AER/AGS Open File Report 2017-02

Hydrocarbon Resource Potential of the Duvernay Formation in Alberta – Update

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Abstract

In 2012 the Alberta Geological Survey (AGS) released an Open File Report (OFR 2012-06) on Alberta's shale- and siltstone-hosted hydrocarbon resources that included those in the Duvernay Formation. The 2012 assessment of the Duvernay Formation included only the very earliest test wells in the Duvernay and therefore made many assumptions about rock properties, water saturation, fluid distributions, and pressure and temperature regimes. There was also relatively little data available for determining net thickness, porosity, and total organic carbon.

New data have shed light on some of the earlier uncertainties resulting in improved assumptions and more precise hydrocarbon resources models. This work provides an update to the estimates of in-place quantities of natural gas, natural gas liquids, and oil in the Duvernay Formation. The new resource estimates were generated by geostatistically simulating the spatial variation of most of the relevant reservoir characteristics, including their uncertainty, over most of the Duvernay Formation extent. One hundred simulated realizations were then used to calculate the in-place resources and the associated uncertainty.

This work produced updated property maps (simulated realizations and means of 100 realizations) and quantities of hydrocarbons in place. The estimates for the total in-place resources in the Duvernay Formation are 22.1×10^{12} m^3 to 24.2×10^{12} m^3 (784 to 858 Trillion Cubic Feet [Tcf]) of raw gas, with a best estimate of 23.1×10^{12} m^3 (820 Tcf); 14.6×10^9 m^3 to 15.8×10^9 m^3 (91.7 to 99.4 billion barrels [Bbbls]) of natural gas liquids, with a best estimate of to 15.2×10^9 m^3 (95.9 Bbbls); and 31.5×10^9 m^3 to 34.9×10^9 m^3 (198 to 220 Bbbls) of oil, with a best estimate of 33.1×10^9 m^3 (208 Bbbls). These are the total in-place resource estimates and do not take into consideration accessibility, recoverability, or economics. The in-place resources are very different than reserves, which are based on estimated recovery from projects currently in development or expected to be within a short time frame.

1. Introduction

In 2012, the Alberta Geological Survey (AGS)—then a part of the Energy Resources Conservation Board (ERCB), now Alberta Energy Regulator (AER)—released a report on shale- and siltstone-hosted hydrocarbons, including the resources in the Duvernay Formation (Rokosh et al., 2012). This assessment of the Duvernay Formation included only the very earliest test wells in the Duvernay and necessarily made many assumptions about rock properties, water saturation, fluid distributions, and pressure and temperature regimes. There was also relatively little data available for determining net thickness, porosity, and total organic carbon.

New data have shed light on some of the earlier uncertainties and allowed better assumptions to be made and more precise models of hydrocarbon resources to be built. This work updates the estimates of in-place quantities of natural gas, natural gas liquids, and oil in the Duvernay Formation. The method largely follows earlier work (Rokosh et al., 2012; Lyster, 2013). The resource estimates in this report are in-place hydrocarbons, including all oil, gas, and natural gas liquids without considering accessibility, recoverability, or economics. This is very different from reserves, which are constrained by recoverability, project status, time frame, and technology. Other work from the AER has looked at reserves in the Duvernay Formation (Alberta Energy Regulator, 2016).

1.1 The Duvernay Formation

The Duvernay Formation is an Upper Devonian source rock that is present across central Alberta, except where the stratigraphically equivalent Leduc Formation carbonate reefs are present (Switzer et al., 1994). The Duvernay organic-rich shale represents a basin-fill sequence with relatively high organic-matter productivity and preservation penecontemporaneous with reef growth in the Leduc Formation. The Duvernay is fairly rich in quartz, and relatively low in clay minerals resulting in a fairly brittle rock (Hunter and Wilcox, 2012; Dunn et al., 2014). The Duvernay thickens to the west, where the carbonate content is generally lower and where wells are presently being drilled in the liquids-rich or volatile oil window (Rokosh et al., 2012; Dunn et al., 2014). The Duvernay shale is still an emerging unconventional play even though drilling and production testing started in 2011. Initial reports suggested gas-condensate ratios were about 50 to 250 barrels of liquids per million cubic feet of gas in liquids-rich areas, with more recent reports indicating this could be even higher (Encana Corporation, 2016; Athabasca Oil Corporation, 2016). The reservoir is overpressured over large areas in the prospective region, and total organic carbon (TOC), porosity, permeability and water saturations rank favourably to other well-known plays in North America (Dunn et al., 2014; Encana Corporation, 2016; Athabasca Oil Corporation, 2016). Presently, well spacing is about 305 to 366 m (1000 to 1200 feet) (Encana Corporation, 2016). Figure 1 shows the location and extent of the Duvernay Formation within Alberta evaluated in this report. Figure 2 shows a closer look at the outline of the Duvernay Formation as evaluated within this study, as well as the assessment areas as defined in the AER reserves report (Alberta Energy Regulator, 2016).

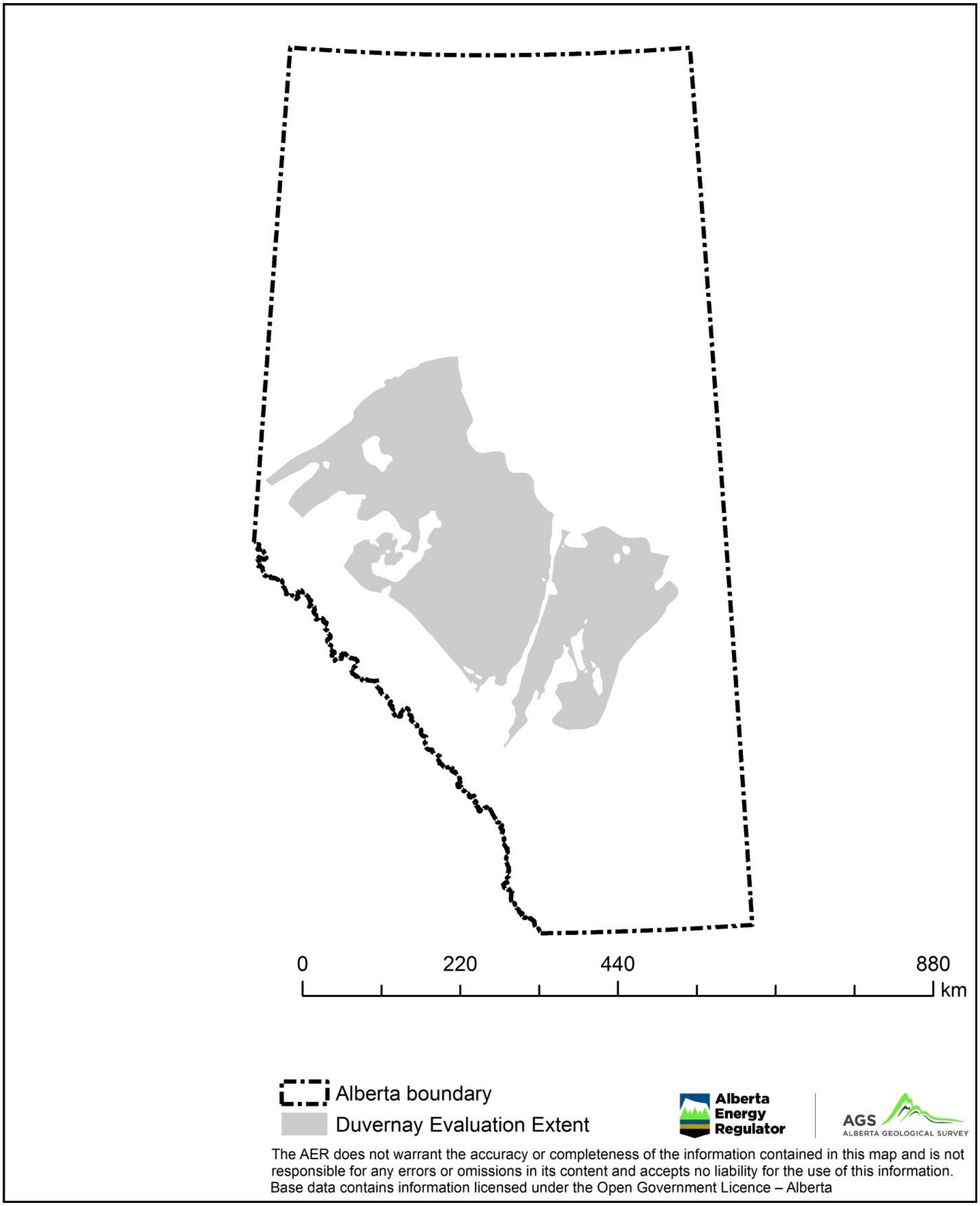

Figure 1. Index map showing the location of the Duvernay Formation in Alberta.

