented data. They do not change the source grids or their evidence class. The legend and selected surface must remain visible when comparing screenshots or VR observations.

References for this update

Regional mapping and methods: D01-D03 and R26-R27. Manitoba geological interpretation: R01-R04, R05-R10 and R17. Their full citations and URLs are retained in the final reference section. The accompanying edge-evidence register records the provenance of every new vector and supplemental surface.

Production: analogue evidence and water behavior

Public archive production: demonstrated oil, substantial associated water



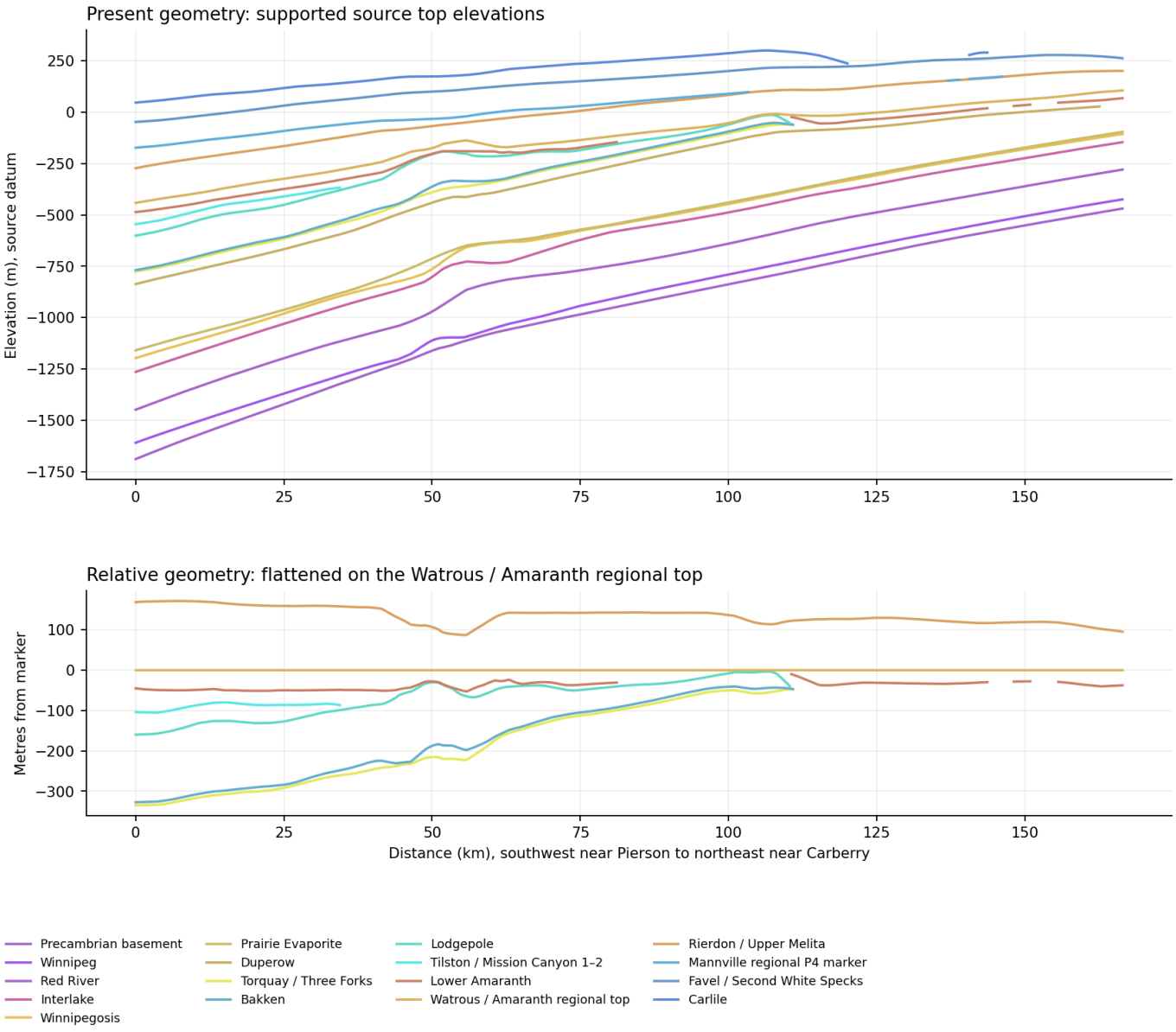
Sum of source monthly rows, 1951-2025; 2026 is partial and excluded here. Not reserves. Province-wide archive totals.
2025 archive oil = 2,360,043.2 m³; headline statistics = 2,375,294.5 m³ (0.64% difference). Reporting/revision cause not established.

Derived from official monthly production Excel archives. Water cut is water / (oil + water) for the accepted source rows, not a forecast or a measure of every pool.

- Production totals are sums of the available monthly rows, not sums of annual cumulative-to-date columns. They describe reported history, not remaining resources, recoverable reserves or a forecast [D04].
- Oil and produced-water volumes are m³. GAS and GSD source values are in 1000 m³. Operating-day and injection categories are retained separately, not combined with oil volumes.
- A licence total can include more than one completion. A pool total is joined by exact field code plus pool code; proximity does not allocate production. Unmatched records are unknown, not dry holes.
- The accepted archive rows sum to 2,360,043.2m³ of oil in 2025; the provincial headline page reports 2,375,294.5m³. The 15,251.3m³ difference is 0.64%. Its cause is not established, so both reporting bases are disclosed [D04-D05].
- 2026 is incomplete. Comparisons should use common time windows and account for operating time, completion length, stimulation, water handling and reservoir history. High historical oil output does not prove an adjacent undrilled accumulation.

Regional geometry and paleogeographic reconstruction

Two views of the same section: structure and relative stratigraphy



Line: NAD83 / UTM14 (335000,5450000) to (475000,5540000). Gaps are retained. Flattening is a geometric aid, not a full paleostructural restoration. The 2 km model cannot resolve small pools, fault throws, channels, reefs or reservoir quality. Vertical and horizontal scales differ.

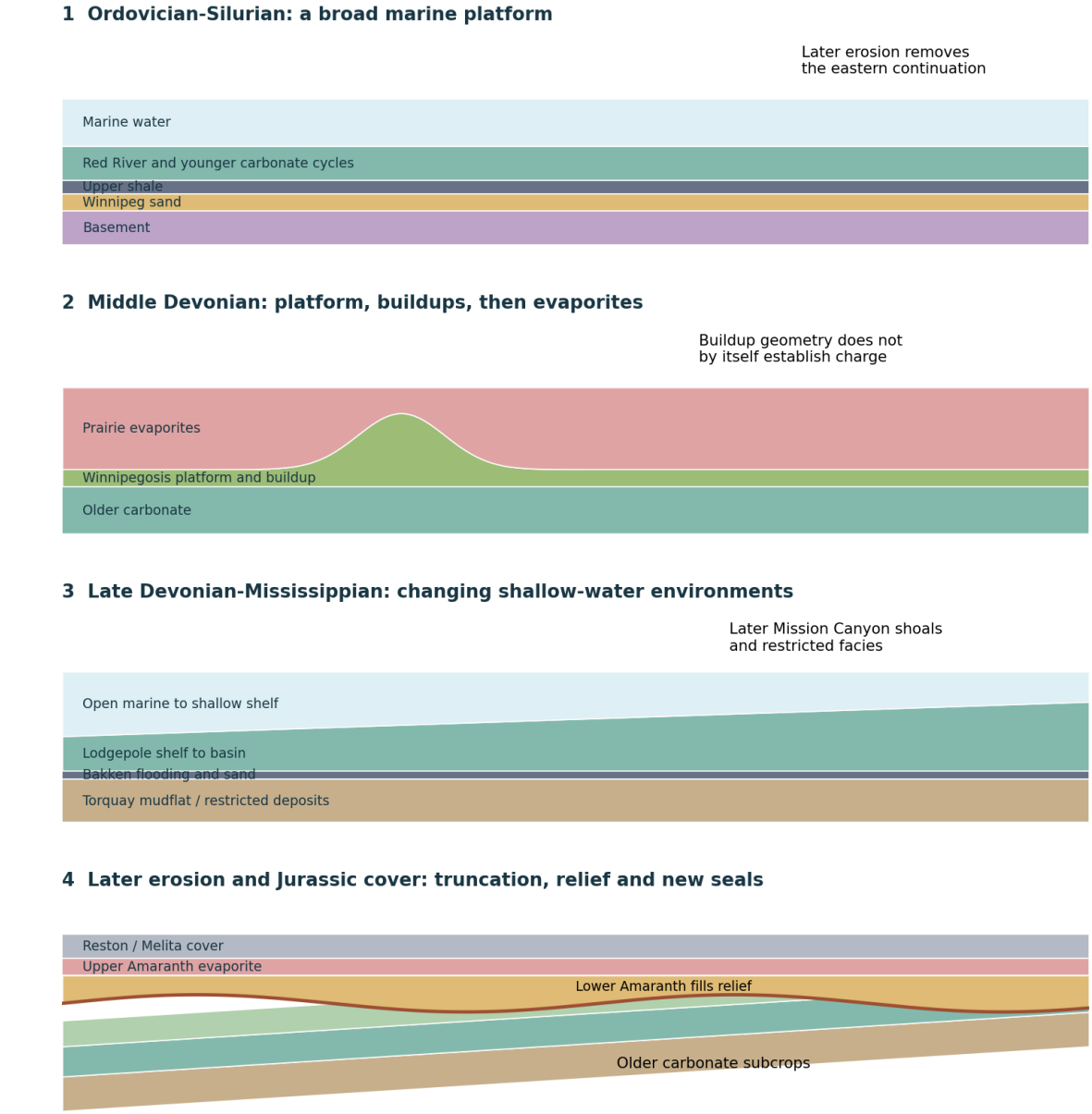
Bilinear sampling requires all four contributing grid nodes; unsupported intervals remain blank. Source TGI model and separately bounded Lower Amaranth interpolation.

The first section shows source elevations. The second subtracts the same younger marker from each supported top. Flattening helps compare relative stratigraphy, but it does not reverse compaction, restore faults, date salt dissolution or reconstruct original bathymetry. A true paleogeographic map requires time slices and facies evidence. The diagrams in the following chapters therefore state their conceptual status.

1. Basin geometry, time and the evidence needed for a trap

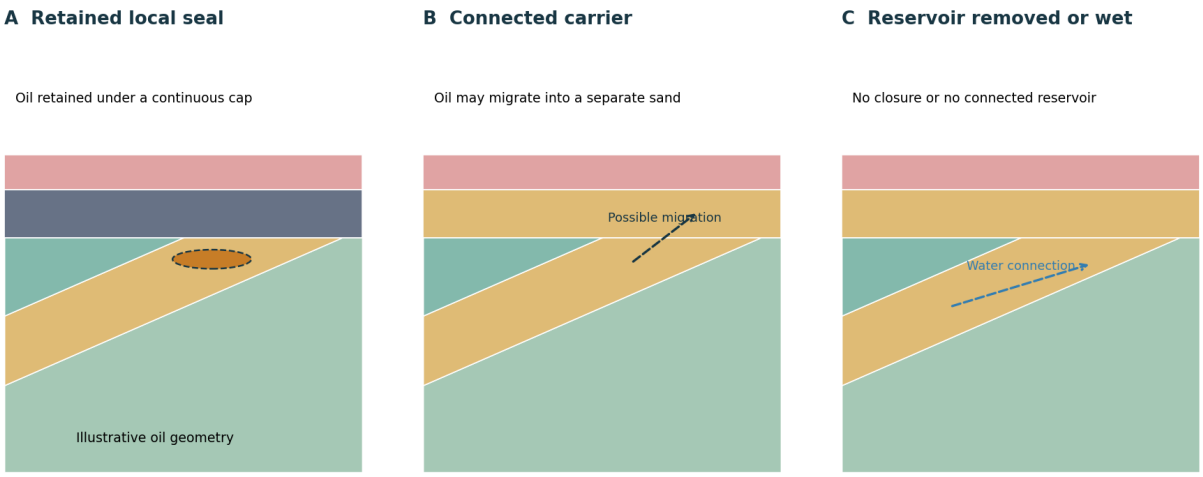
Southwestern Manitoba is the northeastern flank of the Williston Basin, with a southwest-dipping sedimentary wedge and a different Middle Devonian inheritance from the Elk Point Basin. The extreme southwest contains roughly 2.3 km of sedimentary section in the regional synthesis. A present formation edge can record erosion, nondeposition or salt dissolution; these causes predict very different neighboring reservoirs. The old Saskatchewan corridor is not imported into this study. The useful Manitoba framework is a set of overlapping carbonate subcrop, Bakken-Torquay, Lower Amaranth and Jurassic plays tied to their own depositional histories [R01, pp 2-5; R03, p 3].

Different times created different petroleum systems



SCHEMATIC - NOT TO SCALE | Southwest / basinward at left; northeast / cratonward at right. Erosion edges are not ancient shorelines.

Conceptual synthesis of Manitoba basin history. No mapped reservoir bodies or shoreline positions are implied. Sources R01 pp 2-15; R02 pp 4-7; R03 pp 3-4,11-13; R25.



SCHEMATIC - NOT TO SCALE | Identical gross thinning can have different seal and fluid outcomes. Oil shapes are illustrative.

Three alternative outcomes at a subcrop. A source-grid limit is not proof of a geological pinchout. Sources R06 pp 16-18; R08 pp 18-22; R12 pp 4-8.

Precambrian basement and inherited structural framework

Precambrian; reactivated during Phanerozoic | basement surface | structural framework

Crystalline basement forms the substrate on which younger seas advanced. The buried Superior Boundary Zone is a broad crustal boundary; the Birdtail-Waskada Zone is a narrower, north-trending belt of structural and stratigraphic anomalies within southwestern Manitoba. Basement faults, differential subsidence and access of fluids to soluble Devonian salts are linked in published models. Neither lineament is a continuous oil trap [R01, pp 2-5; R03, pp 3-4].

Published observations

- Regional maps, gravity/magnetic interpretations and seismic-supported structural studies underpin the framework; a regional top-basement mesh is not a fault interpretation [R01, pp 2-5].
- The GP2008-2 and GR2012-3 syntheses describe the SBZ as about 40-50 km wide and BWZ about 20-35 km wide. These are structural belts, not prospect boundaries [R03, p 3].

Local / regional orientation. Regional basinward direction is broadly southwest. A local shoreline or reservoir trend requires time-specific facies and paleocurrent evidence.

Reservoir settings to investigate

- Test whether basement-related relief persists upward through several independently picked horizons, and whether growth or onlap dates its activity.
- Separate a basement structure from a salt-collapse low by comparing sub-Prairie and supra-Prairie horizons before attributing reservoir creation.

What would weaken or reject the idea

- Small relief can be below regional-model resolution. Faults may provide charge or water leakage and may compartmentalize reservoirs.
- An apparent anticline created by vertical exaggeration or sparse interpolation is insufficient evidence of closure.

Area significance. Framework for all Manitoba play areas, especially Daly-Sinclair, Virden, Manson and Waskada.

Sources: R01, R03, R26. Full references and links are provided at the end.

Major unconformities and missing stratigraphic section

Multiple Paleozoic and Mesozoic events | bounding surfaces | trap geometry and correlation

Several distinct breaks matter: the basement unconformity; pre-Devonian erosion above Interlake; erosional breaks within and above Torquay-Big Valley-Bakken; the major Paleozoic-Mesozoic surface; and pre-Cretaceous erosion of Jurassic strata. The broad Permian-Pennsylvanian gap in the southwest is part of the regional record, not a suite of missing reservoir surfaces to interpolate [R04; R03, pp 3,11-13; R02, pp 5-8].

Published observations

- Post-Mississippian erosion truncates progressively older units eastward and creates buried ridges and valleys. Lower Amaranth commonly fills this relief [R01, pp 14-15; R08, pp 12-13].
- Lower Bakken and Big Valley remnants in salt-collapse sinks demonstrate preservation after erosion, rather than necessarily a depositional lens [R03, pp 7-8,12-13].

Local / regional orientation. Use restored sections flattened on a younger regional marker before inferring depositional gradient; retain the modern structure section separately.

Reservoir settings to investigate

- Map which bed is immediately below the unconformity, which rock seals it, and where connected porosity terminates.
- Compare thicknesses above and below the surface to distinguish erosional highs from later drape and compaction.

What would weaken or reject the idea

- A formation thinning to zero is not automatically a sealed pinchout; an overlying permeable unit can drain or connect the interval.
- The source model does not independently resolve all unconformities, members or local paleovalleys.

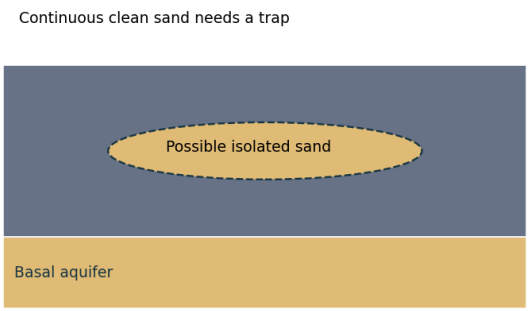
Area significance. Principal control on Mississippian subcrop pools and the selective preservation of older reservoir facies.

Sources: R01, R02, R03, R04. Full references and links are provided at the end.

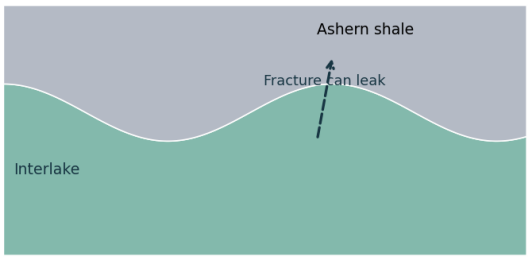
2. Cambrian to Silurian: deep sand bodies, carbonate platforms and charge risk

These units have plausible reservoir fabrics and several documented historical hydrocarbon shows, but the established shallow oil province does not prove a deep accumulation beneath every field. The deepest opportunities require independent closure, effective seal, salinity/pressure data and oil-source evidence. Regional western-basin production is an analogue, not local discovery evidence. The basal Winnipeg system can also be a highly connected aquifer, which makes a continuous clean sand a poor trap without a lateral or structural termination [R21; R22; R01, pp 6-9].

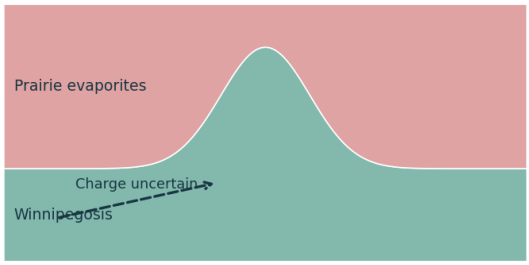
Winnipeg: shale-bounded upper sand lens



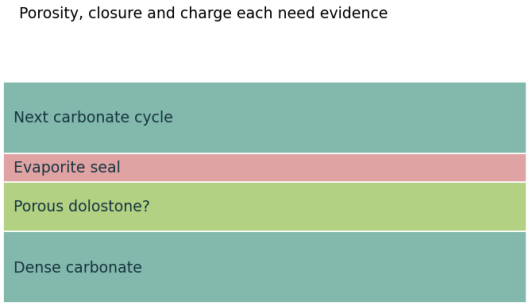
Interlake: karst relief with an intact shale cap



Winnipegosis: buildup inside retained salt



Red River: cyclic porous dolostone and evaporite



SCHEMATIC - NOT TO SCALE | Deep-system hypotheses are not discoveries beneath the shallow oil fields.

Local reservoir fabrics must be paired with effective seals and demonstrated charge. Sources R01 pp 6-10; R19; R21; R22; R25.

Deadwood Formation

Cambrian-Early Ordovician regional usage | formation | reservoir candidate

Glauconitic fine sandstone, siltstone and shale represent shallow marine siliciclastic sedimentation over eroded basement. In Manitoba the subsurface occurrence is an erosional wedge in the extreme southwest; the present limit is not an intact Cambrian shoreline [R21, abstract and regional sections; R01, p 6].

Published observations

- McCabe's 1978 study used only three local penetrations and inferred up to about 53 m in the southwestern wedge; those are historical control and interpretation, not current mapped thickness at every location [R21, abstract].

- The overlying basal Winnipeg sand is highly permeable, so juxtaposition at the unconformity does not itself provide a top seal [R01, p 6].

Local / regional orientation. Basinward to southwest; local basement highs can divert onlap. Do not project a specific shoreline from the erosional edge.

Reservoir settings to investigate

- Sand bounded by shale in a demonstrable closed structure; local onlap against basement relief capped by upper Winnipeg shale or tight lower Red River carbonate.
- Use the deepest wells to test whether separate Deadwood flow units exist before treating the full interval as one connected reservoir.

What would weaken or reject the idea

- Thin or absent section, weak shale continuity and potential loss into Winnipeg aquifer.
- A local oil-prone Cambrian source is unproven; Lillis classifies the Deadwood petroleum system as speculative at basin scale [R19].

Area significance. Extreme southwest only where original well/surface support establishes presence; a frontier target beneath Pierson-Lyleton, not a proven pool extension.

Sources: R21, R22, R01, R19. Full references and links are provided at the end.

Winnipeg Formation: basal sheet sand, upper shale and Carman sand

Ordovician | formation and informal sand units | reservoir candidate

A transgressive sand-shale system records nearshore sand deposition followed by more offshore mud. McCabe's facies work distinguishes a sand-rich northern shelf, a mixed transition and more shale-rich southern/basinal facies. The basal sand sheet and localized upper Carman sand lens must be evaluated separately; their seal geometry differs [R21; R01, p 6].

Published observations

- Quartz-rich lower sand is widespread; upper shale contains additional sands, including a thick, permeable Carman lens that grades laterally to shale [R01, p 6].
- The regional synthesis documents eight historical oil-show wells, but shows neither establish mobile oil nor close a prospect [R01, p 6].

Local / regional orientation. Published regional facies change is broadly sand-rich shelf northward to more basinal mud southward; local high and sand-lens geometry need well sections.

Reservoir settings to investigate

- Upper-sand updip pinchouts into shale; basal onlap against independently mapped basement relief beneath continuous upper shale.
- Test formation-water chemistry, pressure gradients and sand connectivity with DSTs and modern logs to distinguish trapped hydrocarbons from the regional aquifer.