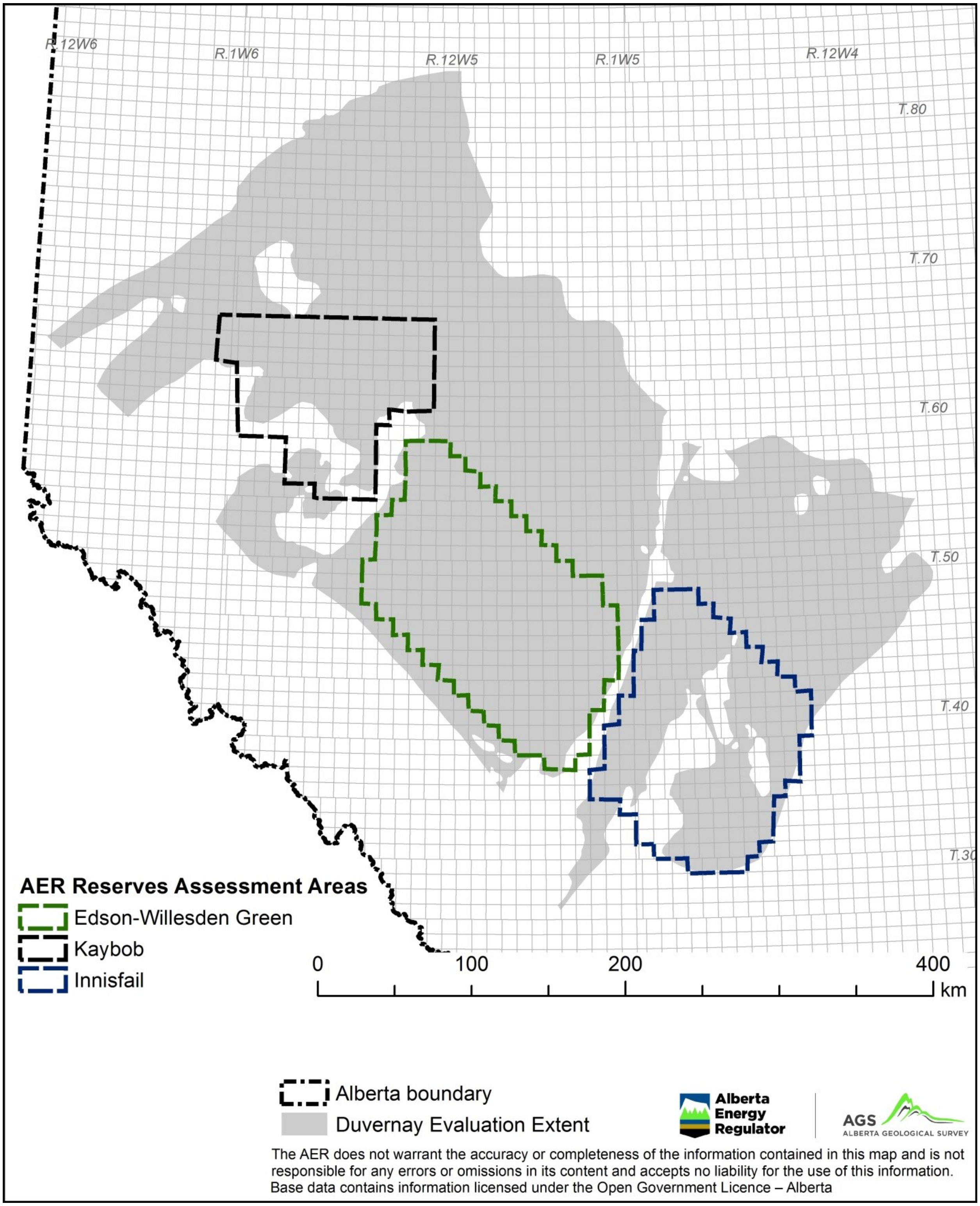

Figure 2. The extent of the Duvernay Formation and AER reserves assessment areas (Alberta Energy Regulator, 2016).

2 Methodology

The methodology used in this study largely follows the previous work (Rokosh et al., 2012; Lyster, 2013). The general outline of the method is as follows:

1. Map variables that have sufficient data to quantify the spatial structure.
2. Determine the secondary variables that have bivariate relationships (i.e., correlations) to the mapped variables.
3. Select values for those variables that have limited data and can only be accounted for by a univariate distribution (i.e., histogram).
4. Stochastically simulate all of the variables and calculate the resources based on the simulated realization.
5. Repeat the simulation step and record the resource calculations for every realization.

2.1 New Data Availability

A major difference between this study and the previous work on the Duvernay Formation is new data. In particular, more data was available for previously mapped variables such as depth, thickness, and porosity, while variables that were previously not possible to map because of a lack of information, such as middle carbonate thickness, gas-oil ratio, and pressure gradient, are now mappable.

2.1.1 Formation Picks

Figure 3 shows a map of wells where the elevation of the Duvernay Formation top was picked by a geologist for this study. A total of 4240 picks were in the initial data set. After eliminating collocated and redundant picks and culling suspect picks, 3224 data points were used to model the top of the Duvernay Formation.

Figure 4 shows a map of wells where the elevation of the Majeau Lake Formation top was picked by a geologist for this study. The Majeau Lake Formation is the base of the Duvernay Formation over most of the West Shale Basin. Also shown are select areas where the Majeau Lake was interpreted to not have been deposited, and the Beaverhill Lake Group was used as the base of the Duvernay. A total of 3941 picks were in the initial data set. After eliminating collocated and redundant picks and culling suspect picks, 2768 data points were used to model the top of the Majeau Lake Formation where it forms the base of the Duvernay.

Figure 5 shows a map of wells where the elevation of the Beaverhill Lake Group top was picked by a geologist for this study. The Beaverhill Lake Group is the base of the Duvernay Formation over a part of the West Shale Basin. Also shown are select areas where the Majeau Lake was interpreted to not have been deposited, and the Beaverhill Lake Group was used as the base of the Duvernay. A total of 2616 picks were in the initial data set. After clipping the data to the area where the Majeau Lake was not deposited, eliminating collocated and redundant picks, and culling suspect picks, 83 data points were used to model the top of the Beaverhill Lake Group where the Majeau Lake is absent and the Duvernay directly overlies the Beaverhill Lake.

Figure 6 shows a map of wells with picks of the Cooking Lake Formation used in this study. The top of the Cooking Lake is the base of the Duvernay in the East Shale Basin. A total of 364 picks were in the initial data set. After eliminating collocated and redundant picks and culling suspect picks, 274 Cooking Lake picks were used to model the top of the Cooking Lake in the East Shale Basin.

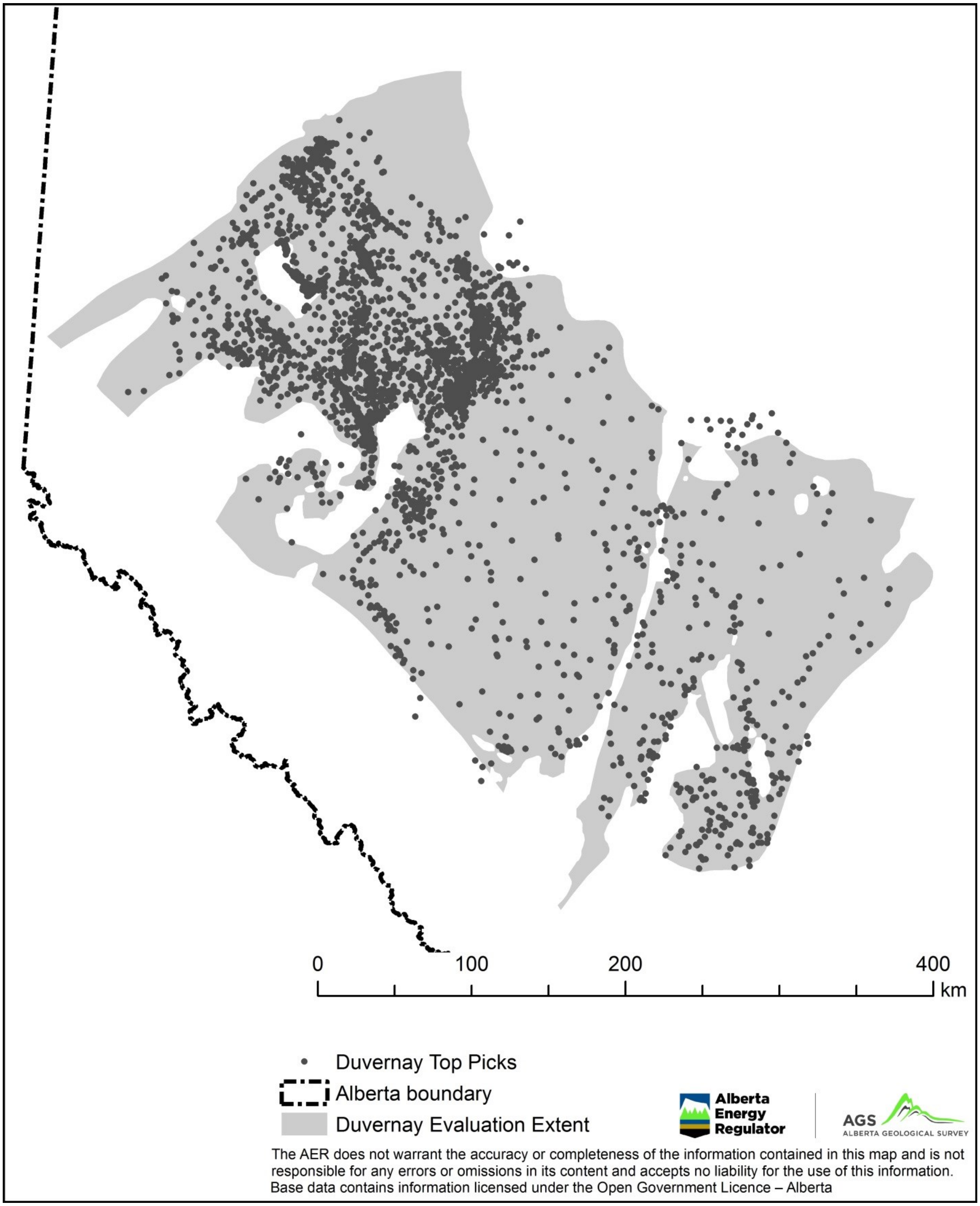

Figure 3. Wells with top picks for the Duvernay Formation used in this study.