What would weaken or reject the idea

- Excellent porosity with high water saturation is an aquifer, not a reservoir discovery.
- The eastern edge of the thick sand is erosional; the original Ordovician depositional basin extended farther east.

Area significance. Deep frontier beneath southern Manitoba; no new pool or movable-oil claim made from reservoir quality alone.

Sources: R21, R22, R23, R01. Full references and links are provided at the end.

Red River Formation

Ordovician | formation | reservoir candidate

Fossiliferous, burrow-mottled platform carbonate passes upward into shallowing and restricted dolostone-anhydrite cycles. Reservoir quality can reflect selective dolomitization and dissolution rather than reef topography. Lower Red River/Yeoman-equivalent carbonate and upper Herald-equivalent cycles should not be collapsed into a single petrophysical interval [R25; R22; R01, pp 6-7].

Published observations

- Lake Alma anhydrite persists in southwestern Manitoba; Coronach evaporite is farther basinward in the regional TGI interpretation. Dissolution modifies their edges [R01, p 7].
- Historical oil shows and strong local variations in porous dolostone are documented, including variations around T4R25W1 [R01, p 7; R22].

Local / regional orientation. Broad carbonate platform; grain-rich belts and diagenetic fronts must be mapped independently of present structural dip.

Reservoir settings to investigate

- Dolomitized burrow fabrics or porous beds beneath intact anhydrite, with structural closure or demonstrable lateral porosity loss.
- Map anhydrite continuity and isolate reservoir cycles with core-calibrated density/neutron, resistivity and pressure data.

What would weaken or reject the idea

- Dissolved evaporite can remove a seal; late cement can destroy initially favorable texture.
- Lower-Paleozoic oil-family compatibility must be measured; overlying Bakken production is not proof of downward charge.

Area significance. Conceptual deep follow-up around Daly/Birdtail-Waskada structural anomalies; no drilling location selected.

Sources: R25, R22, R01, R19. Full references and links are provided at the end.

Stony Mountain Formation: Hartaven, Gunn/Penitentiary and Gunton

Late Ordovician | formation with members | reservoir candidate

Fossiliferous shaly limestone and argillaceous dolostone record normal to restricted shallow shelf conditions; the upper Gunton is a more dolomitic, sparsely fossiliferous unit. North-south facies changes complicate applying outcrop member names to the deep subsurface [R25; R01, pp 7-8].

Published observations

- Gunn and Penitentiary are commonly indistinguishable in subsurface logs; their lithology changes laterally [R01, p 7].
- Only two historical Manitoba oil shows were compiled in the 2008 synthesis; Gunton production elsewhere in the basin is an analogue [R01, p 8].

Local / regional orientation. Low-relief shelf, with facies and diagenesis more useful than a simple shoreline-distance rule.

Reservoir settings to investigate

- Local porous Gunton dolostone beneath tight Stonewall or intraformational beds.

- Use core/thin sections to distinguish connected intercrystalline pores from clay-rich or cemented apparent porosity.

What would weaken or reject the idea

- Argillaceous intervals and variable compaction create thickness changes without reservoir development.
- Charge and lateral seal remain unproved in an untested Manitoba structure.

Area significance. Secondary deep objective where a well already tests a stronger, independently supported lower-Paleozoic target.

Sources: R25, R22, R01. Full references and links are provided at the end.

Stonewall Formation

Latest Ordovician-early Silurian | formation | mainly baffle/seal; conditional reservoir

Sandy and argillaceous dolostone records a relatively stable, shallow shelf. The Williams interval and a basal anhydrite equivalent are useful regional subdivisions; marker beds are correlation tools rather than automatic reservoir contacts [R25; R01, p 8].

Published observations

- Regional thickness/lithology are comparatively uniform in the cited synthesis. One historical oil show is reported at 3-9-4-11W1 [R01, p 8].

Local / regional orientation. Stable-shelf interpretation; present erosion and fractures can obscure primary textures.

Reservoir settings to investigate

- Check any local clean dolostone or fracture interval encountered in deep tests, with explicit permeability and fluid evidence.

What would weaken or reject the idea

- The regional study regards the argillaceous character as unfavorable and reports no established basin production at its date. Do not promote a single show into a play.

Area significance. Primarily a correlation and local seal/baffle interval; low priority for stand-alone exploration.

Sources: R25, R22, R01. Full references and links are provided at the end.

Interlake Group

Silurian | group | reservoir candidate

Fine-crystalline dolostone with ooids, fossils, stromatolites and local biohermal beds represents a shallow carbonate platform with restricted and peritidal settings. Prolonged pre-Devonian emergence generated karst and solution-enlarged fractures at the upper unconformity. Outcrop formations Fisher Branch, Moose Lake, Atikameg, East Arm and Cedar Lake should not be presented as independently mapped model surfaces [R25; R01, pp 8-9].

Published observations

- Karst and fracture enhancement are documented at the pre-Devonian surface; Ashern shaly carbonate commonly overlies it away from the main subcrop [R01, p 9].
- Published oil shows and production elsewhere establish a plausible petroleum-system analogue, not commerciality in any Manitoba map cell [R22; R01, p 8].

Local / regional orientation. A broad shallow platform with exposure relief; local paleotopography is more predictive than one regional shoreline line.

Reservoir settings to investigate

- Karstified or selectively dolomitized upper Interlake beneath a continuous Ashern seal, enclosed in a paleohigh or structural closure.
- Use borehole images, oriented core, losses, pressure tests and capillary data to determine whether fractures connect oil, water or leakage paths.

What would weaken or reject the idea

- Open connected karst can be water-bearing and difficult to seal; cemented collapse breccia may be tight.
- The same fluid pathways that enhance porosity can breach the top seal or precipitate pore-filling minerals.

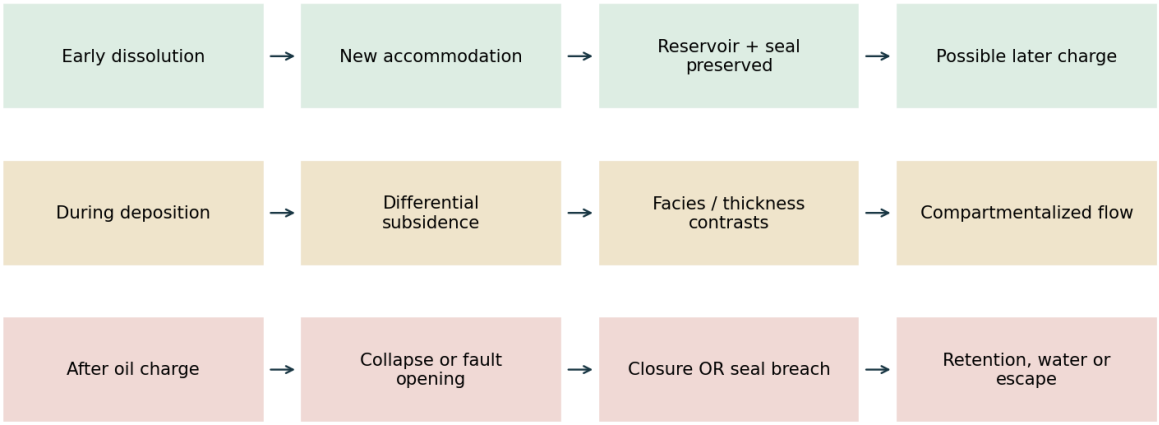
Area significance. Deeper underexplored setting near inherited structural zones, requiring a separate charge and seal case.

Sources: R25, R22, R01. Full references and links are provided at the end.

3. Devonian carbonate-evaporite systems: reefs, cyclic reservoirs and salt removal

The Middle Devonian sea occupied the Elk Point Basin, whose geometry differs from the later Williston-centered system. Winnipegosis platform and reef growth was followed by evaporite deposition; repeated carbonate-evaporite cycles continued through younger Devonian units. Salt removal is a second geological history superimposed on these original environments. A present thick or high interval can therefore be a depositional buildup, a draped residual high, differential compaction, or an interpolation artifact. Distinguishing these alternatives is necessary before targeting a reef [R25; R22; R01, pp 9-12].

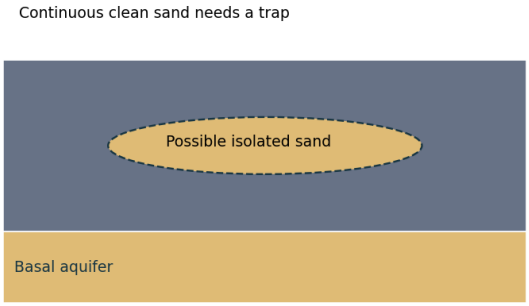
Timing determines whether salt dissolution helps or harms a trap



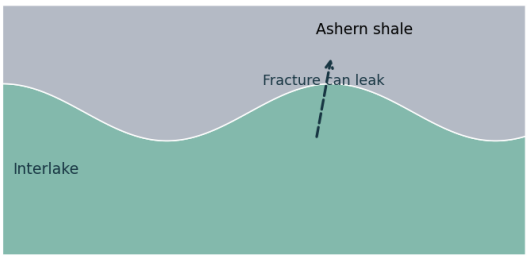
SCHEMATIC - NOT TO SCALE | Causal alternatives; no probability or expected resources assigned.

The same process can create accommodation, preserve a reservoir, open a migration route or breach a seal. Sources R01 pp 9-15; R03 pp 12-15; R11; R17.

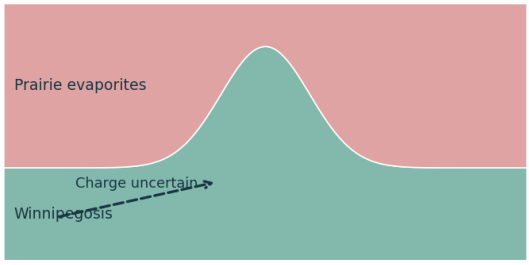
Winnipeg: shale-bounded upper sand lens



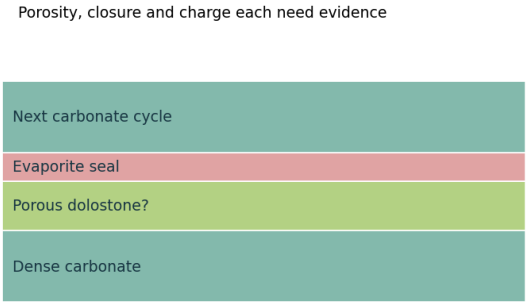
Interlake: karst relief with an intact shale cap



Winnipegosis: buildup inside retained salt



Red River: cyclic porous dolostone and evaporite



SCHEMATIC - NOT TO SCALE | Deep-system hypotheses are not discoveries beneath the shallow oil fields.

Local reservoir fabrics must be paired with effective seals and demonstrated charge. Sources R01 pp 6-10; R19; R21; R22; R25.

Ashern Formation

Middle Devonian | formation | regional seal

Dolostone and shale accumulated during marine flooding across the eroded Silurian landscape. Thickness partly fills pre-existing relief rather than recording a uniform shelf gradient [R25; R01, p 9].

Published observations

- The basal contact is unconformable on Interlake; shaly character gives the Ashern an important regional sealing role [R01, p 9].

Local / regional orientation. Transgressive onlap and paleorelief control; no reservoir shoreline is inferred.

Reservoir settings to investigate

- Map seal continuity above upper-Interlake porosity; distinguish thin depositional cover from later fault or dissolution breach.

What would weaken or reject the idea

- Clay-rich and argillaceous carbonate is generally a poor reservoir. The 2008 synthesis records no Manitoba oil shows in Ashern.

Area significance. Critical to the seal case for Interlake opportunities, primarily not a reservoir target.

Sources: R25, R01. Full references and links are provided at the end.

Winnipegosis Formation: platform, reef and inter-reef facies

Middle Devonian | formation | reservoir candidate

A lower carbonate platform supports upper reefal, patch-reef and inter-reef carbonate. This is the clearest regional setting where a genuine carbonate buildup hypothesis is justified, but source-model topography alone cannot resolve or prove individual reefs [R25; R22; R01, p 9].

Published observations

- Fossiliferous dolostone/limestone and reef-inter-reef thickness variations are documented. The TGI isopach pattern broadly reproduces published Elk Point paleogeography [R01, p 9].
- Potential evaporite-encased reef traps are restricted to areas where reef relief and preserved Prairie salt/anhydrite overlap, principally near the Saskatchewan boundary [R01, p 9].

Local / regional orientation. Use reef distribution and inter-reef facies to reconstruct a specific Middle Devonian platform margin; modern NE-SW dip is insufficient.

Reservoir settings to investigate

- A porous reef flank or crest enclosed laterally and above by intact evaporite; alternatively a shelf porous bed in demonstrable closure beneath Second Red Beds or residual basal anhydrite.
- Test seismic geometry against core facies and original well tops, then map seal thickness and fluid contacts.

What would weaken or reject the idea

- Many carbonate buildups are water-bearing. Salt dissolution can leave an attractive high while destroying enclosure.
- Coarse regional interpolation smooths small buildups and may create false closed contours.

Area significance. Western Manitoba deep frontier; mapped reef analogues need charge and seal proof before prospect status.

Sources: R25, R22, R01. Full references and links are provided at the end.

Prairie Evaporite and residual transitional interval

Middle Devonian | formation | seal and structural control

Restricted hypersaline conditions produced halite, subordinate anhydrite and local potash-bearing intervals. Later dissolution created residual breccias, drape and collapse across much of southwestern Manitoba. The present halite limit is a dissolution boundary, not the depositional edge of the Devonian salt basin [R01, pp 9-10].

Published observations

- Major dissolution stages are associated with Devonian-Mississippian and Paleozoic-Mesozoic breaks; local collapse ranges from well-scale features to field-scale Waskada deformation [R01, p 10].
- The regional source surface can trace residual transitional material where bulk salt is absent. A top-Prairie surface must not be read as a map of surviving salt.

Local / regional orientation. Dissolution follows hydrologic and structural pathways; it need not follow a Devonian shoreline.

Reservoir settings to investigate

- Treat intact salt as a seal, residual highs as potential drape controls, and collapse-created accommodation as a preservation mechanism for younger sand/carbonate intervals.
- Use salt thickness, residual-interval logs and supra/sub-salt structure together to time events.

What would weaken or reject the idea

- Collapse lows themselves commonly lack closure; faulting may connect water-bearing intervals.
- Late dissolution can compromise a previously charged trap, while early collapse may preserve a younger reservoir and seal.

Area significance. Essential overprint at Daly-Sinclair, Virden, Manson and Waskada; no hydrocarbon volume is inferred from salt loss.

Sources: R01, R03, R11, R17. Full references and links are provided at the end.

Dawson Bay Formation

Middle Devonian | formation | reservoir candidate

Carbonate deposition resumed above evaporites, with basal argillaceous Second Red Beds and younger carbonate/evaporite intervals. Draping over Winnipegosis relief and differential salt dissolution modifies the formation after or during deposition [R25; R01, pp 10-11].

Published observations

- Historical oil shows and lateral porosity changes are reported. The regional synthesis explicitly leaves uncertain whether some porosity variability is depositional or diagenetic [R01, p 11].
- Hubbard evaporite and overlying First Red Beds can contribute to the local seal arrangement where preserved [R01, p 11].

Local / regional orientation. Platform carbonate with superimposed relief; reconstruct reef-related drape independently of younger regional tilting.

Reservoir settings to investigate

- Porous dolostone/karst in a verified drape closure with a continuous cap; local sealed subcrop below Amaranth cover.
- Separate original thickness from salt-related deformation using multiple marker surfaces and core textures.

What would weaken or reject the idea

- Drape above an underlying reef does not prove an independent closed reservoir; fractures and modern brine circulation indicate possible leakage.

Area significance. Conditional deep follow-up near known salt-removal zones, not a blanket belt of expected oil pools.

Sources: R25, R22, R01. Full references and links are provided at the end.

Souris River Formation: First Red Beds, Davidson, Harris and Hatfield

Middle-Late Devonian | formation with members | reservoir candidate

Repeated shallow-marine carbonate, shaly and evaporitic cycles record changing restriction and accommodation. Porous dolostone beds alternate with argillaceous or anhydritic baffles. This architecture favors compartmentalized cyclic reservoirs rather than a single homogeneous platform tank [R25; R22; R01, p 11].

Published observations

- Published correlations extend Saskatchewan member names into Manitoba; outcrop equivalents use different names. The lower Davidson and cyclic Harris intervals are identified as potential porous zones [R01, p 11].

- A gas accumulation beneath the Daly structure demonstrates some reservoir and trapping capacity, but gas composition and commercial deliverability must be verified before treating it as an oil analogue [R01, p 11].

Local / regional orientation. Repeated shelf-restricted-basin shifts; lateral cycle continuity and diagenetic fronts matter more than one shoreline.

Reservoir settings to investigate

- Cycle-scale porous beds with both top and basal seals in structural closure or sealed erosional relief.
- Tie lithology, oil/gas composition and pressure separately for each test interval.

What would weaken or reject the idea

- Porosity may be isolated, anhydrite-filled or water-bearing; a generic gas show is not proof of a petroleum charge.

Area significance. Deep Daly/Birdtail-Waskada follow-up only with interval-specific tests and seal mapping.

Sources: R25, R22, R01. Full references and links are provided at the end.

Duperow Formation: Saskatoon, Elstow, Wymark and Seward

Late Devonian | formation with members | reservoir candidate

Cyclic limestone, dolostone, shale and anhydrite reflect repeated carbonate-platform flooding and restriction. The Wymark contains many prospective porous beds in the published regional interpretation; facies transitions and subsequent dolomitization can create lateral permeability terminations [R22; R01, p 12].

Published observations

- Oil shows and a Daly-structure gas occurrence are recorded; member correlations were principally log-based in TGI, without a new cross-border core study [R01, p 12].
- The Manitoba subcrop is beneath Mesozoic cover; variations in Lower Amaranth thickness suggest relief on the eroded surface [R01, p 12].

Local / regional orientation. Platform cycles with local restriction; precise shoal/lagoon direction must be established within each correlated cycle.

Reservoir settings to investigate

- Porous cycle beneath its own shale/anhydrite seal, or a demonstrably sealed subcrop high below Amaranth.
- Confirm whether lateral tightness is original muddy facies, cemented dolostone or a log-processing artifact.

What would weaken or reject the idea

- Multiple good-porosity beds can communicate with water; source access remains a separate risk.
- Subcrop karst and salt-related fractures can improve or destroy reservoir quality.

Area significance. Conditional older-Devonian targets beneath existing shallow fields and along sealed subcrops.

Sources: R22, R01. Full references and links are provided at the end.

Birdbear Formation (legacy Nisku alias)

Late Devonian | formation | reservoir candidate

Fossiliferous carbonate passes into upper biohermal and locally evaporitic facies. Porous dolostone near the top of the lower interval can be sealed by upper anhydrite/argillaceous carbonate, while local reef facies replace the evaporitic interval. This is a testable facies-seal transition rather than a reason to expect reefs around every younger oil pool [R22; R01, p 12].

Published observations

- Core and DST evidence at 6-6-12-24W1 is cited for permeable organic-reef facies replacing upper evaporite near Virden [R01, p 12].
- A completion at 2-8-8-17W1, below Upper Amaranth cover, flowed nitrogen-rich gas in the regional account. This supports a trapping configuration but is negative evidence for assuming hydrocarbon gas [R01, p 12].

Local / regional orientation. Local reef/platform and evaporite facies; orientation must come from Birdbear-specific correlations.

Reservoir settings to investigate

- Porous carbonate with preserved upper cap, or reef-inter-reef juxtaposition supported by core and pressure data.
- Obtain actual DST recovery/composition and a source-compatible oil sample; do not turn the word gas into a hydrocarbon discovery.

What would weaken or reject the idea

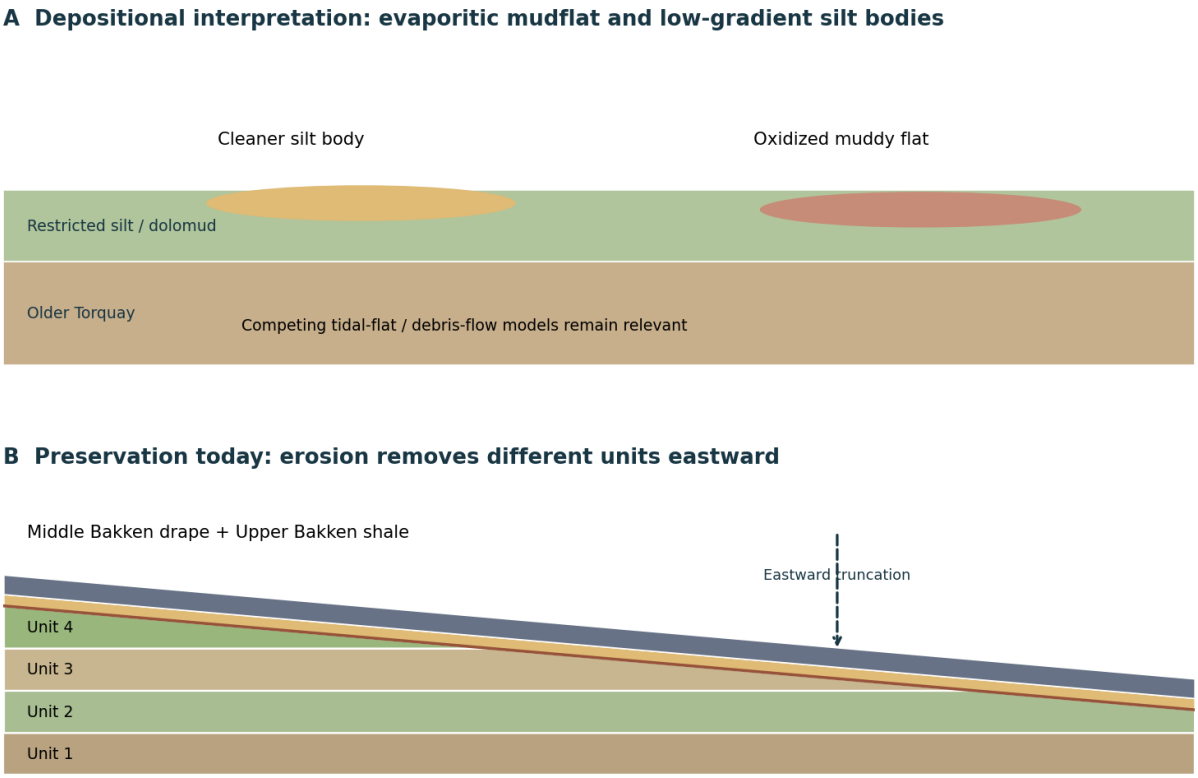
- Evaporite replacement by a permeable facies may remove the seal; strong porosity does not establish charge.

Area significance. Virden-area deeper analogue with explicit well examples; no undiscovered pool boundary drawn.

Sources: R22, R01. Full references and links are provided at the end.

4. Three Forks Group: Torquay, Big Valley and Bakken

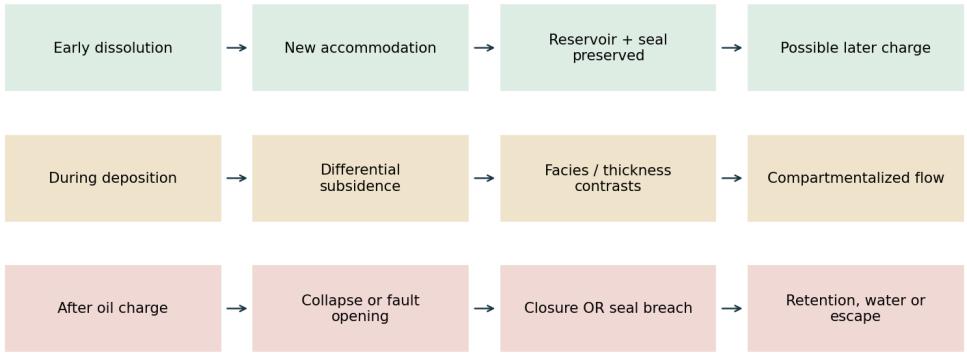
The modern Manitoba Three Forks Group contains Torquay, Big Valley and Bakken. Older well files and papers often use Three Forks Formation or Lyleton for Torquay. These names must be reconciled before correlating reservoir tops. The proven Daly-Sinclair system combines a depositional silt/sand framework, selective erosion, redox and cement effects, and reservoir communication across the sub-Bakken unconformity. A uniformly thick Bakken is not required, and a thicker Bakken is not necessarily the better producing interval [R03, pp 1-3,13-15; R14].



SCHEMATIC - NOT TO SCALE | Collapse lows can preserve Big Valley / Lower Bakken remnants; these are not drawn as a continuous blanket.

Conceptual restoration and preserved section. Cleaner facies may still be cemented; no net pay is inferred. Sources R03 pp 5-15 and Figs 43-48; R14 p 8; R16.

Timing determines whether salt dissolution helps or harms a trap



SCHEMATIC - NOT TO SCALE | Causal alternatives; no probability or expected resources assigned.

The same process can create accommodation, preserve a reservoir, open a migration route or breach a seal. Sources R01 pp 9-15; R03 pp 12-15; R11; R17.

Torquay units 1-2: cyclic siltstone and mudflat deposits

Late Devonian | formation subdivisions | reservoir candidate

Interbedded dolomitic siltstone, claystone and mudstone, with ripple marks, flasers, crossbedding, soft-sediment deformation and local breccia, support intermittent inundation of a low-gradient, arid coastal platform. Nicolas 2012 interprets an extensive evaporitic mudflat; an earlier Sinclair model used a prograding carbonate tidal flat. These models share shallow-water and repeated-exposure elements but differ in the origin of breccia and basin-scale geometry [R03, pp 5-6,11-12].

Published observations

- Subunit 2c contains roughly 75% sandy siltstone and 25% muddy material in the descriptive model, with ripples, trough crossbedding and escape structures. Descriptive porosity is around 15%; it is productive with Middle Bakken where minimally oxidized [R03, p 6].
- Oil staining and UV fluorescence in unit 1c at 6-7-4-21W1 and 5-11-11-26W1 were reported without demonstrated production from those intervals. Unit 2 averages about 14 m in the study correlation; this is gross thickness [R03, pp 5-6].

Local / regional orientation. The original shelf broadly sloped west; modern north-trending erosional unit edges differ from the inferred northwest-southeast depositional orientation [R03, p 12].

Reservoir settings to investigate

- Preserved 2c clean siltstone near the unconformity, capped by thin unit 3 and connected to a sealed Middle Bakken system.
- Unit 1 is conditional where clean silt persists, requiring new core calibration rather than an attractive gamma-ray pattern.

What would weaken or reject the idea

- Redox alteration is variable and may occlude pores; unit 2b is generally poorer than clean 2c and reservoir quality decreases away from the unconformity.
- Thin silt beds, incomplete core recovery and shale microporosity can create misleading log-derived pay.

Area significance. Daly-Sinclair eastward transition, Virden beneath existing shallow pools and local Birdtail extensions are hypotheses requiring current-well tests.

Sources: R03, R14, R16. Full references and links are provided at the end.

Torquay units 3-4: oxidized mud and haloturbated/silty reservoir cycles

Late Devonian | formation subdivisions | reservoir candidate

Unit 3 is commonly oxidized, mud-rich material representing exposure and low sediment supply in the 2012 model. Unit 4b contains angular siltstone fragments in muddy matrix; Nicolas interprets in-place disruption through repeated evaporite growth and dissolution rather than transported debris flow. Cleaner 4c records a gently sloping silt shoal affected by waves/storms. Calling every breccia a channel or every clean bed a beach would overstate the evidence [R03, pp 6-7,11-12].

Published observations

- Unit 4 is the main Torquay reservoir in southern Daly-Sinclair, averages about 7.5 m there, and is eroded eastward. Local preserved sections reach 23 m where older Bakken/Big Valley cover survives [R03, p 7].
- The 223-well core compilation shows best unit 4 quality where 4c reaches the unconformity, poorer results where lower 4b reaches it, and variable unit 2 quality related to redox alteration [R03, p 14, Figs 47-48].
- The Sinclair 2006 report gives local mean porosities 14.7% for Bakken and 16.5% for legacy Three Forks, with mean permeabilities 1.8 and 4.3 mD. These 12-core statistics are sample-specific [R14, p 8].

Local / regional orientation. Subcrop and clean-silt belts are the relevant map objects. A conceptual shoreface lies basinward of exposed mudflat, but no precise paleoshoreline is drawn without correlated facies.

Reservoir settings to investigate

- Map the subunit at the unconformity, not only total Torquay thickness; seek connected 4c/upper 4b in the proved petroleum system.
- Use core/thin sections to distinguish angular in-place breccia from transport, identify pore-filling iron oxides, and quantify clay-bound versus movable fluids.

What would weaken or reject the idea

- Eastward continuation can lose unit 4 entirely; isolated thick remnants may be water-filled collapse compartments.
- Red/green color alone is not a formation boundary or oil indicator; the oxidation boundary can cross stratigraphy.

Area significance. Highest-evidence analogue is Daly-Sinclair; additional unit 4 remnants eastward are separate test cases.

Sources: R03, R14, R15, R16. Full references and links are provided at the end.

Big Valley Formation and locally preserved basal transitional sand

Latest Devonian | formation; local erosional remnants | reservoir candidate

A transgression after Torquay deposition introduced bioturbated sand/silt and shale. Nicolas interprets eastern Manitoba remnants as coarser, nearshore equivalents of a more mud-rich basinward Big Valley succession. Subsequent erosion left local preservation in collapse lows. Legacy Sanish sandstone or basal Bakken silt labels are not interchangeable without checking the specific core and contacts [R03, pp 7-8,12-13].

Published observations

- Core at 12-24-11-29W1 provides physical evidence; the lower sand is strongly bioturbated, oil-stained and described as productive. Its log expression is approximately 10 m thick [R03, p 7, Figs 23-24].
- A roughly 26 m low-gamma sand interval at 16-35-2-24W1 is correlated in the report; its log response is not itself proof of identical lithofacies or pay thickness [R03, pp 7-8].

Local / regional orientation. Nearshore-to-basinward facies change broadly westward; collapse accommodation can dominate local thickness.

Reservoir settings to investigate

- Preserved coarse transgressive fill with direct core support, enclosing seal and demonstrated charged reservoir system.
- Test Big Valley versus basal Bakken versus reworked Torquay using contacts, fossils/ichnology, grain composition and adjacent wells.

What would weaken or reject the idea

- Very local preservation makes regional interpolation unreliable. Gross sand and stain are insufficient without saturation, permeability and pressure data.

Area significance. Local Daly-Sinclair and Waskada-area collapse structures; not a continuous regional surface.

Sources: R03, R16. Full references and links are provided at the end.

Lower Bakken Member

Latest Devonian-earliest Mississippian boundary interval | member | seal/source facies; local preservation

Organic-rich black shale represents offshore marine flooding. It was subsequently removed across much of the Manitoba producing fairway, while local collapse lows preserve it and older transition beds. Its absence changes the hydraulic relationship between Middle Bakken and Torquay [R03, pp 8,12-13].

Published observations

- Local preservation in salt-collapse structures is documented in core/log correlations [R03, pp 7-8,12-13].

Local / regional orientation. Offshore flooding over older relief; local remnant boundaries largely reflect erosional preservation.

Reservoir settings to investigate

- Use its presence as a preservation and seal marker; test whether it separates underlying sand from the Middle Bakken flow system.

What would weaken or reject the idea

- Do not assert universal absence or infer a mature local source simply from black, radioactive shale.

Area significance. Compartmentalization control in local collapse-related sand targets.

Sources: R03, R16. Full references and links are provided at the end.

Middle Bakken Member

Early Mississippian regional interval | member | reservoir candidate

Siltstone and sandstone record shallowing/regression between black-shale flooding events, including shelf, nearshore and locally channel-like sand bodies. Clean sand onlaps the eroded Torquay surface. Northward coarsening/thickening is described regionally, but local collapse accommodation and erosion produce important exceptions [R03, pp 8,13].

Published observations

- NearT4R29W1 it can be a lag less than 10 cm thick; north ofT16 it locally reaches 8 m with coarser sand lenses. These are local observations, not a linear thickness gradient [R03, p 13].
- Northern sandier occurrences have reported porosity up to 20% and common oil stain, while southern production can rely more on Torquay storage [R03, pp 13-15].

Local / regional orientation. Published sand trends are commonly northerly; coarser northern bodies may be channelized. The coarse model cannot locate exact shorefaces or channels.

Reservoir settings to investigate

- Core-calibrated clean sand with upper shale seal and connected Torquay where Lower Bakken is absent.
- Map net sand, grain size, clay and first-year water/oil behavior separately from total Bakken thickness.

What would weaken or reject the idea

- The 2012 northern thickening also coincides with increased water/oil ratio; more sand can mean more aquifer connectivity.
- High resistivity can reflect cement or low-salinity water; calibrate saturation with actual water chemistry.

Area significance. Daly-Sinclair, Kirkella, Birdtail and Manson pools; northern analogues need fluid-contact tests.

Sources: R03, R14, R16. Full references and links are provided at the end.

Upper Bakken Member

Early Mississippian | member | regional seal and source-rock analogue

Organic-rich marine shale caps Middle Bakken and is a principal seal. Basinward mature equivalents may generate oil, but sampled Manitoba shales are locally immature. Source quality and source maturity are separate questions [R03, pp 8,13; R01, pp 13-14].

Published observations

- Sinclair samples in GP2008-2 have TOC16.86-25.93% and Tmax 408-418°C: rich but interpreted thermally immature [R01, pp 13-14].
- At 3-33-10-29W1 high gamma, low density and high resistivity coincide with organic-rich shale, but do not establish in-situ generation [R01, p 13].

Local / regional orientation. Offshore transgressive blanket modified by local thickness and erosion.

Reservoir settings to investigate

- Map continuity as seal evidence; retain local geochemistry to constrain maturity and oil-source correlation.

What would weaken or reject the idea

- High gamma or TOC is not oil pay. Fractures can breach the cap.
- A deep North Dakota source model cannot be transferred without local burial/thermal calibration.

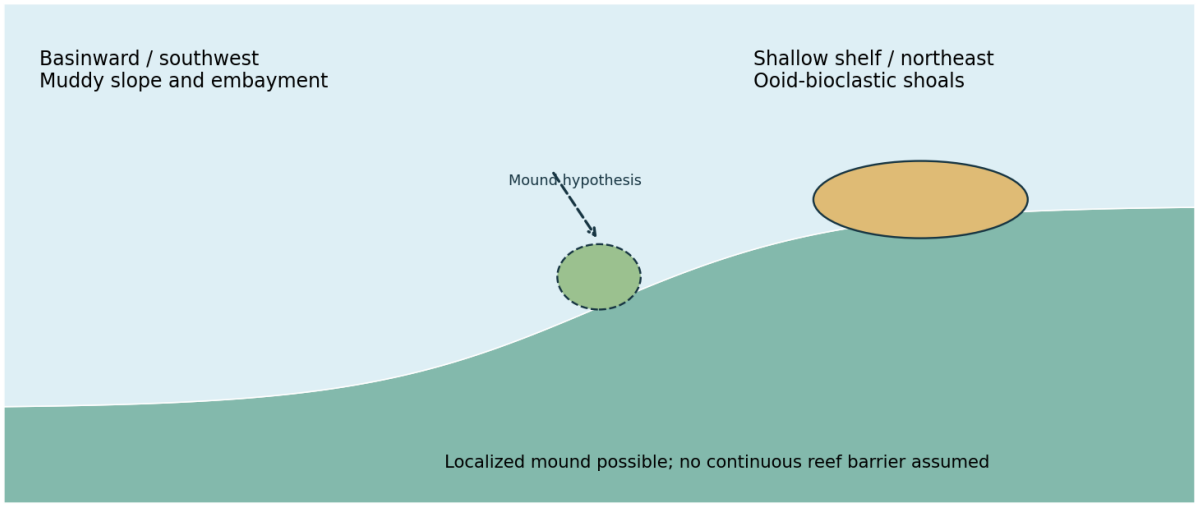
Area significance. Seal for the principal Bakken-Torquay play and a regional charge constraint.

Sources: R03, R01, R19, R20. Full references and links are provided at the end.

5. Lodgepole: carbonate banks, shoals, slope facies and subcrop pools

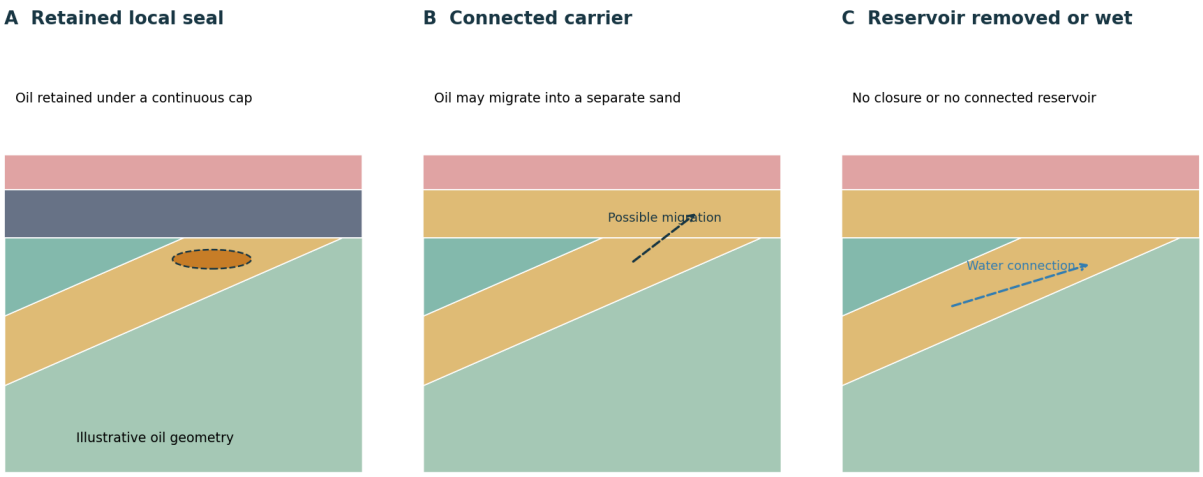
A western Mandak embayment, shallow carbonate banks and shoals to the east, and muddier slope/basin deposits created the Lodgepole facies framework. Later erosion and diagenesis created many traps at Virden, Daly, Souris Hartney, Whitewater, Regent, Mountainside and Lulu Lake. The regional formation top does not locate each productive member, and slope names are not simply a stack of shelf formations [R05, pp 9-10,25-26; R01, p 14].

Lodgepole: shelf, slope, shoal and local buildup



SCHEMATIC - NOT TO SCALE | Depositional energy, later dolomitization, cement and fractures all affect present pore connectivity.

Member nomenclature differs across shelf and slope; a single Lodgepole model top does not map these reservoir facies. Sources R05 pp 9-10,25-26; R12 pp 4-8; R01 p 14.



SCHEMATIC - NOT TO SCALE | Identical gross thinning can have different seal and fluid outcomes. Oil shapes are illustrative.

Three alternative outcomes at a subcrop. A source-grid limit is not proof of a geological pinchout. Sources R06 pp 16-18; R08 pp 18-22; R12 pp 4-8.

Routledge Shale and basal Lodgepole carbonate

Early Mississippian | local facies/member equivalents | seal/baffle and source assessment

Dark shale and carbonate mud represent lower-energy marine deposition near the transition from Bakken flooding to the Lodgepole carbonate system. Routledge shale is locally preserved between Bakken and Scallion; basal carbonate passes laterally into shelf deposits [R05; R01, p 14].

Published observations

- Routledge samples have TOC6.39-10.77%, Tmax 413-423°C and conodont color alteration index 1: organic-rich but thermally immature [R01, p 14, Appendix 1].
- Basal-limestone shale samples have TOC0.11-0.79%, poor evidence for an effective local source [R01, p 14].

Local / regional orientation. Lower-energy settings basinward of the shallow bank; remnants may follow pre-existing relief.

Reservoir settings to investigate

- Treat shale as baffle/source-facies evidence; separate fractured-gas research concepts from demonstrated production.

What would weaken or reject the idea

- Organic-rich shale does not imply mature source or producible gas; small sample suites do not characterize every location.

Area significance. Base-Lodgepole correlation and charge assessment, secondary research priority.

Sources: R05, R01. Full references and links are provided at the end.

Scallion Member and basal carbonate bank

Early Mississippian | member | reservoir candidate

A shelf carbonate-bank complex passed basinward into a thinner condensed section. Local exposure at its top and later recrystallization modify primary fabric. Microporosity may occur in chalky/cherty limestone rather than coarse reef framework [R05, pp 9-10; R12, p 6].

Published observations

- Whitewater's local description is clean cherty limestone with fine-crystalline/chalky texture, abundant microporosity and a prominent SP response [R12, p 6].
- Virden Roselea Unit 6 applies local 9% porosity and 1 mD cutoffs to Scallion and Sandhill/oolite reservoirs, while noting sparse core-analysis control [R13].

Local / regional orientation. Shallow bank eastward of the embayment; actual bank edges require member picks.

Reservoir settings to investigate

- Connected microporosity or leached bank facies in a sealed subcrop/structural trap.
- Use relative-permeability and saturation evidence: high total porosity may have very small pore throats.

What would weaken or reject the idea

- Chert, cement and clay can produce low permeability despite apparent porosity. Local cutoffs are not transferable to every facies.

Area significance. Virden-Roselea and parts of the Lodgepole trend; Sandhill is local terminology, not a modeled regional formation.

Sources: R05, R12, R13. Full references and links are provided at the end.

Lower and Upper Virden members

Early Mississippian | members | reservoir candidate

Muddy carbonate alternates with grainier ooid/crinoid beds as water depth and energy change on the shelf. Upper Virden commonly includes bioclastic packstone-grainstone. Regional Lower Virden descriptions include ooid beds, but a particular pool may contain a tight argillaceous equivalent [R05; R12, pp 5-6].

Published observations

- At Whitewater Unit 2 the Upper Virden has two leached crinoidal grainy layers separated by wackestone; Lower Virden is an 11-12 m nonreservoir barrier [R12, p 6].

Local / regional orientation. Shelf shoal/intershoal mosaic; associated restricted/deeper facies are needed to infer shoreward direction.

Reservoir settings to investigate

- Connected crinoidal/oolitic shoals with preserved pores terminating against muddy facies or the sealed erosion edge.
- Follow internal mud markers and core-supported grain-size changes rather than merging all low-gamma carbonate.

What would weaken or reject the idea

- Mud barriers can separate pressure cells; leaching can be followed by anhydrite cementation.
- Reworked crinoidal sand does not prove an in-place reef.

Area significance. Virden, Whitewater and the shelf subcrop trend; analogues must share member and diagenetic history.

Sources: R05, R12. Full references and links are provided at the end.

Whitewater Lake members and local basal lower unit

Early Mississippian | members and local operational subdivision | reservoir candidate

Ooid and bioclastic packstone-grainstone shoals alternate with muddy carbonate. Whitewater core and drilling observations show compartmentalization much finer than the regional model. Anhydrite/dolomite alteration beneath the younger unconformity forms a cap and locally destroys reservoir [R12, pp 4-8].

Published observations

- The 2020 unit study describes a tight upper 1-3 m cap and an approximately 0.2 m argillaceous bed separating upper and lower reservoirs [R12, p 5].
- Two lower-member grainy lenses occupy the upper 2-4 m, separated by 0.5-1 m mudstone; underlying 4-5 m muddy carbonate adds a barrier. A local basal lower ooid bed is 1-2 m thick [R12, p 5].

Local / regional orientation. A shelf shoal-intershoal mosaic; muddy restricted or deeper facies constrain direction better than an unmapped shoreline.

Reservoir settings to investigate

- Shoal compartments with grainy fabric below the cap and independent pressure/production response.
- Compare drilling gamma, core, completions and DSTs to verify whether thin barriers actually isolate flow units.

What would weaken or reject the idea

- More carbonate can mean more nonreservoir mud. A water-producing lower member can dominate a commingled well.
- The local operator model allows both diagenetic occlusion and depositional shoal separation as explanations.