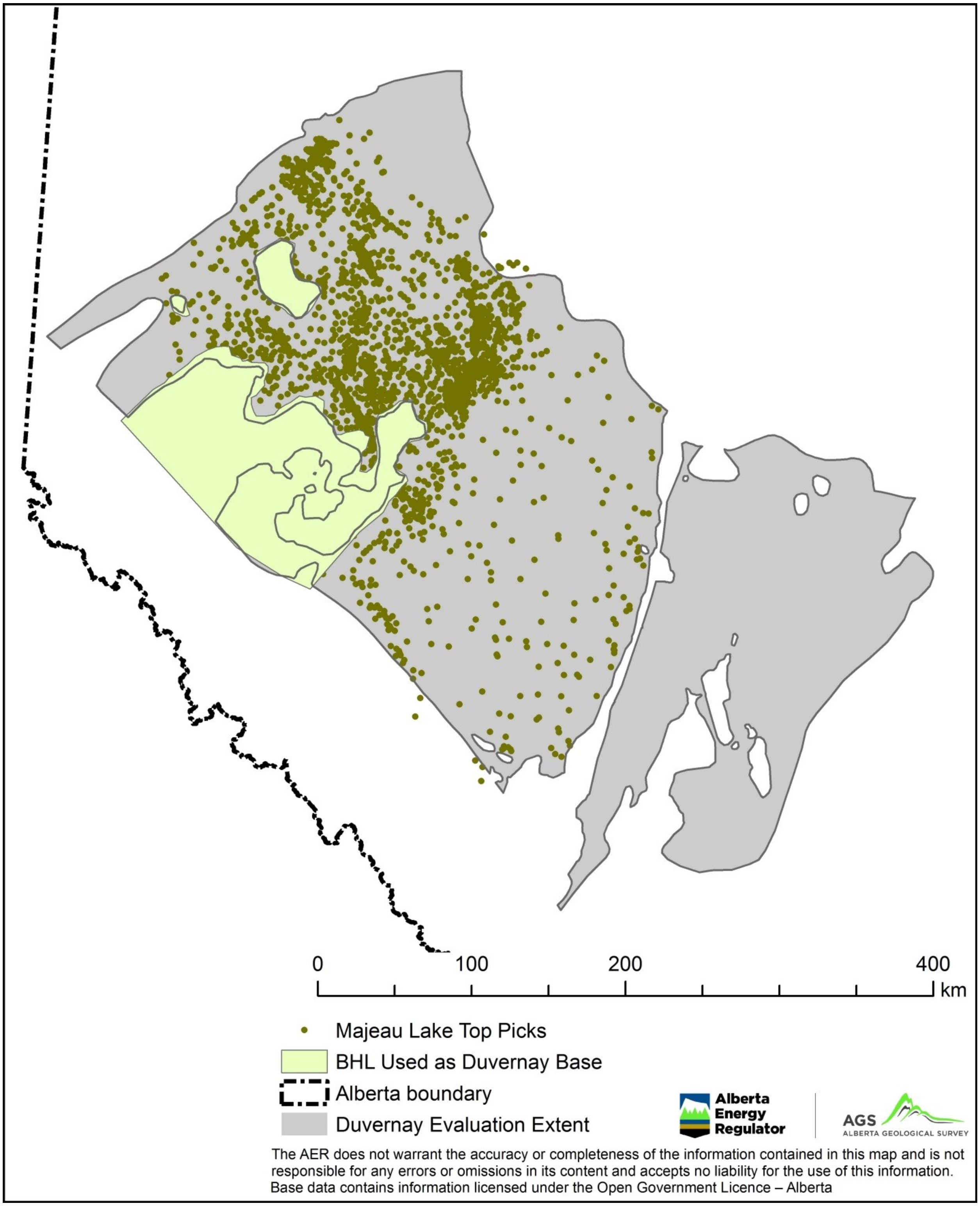

Figure 4. Wells with top picks for the Majeau Lake Formation used in this study. (BHL=Beaverhill Lake)

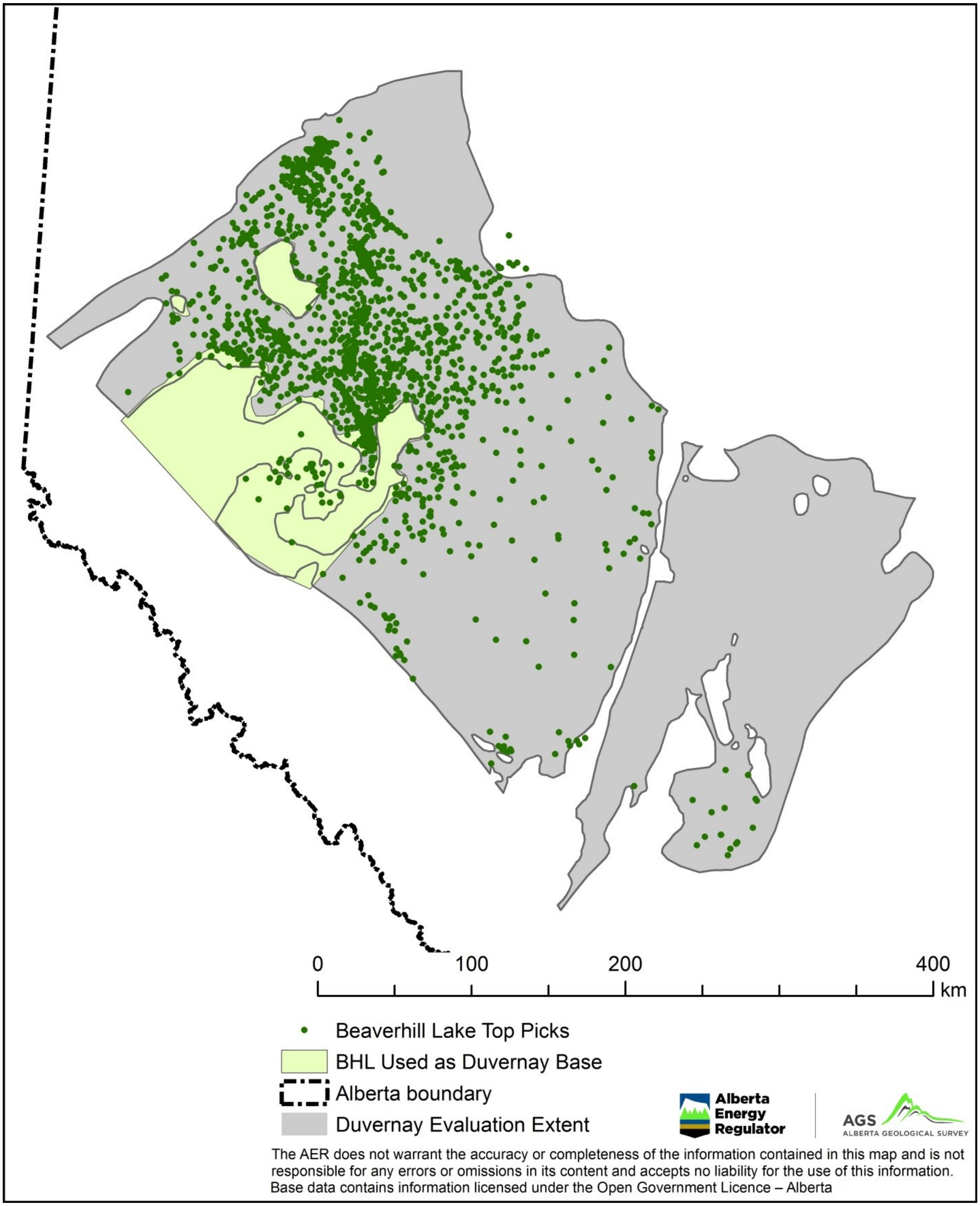

Figure 5. Wells with top picks for the Beaverhill Lake Group used in this study.