Area significance. Whitewater, Regent, Mountainside, Lulu Lake and Souris Hartney analogues, conditional on facies correlation.

Sources: R05, R12. Full references and links are provided at the end.

Flossie Lake Member and upper Lodgepole fill

Early Mississippian | member | reservoir candidate

Upper Lodgepole deposition filled remaining accommodation as the system shallowed toward Mission Canyon conditions. At Manson, Flossie Lake contains fossiliferous mudstone, wackestone and packstone with anhydrite and siliceous layers. Dissolution/recrystallization strongly modify present texture [R05, pp 9-10; R17, p 194].

Published observations

- Manson cores have anhydrite-bearing and anhydrite-absent variants; the latter show vuggy/moldic pores, fractures, stain and sulphides. These are visual core observations, not a regional plug-analysis distribution [R17, p 194].

Local / regional orientation. Later shallow-platform fill, modified by local accommodation and diagenesis.

Reservoir settings to investigate

- Connected carbonate or fractured siliceous intervals below a verified cap where dissolution history is documented.

What would weaken or reject the idea

- Missing section can mean erosion, nondeposition or miscorrelation. Vugs may be isolated and fractures water-connected.

Area significance. Manson and preserved upper-Lodgepole areas; not continuous with every Whitewater pay interval.

Sources: R05, R17. Full references and links are provided at the end.

Cromer, Cruickshank and Daly slope facies; local mound hypotheses

Early Mississippian | lateral facies/member equivalents | reservoir candidate

Slope/embayment argillaceous carbonate includes grainier crinoidal beds and possible local buildups. Klassen's Manitoba mounds are small mid-slope features, distinguished from some Saskatchewan Waulsortian examples. A mound is a supported local hypothesis, not a presumed reef belt [R05, pp 9-10,25-26].

Published observations

- Candidate buildups are commonly 0.4-0.8 km or less in lateral dimension, below broad regional-grid resolution [R05, p 9].
- A Kirkella buildup at 11-15-12-29W1 has reported high permeability and pressure behavior unlike surrounding water-driven wells, suggesting isolation [R01, p 14].

Local / regional orientation. Basinward/westward slope relative to the eastern shelf; internal mound geometry must be measured locally.

Reservoir settings to investigate

- A local grainy thick with mound/flank geometry, connected pores and tight-facies enclosure.
- Tie high-resolution seismic to core, biostratigraphy and pressure; distinguish buildup from collapse fill or drape.

What would weaken or reject the idea

- Carbonate thicks may be muddy, cemented or water-bearing. Buildup age relationships can remain uncertain.
- Regional surfaces cannot establish small-mound closure.

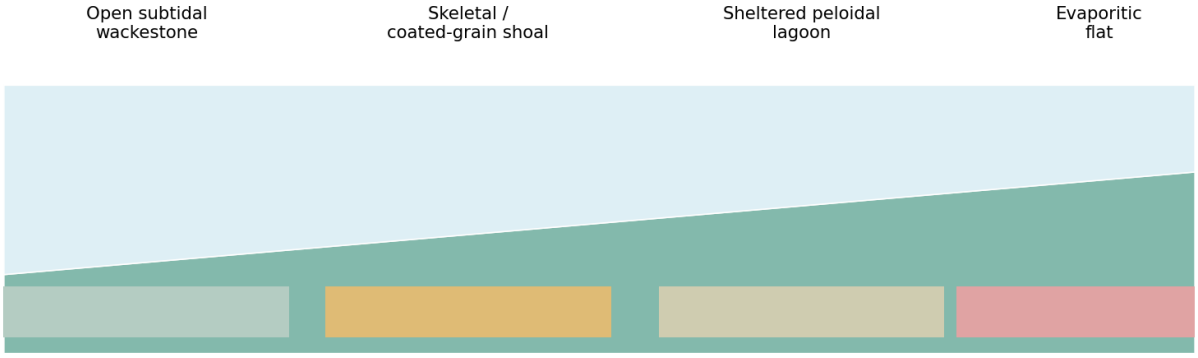
Area significance. Daly-Kirkella and western/southwestern Lodgepole analogues; current well control must replace historical undrilled-area claims.

Sources: R05, R01. Full references and links are provided at the end.

6. Mission Canyon and Manitoba Charles: facies belts and a later alteration cap

The carbonate system shallowed toward coated-grain shoals, sheltered peloidal/muddy settings and evaporites. Reservoir quality can reverse a simple energy ranking: an ooid shoal can be cemented, while muddy carbonate becomes productive after dolomitization. The model Tilston top covers MC-1 plus MC-2; Alida corresponds to MC-3. Frobisher/Manitoba Charles differs from Saskatchewan Charles, so source markers retain qualified aliases [R06; R07; R01, p 15].

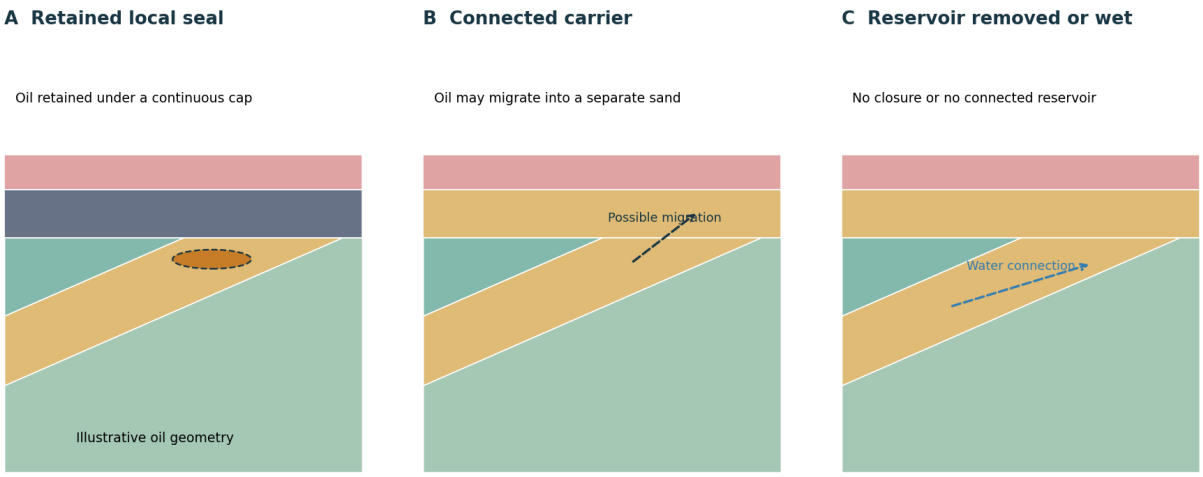
Mission Canyon: deposition and present reservoir quality can disagree



Original setting / overprint	Possible present behavior
Dolomitized muddy precursor	Intercrystalline pores can improve flow
Grain-rich shoal	Cement can occlude original pores
Altered upper surface	Anhydrite can form cap or destroy reservoir

SCHEMATIC - NOT TO SCALE | MC-1 / MC-2 correspond to a composite Tilston marker; MC-3 correlates with Alida.

Published MC-1 facies evidence supports porous dolomitized mud-rich facies as well as locally tight ooid-rich rock. Sources R06 pp 7-18; R07 pp 42-47; R01 p 15.



SCHEMATIC - NOT TO SCALE | Identical gross thinning can have different seal and fluid outcomes. Oil shapes are illustrative.

Three alternative outcomes at a subcrop. A source-grid limit is not proof of a geological pinchout. Sources R06 pp 16-18; R08 pp 18-22; R12 pp 4-8.

MC-1 Member, Mission Canyon Formation

Mississippian | member; lower Tilston composite | reservoir candidate

Eight published lithofacies span quiet subtidal carbonate, skeletal nearshore buildup, sheltered shelf/lagoon, peloidal backshoal, ooid shoal and a later anhydrite/dolomite cap. Productive facies 3 is dolomitic mudstone-wackestone; facies 4 is bioclastic wackestone-packstone. High original energy does not ensure good present reservoir [R06, pp 7-17].

Published observations

- Producing-well samples of facies 3 average 15.9% porosity and 6.3 mD; facies 4 averages 15.7% and 14.0 mD. Selection of producing wells means these are not unbiased facies-wide averages [R06, pp 7,11].
- Seven studied pools have average net pay 5.2-10.3 m and average porosity 14.1-17.5%, with approximately 9% porosity,1 mD and 60% water-saturation cutoffs and pool-specific variations [R06, p 18].
- At 5-30-5-26W1,836.1 mKB, thin sections show pore occlusion by small dolomite rhombs and calcite overgrowths: dolomitization is not always beneficial [R06, Fig 17,p 16].

Local / regional orientation. Published skeletal facies 4 occurs aroundT5-6R26-29W1; ooid/peloid belts farther south trend approximately NW-SE. These are historical study distributions, not newly mapped prospects [R06, pp 11-17].

Reservoir settings to investigate

- A productive facies preserved beneath the alteration cap on a sealed paleohigh, with an updip/lateral permeability termination.
- At Tilston/East Tilston test skeletal-facies distribution; at Reston-Pipestone/Deloraine test relief and selective dolomitization.

What would weaken or reject the idea

- Cap thickness and reservoir destruction can increase together; total MC-1 is not net pay.
- Formation-level closure may disappear at the top of connected porosity.

Area significance. Tilston MC-1 A/C, East Tilston and small Reston-Pipestone/Deloraine pools are strong small-pool analogues.

Sources: R06, R01. Full references and links are provided at the end.

MC-2 Member, Mission Canyon Formation

Mississippian | member; upper Tilston composite | correlation and conditional reservoir

MC-2 forms part of the shallow carbonate succession above MC-1 and below MC-3. It participates in the regional regressive carbonate-evaporite architecture, but the GOCAD model does not separately resolve its surfaces within the Tilston composite [R01, p 15; R07, pp 5-8].

Published observations

- The cross-border correlation assigns both MC-1 and MC-2 to Tilston. Separate member thicknesses require well picks; Alida-minus-Tilston is not an MC-1 isopach [R01, p 15].

Local / regional orientation. Shallow carbonate platform; member-specific local facies remain to be constrained.

Reservoir settings to investigate

- Local porous beds require member-scale core, seal and fluid evidence; treat MC-2 as a secondary interval in Mission Canyon evaluation.

What would weaken or reject the idea

- The composite marker does not prove a discrete MC-2 reservoir. MC-1 statistics cannot simply be transferred.

Area significance. Full-stratigraphy correlation and secondary reservoir assessment; no new MC-2 discovery claim.

Sources: R01, R07. Full references and links are provided at the end.

MC-3a and MC-3b, Mission Canyon Formation (Alida equivalent)

Mississippian | member subdivisions | reservoir candidate

The Pierson core study describes low-energy bioclastic subtidal carbonate, coated-grain shoals, sheltered peloidal backshoal, restricted ponds/mudflats and intraclastic deposits. A shoal belt may parallel a coastline while individual bodies cross it, but shoreline position is interpretive. Exposure, solution, anhydrite replacement and dolomitization later reorganized pores [R07, pp 26-47].

Published observations

- Pierson MC-3b D pool 07 42D lacks a structural anomaly in the original study and is interpreted as facies/porosity trapping. South Pierson 12 42A is mainly a facies trap despite small porosity-top closures [R07, p 25].
- Other pools preserve porous beds beneath an alteration zone with local paleorelief; Waskada adds multistage salt-collapse effects [R07, pp 24-26; R11].

Local / regional orientation. Conceptual normal-marine carbonate → shoal → protected peloidal/lagoonal facies; establish local direction from facies cross-sections.

Reservoir settings to investigate

- Connected coated-grain or peloidal beds passing updip into tight mud or altered carbonate, with a downdip oil column.
- Map top of effective porosity as well as formation top; test whether closures coincide.

What would weaken or reject the idea

- Grainy rocks may be anhydrite-cemented. Fenestral pores can connect horizontally but poorly vertically.
- Proximity to a pool is insufficient without the same subunit and porosity front.

Area significance. Pierson/South Pierson small pools and Waskada compartments; strong analogues for facies/diagenetic pinchouts.

Sources: R07, R11, R01. Full references and links are provided at the end.

Kisbey interval and Manitoba Charles/Frobisher evaporitic cap

Mississippian | interval and formation-correlation composite | seal; tentative local sand target

A sandstone-bearing Kisbey interval and overlying evaporitic carbonate/anhydrite occupy the most southwestern preserved succession in TGI. Manitoba Charles is mainly anhydrite and subordinate dolostone, corresponding to regional Frobisher; it is not uncritically equivalent to younger Saskatchewan Charles [R01, p 15].

Published observations

- Kisbey was correlated from logs inT1R28-29W1 without core verification in that study. Suggested MC-4/MC-5 names are correlation proposals [R01, p 15].
- Manitoba Charles is described as a nonproductive MC-3 seal. Midale, Ratcliffe, Poplar and Big Snowy source surfaces have no local supported model geometry and are not fabricated as Manitoba reservoirs.

Local / regional orientation. Late restricted basin-margin succession; present remnants do not locate the original shoreline.

Reservoir settings to investigate

- Treat Kisbey as conditional until core confirms local sand; prioritize actual cap continuity over a borrowed western play name.

What would weaken or reject the idea

- Gamma markers may not uniquely identify lithology. Limited preservation and differing nomenclature can create false thicknesses.

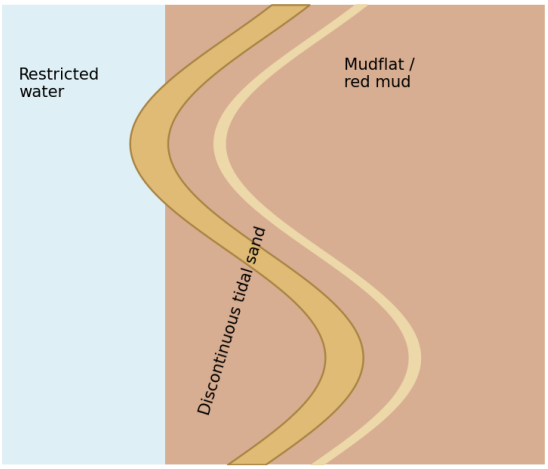
Area significance. Extreme southwest; included for completeness and seal assessment.

Sources: R01, R04, R33. Full references and links are provided at the end.

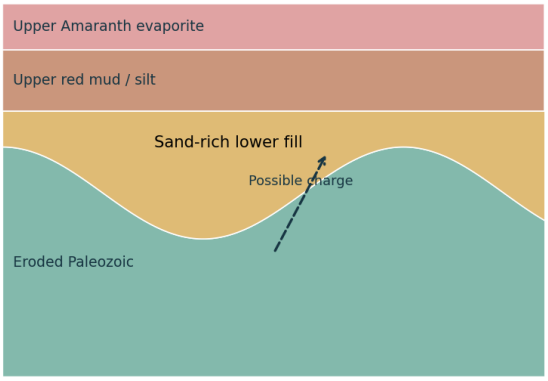
7. Amaranth: sand reservoirs inside a redbed-evaporite seal system

The modern chart places Lower Amaranth redbeds in the Triassic and Upper evaporitic member in the Jurassic; older studies often call both Jurassic. Environmental interpretation is firmer than a precise age for each lower cycle. Regional red mud and evaporite seal many pools, while local Lower Amaranth sand/silt bodies are proven reservoirs. Both depositional architecture and cement determine where the seal becomes a reservoir [R04; R08; R09].

A Conceptual plan: restricted coastal plain

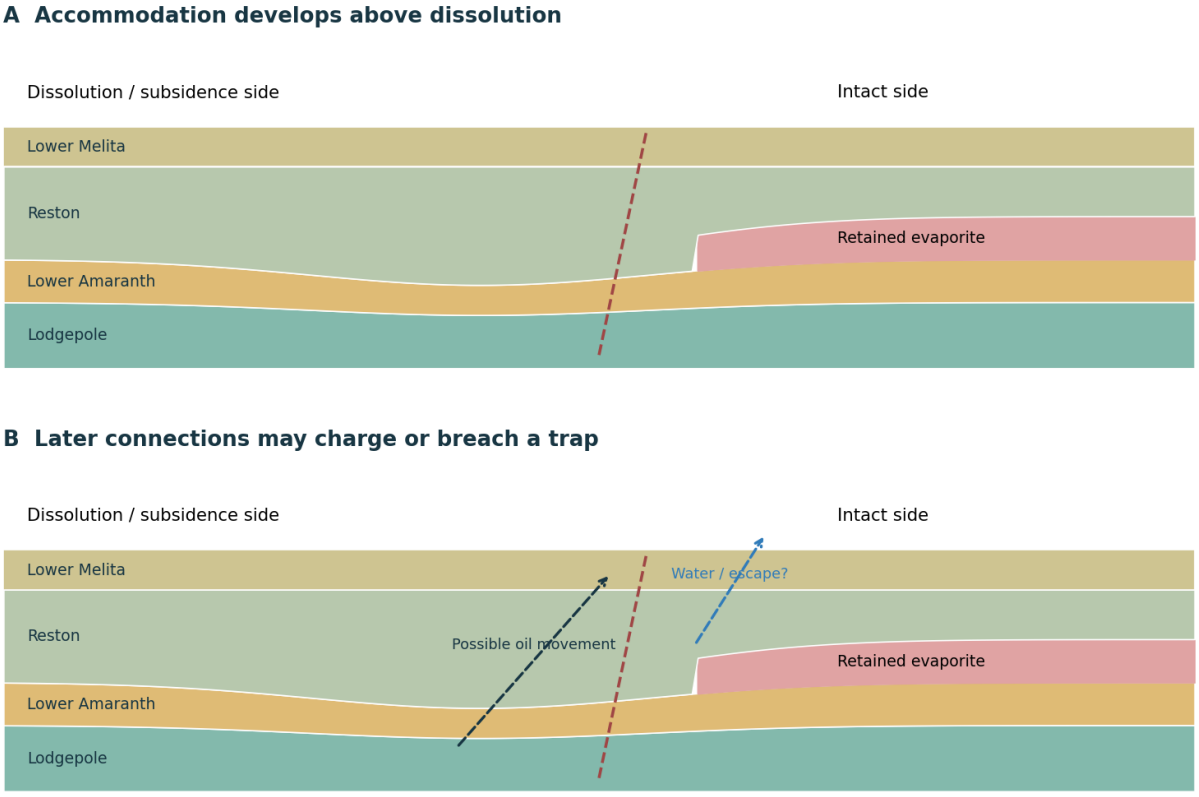


B Section: older relief, fill and cover



SCHEMATIC - NOT TO SCALE | Tidal, storm/flood and aeolian contributions require local sedimentary evidence; plan shape is not a mapped channel.

Local sand bodies and cemented intervals need core and log ties; regionally correlated sand names do not establish hydraulic continuity. Sources R08 pp 12-14,22; R09 pp 17-22; R10.



SCHEMATIC - NOT TO SCALE | Manson multiformation pools: dashed fault / migration relationships are interpretations, not measured pathways.

Published core, correlation and fluid evidence supports a complex local system; one fluid sample does not establish universal migration paths. Sources R17 pp 194-198; R18 pp 155,159-160.

Lower Amaranth Member: lower sand-rich and upper shaly units

Triassic in modern chart; historical assignments differ | member | reservoir candidate

The strongest regional interpretation is a restricted, low-gradient tidal-flat system with subtidal channel sand, intertidal sand/silt and supratidal red mud, repeatedly flooded and exposed. Barchyn also considered playa, flash-flood and aeolian contributions and emphasized that one simple model is insufficient. Frosted grains, desiccation, cross-lamination and fining-up cycles are process evidence; none uniquely proves tides [R08, pp 12-13; R09, pp 17-18].

Published observations

- Coulter-Pierson thick belts coincide with Mississippian paleolows; discontinuous channel fills occur inside broader silt/mud intervals [R09, pp 19-22].
- A representative Waskada section has 8.2 m net pay at 1 mD cutoff,14.5% mean porosity and 14.8 mD mean permeability. Laminated sand locally exceeds 100 mD, while silty reservoir commonly has 1-10 mD [R08, p 14].
- Selected South Pierson pool cores range 12-25% porosity and 2-19 mD. Lowermost sands were commonly wet in the 1990 study [R09, p 20].

Local / regional orientation. Early mapping inferred decreasing sand north/east, but individual channel axes and cement fronts need local control; one linear shoreface belt is not justified.

Reservoir settings to investigate

- Channel/sheet-sand compartments terminating laterally or updip in red mud or cemented rock, with a separate charge and top-seal case.
- Map local sand cycles, anhydrite content and pressure systems; compare productive, wet and tight equivalents.
- Test upward charge where the Mississippian altered cap is thin, absent or fractured, without assuming that route everywhere.

What would weaken or reject the idea

- Coarse massive sand may be poor because anhydrite fills pores. A continuous gamma marker does not establish hydraulic connection.
- Stained tight rock can lie beside clean water-bearing sand. Colored sand names are local operational correlations, not formal basin-wide formations.

Area significance. Waskada, Goodlands, Coulter, Pierson/South Pierson and Lyleton. The supplemental Lower Amaranth top is gross geometry, not an individual pay-sand map.

Sources: R04, R08, R09, R10. Full references and links are provided at the end.

Upper Amaranth Member: evaporite seal and local dissolution exceptions

Jurassic | member | seal and local secondary reservoir

Anhydrite/gypsum with carbonate records restricted evaporitic conditions. Intact evaporite seals underlying Amaranth and Paleozoic reservoirs. Local dissolution can remove separation, create accommodation and permit cross-formation flow, as documented at Manson [R02, pp 4-5; R17, pp 194-198].

Published observations

- Manson cores include up to 38 m of upper-member evaporite, but local anhydrite-free intervals preserve siliceous residues, fractures and slickensided rubble [R17, p 194].
- The model’s Upper Watrous surface is an Upper Amaranth top proxy, not the Lower Amaranth sand top.

Local / regional orientation. Restricted basin-margin evaporites; younger dissolution fronts are not original shorelines.

Reservoir settings to investigate

- Map intact versus dissolved evaporite before evaluating either a sealed underlying trap or migrated oil above.
- For nominal Upper Amaranth pools, inspect actual perforations and rock types; massive anhydrite is not assumed to be the reservoir.