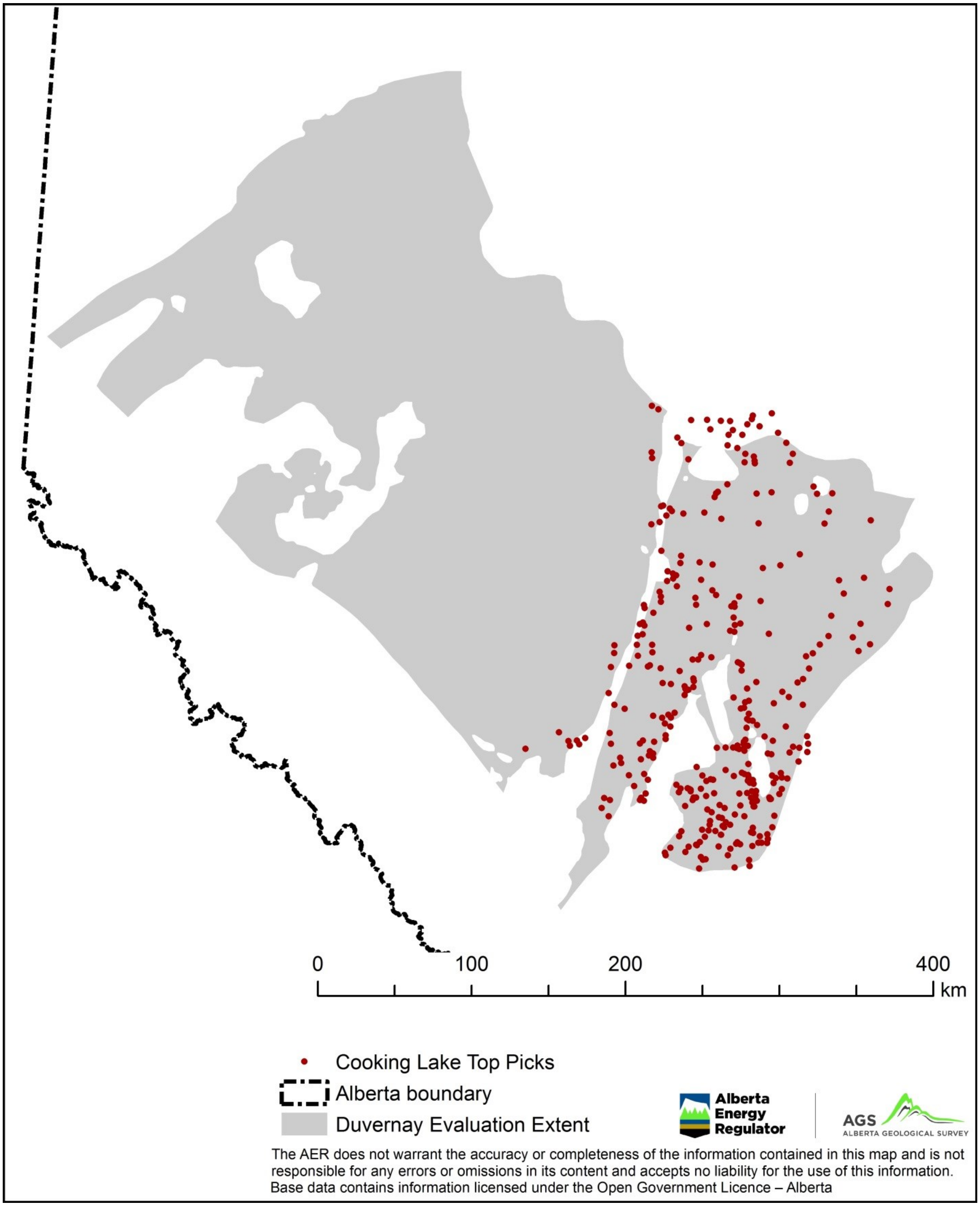

Figure 6. Wells with top picks for the Cooking Lake Formation used in this study.

2.1.2 Carbonate Picks

In the earlier work on Duvernay in-place hydrocarbon resources, carbonate-rich portions of the reservoir were removed from the resource estimation by applying a simple cutoff of 105 API on gamma-ray logs. The approach assumed that intervals with a gamma ray log value greater than 105 were relatively organic-rich and argillaceous, and hence were suitable for hydraulic fracturing. Resources were calculated in just the shale-dominated portion of the reservoir. Operators presently fracturing the Duvernay produce from the entire stimulated zone, and cannot selectively avoid relatively thin carbonate stringers within the shales.

It is now recognized that there is a distinct 'B' carbonate unit in the middle of the Duvernay Formation. Picks of the B carbonate's top and base were used to model the middle zone that was then removed from the resource calculations. However, the resource estimate includes any carbonate within the upper and lower shale units and excludes any shale within the middle carbonate. Hence, shale-hosted hydrocarbons within the carbonate-dominated middle unit are not included in the estimate.

The middle carbonate is mappable over most of the West Shale Basin, pinching out to the west and northwest. Figure 7 shows a map of wells with picks of the top of the middle carbonate unit. A total of 2796 picks were in the initial data set. After eliminating collocated and redundant picks and culling suspect picks, 2151 picks were used to model the top of the middle carbonate. There were 2792 wells with picks of the base of the middle carbonate unit. After eliminating collocated and redundant picks and culling suspect picks, 2153 picks were used to model the base of the carbonate unit.

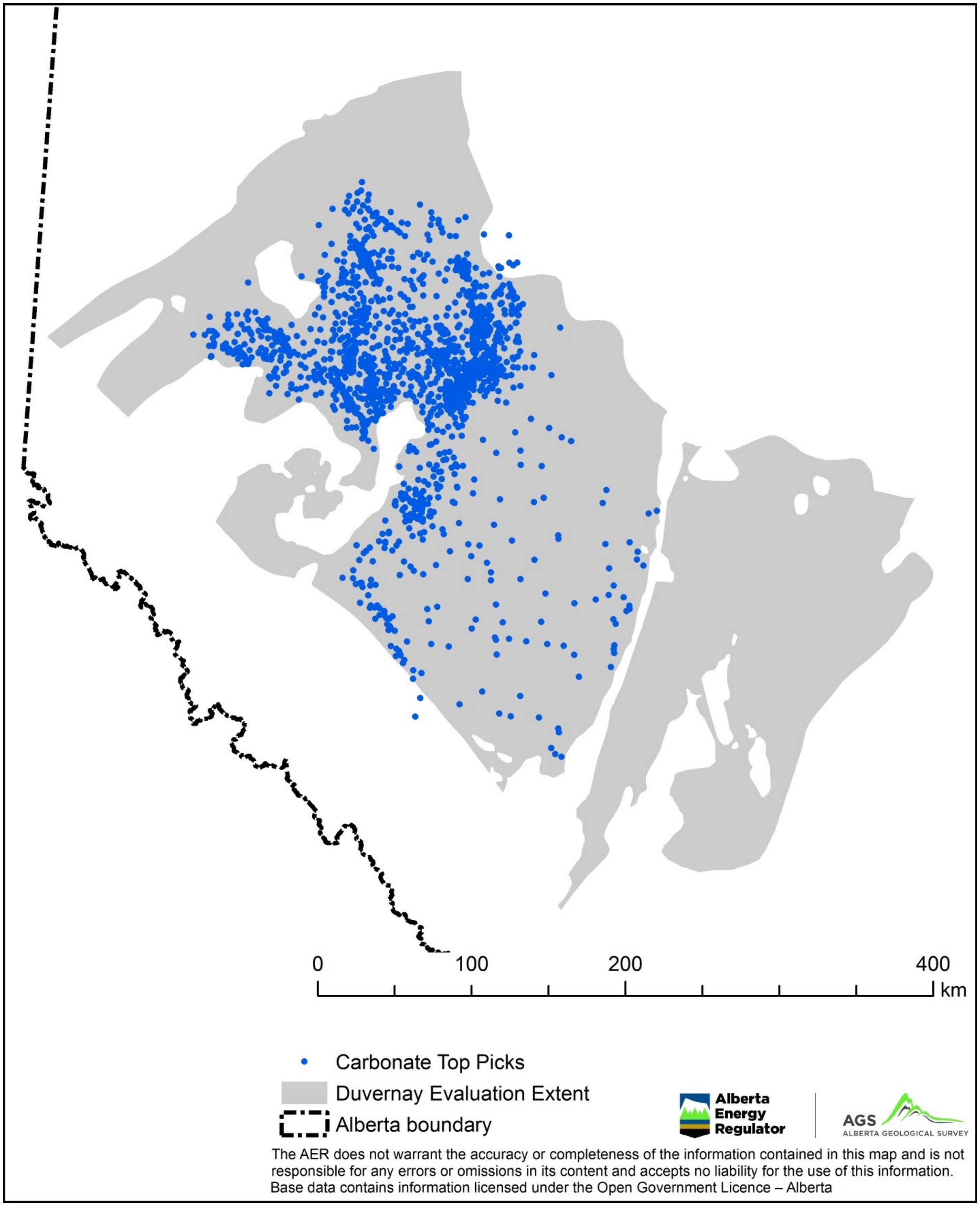

Figure 7. Top picks for the middle carbonate unit of the Duvernay Formation.

2.1.3 Porosity and Total Organic Carbon

Porosity and total organic carbon (TOC) of the net thickness in the Duvernay Formation were calculated using geophysical well logs. Figure 8 shows a map of 1079 wells where the porosity was calculated from density logs. Figure 9 shows a map of 819 wells where the TOC was calculated using Passey's method (Passey et al., 1990).

2.1.4 Pressure and Temperature

The pressure and temperature in a reservoir can have a significant impact on the hydrocarbon quantities in place, in particular both free and adsorbed gas. The previous study (Rokosh et al., 2012) was done with very little information on these reservoir properties because of the lack of production history in the Duvernay. Now that many wells have been on production for several years, more data points are available and the pressure and temperature gradients can be directly modelled.

Figure 10 shows a map of wells with pressure gradient data used in this study. There are 157 data points from pressure tests within the Duvernay Formation. Some of the tests were reviewed for quality. Of these, 24 were deemed high quality, 17 medium quality, 23 low quality, and 93 were not reviewed in detail and deemed the lowest quality. Also within the dataset are 680 pressure tests from the Leduc Formation; these were used to constrain the pressure gradient at the edge of the Duvernay and were given the least weight.

Figure 11 shows a map of wells with temperature gradient data used in this study. There are 230 data points that were used, almost entirely in the Kaybob and Willesden Green areas.

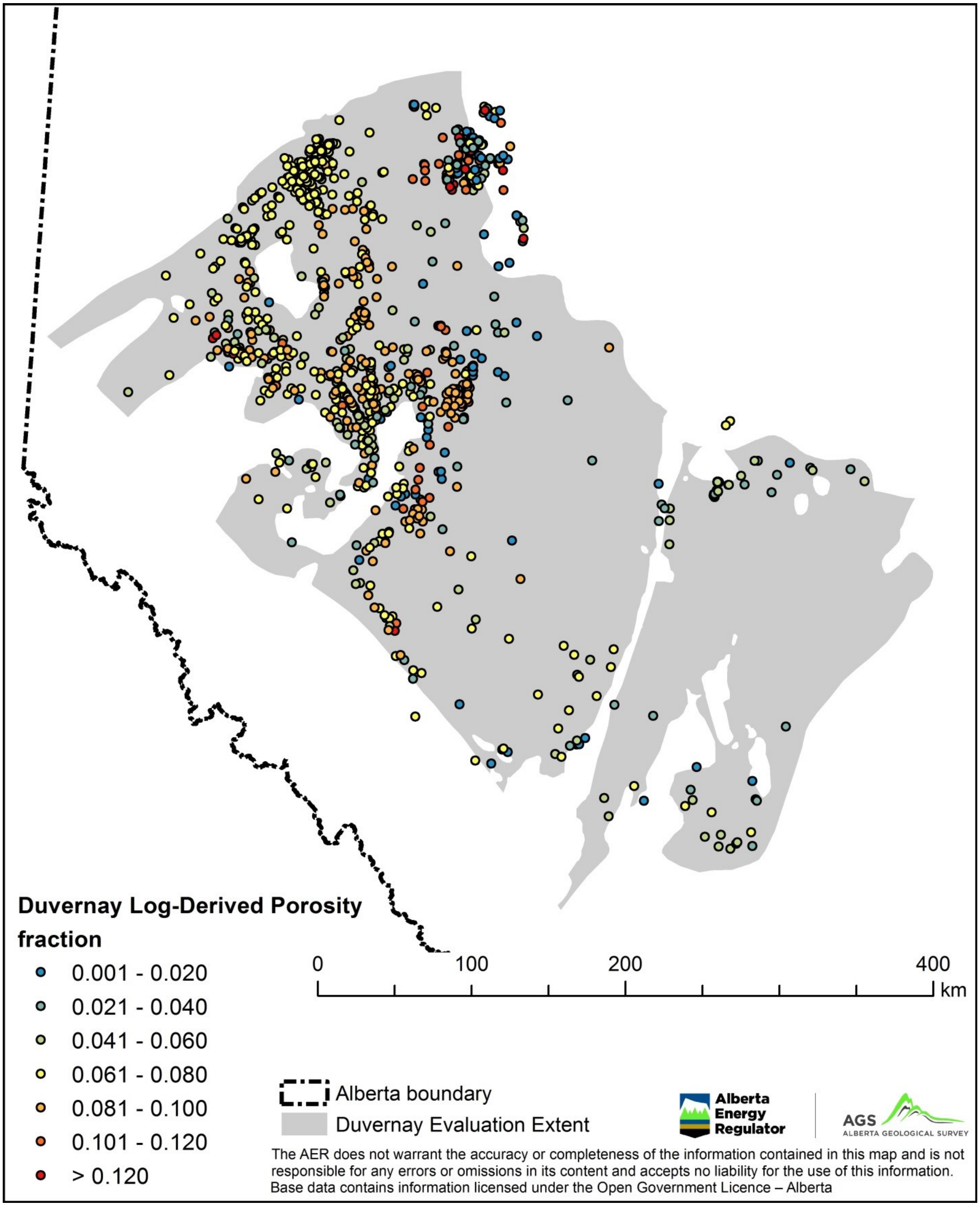

Figure 8. Log-derived porosity in the Duvernay Formation.

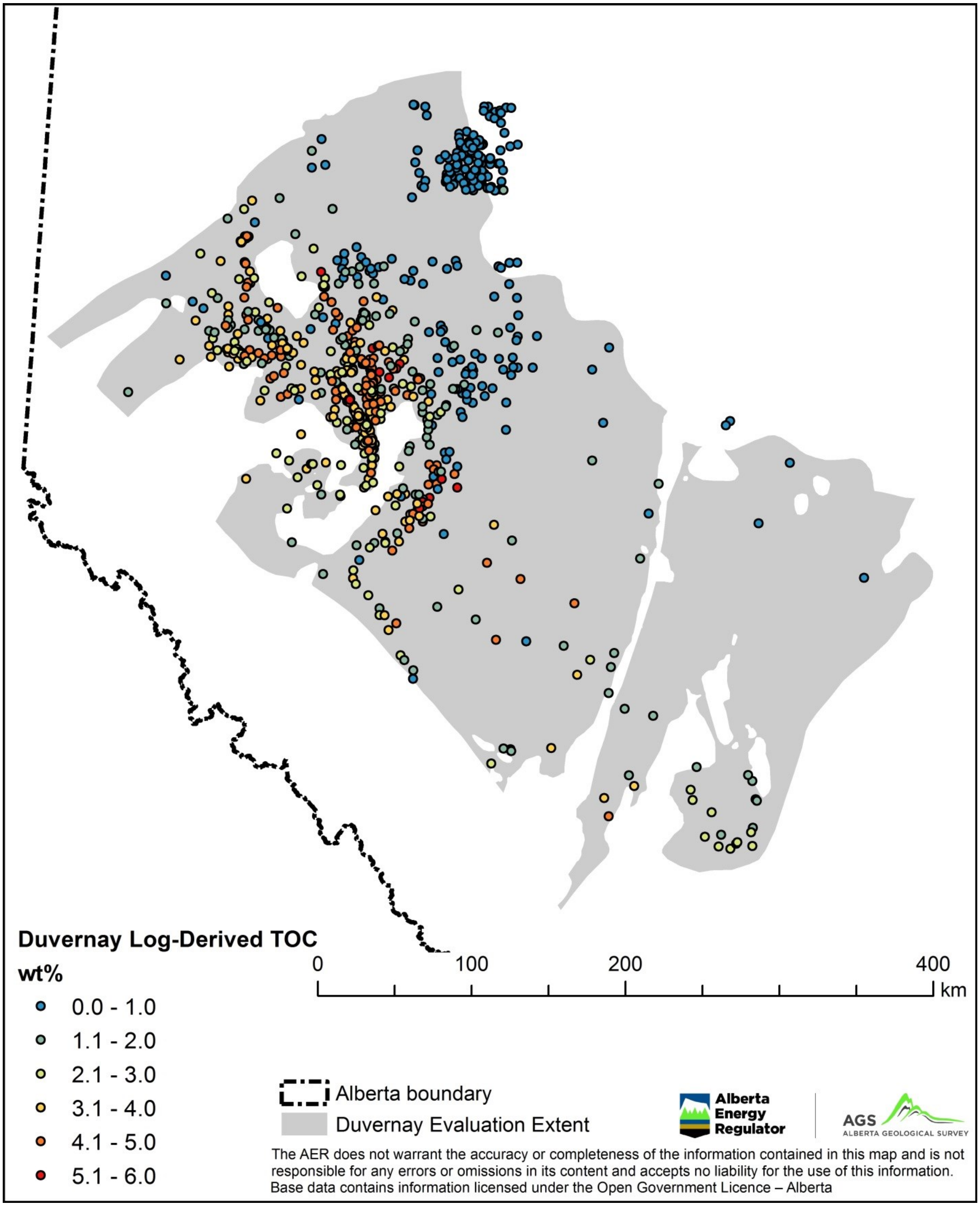

Figure 9. Log-derived total organic carbon (TOC) in the Duvernay Formation.