What would weaken or reject the idea

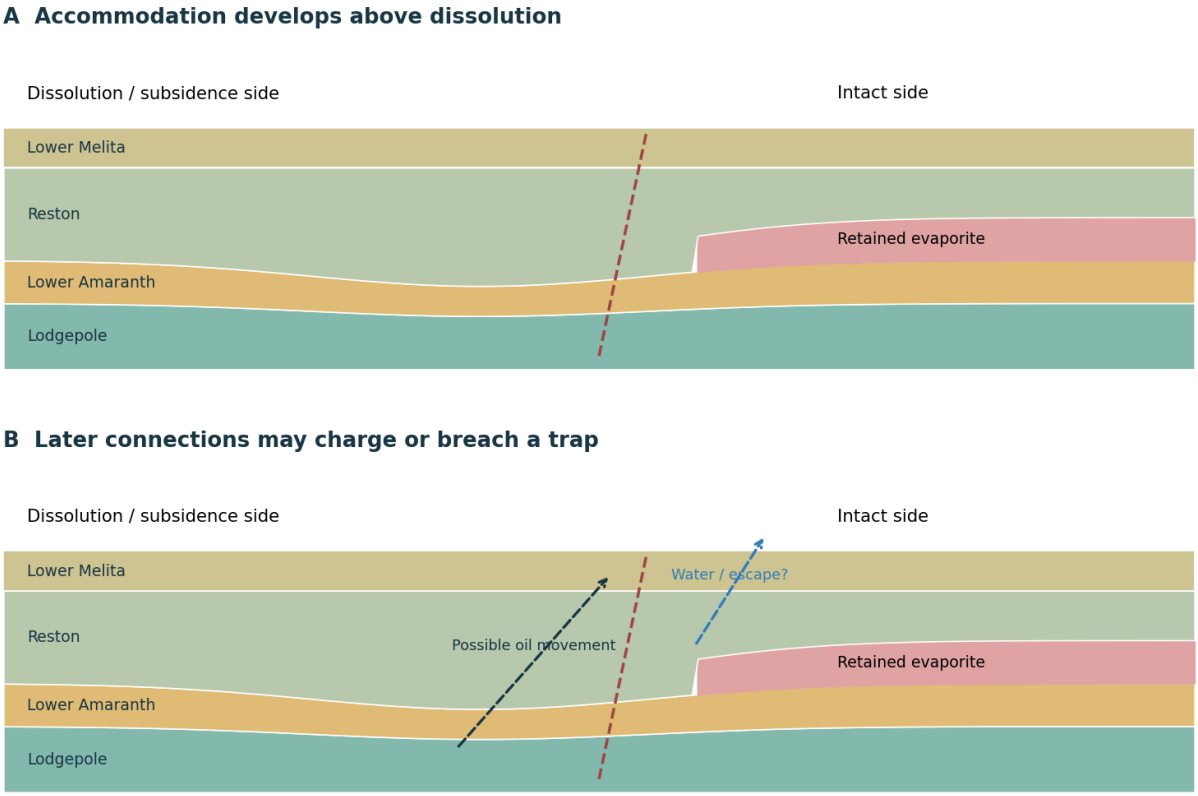
- Dissolution can enable charge and water leakage simultaneously. Missing evaporite can also be a correlation problem.

Area significance. Regional seal, with important localized Manson exceptions.

Sources: R02, R04, R17. Full references and links are provided at the end.

8. Jurassic: Reston, Melita, Waskada and the Manson multiformation reservoir

Jurassic flooding and renewed subsidence covered an irregular older landscape. Reston carbonate/shale and younger Melita mixed clastics differ from the Lower Amaranth reservoir system. A long-lived high near the Birdtail-Waskada structural belt affected onlap and thickness. Recent Manson core work demonstrates that several formations can participate in one reservoir system where evaporites are locally removed and fractures, siliceous breccia and sand provide flow paths. This is a compelling local analogue, but it does not prove every nearby fault carries oil [R02, pp 5-7; R17; R18].



SCHEMATIC - NOT TO SCALE | Manson multiformation pools: dashed fault / migration relationships are interpretations, not measured pathways.

Published core, correlation and fluid evidence supports a complex local system; one fluid sample does not establish universal migration paths. Sources R17 pp 194-198; R18 pp 155,159-160.

Reston Formation (Gravelbourg correlation)

Middle Jurassic | formation | reservoir candidate

Basal grey/green shale, argillaceous carbonate and an upper oolitic or sandy interval record restricted-to-shallow marine deposition during flooding. Correlated lower shale, middle limestone and upper sand/oolite subdivisions can be individually absent. Onlap across older relief and later dissolution mean thickness does not follow one simple regional shoreline [R02, p 5].

Published observations

- At Manson the 2024 core study records 0.3-52.5 m of Reston, including dolomitized mudstone, siliceous layers/breccias and reworked chert sand. These local values exceed a simplistic uniform-platform picture [R17, pp 194-195].
- Reston is a productive part of the Manson multiformation system; perforations and oil staining occur in several different rock types [R17, p 197, Table 1].

Local / regional orientation. Around a paleo-high, potential shoreline/onlap facies wrap around relief; near Manson a NNW dissolution/fault trend may dominate local accommodation.

Reservoir settings to investigate

- Local porous carbonate, siliceous breccia/fracture zones or reworked sands, with a seal/charge geometry demonstrated independently.
- Compare Reston thickening to missing Upper Amaranth and repeated facies cycles to test subsidence-fill versus depositional shoal hypotheses.

What would weaken or reject the idea

- A thick Reston section can consist mainly of tight mudstone. Visual vugs or a few perforations do not determine the allocation of commingled production.
- Broad regional Gravelbourg top is not a detailed map of local Reston porosity.

Area significance. Manson and adjacent Virden-Miniota area; local confirmed oil system, conditional outward extensions.

Sources: R02, R17, R18. Full references and links are provided at the end.

Lower and Upper Melita members

Middle Jurassic | formation with members | reservoir candidate

Lower Melita contains varicolored shale and calcareous sandstone with local fossiliferous marine beds; Upper Melita is generally greyer, marine mud-rich material. Regional correlation is Lower Melita≈Shaunavon and Upper Melita≈Rierdon. Continued flooding with periodic shoaling and subsidence gives several possible sand environments, not one continuous shoreface [R02, pp 5-6].

Published observations

- Official discovery chronology records Melita oil at St. Lazare in 1993 [R29].
- Manson Lower Melita cores include fining-upward siliceous breccia/conglomerate-sand-mud sequences, rarer coarsening-upward beds, wood, local 1 cm lignite/paleosol layers and bivalve-bearing beds [R17, pp 195-196].
- The 2024 Manson study reports locally 46-205 m for the lower member in a structurally complex area. This is a study-specific pick/model result, not a province-wide stratigraphic norm [R17, p 195].

Local / regional orientation. Potential shoreface would lie on the marine side of documented paleosol/coal and landward of offshore shale; the direction must be reconstructed locally from correlated sections, not guessed from modern contours.

Reservoir settings to investigate

- Enclosed sand bodies associated with shoreline progradation, channels, tidal inlets or reworked collapse-margin sediment - competing interpretations to discriminate with sedimentary structures and fossils.
- Seek facies/diagenetic continuity around actual St. Lazare or Manson pools, with confirmed charge and an upper muddy seal.

What would weaken or reject the idea

- Fining-upward sand is not uniquely fluvial or tidal; coarse breccia can be local reworking of siliceous layers.
- The top of an undifferentiated Melita pool cannot be assigned confidently to either member from the pool label alone.

Area significance. St. Lazare and Manson are producing analogues with distinct reservoir styles; broader northern margin is a testable search area.

Sources: R02, R17, R29. Full references and links are provided at the end.

Waskada Formation (Masefield correlation)

Late Jurassic | formation | cover/seal; conditional local sand

Bentonitic and locally carbonaceous/red shale with cemented sandstone represents a more continental interval above marine-dominated Melita. Pre-Cretaceous incision and erosion leave discontinuous preserved wedges. This formal Waskada Formation is not the informal Waskada sand unit used for Lower Amaranth colored sands [R02, p 6].

Published observations

- Regional correlation is to Masefield shale and possibly SuccessS1. Strong erosion and channel cutting complicate thickness and upper-contact recognition [R02, p 6].

Local / regional orientation. Continental low-relief landscape later cut by Cretaceous drainage; no single marine shoreface model applies.

Reservoir settings to investigate

- Evaluate only locally clean, sealed sandstone with direct core/log and fluid evidence; otherwise treat shale as cover and a marker of pre-Cretaceous erosion.

What would weaken or reject the idea

- Cemented sand and shale dominate the regional description; reservoir quality and charge are not demonstrated by the name Waskada.

Area significance. Stratigraphic completeness and local seal assessment, lower priority than proved Amaranth/Melita systems.

Sources: R02, R04. Full references and links are provided at the end.

Success S2 interval

Latest Jurassic-earliest Cretaceous regional usage | informal member/remnant | correlation and weathered cover

Weathered shale and kaolinitic sand accumulated in isolated northern subbasins on an eroded landscape. The correlation into Manitoba is less secure than the major carbonate/evaporite markers. It is included because the regional source model contains a Success surface, not because a continuous southwest Manitoba reservoir is established [R02, pp 6-7].

Published observations

- The TGI synthesis describes unconformity-bounded northern remnants, a continental setting and kaolinitic/weathered lithology unfavorable for a major local reservoir [R02, p 7].

Local / regional orientation. Local continental subbasins; regional marine shoreline inference is inappropriate.

Reservoir settings to investigate

- Confirm any occurrence from core and actual picks before computing local interval thickness or proposing a sand target.

What would weaken or reject the idea

- Misidentification as Waskada or Melita and weak control can produce false isopach bodies.

Area significance. Minor preserved cover interval in the broader margin, not a ranked petroleum play.

Sources: R02, R04. Full references and links are provided at the end.

Manson Melita-Reston-Amaranth-Lodgepole pools: observed system and competing explanations

Mississippian reservoir to Middle Jurassic cover | multiformation petroleum system | reservoir candidate

Fulton-Regula examined 51 cores fromT12-13R26-27W1 during 2015-2024. Missing evaporite, siliceous breccia, slickensides, abrupt thickness changes and sulphides define a complex diagenetic/structural setting. A NNW lineament separates evaporite-bearing east from evaporite-poor west and coincides with Reston thickening; it is interpreted as a fault with dissolution/subsidence, still requiring further validation [R17, pp 192-198].

Published observations

- The table of productive perforations is dominated by Lodgepole and Reston intervals, with fewer Amaranth siliceous and Lower Melita intervals. This supports a multiformation reservoir interpretation but does not quantify each formation’s flow contribution [R17, p 197].
- One 2025 sample from 12-1-13-27W1,licence 9990,pool 17 22D has 29.1°API oil and 1.76 wt% sulphur. Similarity to Lodgepole oils supports migrated oil as a hypothesis; biomarker oil-source confirmation was not reported [R18, pp 155,159-160].

Local / regional orientation. A local NNW structural/dissolution pattern modifies onlap and paleorelief. Do not replace this evidence with a generic SW-dipping shoreface.

Reservoir settings to investigate

- Adjacent areas where missing/attenuated evaporite, Reston accommodation and porous carbonate/siliceous/sandy facies overlap a proven migration system.
- Compare time-normalized production and fluid chemistry on both sides of the lineament; use seismic and core to distinguish fault, dissolution-front and depositional-facies alternatives.

What would weaken or reject the idea

- A larger cumulative volume in older pools is confounded by longer production time [R17, p 198].
- The same missing seal can provide charge or leak hydrocarbons. Higher local heat flow and local Melita generation were hypotheses requiring testing, not established findings.

Area significance. Actual Manson 17 22A-F pool system; the geological model should show its vertical span rather than place it wholly on one formation.

Sources: R17, R18. Full references and links are provided at the end.

9. Lower Cretaceous and Ashville: valleys, marine sand belts and strong water risk

Cretaceous drainage and marine transgression introduced a different clastic system. Swan River valley/shelf sands, Newcastle sand belts and intervening marine shale may provide reservoir/seal combinations, but existing Manitoba evidence commonly identifies water-bearing aquifers or gas shows rather than commercial oil. These units belong in the model and petroleum-system assessment, with a lower evidence category than proved Mississippian, Bakken-Torquay and Amaranth systems [R02, pp 7-10; R24].

A reservoir idea must survive six independent tests

Requirement	Observe	Interpret	Test against
Reservoir	Core texture + plug permeability + corrected logs	Connected effective pores	Cemented or isolated pores
Seal	Lithology + continuity + capillary test	Oil column retained	Absent cap or throughgoing fracture
Trap	Depth-corrected picks + restored section + seismic	Closure/pinchout at reservoir level	Artifact or open updip pathway
Charge	Produced oil + biomarker/fluid match	Migration access	Stain only or incompatible gas
Timing	Crosscutting relations + burial history	Trap before charge	Late breach or reservoir destroyed
Water	DST/pressure + salinity + normalized production	Bounded mobile-oil interval	Connected aquifer/water-only test

Analytical workflow proposed for this study, grounded in the local examples [R03, R06, R08, R17, R19].

Observations, interpretations and disproof are kept separate. No numerical prospect chance is assigned without local data.

Swan River Formation and uncertain Mannville/Pense marker correlation

Early Cretaceous | formation; source-model composite caveat | reservoir candidate

Lower terrestrial sand/silt fills an incised drainage network; upper glauconitic sand/silt records marine flooding. The surface is strongly irregular and regionally discontinuous. The source Mannville top was correlated using aP4 shale pick that the authors themselves question; it does not everywhere coincide with top Swan River sand [R02, pp 7-8].

Published observations

- Published formation tests repeatedly support a major freshwater aquifer. The 2009 report discusses hydrocarbon possibility by analogy, not a proven Manitoba oil play [R02, p 8].
- Sands are absent across a broad intervening belt and thicken toward the border/north ofT20 in the regional mapping; paleovalley fill, not uniform blanket deposition, is the useful model [R02, pp 7-8].

Local / regional orientation. Drainage axes and transgressive shorelines must be reconstructed from incised geometry, grain size, fossils and paleocurrents.

Reservoir settings to investigate

- A locally enclosed channel/valley sand with demonstrated saline reservoir water, pressure separation and hydrocarbon charge, beneath continuous marine shale.
- Map actual lithologic sand top from wells instead of treating a cross-border composite marker as an identical reservoir surface.

What would weaken or reject the idea

- Freshwater aquifer connectivity is substantial negative evidence for petroleum trapping.
- A clean thick sand is not enough; absence of charge or a lateral seal can dominate.

Area significance. Broader margin research target, with water/charge screening before expensive follow-up.

Sources: R02, R24, R33. Full references and links are provided at the end.

Skull Creek Member, Ashville Formation

Early Cretaceous | member | marine seal

Dark marine shale with silt and occasional sand lenses overlies older valley deposits or Jurassic strata. Manitoba usage can include basal transgressive shale correlated with PenseP4, while the regional Joli Fou relationship is not one-to-one everywhere [R02, pp 7-8].

Published observations

- The regional study explicitly questions some P4 assignments after microfossil work; missing Newcastle sand can also make Skull Creek/Westgate separation difficult [R02, pp 7-8].

Local / regional orientation. Marine transgression across an irregular substrate.

Reservoir settings to investigate

- Primary use is mapping top-seal continuity above Swan River and local intra-shale sand bodies supported by core.

What would weaken or reject the idea

- Radioactive shale is not reservoir pay. Mis-picks can create artificial sand pinchouts.

Area significance. Seal and correlation interval for shallow clastic hypotheses.

Sources: R02, R24. Full references and links are provided at the end.

Newcastle Member, Ashville Formation

Early Cretaceous | member; regional Viking correlation | reservoir candidate

Fine sand interbedded with silt and clay occurs in an irregular southeast-trending belt. The TGI interpretation distinguishes major western shoreface thickening from more basinal Manitoba settings with curvilinear/lobate sand bodies and a northeastern sandy shelf [R02, pp 8-9].

Published observations

- A blocky low-gamma signature commonly distinguishes the sand; where absent, a thin shale marker is used instead. Official charts record oil and gas shows, not a generic blanket oil pool [R02, p 8; R04].

Local / regional orientation. Published sandbelt trends southeast; the northeastern flank is interpreted as sandy shelf, but individual-body direction remains local.

Reservoir settings to investigate

- Enclosed clean sand in a mapped lobate or channel-like body, with overlying Westgate shale and an independently proved charge.

- Test coarsening-up shoreface versus erosive channel-fill versus offshore reworked sand with core sedimentary structures and fossils.

What would weaken or reject the idea

- A low-gamma bed can be wet sand; regional lithologic correlation does not prove pressure or hydrocarbon continuity.

Area significance. Virden-Kirkella-Binscarth broader margin, a lower-evidence analogue near established deeper pools.

Sources: R02, R04, R24. Full references and links are provided at the end.

Westgate and Belle Fourche members, Ashville Formation

Early-Late Cretaceous transition | members | marine seals and source-facies research

Westgate marine shale/silt locally contains fine sand, while Belle Fourche is mainly dark marine shale with bentonite and the fish-scale interval. They record changing marine accommodation and sediment supply as regional foreland-basin influence increased [R02, pp 8-9; R24].

Published observations

- Regional thickness trends differ between members; Westgate locally thickens over Virden/Kirkella while Belle Fourche thickens toward the southwest border junction [R02, p 9].
- Distinctive fish-scale and bentonite markers aid correlation but do not by themselves establish organic maturity or gas producibility [R24].

Local / regional orientation. Offshore marine shale system with local sandy shelf influence.

Reservoir settings to investigate

- Evaluate as seals above Newcastle and as local thin-sand/fracture research intervals only with test evidence.

What would weaken or reject the idea

- Thicker shale mostly means more seal/overburden, not more reservoir. Correlation markers can be affected by erosion and facies change.

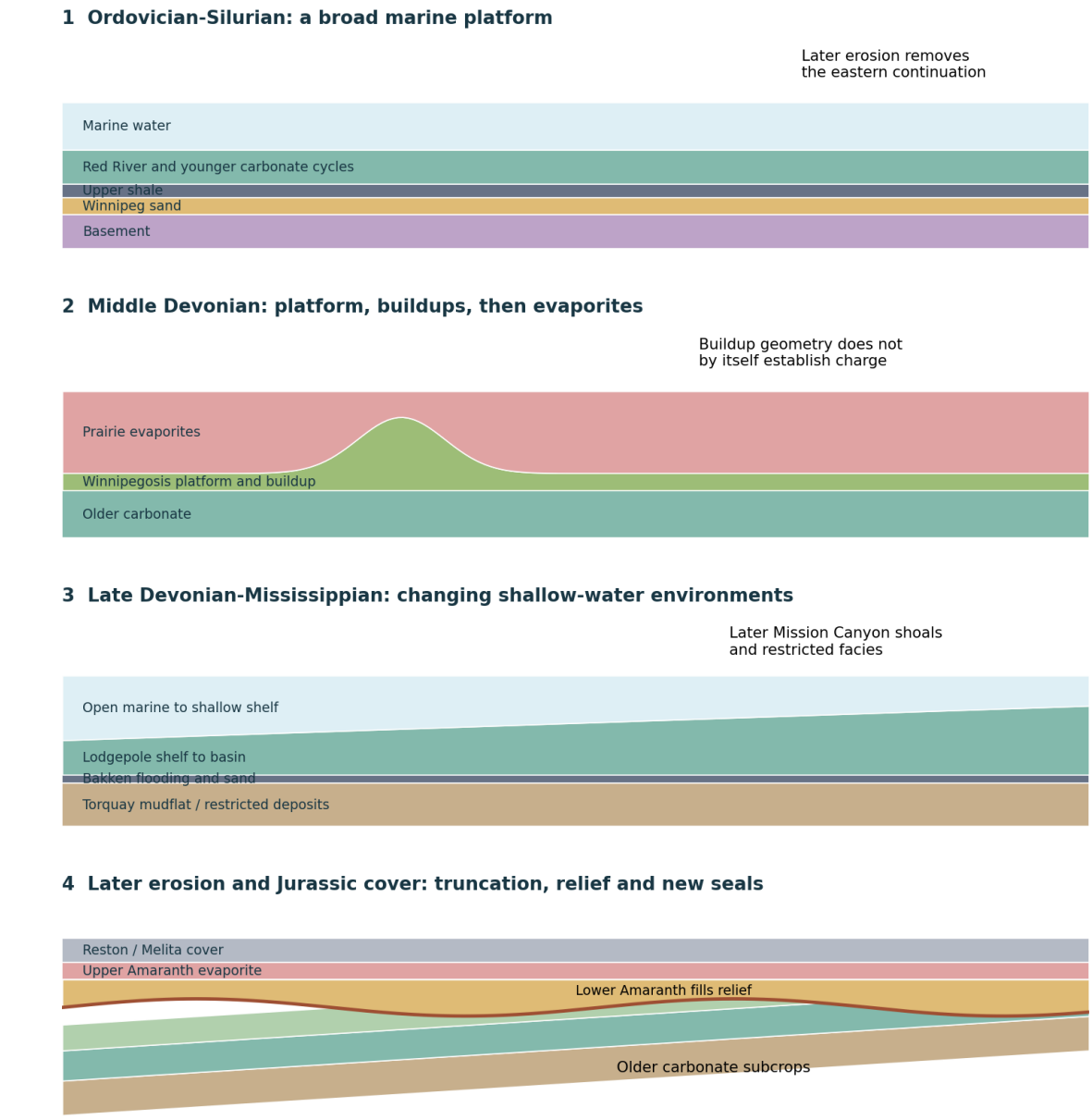
Area significance. Regional seal/baffle framework across the southwest.

Sources: R02, R24. Full references and links are provided at the end.

10. Upper Cretaceous to Quaternary: marine shale, regressive sand and shallow cover

These units complete the regional section and constrain overburden, groundwater and source maturity. Their published gas shows and organic richness deserve explicit treatment, but should not be colored as proved oil reservoirs. The model Niobrara surface does not have supported Manitoba geometry: the TGI study rejects the old direct Boyne-Niobrara equivalence. Boissevain, Turtle Mountain and Quaternary deposits are geologically present but are not independently resolved by the source regional horizons [R02, pp 9-12; R04; R24].