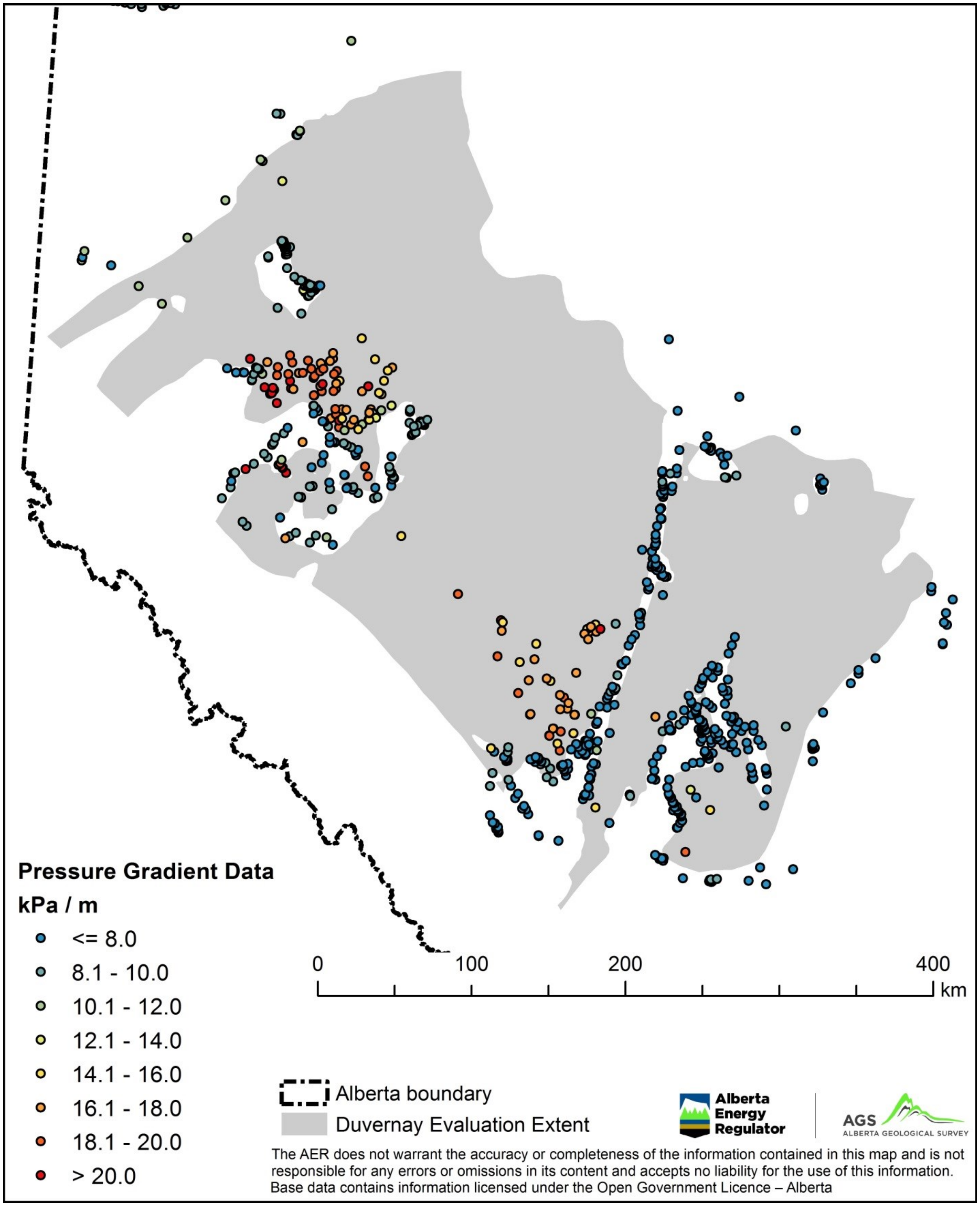

Figure 10. Pressure gradient data used for this study.

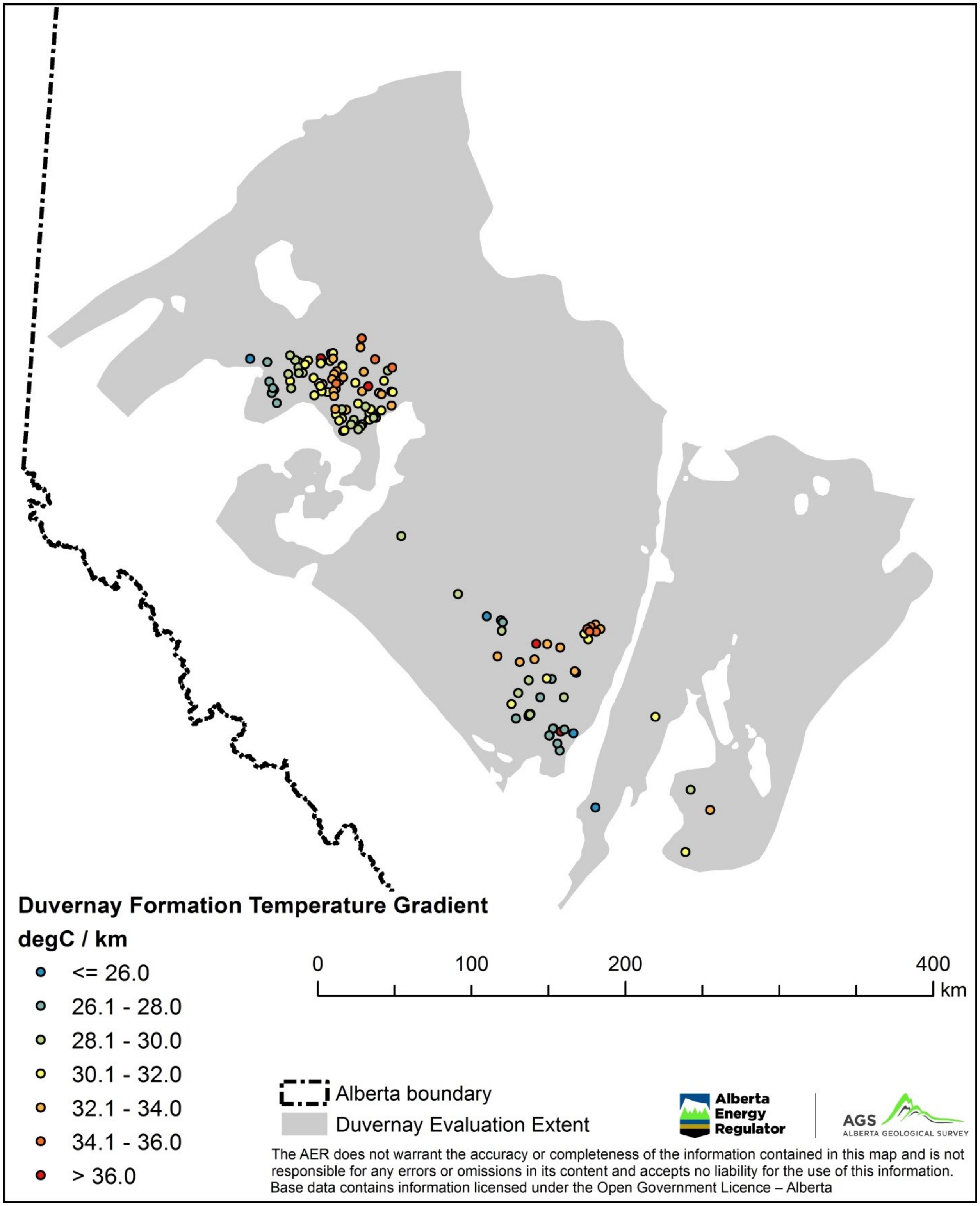

Figure 11. Temperature gradient data used for this study.

2.1.5 Hydrocarbon Ratios

The Duvernay Formation is extensive and spans a range of kerogen maturity windows, from immature in the northeast where the depth is the shallowest to dry gas in the southwest where it is the deepest and has the highest pressure and temperature. The ratio of gas–to-oil within the reservoir changes continuously, increasing with depth such that northeastern shallow areas are oiliest, the southwest deepest areas are dry gas, and wet gas can be found in between. The previous study on Duvernay resources used maturity as a proxy to estimate gas-to-oil ratios (GOR) and condensate-to-gas ratios (CGR) (Rokosh et al., 2012). In this study condensates are considered to be hydrocarbons that are in a gaseous state within the reservoir, then condense to a liquid once at surface conditions. By this definition, condensates, also known as natural gas liquids (NGLs), include a portion of the ethane, propane, butane, and pentanes plus. Any hydrocarbons that are liquid in the reservoir are treated as oil by this definition, including lighter liquids such as pentanes plus.

This study used well production to estimate gas-to-oil ratios. Figure 12 shows a map of the 327 data points used to model the GOR in the Duvernay. The data points used were selected from wells labelled as producing from the Duvernay Formation with at least 2160 hours (90 days) production time. Liquid hydrocarbons produced were all treated as oil as per the definition of condensate, whether it was labelled as oil (from an oil well) or field condensate (from a gas well).

The condensate-to-gas ratios, for hydrocarbons that are gas at reservoir conditions then change state to liquid once produced, were estimated from routine gas analysis data by the equation:

$$CGR[m^3/m^3] = \left(C_2 \cdot \frac{0.65}{281.3} + C_3 \cdot \frac{0.85}{272.3} + C_4 \cdot \frac{0.90}{234.5} + C_{5+} \cdot \frac{1.0}{182.0}\right)$$

Figure 13 shows a map of the 957 data points used to model the CGR in the Duvernay at 230 distinct locations. The colour scale of the CGR is in $m^3/10^6m^3$.