Different times created different petroleum systems



SCHEMATIC - NOT TO SCALE | Southwest / basinward at left; northeast / cratonward at right. Erosion edges are not ancient shorelines.

Conceptual synthesis of Manitoba basin history. No mapped reservoir bodies or shoreline positions are implied. Sources R01 pp 2-15; R02 pp 4-7; R03 pp 3-4,11-13; R25.

Favel Formation: Keld and Assiniboine members

Late Cretaceous | formation with members | seal/source facies; unproven shallow gas

Calcareous organic-rich marine shale with thin limestone and bentonite records widespread marine flooding. Laurier limestone and Marco calcarenite beds are member-scale markers; regional Favel correlates with Second White Specks [R02, p 9; R24].

Published observations

- Published Rock-Eval samples have TOC0-10.8% and Tmax 401-428°C and are interpreted as immature. Three EOG wells 10-17-1-24W1,3-27-1-25W1 and 1-3-2-25W1 tested Assiniboine but produced water and were abandoned [R02, p 10].
- Other historical gas shows motivate biogenic/shallow-gas investigation. They do not erase the water-only test evidence or prove commercial flow.

Local / regional orientation. Open marine flooding; thin reservoir lenses/fractures are not a conventional shoreface belt.

Reservoir settings to investigate

- A measured gas-bearing fracture/silt interval with sustained test flow and pressure evidence; gas origin and water mobility must be established.

What would weaken or reject the idea

- Thermogenic maturity is low in the cited samples; drilling damage was proposed as one explanation of failed tests, not demonstrated as the sole cause.
- Favel pool polygons must remain generic petroleum-designation features unless actual oil production is verified.

Area significance. Lower-priority gas research around Waskada and broader shallow tests; not ranked as a new oil belt.

Sources: R02, R04, R24. Full references and links are provided at the end.

Carlile Formation: Morden and Boyne members

Late Cretaceous | formation with members | marine shale and immature source facies

Morden dark noncalcareous organic shale and Boyne calcareous/chalky shale represent marine depositional episodes separated by stratigraphic complexity. The modern TGI cross-border correlation does not equate Boyne directly to the western Niobrara horizon [R02, p 10; R24].

Published observations

- The 2009 sample suite gives Morden TOC0.7-11.69%, Tmax 396-423°C and Boyne TOC7.34-7.57%, Tmax 416-417°C. The meaningful conclusion is low thermal maturity, not uniformly low organic content [R02, p 11].
- Two 2006-2007 wells 32-11-4-29W1 and 8-29-4-29W1 cored Boyne; no production was reported in that study [R02, p 11].

Local / regional orientation. Open marine shale/chalk system with erosion and changing water depth.

Reservoir settings to investigate

- Test actual gas saturation, connected fracture/silt permeability and sustained deliverability before considering a shale-gas concept.

What would weaken or reject the idea

- Organic richness alone is not maturity or commerciality. No oil potential is assigned from a shale isopach.

Area significance. Cover and research-scale shallow gas assessment.

Sources: R02, R24. Full references and links are provided at the end.

Pierre Shale: Gammon Ferruginous, Pembina and Millwood members

Late Cretaceous | formation members | seal/overburden; gas-show context

Gammon ferruginous mud/silt, bentonite-rich Pembina shale and clay-rich Millwood accumulated in a marine seaway. Erosion removes Gammon locally. Regional source-model Milk River is a Gammon remnant correlation; Lea Park represents Pembina plus Millwood rather than a single Manitoba member [R02, p 11; R24].

Published observations

- A shallow test at 4-6-4-29W1 reached 348 m in Millwood and was abandoned; historical low-grade gas shows are documented elsewhere [R02, p 12].

Local / regional orientation. Marine mud deposition with regional regression and erosion; no direct shoreface reservoir assumption.

Reservoir settings to investigate

- Map these units principally as cover/seal and distinguish any supported gas test from dissolved or minor gas in groundwater.

What would weaken or reject the idea

- Sparse testing and gas shows do not establish a viable reservoir. Bentonite and shale have low matrix permeability and complex borehole responses.

Area significance. Whole southwest cover; low-priority local shallow-gas questions.

Sources: R02, R24. Full references and links are provided at the end.

Pierre Shale: Odanah and Coulter members

Late Cretaceous | formation members | overburden and correlation

Hard siliceous Odanah shale and younger soft silty Coulter clay record later marine deposition and regression. Odanah forms a resistant escarpment cap. Its lower regional marker grades westward toward Belly River facies, while upper Odanah and Coulter relate to Bearpaw intervals; the modeled Belly River surface is not the top of all Pierre [R02, pp 11-12; R24].

Published observations

- The 2013 field guide reports approximately 230 m of Odanah in the extreme southwest, a local cover thickness rather than petroleum net pay [R24, formation description].

Local / regional orientation. Marine mud to more regressive shallow shelf.

Reservoir settings to investigate

- Use as overburden and structural datum; any fracture-gas idea requires independent testing.

What would weaken or reject the idea

- Weathering, silica and groundwater fractures can mimic favorable reservoir characteristics; no regional commercial oil inference follows.

Area significance. Regional geometry and environmental context, not a selected oil target.

Sources: R02, R24. Full references and links are provided at the end.

Boissevain Formation

Latest Cretaceous | formation | shallow sand/overburden

Quartz-rich crossbedded sand with an upper kaolinitic interval reflects regression and river-mouth/coastal to continental deposition. Bamburak's original crossbedding study indicates eastward sediment transport locally. This differs from the lower-Paleozoic basin orientation and illustrates why modern dip cannot determine every paleo-environment [R30, abstract; R24].

Published observations

- Preservation is limited to the Turtle Mountain area. The source regional TGI model did not map it because of discontinuity and correlation uncertainties [R02, p 12].

Local / regional orientation. Local river-mouth/coastal sediment transport eastward in the original study, with later erosion limiting preservation.

Reservoir settings to investigate

- Include in stratigraphic and groundwater context; no petroleum target is promoted without burial, seal and charge evidence.

What would weaken or reject the idea

- Shallow erosion and aquifer connectivity make a conventional oil accumulation poorly supported by the cited evidence.

Area significance. Boissevain-Turtle Mountain cover.

Sources: R30, R24, R02. Full references and links are provided at the end.

Turtle Mountain Formation: Goodlands and Peace Garden members

Paleocene | formation with members | shallow cover

Carbonaceous sand/silt/clay with minor lignite in Goodlands records coastal-plain, lagoonal and swamp/fluvial conditions. Peace Garden includes silty clay and fine sand interpreted as shallow-marine influence. The local succession therefore includes more than one environment, not simply a uniform terrestrial cap [R30; R24].

Published observations

- The units are discontinuously preserved around Turtle Mountain; they were not mapped as separate TGI model surfaces [R02, p 12].

Local / regional orientation. Local coastal plain and marine re-advance, independent of older Paleozoic facies belts.

Reservoir settings to investigate

- Retain for full regional stratigraphy and understanding younger erosion/overburden; no petroleum prospect is assigned.

What would weaken or reject the idea

- Near-surface position, discontinuity and lack of demonstrated seal/charge make the requested conventional oil criteria unmet.

Area significance. Turtle Mountain and Goodlands area cover; the Goodlands member name is not evidence that a local Amaranth oil pool produces from Paleocene rocks.

Sources: R30, R24, R02. Full references and links are provided at the end.

Quaternary glacial, glaciofluvial, lacustrine and modern deposits

Quaternary | unconsolidated cover | surface cover and datum

Glacial and postglacial deposits blanket much of the bedrock and strongly influence modern relief, water and the visibility of outcrop. Modern valleys and escarpments are therefore unreliable stand-ins for Paleozoic or Mesozoic shorelines [R04; R24, regional setting].

Published observations

- The regional topographic surface is modern terrain, while formation surfaces are subsurface interpretations; they have different measurement and resolution histories.

Local / regional orientation. Glacial/modern landscape processes, not an ancient hydrocarbon depositional setting.

Reservoir settings to investigate

- Use topography for orientation and wellhead context, not to infer a buried reservoir trend.

What would weaken or reject the idea

- A topographic ridge is not a subsurface closure; ground elevation, KB and subsea depth must be handled separately.

Area significance. Surface context throughout the study area.

Sources: R04, R24. Full references and links are provided at the end.

11. Charge, seals, migration, timing and water: the complete reservoir test

Reservoir texture is only one part of a petroleum accumulation. A useful prospect requires connected pores, a retaining geometry and seal, access to mobile oil, and compatible timing. These conditions must be demonstrated at the same stratigraphic level. The best evidence in southwestern Manitoba comes from produced oil, tested pressure/fluids and core-calibrated local studies; a stain, a high-resistivity bed, a topographic high or an inherited regional contour is weaker evidence [R03; R06; R08; R17; R19].

A reservoir idea must survive six independent tests

Requirement	Observe	Interpret	Test against
Reservoir	Core texture + plug permeability + corrected logs	Connected effective pores	Cemented or isolated pores
Seal	Lithology + continuity + capillary test	Oil column retained	Absent cap or throughgoing fracture
Trap	Depth-corrected picks + restored section + seismic	Closure/pinchout at reservoir level	Artifact or open updip pathway
Charge	Produced oil + biomarker/fluid match	Migration access	Stain only or incompatible gas
Timing	Crosscutting relations + burial history	Trap before charge	Late breach or reservoir destroyed
Water	DST/pressure + salinity + normalized production	Bounded mobile-oil interval	Connected aquifer/water-only test

Analytical workflow proposed for this study, grounded in the local examples [R03, R06, R08, R17, R19].

Observations, interpretations and disproof are kept separate. No numerical prospect chance is assigned without local data.

Source families and migration routes

Petroleum-system history | interpretive framework | petroleum-system assessment

Canadian Williston geochemistry distinguishes Ordovician, Winnipegosis, Bakken and Lodgepole-associated oil families. Later USGS synthesis recognizes multiple known systems, but classifies Winnipeg, Duperow and Birdbear source systems as hypothetical and Deadwood as speculative at basin scale. These categories concern source attribution, not a numerical chance of a particular Manitoba prospect [R19; R20].

Published observations

- The MC-1 study attributes its oils to a Lodgepole-family system with long-distance lateral migration from mature basinward sources [R06, p 17].
- Sampled Manitoba Upper Bakken and Routledge shales can be rich but immature; local charge cannot be assumed from TOC alone [R01, pp 13-14].
- Manson 2025 API/sulphur similarity suggests migrated Lodgepole oil, but one sample does not resolve unique source, migration route or the contribution of each completed interval [R18].

Local / regional orientation. Regional migration is commonly considered from deeper basinward areas toward the margin, but faults, hydrodynamics and facies barriers can redirect it.

Reservoir settings to investigate

- Obtain biomarkers, stable isotopes and whole-oil properties from nearby produced oils and candidate reservoirs; check biodegradation/mixing before assigning a family.
- Use carrier-bed continuity, capillary barriers, pressure gradients and timing to test lateral versus cross-formational migration.

What would weaken or reject the idea

- A connected carrier can deliver oil or water. A fault may charge one interval and drain another.
- The evidence does not date a single basin-wide charge event for every unit; trap formation must be evaluated against a local burial/thermal history.

Area significance. Applies to every local opportunity; prevents a blanket projection of shallow oil into deeper formations.

Sources: R19, R20, R06, R01, R18. Full references and links are provided at the end.

Criteria for a producible reservoir and a convincing negative test

All ages | decision framework | evaluation criteria

A reservoir interval should be evaluated with effective porosity, directional permeability, fluid saturation, pressure, thickness, connectivity and a development concept. There is no single Manitoba porosity cutoff: published local choices range from 8-9% in some carbonate/Amaranth studies to 12.6% associated with a 1 mD cutoff in an early Sinclair sample. These cutoffs are evaluation assumptions, not laws of geology [R06, p 18; R09, p 20; R14, p 8].

Published observations

- MC-1, Lower Amaranth and Bakken-Torquay examples show that cement, clay, fractures and pore-throat size change the porosity-permeability relation.
- Source studies report water-bearing sands, immature source candidates, cemented ooid facies and nitrogen gas: these are useful negative evidence, not inconvenient exceptions [R01; R02; R06; R09].

Local / regional orientation. Choose cross-sections both along and across the predicted facies trend; one favorable well cannot establish a belt.

Reservoir settings to investigate

- Require a retained column or mapped pressure/saturation compartment, sustained test/production evidence, and a seal capable of containing the anticipated column.
- Use dry/wet wells to falsify predicted sand continuity, closure, charge access or cement trends; preserve their formation-depth and test-quality limitations.

What would weaken or reject the idea

- No reserve volume, recoverable-resource estimate, drilling recommendation or numerical chance of success is calculated from this regional package.
- An uneconomic historical test may reflect both geology and old completion technology; neither explanation should be assumed without evidence.

Area significance. Defines the evidence needed to advance the local analogue areas below into prospect-scale work.

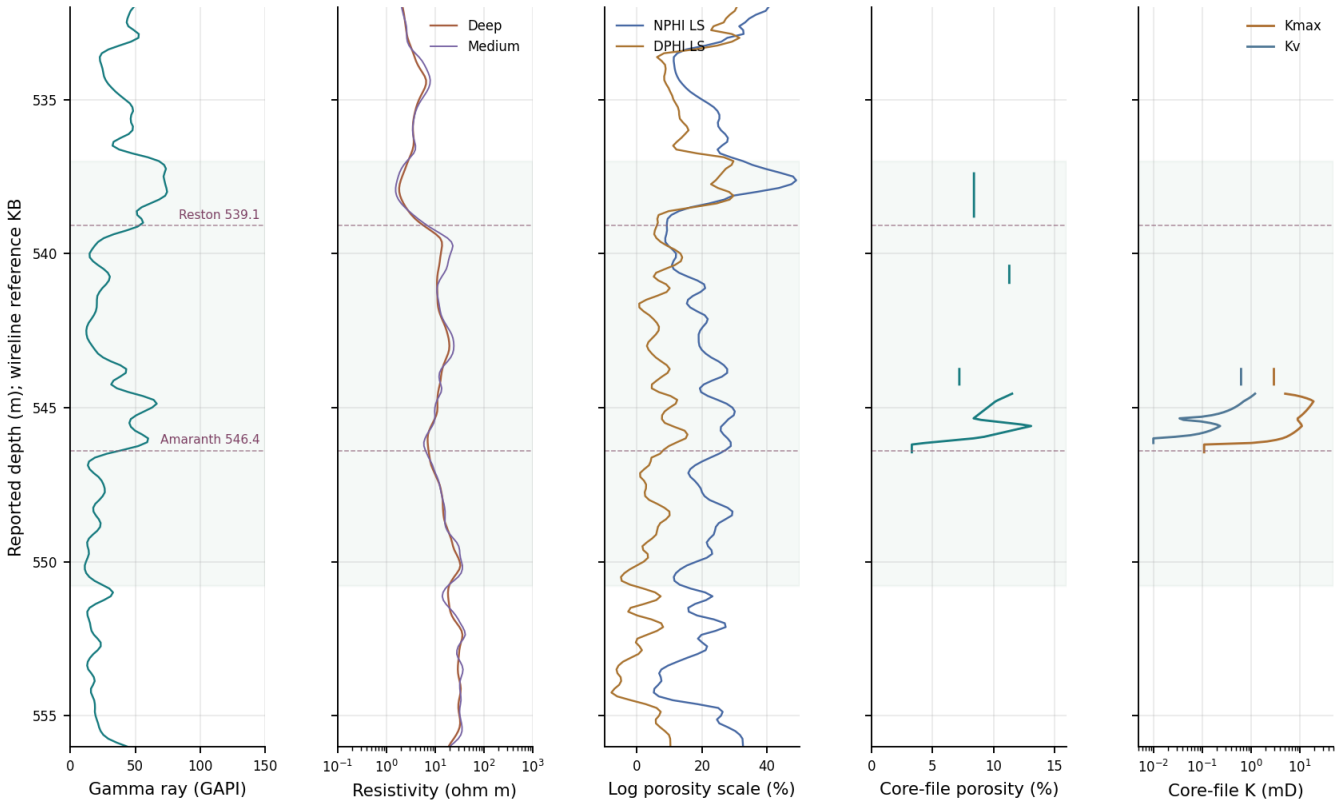
Sources: R06, R09, R14, R01, R02. Full references and links are provided at the end.

12. Two actual well-file checks: useful measurements and model failure modes

This study includes a limited direct examination of public data for two named wells in addition to published interpretations. It does not claim that all available well logs or cores were interpreted. Licence 9990 supplies real wireline and core-analysis curves tied to the Manson study. Licence 2612 illustrates why a faulted/repeated stratigraphic section cannot be forced into a simple single-valued regional formation surface [R35-R37].

Manson licence 9990: real public LAS curves and core-file series

12-01-13-27W1 | August 2014 log package | Published 2025 fluid case: pool 17 22D



Source: Manitoba public log ZIP 0009990. Nulls retained. Regularly sampled core-file rows are not independent plugs.
Dashed contacts are the dated 2014 Fulton-Regula picks (technical file page274), not an assertion that later interpretation is unchanged.
No core-to-log depth shift applied. Published cored interval 537.0-550.8 m is shaded; core LAS extends to 551.9 m.
No corrected porosity, saturation, net pay or unique depositional facies is inferred from these curves.

Original plot from downloaded public LAS files, null value -999.25 removed. Main wireline file 6052365 and core file 6055756. Curves remain on their reported depth bases; the apparent density-porosity response alone cannot establish oil saturation or environment.

Licence 9990, Elcano Miniota 12-1-13-27W1: Manson core/log example

2014 well;2025 produced-fluid sample | measured well evidence with historical picks | direct representative data

The public core-analysis LAS spans 537-551.9 m at 0.05 m steps. Its Kmax, K90, Kv and porosity tracks contain repeated and smoothly varying values, consistent with a resampled presentation rather than 299 independent laboratory plugs. We retained nulls and summarized only the supplied valid curve values. Formation assignment uses a dated 2014 stratigraphic sheet, not an invented current interpretation [R35, PDFp 274; R36].

Published observations

- Valid porosity-track values range 3.3-13.09% across 91 grid samples. Kmax ranges 0.11-19.3156 mD across 50 valid rows within 543.75-546.45 m; Kv ranges 0.01-1.2178 mD across 44 rows. These are curve extrema/counts, not independent-plug statistics [R36; package calculation].
- At 544.8 m the supplied values are 10.17% porosity,Kmax 19.3156 mD,K90 2.5444 mD andKv 0.7078 mD. At 546.2 m porosity is 3.3%,Kmax 0.11 mD,K90 0.08 mD andKv is null. This demonstrates sharp quality/anisotropy changes in the supplied record [R36].
- The dated sheet picks Reston 539.1 m,Upper Amaranth 546.4 m and Lodgepole 557.8 m; Lower Amaranth is unpicked. Older operational completion text calls 539-541.4 m and 542-545 m Amaranth. The discrepancy is retained rather than silently reconciled [R35].
- The 2014 sheet listsKB471.76 m andTVD614.6 m, while LAS headers containKB471.8 m,drillerTD600 m andloggerTD590.3 m. These distinct records are not forced into one value [R35; R36].

Local / regional orientation. One well constrains vertical heterogeneity; it cannot locate a lateral shoreline or a new pool.

Reservoir settings to investigate

- Tie resampled tracks to original laboratory plug sheets and core depths, then examine cement, fractures and carbonate versus siliceous fabric across the permeability transition.
- Use the 2024 facies study to test formation assignments, and production logging or interval isolation to allocate flow from commingled perforations.

What would weaken or reject the idea

- Core Oil/Water fractions are not an uncorrected in-situ saturation model; extraction, invasion and sampling history are not resolved here.
- Low/high core-scan density, null permeability and resampling prevent calculating defensible net pay, hydrocarbon volume or a unique depositional environment from the LAS alone.

Area significance. A real Manson 17 22D example linked to the 2025 fluid study, with interpretation scope explicitly limited.

Digital record and curve handling

The viewer uses the explicitly reported stratigraphic-sheet TVD of 614.6 m, KB 471.76 m and Lodgepole at TD (technical-file page 274). Discrepant LAS-header values remain in provenance; maximum sampled log depth is not used to assign TD. Wireline and core curves remain on their reported depth bases. No core-to-log shift, environmental correction or saturation inversion was applied [R35-R36; D08-D09].

Sources: R35, R36, R17, R18. Full references and links are provided at the end.

Licence 2612, Hartney 1-28-5-24W1: repeated section and failed simple-surface assumption

1979 well record | structural data-quality case | structural anomaly and model limitation

The technical file explicitly records faulting/repetition: top carbonates/Mississippian near 542 m, Lyleton at 708 m marked faulted and again 827.5 m, Lodgepole 867.5 m,Upper Bakken 1071 m and basement 1555 m. The well is nearly vertical in the limited inclination checks, so stratigraphic repetition cannot simply be treated as horizontal-well geometry [R37, PDFpp 20,22].

Published observations

- The record givesKB442 m andTD1575 m. DST1 at 544-555 m recovered 342 m of drilling mud, not an established hydrocarbon flow [R37, PDFpp 20,22].
- The anomalous Lower Amaranth control is excluded from the supplemental single-valued regional interpolation while remaining in the raw dataset and well audit. This is model suitability screening, not deletion of inconvenient geology.

Local / regional orientation. Local structural disruption; regional depositional orientation does not resolve the geometry.

Reservoir settings to investigate

- Build a dedicated faulted section with original logs, seismic and core before assigning repeated tops or assessing any reservoir trap.

What would weaken or reject the idea

- The record alone does not establish the mechanism of the Hartney structure, closure, oil charge or a new prospect.
- Including a repeated pick as an ordinary regional top can manufacture a false thickness bowl or apparent reservoir high.

Area significance. Hartney anomaly demonstrates the limits of smooth regional 3-D surfaces.

Sources: R37, R01. Full references and links are provided at the end.

Local reservoir settings near established pools

These are testable extensions of documented geological settings. They are not prospect outlines, discovery claims or assigned probabilities. “Near a pool” refers to an analogue and data neighborhood; it does not establish shared pressure, facies, charge or remaining oil.

1. Daly-Sinclair: map the Torquay subunit at the unconformity

Area and intervals

Daly-Sinclair, especially transitions between unit 4 and unit 2 reservoir settings

Evidence confidence

High evidence for the existing system; untested extensions remain conditional, not mapped prospects.

Published pool / reservoir evidence

- Published core compilation and established Bakken-Torquay production demonstrate the local petroleum system; the historical 01 62B pool in GR2012-3 must be reconciled with later pool designations [R03; R31].

Depositional and geological interpretation

Preserved cleaner silt and local sub-Bakken diagenesis combine with the Upper Bakken seal and structural/facies trapping.

Nearby environment to test

Small compartments may occur where minimally oxidized 2c or retained 4c connect to charged Middle Bakken but terminate against tight or eroded facies.

Required reservoir conditions

- Identify the actual subunit at the unconformity.
- Show permeability, saturation and seal continuity across the proposed compartment.

Decisive tests

- Correlate core-calibrated units in an east-west section and an along-strike section.
- Normalize early oil/water response for lateral length, completion and production time; test pressure communication across the inferred boundary.

Negative evidence / rejection

- Unit 4 is removed eastward; thicker Middle Bakken can be wetter.
- Oxidation/cement may destroy apparent good silt.

Sources: R03, R14, R31

2. Birdtail-Kirkella-northern Manson: sandier Middle Bakken and local preserved beds

Area and intervals

Northern proven Bakken-Torquay fields and nearby margin

Evidence confidence

Proved regional analogue; moderate confidence in facies direction, lower confidence in untested compartments.

Published pool / reservoir evidence

- Real named pools plus the 2012 northward sandier trend establish an analogue; oil stain north ofT16 is weaker than production [R03; R31].

Depositional and geological interpretation

Increasing sand content can improve flow, while basement/salt-related relief and variable erosion modify accommodation.

Nearby environment to test

Isolated charged sand bodies or preserved basal beds could occur beside the known pools where local enclosing shale and saturation boundaries persist.

Required reservoir conditions

- Core-supported coarse sand and meaningful effective permeability.
- A boundary that retains oil rather than connects the regional aquifer.

Decisive tests

- Map grain-size/net-sand trends and distinguish channel fill from broad shoreface sheets.
- Run salinity/pressure and saturation checks in both good and wet offsets.

Negative evidence / rejection

- Published water/oil ratio increases northward in parts of the system.
- Gross thickness and oil stain alone fail the mobility/retention test.

Sources: R03, R14, R16, R31

3. Virden-Roselea: carbonate-bank and shoal compartments

Area and intervals

Virden and nearby Lodgepole subcrop/paleohigh trend

Evidence confidence

Strong producing analogue; prospect geometry must be resolved far finer than the regional model.

Published pool / reservoir evidence

- Named Lodgepole pools and the 2023 Roselea application document reservoir heterogeneity and local net-pay practice [R13; R31].

Depositional and geological interpretation

Original carbonate bank/shoal texture is modified by pore-scale diagenesis and younger truncation.

Nearby environment to test

A neighboring sealed paleohigh or isolated shoal may retain oil if connected pores survive below the alteration cap.

Required reservoir conditions

- Member-specific facies correlation and preserved pore system.
- Top-of-porosity closure or stratigraphic termination at the same level as oil.

Decisive tests

- Compare cored productive and tight wells; inspect cement and microporosity.
- Separate waterflood sweep effects from original geological compartmentalization.

Negative evidence / rejection

- Sparse core analyses in the application limit permeability maps.
- A structural high or thick carbonate need not contain net pay.

Sources: R05, R13, R31

4. Souris Hartney-Regent-Whitewater-Mountainside-Lulu Lake: member-scale subcrop mosaic

Area and intervals

Shelf carbonate trend southeast of Virden

Evidence confidence

Strong play analogue; no continuous undiscovered belt is asserted.

Published pool / reservoir evidence

- Several actual pools and Whitewater core/DST observations establish grainy reservoirs separated by thin mud barriers and altered caps [R05; R12; R31].

Depositional and geological interpretation

A shelf shoal mosaic was later cut by erosion; anhydrite/dolomite cap and muddy interbeds compartmentalize it.

Nearby environment to test

Small missed pools or isolated compartments could lie where a specific shoal remains below its seal but is cut off from connected water-bearing facies.

Required reservoir conditions

- Correct member and internal barrier correlation.
- Retained reservoir below cap; demonstrable updip/lateral seal and fluid boundary.

Decisive tests

- Use two-direction cross-sections with core ties and exact completion intervals.
- Check pressure/DST and historical waterflood response before declaring hydraulic isolation.

Negative evidence / rejection

- Upper cap can replace the entire shoal locally.
- Lower Whitewater water and fracture connectivity can dominate production.

Sources: R05, R12, R31

5. Tilston-East Tilston-Reston/Pipestone-Deloraine: small MC-1 pools

Area and intervals

Mission Canyon subcrop from the western border toward Deloraine

Evidence confidence

High-confidence analogue architecture; individual undrilled settings remain hypotheses.

Published pool / reservoir evidence

- The 2000 study maps real small pools and ties reservoir behavior to specific facies, alteration and paleorelief [R06].

Depositional and geological interpretation

Skeletal buildup and selectively dolomitized muddy carbonate are productive beneath a later cap.

Nearby environment to test

Comparable small accumulations may occur where a retained porous facies intersects sealed subcrop relief, including places without a large formation-top closure.

Required reservoir conditions

- Demonstrate productive lithofacies, connected pores and cap continuity.
- Separate top-of-effective-porosity relief from formation top.

Decisive tests

- Rebuild member/porosity maps using current wells and dated source picks.
- Use thin sections to test whether dolomitization enhanced or occluded the target.

Negative evidence / rejection

- Ooid facies can be cemented and nonproductive.
- The model Tilston surface combinesMC-1 andMC-2 and cannot locate individual small pools.

Sources: R06, R01, R31

6. Pierson and South Pierson: facies/diagenetic MC-3 pinchouts

Area and intervals

Southern carbonate producing area near actual Pierson pools

Evidence confidence

Strong producing analogue; regional surfaces cannot delineate the target boundaries.

Published pool / reservoir evidence

- Published MC-3 examples include pools without meaningful structural closure, demonstrating the importance of porosity/facies termination [R07].

Depositional and geological interpretation

Shoal/backshoal carbonate is altered unevenly beneath the unconformity; the effective reservoir edge differs from the gross stratigraphic edge.

Nearby environment to test

Adjacent small compartments could lie along a preserved grainy/peloidal facies or diagenetic front beneath a continuous cap.

Required reservoir conditions

- SameMC-3 subunit and a connected pore network.
- Lateral/updip permeability loss plus an independently constrained oil-water relationship.

Decisive tests

- Map individual reservoir subunits and top porosity.
- Sample tight offsets and test the cement hypothesis rather than assuming depositional pinchout.

Negative evidence / rejection

- Some apparent closures are irrelevant to trapping.
- Anhydrite cement and directional permeability can defeat a simple shoal target.

Sources: R07, R11, R31

7. Coulter-Pierson-South Pierson-Lyleton: Lower Amaranth sand compartments

Area and intervals

Southern Lower Amaranth producing fairway

Evidence confidence

Proved reservoir family; local paleochannel/shoreface assignment remains interpretation.

Published pool / reservoir evidence

- Core-based tidal-flat/channel models, actual Lower Amaranth pools and mixed Amaranth-MC3B pool codes show a proven but heterogeneous system [R08-R10; R31].

Depositional and geological interpretation

Discontinuous sand fills and silty sheets occupy paleorelief; mud and cement create compartments, with locally possible charge from Mississippian carriers.

Nearby environment to test

Untested sand lobes or channels may retain oil where they are enclosed and remain connected to a demonstrated charge route.

Required reservoir conditions

- Local net sand with low clay/anhydrite occlusion.
- Independent pressure/saturation compartment and intact upper/lateral seal.

Decisive tests

- Trace each sand cycle using core-calibrated logs, not color names alone.
- Test wet lower sands and compare fluid chemistry between Amaranth and MC3B completions.

Negative evidence / rejection

- Lower sands were commonly wet in the published study.
- Thick clean-looking sand can be cemented; commingling obscures formation-specific contribution.

Sources: R08, R09, R10, R31

8. Waskada-Goodlands-Deloraine: collapse-modified sand and carbonate reservoirs

Area and intervals

Southern basin margin around Waskada,Goodlands and Deloraine

Evidence confidence

Strong local petroleum system; specific collapse geometry/charge timing require prospect-scale work.

Published pool / reservoir evidence

- Waskada has proved Lower Amaranth and Mission Canyon pools; published work links field-scale deformation to multistage salt loss [R08; R11; R01].

Depositional and geological interpretation

Early and late collapse affect paleorelief, sand distribution, preservation and compartmentalization in different ways.

Nearby environment to test

A neighboring collapse flank or preserved carbonate/sand compartment may be favorable if its closure/seal predates effective charge and survives later movement.

Required reservoir conditions

- Date deformation using growth/thickness relationships.
- Demonstrate reservoir facies and seal after the final collapse phase.

Decisive tests

- Compare sub-Prairie, supra-Prairie, Mississippian and Amaranth structure.
- Use current deep-well control to test preserved Bakken/Big Valley hypotheses separately from established shallow pools.

Negative evidence / rejection

- A collapse low is not automatically a trap.
- Water-onlyFavel tests are not evidence for a new oil play; they must remain separate from the proven deeper systems.

Sources: R08, R11, R03, R02, R31

9. Manson-Miniota: dissolution-associated multiformation reservoirs

Area and intervals

ActualManson 17 22 pools and adjacent Virden-Miniota area

Evidence confidence

Strong observed system; extension mechanism is preliminary and requires falsifiable tests.

Published pool / reservoir evidence

- 51-core 2024 study, designated multiformation pools and the 2025 licence 9990 fluid sample provide direct local evidence [R17; R18].

Depositional and geological interpretation

A NNW lineament, missing evaporite, Reston thickening and altered/fractured siliceous-carbonate beds suggest coupled dissolution, subsidence and fluid movement.

Nearby environment to test

Equivalent juxtaposition of dissolution-related accommodation, porous facies and a charged migration pathway may occur around the proved pool margins.

Required reservoir conditions

- Confirm evaporite absence/dissolution rather than a bad pick.
- Demonstrate connected reservoir and a remaining top/lateral seal; resolve the producing interval.

Decisive tests

- Compare current core-based formation picks with historic operational labels.
- Use seismic, pressure, fluid biomarkers and interval-specific flow tests to evaluate the fault/migration model.
- Normalize production histories before comparing pools on opposite sides of the lineament.

Negative evidence / rejection

- OneAPI/sulphur sample does not uniquely identify oil source.
- Faults and missing evaporite can cause leakage and water connection; visual porosity is not a permeability measurement.

Sources: R17, R18, R35, R36, R31

10. St. Lazare and the northern Jurassic margin: enclosed Melita sand

Area and intervals

Near actualOtherAreasMelitaA/B pools and broader northern margin

Evidence confidence

Real local oil analogue; exact paleoenvironment and outward continuity less constrained.

Published pool / reservoir evidence

- Official chronology recordsMelita oil discovery at St. Lazare in 1993; government pool inventory includesMelitaA/B [R29; R31].

Depositional and geological interpretation

Periodic shoaling, channels and local paleorelief within a mud-rich Jurassic succession can create isolated sand reservoirs.

Nearby environment to test

Nearby sand bodies may contain retained migrated oil if depositional enclosure and a charge pathway can both be demonstrated.

Required reservoir conditions

- Core evidence for reservoir-quality sand and enclosing mud.
- Hydrocarbon mobility and pressure separation from water-bearing sand.

Decisive tests

- Map fining- versus coarsening-up cycles, erosive bases, trace fossils and sediment transport indicators.
- Distinguish shoreline progradation, tidal channels and reworked local debris with multiple cores.

Negative evidence / rejection

- The two Melita polygons are undifferentiated; a specific member cannot be assigned solely from the name.
- Similar sand in a nearby well can belong to another depositional episode.

Sources: R02, R17, R29, R31

11. Beneath Daly-Virden and western Manitoba: separate deeper petroleum-system tests

Area and intervals

Lower Paleozoic/Devonian underexplored section, not an extension of shallow pool polygons

Evidence confidence

Frontier hypotheses with greater charge/retention uncertainty; no resource estimate or prospect ranking.

Published pool / reservoir evidence

- Historical shows, reservoir-quality carbonate/sand and basinward production support conditional analogues. Birdbear 6-6-12-24W1 provides a cited reef-facies example [R01; R22].

Depositional and geological interpretation

Selective dolomitization, reef/evaporite geometry, karst and older structural closure can create reservoir/seal pairs unrelated to the shallow producing horizon.

Nearby environment to test

Some structures beneath existing fields may contain separate deep accumulations, but each requires its own charge, seal and timing case.

Required reservoir conditions

- An actual local reservoir interval and closed retaining geometry.
- Compatible oil/gas chemistry, pressure and effective seal independent of shallow production.

Decisive tests

- Review complete deep DST recovery/composition and original logs.
- Use high-resolution seismic and core to distinguish depositional buildup, salt drape and fault repetition.

Negative evidence / rejection

- Nitrogen gas at 2-8-8-17W1 warns against treating every gas flow as petroleum.
- Good deep porosity commonly contains water; a shallow pool does not prove downward migration.

Sources: R01, R19, R21, R22, R23

Model methods, exceptions and reproducibility

Published surfaces

Barycentric sampling inside original published GOCAD triangles; outside source triangle coverage remains null. Provincial boundary from the same source cultural layer; geographic study limits 49-51.2N,98.5W to Manitoba west border.

Display resolution

2 km display grid. Regional basin geometry, unsuitable for delineating small traps or well placement.

Thickness definition

Gross interval between explicitly named tops; no net-pay estimation. Nulls include unsupported base horizons, not zero-thickness claims.

Historical controls

Verified source workbook depth picks with positive depths, converted to elevation using same-row KB; source zeros not promoted to surfaces.

Lower Amaranth supplement

Separate bounded interpolation from verified controls, not a published TGI surface. See unit metadata for support masks.

Well evidence

Current GIS/weekly inventory is stored separately from historical wells used to constrain regional interpretation. No TD inferred from deepest picked top.

Only inside the well-control convex hull, within 7.5 km of a control and in triangles with longest edge at most 20 km; additionally clipped to the published Watrous/Amaranth footprint. Lack of mapped support is not proof of absence. Upper Amaranth evaporite top and Lower Amaranth reservoir top are separate surfaces. Licence 2612 Hartney is excluded from this supplemental fit because its official technical file documents faulted and repeated stratigraphy; the original pick remains in the historical data. Lower member assigned Triassic in the modern OF2020-7 chart; its age was historically uncertain.

The Hartney faulted-section exception

A historical Lower Amaranth pick at licence 2612 is internally incompatible with a simple, single-valued stratigraphic stack. Review of the technical file documents a repeated Mississippian section and faulted/repeated picks. The measured source row remains in the historical data. Its exclusion from the supplemental regional fit is a modeling decision for a faulted local section, not deletion of inconvenient evidence or proof that the original pick was a typo [D10].

Uncertainty cannot be removed by visual smoothness

- Sparse control and source triangle boundaries limit confidence near unit edges. A smooth mesh is not a confidence interval.
- Supplemental interpolation is restricted by control distance, triangle size and supported regional footprint. Its boundary is not a proven geological termination.
- The source vertical datum is retained as released. No unsupported CGVD conversion is applied.
- Portable GLBs include 1x and 25x vertical versions. Named surfaces and pool placements are retained. A separate well-location/plan scene preserves mapped paths without converting them into surveyed laterals.

- The browser viewer supports WebXR where available; headset operation has not been physically tested in this work. Software projection is available where WebGL is unavailable.

Recommended local evaluation sequence

- step: 1; title: Resolve the question at a named pool; detail: Start with the regulatory pool code, actual producing formations, completions and time-normalized oil/water history. A field label can span several reservoirs; a pool polygon is not an oil-water contact.
- step: 2; title: Build a defensible correlation; detail: Use a common vertical datum, distinguish MD/TVD/KB/subsea, check stratigraphic order and reconcile legacy formation names. Preserve conflicting or repeated tops. Cross-sections should include productive, water-bearing, dry and uncored wells.
- step: 3; title: Translate core observations into competing environments; detail: Describe grain size, sorting, sedimentary structures, fossils/trace fossils, mud drapes, exposure/evaporite fabrics and transport evidence before assigning shoreface, channel, lagoon or reef. Distinguish original deposition from later brecciation, replacement and dissolution.
- step: 4; title: Measure the reservoir rather than infer it from thickness; detail: Use plug/core permeability and effective porosity, thin sections, clay/anhydrite fractions, local water resistivity and corrected logs. Where curves are resampled, count original plugs separately. Do not convert gross isopach into net pay.
- step: 5; title: Test seal, closure and charge together; detail: Map top of connected porosity, enclosing facies/cap, possible oil-water contact and carrier pathways. Compare measured fluids with known local oil families; test whether trap formation preceded charge and survived later dissolution.
- step: 6; title: Seek evidence that would defeat the model; detail: A wet connected offset, missing cap, cemented facies, non-hydrocarbon gas, incompatible age or loss of closure after datum correction can disprove the proposed setting. Preserve these results in the map and report.
- step: 7; title: Advance only resolved local questions; detail: High-resolution seismic, targeted core work, pressure/flow testing and modern petrophysics follow only where the first six steps leave a coherent testable reservoir hypothesis. This package does not select a drilling location or calculate reserves.

Additional scientific limits

- The geological interpretation is regional and analogue-based. Except for the explicitly described representative well checks, published authors interpreted the cited cores/logs; this project did not independently reinterpret every available well.
- Regional GOCAD surfaces, a bounded Lower Amaranth interpolation, regulatory pool polygons, well positions, trajectories and production records have different dates, resolution and purpose. Their coincidence in 3-D does not prove reservoir communication.
- There are 42 source geological horizons,37 with supported local model geometry, plus a supplemental Lower Amaranth surface. Five absent western/source horizons are not extrapolated into Manitoba. The scientific formation/member catalogue is more detailed than the model.
- Source-model surface differences are gross modeled interval thicknesses. They are not measured local net pay, a guaranteed depositional wedge, reservoir quality or hydrocarbon saturation.
- Known pool polygons represent regulatory designations. Some mixed pools span several formations, and source code/name mismatches are retained in the audit. Formation-plane placement is a proxy where member-level depth is unavailable.
- A straight vertical wellbore is an explicit assumption where survey geometry is unavailable; an independently known horizontal designation does not supply lateral azimuth or trajectory. No formation at TD is invented from unvalidated model intersections.
- Historical porosity/permeability averages and cutoffs are local, sample-selected and sometimes based on older completions. They are not global economic thresholds or present reservoir pressures.

- Oil stain, UV fluorescence, oil-cut mud, gas show and produced mobile oil are distinct evidence levels. Nitrogen flow, water-only tests, immature source samples and tight facies remain visible negative evidence.
- Paleoenvironment diagrams are original schematic reconstructions. Exact shorelines, channels, reefs, faults and undiscovered pool boundaries are not mapped where data cannot resolve them.
- No reserves, recovery forecasts, development economics or numerical discovery probabilities are inferred from this regional model. Historical resource estimates in source papers are not adopted as current values.