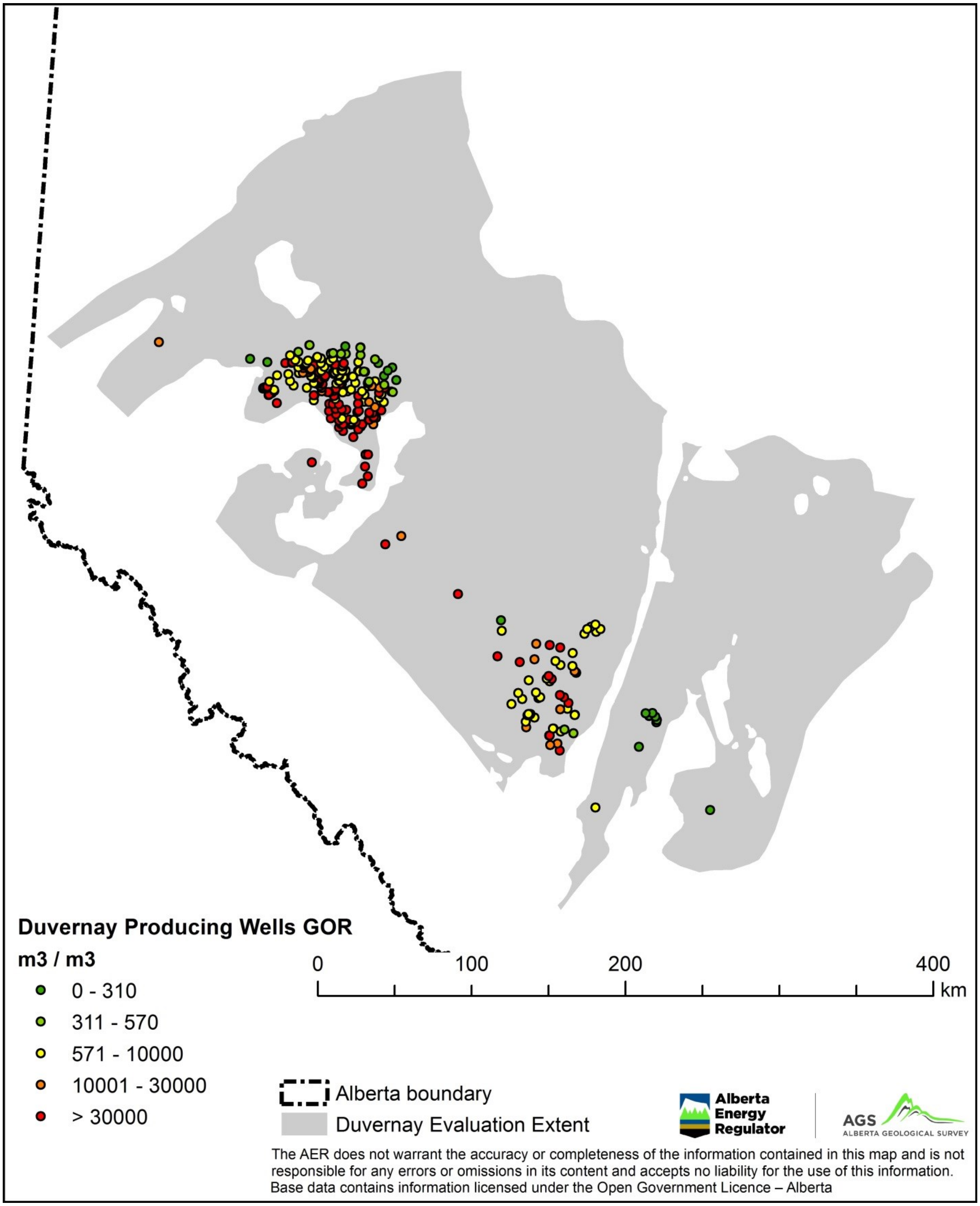

Figure 12. Gas-to-oil ratio data from producing Duvernay wells used in this study.

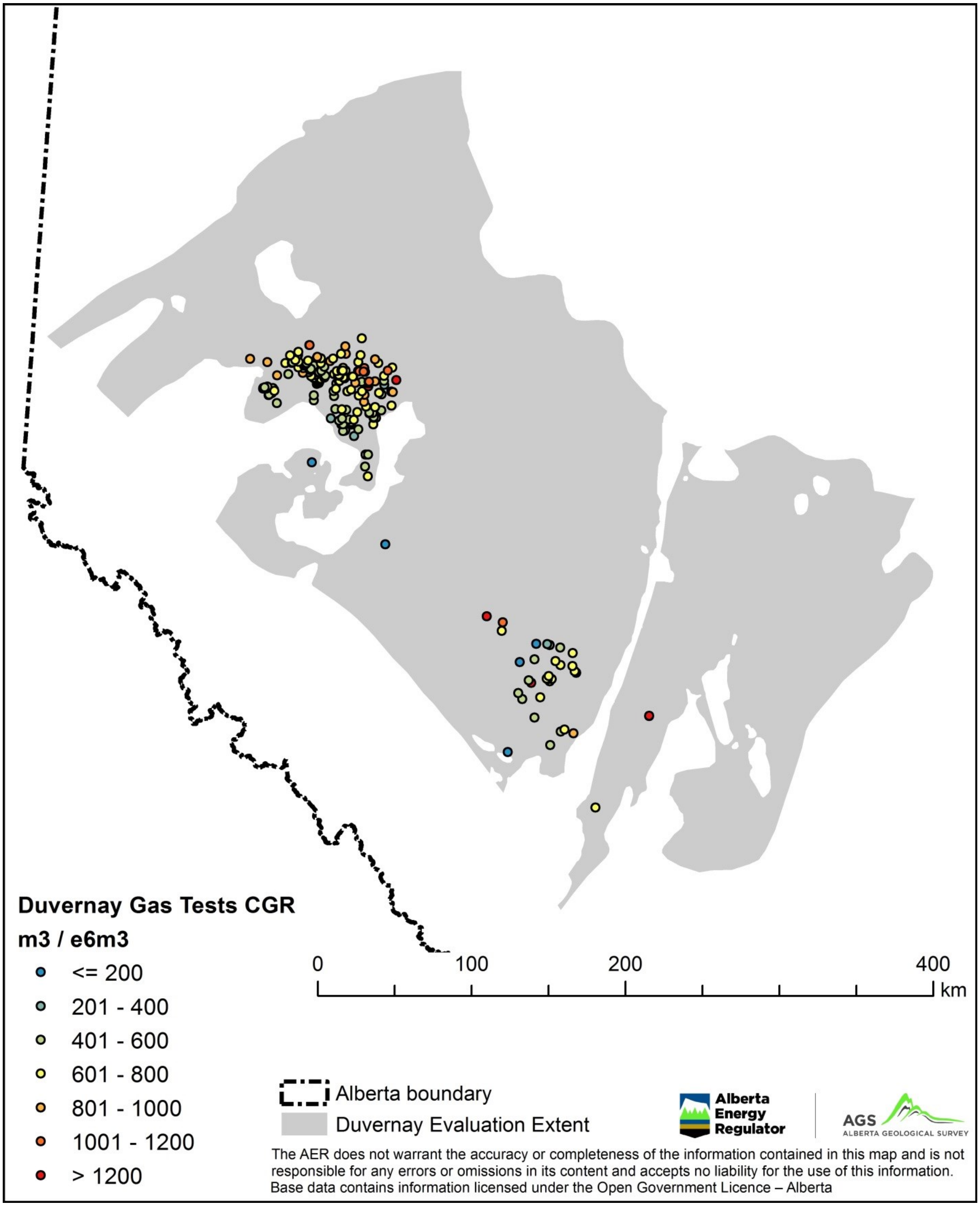

Figure 13. Condensate-to-gas ratio data from Duvernay gas test data used in this study.

3 Geostatistical Simulations

Most of the variables for resource calculations were simulated using geostatistical methods (see Pyrcz and Deutsch, 2014, for more details on geostatistics). The simulations were based on a simple kriging model, where a variogram quantified the spatial structure of each variable. Interpolation via simple kriging produces maps that are too smooth by their very nature: best estimates will never reproduce values at the tail ends of the input distributions (extreme highs and lows).

The “missing” variability of the simple kriging model was stochastically added to the mapped estimates to properly reproduce the spatial structure and reference distribution of the input data. This process is not unique, however, and 100 realizations were used to fully quantify spatial uncertainty.

Figure 14 shows two simulated realizations of depth to the top of the Duvernay Formation, as well as the mean of 100 simulated realizations. The difference between the realizations is not readily apparent, because the large-scale trend dominates over local fluctuations. In general, the Duvernay is deeper to the southwest and shallower to the northeast, which follows the trend of most subsurface geology in Alberta.

Figure 15 shows two simulated realizations of gross thickness of the Duvernay Formation, as well as the mean of 100 simulated realizations. There are four particular areas of note: the Kaybob area, where most of the development has occurred in the Duvernay; the far south portion of the Duvernay, which shows a major thickening to over 100 metres in several logs but may or may not be prospective; the far east of the Duvernay, which also shows a thickening to over 100 metres but is based on only a few data points and is well outside of the area where exploration has occurred and may be in the immature window of hydrocarbon generation; and the thick package of Duvernay just west of Edmonton, near the eastern edge of the West Shale Basin, which was not seen in previous work because no data were available in that area.

Figure 16 shows two simulated realizations of the thickness of the middle carbonate unit, as well as the mean of 100 realizations. Because of the carbonate-rich nature of the rock in the East Shale Basin, the middle carbonate unit was not considered to be a distinct mappable unit in this location. The carbonate thickens to the northeast and pinches out to the west and northwest. The location of the pinchout varies in the individual realizations, reflecting uncertainty.

Figure 17 shows two realizations of the net thickness of the Duvernay Formation, as well as the mean of 100 realizations. In this report, the net thickness is assumed to be the sum of the upper and lower shales, or the gross thickness minus the carbonate thickness. The net thickness itself was not simulated, but was calculated from the difference between the gross and carbonate thicknesses. The net thickness largely follows the pattern of the gross thickness, with the areas of greatest thickness even more visually pronounced.

Figure 18 shows two realizations of porosity within the net portion of the Duvernay Formation, as well as the mean of 100 realizations. Because there is less data than other variables and because of the short range of correlation in the spatial structure of the variables, the log-derived properties show significantly greater variability between the simulated realizations. The map of the mean is notable because it significantly differs from the realizations, with much of the Duvernay having a best estimate near the mean of the porosity distribution at about 6%. Local porosities in different realizations can be high or low at most locations; this shows that there is high uncertainty where there are few data points.

Figure 19 shows two realizations of TOC within the net thickness of the Duvernay Formation, as well as the mean of 100 realizations. The map of the mean shows a fairway of higher TOC from the northwest to the southeast, going through the prospective areas in Kaybob and Willesden Green. The realizations show more variability but the same fairway of high TOC.

Figure 20 shows two realizations of the pressure gradient within the Duvernay Formation, as well as the mean of 100 realizations. The lack of data over most of the Duvernay means that the best estimates are approximately hydrostatic, but high overpressure is possible at almost any unsampled location because of the high uncertainty. The areas where there has been significant drilling, in Kaybob and Willesden Green, both show consistently high overpressure.