Surface / Manitoba stratigraphy crosswalk

Model horizon	Manitoba interpretation	Thickness / support
Belly River / lower Odanah marker	Lower Odanah regional marker; GP2009-1 p 11: lower Odanah grades westward into Belly River; this is not top Pierre or top Odanah.	Belly River / lower Odanah marker top to Lea Park / Pembina-Millwood top
Lea Park / Pembina-Millwood	Pembina-Millwood composite (Pierre Shale); GP2009-1 p 11: Pembina correlates to lower Lea Park and Millwood to upper Lea Park.	Lea Park / Pembina-Millwood top to Milk River / Gammon top
Milk River / Gammon	Gammon Ferruginous Member remnant (Pierre Shale); GP2009-1 pp 10-11: Gammon is interpreted as an erosional Milk River remnant; basal contact and cross-border correlation remain uncertain.	Milk River / Gammon top to Niobrara top
Carlile (Morden-Boyne)	Carlile Formation (Morden and Boyne members); GP2009-1 p 10 and OF2020-7. Internal member surfaces are not provided by this model.	Carlile (Morden-Boyne) top to Favel / Second White Specks top
Favel / Second White Specks	Favel Formation (Keld and Assiniboine members); GP2009-1 p 9: Favel correlates with Second White Specks; not a single limestone bed.	Favel / Second White Specks top to Belle Fourche top
Belle Fourche	Belle Fourche Member, Ashville Formation; GP2009-1 pp 8-9; retain source horizon age/definition.	Belle Fourche top to Westgate top
Westgate	Westgate Member, Ashville Formation; GP2009-1 pp 8-9.	Westgate top to Newcastle top
Newcastle	Newcastle Member, Ashville Formation; GP2009-1 pp 8-9; equivalent regional Viking interval, not all sandstone.	Newcastle top to Joli Fou / Skull Creek top
Joli Fou / Skull Creek	Skull Creek Member correlation, Ashville Formation; GP2009-1 pp 7-8. Basal Pense/P4 correlation is explicitly questioned; do not equate all Skull Creek to Joli Fou without qualification.	Joli Fou / Skull Creek top to Mannville regional P4 marker top
Mannville regional P4 marker	Mannville regional top; Swan River/Pense correlation; Source spelling Manville retained as ID. GP2009-1 p 7: mapped P4 shale pick may be lower Skull Creek; top Swan River sand is a different lithologic pick.	Mannville regional P4 marker top to Success S2 top
Success S2	Success S2 regional remnant; GP2009-1 pp 6-7: local northern subbasins and uncertain correlations; no complete southern blanket inferred.	Success S2 top to Masefield / Waskada Formation top

Model horizon	Manitoba interpretation	Thickness / support
Masefield / Waskada Formation	Waskada Formation correlation; GP2009-1 p 6: Waskada correlates to Masefield Shale and possibly Success S1. Not the informal Waskada sand unit in Lower Amaranth.	Masefield / Waskada Formation top to Rierdon / Upper Melita top
Rierdon / Upper Melita	Upper Melita Member; GP2009-1 p 5. Same formation rank not implied across provinces.	Rierdon / Upper Melita top to Shaunavon / Lower Melita top
Shaunavon / Lower Melita	Lower Melita Member; GP2009-1 p 5.	Shaunavon / Lower Melita top to Gravelbourg / Reston top
Gravelbourg / Reston	Reston Formation; GP2009-1 p 5: Gbg 3 basal shale, Gbg 4 limestone, Gbg 5 sandy/oolitic upper unit may be locally absent.	Gravelbourg / Reston top to Watrous / Amaranth regional top top
Watrous / Amaranth regional top	Amaranth Formation regional top; GP2009-1 pp 4-5; source Watrous/Amaranth top does not isolate the Lower Amaranth reservoir sands from the Upper evaporitic seal.	Upper Amaranth interval: published regional Amaranth top minus bounded Lower Amaranth top
Lower Amaranth (bounded well-control interpretation)	Triassic; Only inside the well-control convex hull, within 7.5 km of a control and in triangles with longest edge at most 20 km; additionally clipped to the published Watrous/Amaranth footprint. Lack of mapped support is not proof of absence. Upper Amaranth evaporite top and Lower Amaranth reservoir top are separate surfaces. Licence 2612 Hartney is excluded from this supplemental fit because its official technical file documents faulted and repeated stratigraphy; the original pick remains in the historical data. Lower member assigned Triassic in the modern OF2020-7 chart; its age was historically uncertain.	Published Lower Amaranth ISO control thickness interpolated within supported triangles
Frobisher / Manitoba Charles	Frobisher / Manitoba Charles evaporitic interval; GP2008-2 p 15: Manitoba Charles is the Frobisher equivalent, distinct from Saskatchewan Charles nomenclature; suggested MC-5 terminology is not treated here as universally adopted.	Frobisher / Manitoba Charles top to Kisbey interval top
Kisbey interval	Kisbey interval (tentative Manitoba correlation); GP2008-2 p 15: identified from logs in T1 R28-29W1; no core verification in that study. Proposed MC-4 alias only.	Kisbey interval top to Alida / Mission Canyon 3 top
Alida / Mission Canyon 3	MC-3 Member, Mission Canyon Formation; GP2008-2 p 15 explicitly correlates Alida with MC-3.	Alida / Mission Canyon 3 top to Tilston / Mission Canyon 1-2 top
Tilston / Mission Canyon 1-2	MC-1 and MC-2 members, Mission Canyon Formation; GP2008-2 p 15 explicitly correlates Tilston with both MC-1 and MC-2; this surface cannot separate them.	Tilston / Mission Canyon 1-2 top to Lodgepole top
Lodgepole	Lodgepole Formation; Multiple shelf/slope members and facies are not independently resolved by a single formation top.	Lodgepole top to Bakken top
Bakken	Bakken Formation; Upper, Middle and locally preserved Lower members; regional top does not locate middle-member net pay.	Bakken top to Torquay / Three Forks top
Torquay / Three Forks	Torquay Formation (legacy Three Forks/Lyleton); GR2012-3 pp 1-3: modern Three Forks Group includes Torquay, Big Valley and Bakken. Legacy source name preserved in metadata. Big Valley is local and not a separate regional modeled surface.	Torquay / Three Forks top to Birdbear top

Model horizon	Manitoba interpretation	Thickness / support
Birdbear	Devonian; Published regional model horizon; local reservoir quality is unresolved.	Birdbear top to Duperow top
Duperow	Duperow Formation; GP2008-2 p 12.	Duperow top to Souris River top
Souris River	Souris River Formation; GP2008-2 p 11.	Souris River top to Dawson Bay top
Dawson Bay	Dawson Bay Formation; GP2008-2 pp 10-11.	Dawson Bay top to Prairie Evaporite top
Prairie Evaporite	Prairie Evaporite Formation / residual interval; GP2008-2 pp 9-10: top residual transitional beds and preserved halite edge are distinct. Source surface must not be shown as proven present salt everywhere.	Prairie Evaporite top to Winnipegosis top
Winnipegosis	Winnipegosis Formation; GP2008-2 p 9; local reefs are below regional-model resolution.	Winnipegosis top to Ashern top
Ashern	Ashern Formation; GP2008-2 p 9.	Ashern top to Interlake top
Interlake	Interlake Group; GP2008-2 pp 8-9; not a single formation. Internal formations in outcrop and upper/lower subsurface units are not independently modeled.	Interlake top to Stonewall top
Stonewall	Stonewall Formation; GP2008-2 p 8.	Stonewall top to Stony Mountain top
Stony Mountain	Stony Mountain Formation; GP2008-2 pp 7-8.	Stony Mountain top to Red River top
Red River	Red River Formation; GP2008-2 pp 6-7; subsurface Herald/Yeoman-equivalent markers are not individually modeled.	Red River top to Winnipeg top
Winnipeg	Winnipeg Formation; GP2008-2 p 6; lower sand, upper shale and Carman sand lens are not separate modeled surfaces.	Winnipeg top to Deadwood top
Deadwood	Deadwood Formation; GP2008-2 p 6: thin erosional wedge at extreme southwest; absent surfaces should remain absent.	Deadwood top to Precambrian basement top
Precambrian basement	Precambrian basement unconformity; Not a sedimentary formation or hydrocarbon-bearing horizon by definition.	Top only

Unmodeled wider-basin source horizons

The following source horizons have no supported grid nodes inside the selected Manitoba area and are not displayed as local surfaces. This is a statement about available model support, not a new claim that every listed formation is absent everywhere in Manitoba [D01-D02].

Source horizon	Age	Why no local surface is displayed
Niobrara	Cretaceous	No local grid nodes within the original source-triangle coverage. GP2009-1 p 10 rejects the older Boyne-Niobrara equivalence; mapped Niobrara is truncated west of Manitoba.
Big Snowy	Mississippian	No local grid nodes within the original source-triangle coverage. Do not construct an occurrence in Manitoba from a regional name; retain only original supported geometry.
Poplar Beds	Mississippian	No local grid nodes within the original source-triangle coverage. Do not construct an occurrence in Manitoba from a regional name; retain only original supported geometry.
Ratcliffe Beds	Mississippian	No local grid nodes within the original source-triangle coverage. Do not construct an occurrence in Manitoba from a regional name; retain only original supported geometry.
Midale Beds	Mississippian	No local grid nodes within the original source-triangle coverage. Do not construct an occurrence in Manitoba from a regional name; retain only original supported geometry.

References and data sources

Bracketed R identifiers refer to geological studies; D identifiers refer to the acquired datasets and original well files. Source descriptions distinguish published observations from this study's interpretations. Government information is attributed to the Province of Manitoba / Manitoba Geological Survey / Petroleum Branch as applicable; no government endorsement is implied. Third-party reports and technical files are linked for source verification.

[R01] Nicolas & Barchyn (2008). Williston Basin Project (TGI II): summary report on Paleozoic stratigraphy, mapping and hydrocarbon assessment, southwestern Manitoba. GP2008-2

Regional stratigraphy, cross-border correlations, salt dissolution, documented historical shows and source-rock analyses. Printed pp 5-16; Appendix 1. Historical exploration statements require current well reconciliation.

https://www.manitoba.ca/iem/info/libmin/GP2008-2.pdf

[R02] Nicolas (2009). Williston Basin Project (TGI II): summary report on Mesozoic stratigraphy, mapping and hydrocarbon assessment, southwestern Manitoba. GP2009-1

Printed pp 4-12; regional Mesozoic facies, model-marker correlations, maturity analyses and failed shallow tests. ZIP includes report and correlation figure.

https://www.manitoba.ca/iem/info/libmin/GP2009-1.zip

[R03] Nicolas (2012). Stratigraphy and regional geology of the Late Devonian-Early Mississippian Three Forks Group, southwestern Manitoba. GR2012-3

Core-based unit descriptions, competing Torquay models, Big Valley remnants, mapped subcrops, 223-well core-analysis compilation, Figures 43-49 and core appendices.

https://www.manitoba.ca/iem/info/libmin/GR2012-3.pdf

[R04] Manitoba Geological Survey (2020). Phanerozoic stratigraphic correlation chart for Manitoba. OF2020-7

Preferred broad Manitoba stratigraphic framework; distinguishes formations, members and groups, gaps, producing units and shows.

https://www.gov.mb.ca/iem/info/libmin/OF2020-7.pdf

[R05] Klassen (1996). Regional geology and petroleum potential of the Lodgepole Formation. POF15-96

Printed pp 9-10, lithofacies descriptions, pp 25-26, core appendices and cross-sections. Shelf-slope-basin and localized mound models; historical sparse-control statements are not current acreage assessments.

https://www.gov.mb.ca/iem/petroleum/pubcat/pof_15-96.zip

[R06] Martiniuk, Nicolas & Fox (2000). Geology, reservoir characteristics and petroleum potential of the MC-1 Member. POF18-2000

Eight lithofacies; core photographs and thin sections; printed pp 7-18,28; Table 2 and Figures 5,7,17-29. Explicit producing-pool petrophysical cutoffs and diagenesis.

https://www.gov.mb.ca/iem/petroleum/pubcat/POF18-2000.pdf

[R07] Husain & Halabura (1987). Petroleum geology of the MC-3 Member, Pierson area. POF7-86

Report number retains 86; title-page year is 1987. Printed pp 24-26 and 42-47; named MC-3 pools, six facies and stratigraphic trapping.

https://www.gov.mb.ca/iem/petroleum/pubcat/pof_7-86.zip

[R08] Barchyn (1982). Geology and hydrocarbon potential of the Lower Amaranth Formation, Waskada-Pierson area. GR82-6

Printed pp 12-14,18-22; detailed alternative depositional models, cement controls and representative Waskada core/log section. Legacy Jurassic age terminology is updated with OF2020-7.

https://www.manitoba.ca/iem/info/libmin/GR82-6.zip

[R09] Husain (1990). Regional geology and petroleum potential of the Lower Amaranth Formation, Coulter-Pierson. POF11-90

Printed pp 17-22; subtidal channel, intertidal and supratidal facies; lithologic heterogeneity, petrophysical ranges and negative wet-sand evidence.

https://www.gov.mb.ca/iem/petroleum/pubcat/pof_11-90.zip

[R10] Arbez (1990). Evaluation of the Lower Amaranth Formation in the South Pierson Field. POF10-90

Local petrophysical evaluation, net-pay methodology and heterogeneous Lower Amaranth pools; source assumptions should not be applied globally.

https://www.gov.mb.ca/iem/petroleum/pubcat/pof_10_90.pdf

[R11] Rodgers (1986). Petroleum geology of the Mission Canyon Formation, Waskada Field. PR1-85

Waskada MC-1/MC-3 reservoir context and multistage Prairie salt-collapse interpretation. Report number retains 85; title-page year 1986.

https://www.gov.mb.ca/iem/petroleum/pubcat/pr_1_85.zip

[R12] Tundra Oil & Gas (2020). Whitewater Unit No.2 waterflood application

Officially filed operator interpretation, 20 April 2020; printed pp 4-8. Type log 100/06-02-003-21W1, local reservoir barriers, core and DST interpretation. Operator model, not independent regional truth.

https://www.gov.mb.ca/iem/petroleum/applications/tundra_whitewater_2/application.pdf

[R13] Corex Resources (2023). Virden Roselea Unit No.6 waterflood application

Officially filed operator interpretation, 12 April 2023; local Scallion and Sandhill/oolite reservoir criteria and core-control limitations.

https://www.gov.mb.ca/iem/petroleum/applications/virden_roselea_6/application.pdf

[R14] Davidson & Gompf (2006). Sinclair Bakken-Three Forks development overview

18 January 2006; p 8, Figure 10, AppendicesB-C:12 nonconfidential cores and 7 DST wells. Historic sample-specific porosity/permeability and test recoveries.

https://www.gov.mb.ca/iem/petroleum/pubcat/sinclair.pdf

[R15] Manitoba Petroleum Branch (2006). Three Forks-Bakken, Sinclair core workshop paper

Published core-workshop evidence for the Sinclair reservoir interval; use alongside modern GR2012-3 nomenclature.

https://www.gov.mb.ca/iem/petroleum/pubcat/tf_sinclair_core_workshop_paper_oct_2006.pdf

[R16] Nicolas (2008). Three Forks and Bakken formations, southwestern Manitoba. GS-16

Printed pp 171-179: core/log study, oil-stained outliers and tentative Sanish-like correlation. Superseded nomenclature and expanded interpretation in GR2012-3.

https://www.gov.mb.ca/iem/geo/field/roa08pdfs/GS-16.pdf

[R17] Fulton-Regula (2024). Preliminary observations from Manson Reston-Amaranth-Lodgepole reservoir. GS2024-23

Printed pp 192-199:51 cores, interpreted NNW fault/dissolution boundary, revised formation assignments, perforation-count and pool-production tables; conclusions explicitly preliminary.

https://www.gov.mb.ca/iem/geo/field/roa24pdfs/GS2024-23.pdf

[R18] Fulton-Regula (2025). Critical minerals in oil and produced water, Manson field. GS2025-16

Printed pp 155-161: one produced-fluid sample, licence 9990; API/sulphur comparison suggests migrated Lodgepole oil. Not a definitive biomarker oil-source correlation.

https://www.gov.mb.ca/iem/geo/field/roa25pdfs/GS2025-16.pdf

[R19] Lillis (2013). Review of oil families and their petroleum systems of the Williston Basin

USGS-authored primary synthesis, Mountain Geologist 50(1),5-31. Distinguishes known, hypothetical and speculative systems and cautions against assuming vertical charge.

https://pubs.usgs.gov/publication/70042999

[R20] Osadetz, Brooks & Snowdon (1992). Oil families and their sources in the Canadian Williston Basin

Bulletin of Canadian Petroleum Geology 40(3),254-273. Original oil-source family framework: Ordovician, Winnipegosis, Bakken and Lodgepole; source-family terminology differs from later USGS usage.

https://pubs.geoscienceworld.org/cspg/bcpg/article-abstract/40/3/254/57569/Oil-families-and-their-sources-in-Canadian?redirectedFrom=fulltext

[R21] McCabe (1978). Reservoir potential of the Deadwood and Winnipeg formations, southwestern Manitoba. GP78-3

Original lithofacies and cross-section study; basal sand connectivity, upper sand pinchouts, basement paleorelief and hydrodynamic issues.

https://www.manitoba.ca/iem/info/libmin/GP78-3.zip

[R22] Martiniuk & Barchyn (1993). Petroleum potential of the pre-Mississippian, southwestern Manitoba. POF14-93

Original deeper-play review with regional maps and tests. Historical shows and target concepts require new data audit.

https://www.gov.mb.ca/iem/petroleum/pubcat/pof_14_93.zip

[R23] Manitoba Petroleum Branch. Lower Paleozoic water-analysis compilation

Supporting historical formation-water chemistry; useful for distinguishing connected aquifers and testing fluid models, not a direct oil-saturation measurement.

https://www.gov.mb.ca/iem/petroleum/pubcat/lower_paleozoic_water_analysis.pdf

[R24] Bamburak & Nicolas (2013). Upper Cretaceous-Paleocene stratigraphy and mineral resources of southwestern Manitoba. OF2013-9/FT-A4

Outcrop, core, correlation and field-guide evidence for Cretaceous-Paleocene cover; Table 1 and formation descriptions.

https://www.manitoba.ca/iem/info/libmin/gacmac/OF2013-9_FT-A4.pdf

[R25] Bezys & Bamburak (2004). Lower to Middle Paleozoic stratigraphy of southwestern Manitoba, TGI field guide

Original survey field guide with outcrop facies and basin-evolution synthesis. Outcrop diagenesis is an analogue, not a measured subsurface property.

https://www.gov.mb.ca/iem/geo/willistontgi/downloads/fieldtripguidebook_paleozoic.pdf

[R26] Manitoba Geological Survey. Williston Basin TGI structure and isopach maps

Regional government maps and source datasets. Mapped contour geometry is not well-by-well reservoir characterization.

https://www.manitoba.ca/iem/geo/willistontgi/maps.html

[R27] Manitoba Geological Survey. Williston Basin 3-D geological model

Source regional GOCAD geological surfaces; exact download/provenance retained in package data audit. Geometry is a regional interpretation.

https://www.manitoba.ca/iem/geo/willistontgi/3dmodel.html

[R28] Manitoba Petroleum Branch. Statistical and annual petroleum reports

Production and drilling archive. Package inventories and dated tables are authoritative for the downloaded snapshot; historic paper counts are not presented as current totals.

https://www.manitoba.ca/iem/petroleum/reports/index.html

[R29] Manitoba Petroleum Branch. Manitoba Oil Facts

Official discovery chronology and regional industry context. Some numeric summaries on the page are historic and are not substituted for the package snapshot.

https://www.manitoba.ca/iem/petroleum/oilfacts/index.html

[R30] Bamburak (1978). Riding Mountain, Boissevain and Turtle Mountain formations. GR78-2

Original late-Cretaceous/Paleocene facies and crossbedding study. Historical Riding Mountain nomenclature is reconciled to modern Pierre members.

https://www.manitoba.ca/iem/info/libmin/GR78-2.zip

[R31] Manitoba Petroleum Branch. Field and pool codes

Official field/pool nomenclature and reservoir assignments; legal/regulatory pool boundaries are not mapped oil-water contacts.

https://www.manitoba.ca/iem/petroleum/f_p_codes/codes.html

[R32] Manitoba Petroleum Branch. Reservoir documents and unitization applications

Official portal for filed local reservoir studies. Application scenarios and forecasts are operator submissions, not verified outcomes.

https://www.gov.mb.ca/iem/petroleum/reservoir/index.html

[R33] TGI Williston Basin Working Group. Cross-border stratigraphic correlation chart

Explains source-model horizon names and Manitoba-Saskatchewan correlation; not every named western interval is preserved in Manitoba.

https://www.gov.mb.ca/iem/geo/willistontgi/downloads/tgi_strat_column.pdf

[R34] Manitoba Geological Survey. Core and sample resources

Public core-striplog index used with technical well files; an index entry is availability evidence, not proof of interpreted or digitized curves.

https://www.manitoba.ca/iem/petroleum/documents/reservoir/

[R35] Manitoba technical well file, licence 009990: Elcano Miniota 12-1-13-27W1

PDF page 274: stratigraphic sheet entered 17 December 2014, picks attributed to Fulton-Regula; historical completion labels and conflicting TD/header values retained. Root visually verified the sheet.

https://content.gov.mb.ca/iem/petroleum/documents/technical/009990.pdf

[R36] Manitoba public LAS/log archive, licence 0009990

Actual downloaded LAS files. Core-analysis file 6055756,0.05 m grid,537-551.9 m; wireline headers provide datum and depth metadata. Resampled curves are not independent plugs.

https://content.gov.mb.ca/petroleum/logs/update/0009990.zip

[R37] Manitoba technical well file, licence 002612: Hartney 1-28-5-24W1

PDF pp 20,22: faulted/repeated section,KB442 m,TD1575 m and drilling-mud recovery in DST544-555 m. Verified from image by data agent; not proof of a hydrocarbon trap.

https://content.gov.mb.ca/iem/petroleum/documents/technical/002612.pdf

[D01] Manitoba Geological Survey, Williston Basin TGI 3D model and original control pointsets

42 source surfaces across the larger basin; this study samples only local support. Retrieved 27 October 2026.

https://www.manitoba.ca/iem/geo/willistontgi/3dmodel.html

[D02] Manitoba Geological Survey, TGI formation-top databases

Three source workbooks; depths, elevations and zero/missing-value handling documented in the data package.

https://www.manitoba.ca/iem/geo/willistontgi/database.html

[D03] Manitoba Petroleum, GIS datasets

Current well points, mapped horizontal traces and pools_2025. Source snapshots differ in date; source hashes retained.

https://www.manitoba.ca/iem/petroleum/gis/index.html

[D04] Manitoba Petroleum, well and monthly production reports

Weekly UWI register and ten production Excel archives advertised for 1950-2026; accepted data rows begin in 1951.

https://www.manitoba.ca/iem/petroleum/reports/index.html

[D05] Manitoba Petroleum, Oil and Gas Statistics

Headline annual summary used to expose, rather than conceal, a 2025 reconciliation difference.

https://www.manitoba.ca/iem/petroleum/stats/index.html

[D06] Manitoba Petroleum, non-confidential core inventory

Report run 9 October 2026. Physical sample availability; not a database of measured petrophysical properties.

https://www.manitoba.ca/iem/petroleum/core/core_100.pdf

[D07] Manitoba Petroleum, non-confidential cuttings inventory

Report run 9 October 2026. Duplicate storage rows and unknown zero intervals retained in derived CSV.

https://www.manitoba.ca/iem/petroleum/core/cuttings.pdf

[D08] Manitoba Petroleum, public log package for licence 9990

Six LAS files and raster logs. Original log and core-analysis series inspected; regularly sampled core data are not independent plug counts.

https://content.gov.mb.ca/petroleum/logs/update/0009990.zip

[D09] Manitoba Petroleum, technical well file 009990

Page 274: stratigraphic sheet entered 17 December 2014; TVD614.6m, KB471.76m, Lodgepole at TD. Operational and log-header labels differ.

https://content.gov.mb.ca/iem/petroleum/documents/technical/009990.pdf

[D10] Manitoba Petroleum, technical well file 002612

Faulted/repeated stratigraphy at Hartney: a source-supported local exception to a single-valued regional surface. See supplemental-fit audit.

https://content.gov.mb.ca/iem/petroleum/documents/technical/002612.pdf

[D11] Manitoba Petroleum, technical file access guide

Documents may contain drilling, completion, survey, test, log and core information; individual availability varies.

https://www.manitoba.ca/iem/petroleum/gis/technical.html

[D13] Manitoba Geological Survey, Mississippian erosion surface and subcrop map M-2

Published geological map used as an interpretation reference. No unsupported precise vector is fabricated from the raster/source plate.

https://www.gov.mb.ca/iem/geo/stratmaps/pdfs/m-2.pdf

[D14] Manitoba Geological Survey, Paleozoic erosion/subcrop map P-1

Published map context. Distinguish mapped older-unit subcrop from interpolation of MES elevation and modern bedrock contacts.

https://www.gov.mb.ca/iem/geo/stratmaps/pdfs/p-1.pdf

[D12] Province of Manitoba, copyright and OpenMB information-use terms

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