Figure 21 shows two realizations of the temperature gradient within the Duvernay Formation, as well as the mean of 100 realizations. The simulated maps of temperature gradient appear deceptively smooth because of the lack of data; the uncertainty is high for most of the area.

Figure 22 shows two realizations of simulated gas-to-oil ratio in the Duvernay Formation, as well as the median of 100 realizations. The trend of the GOR follows the depth, with the shallower and less mature portions of the Duvernay to the northeast having more oil and less gas, and the more mature and deeper portions to the southwest containing dry gas and very little oil. Between the two areas is the liquids-rich fairway that has been targeted by most of the development to date in the Duvernay. Of note in Figure 22 is the pattern of GORs in the simulated realizations. While the overall trend is from oil in the northeast to gas in the southwest, it varies locally, perhaps coincident with increased drilling activity, and the transitions from oil to wet gas to dry gas are irregular. The Willesden Green area shows more local variability in the GORs than does the Kaybob area, with pockets of dry gas and oil mixed over a large area.

Figure 23 shows two realizations of simulated condensate-to-gas ratio in the Duvernay Formation, as well as the mean of 100 realizations. CGR inversely trends the GOR and depth, with the highest values and richest gas to the northeast and the leanest, driest gas to the southwest. It should be noted that, while the northeast of the Duvernay shows very high CGRs, very little gas is in the reservoir as it is mostly filled with oil. Therefore, the quantity of condensate or natural gas liquids peaks in the liquids-rich fairway running northwest to southeast and encompassing the Kaybob and Willesden Green areas.

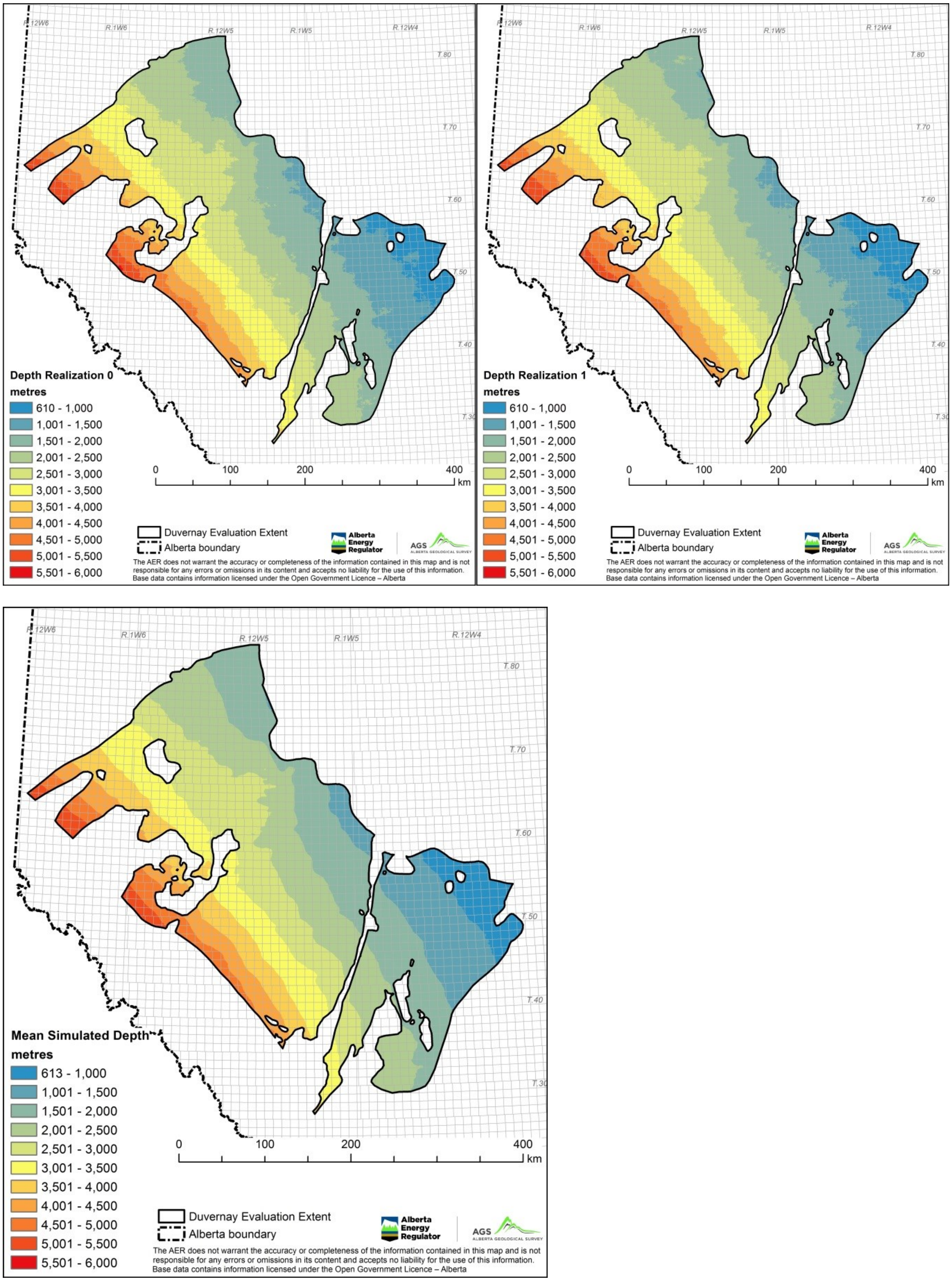

Figure 14. Simulated depth to the top of the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

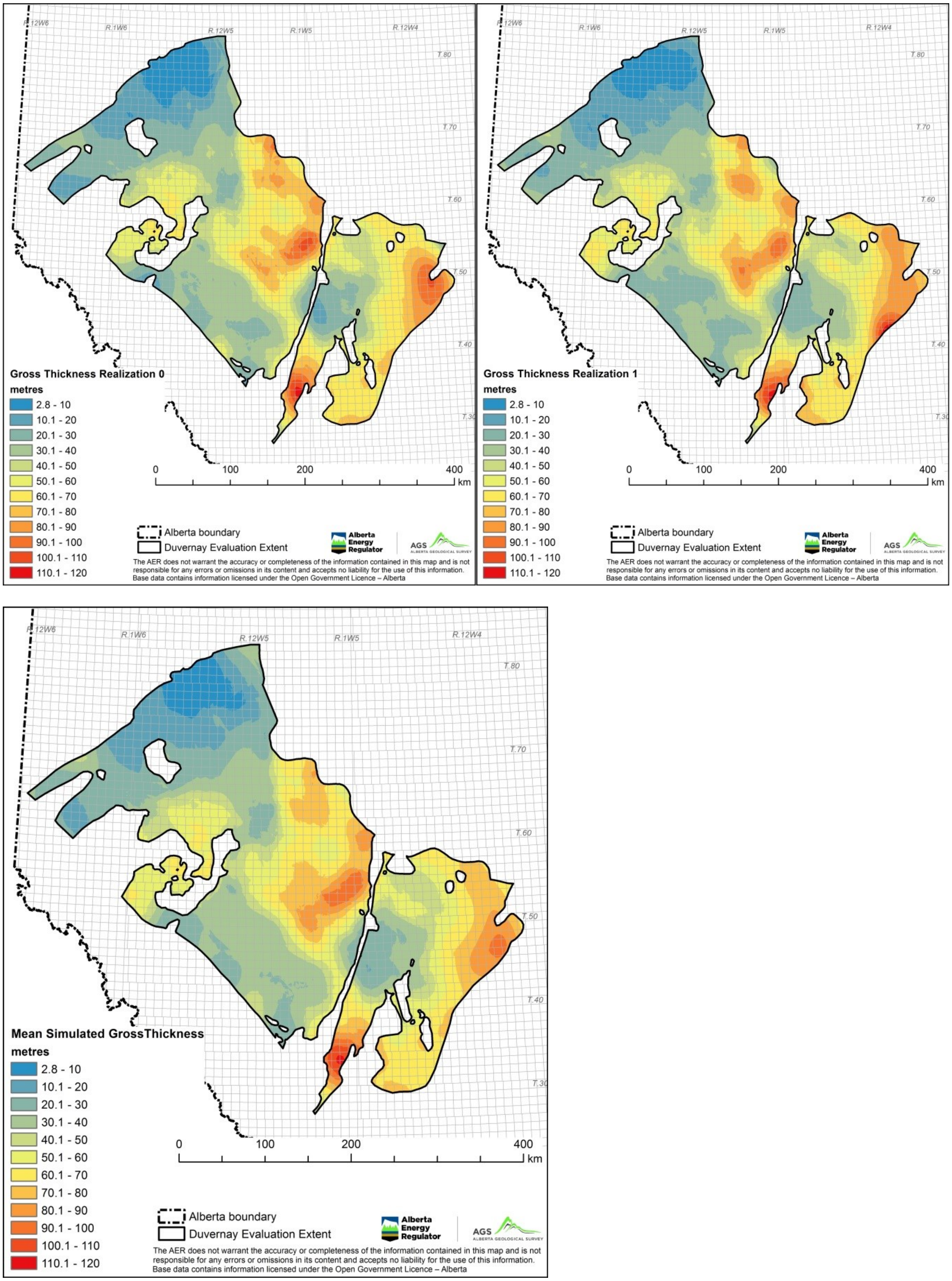

Figure 15. Simulated gross thickness of the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

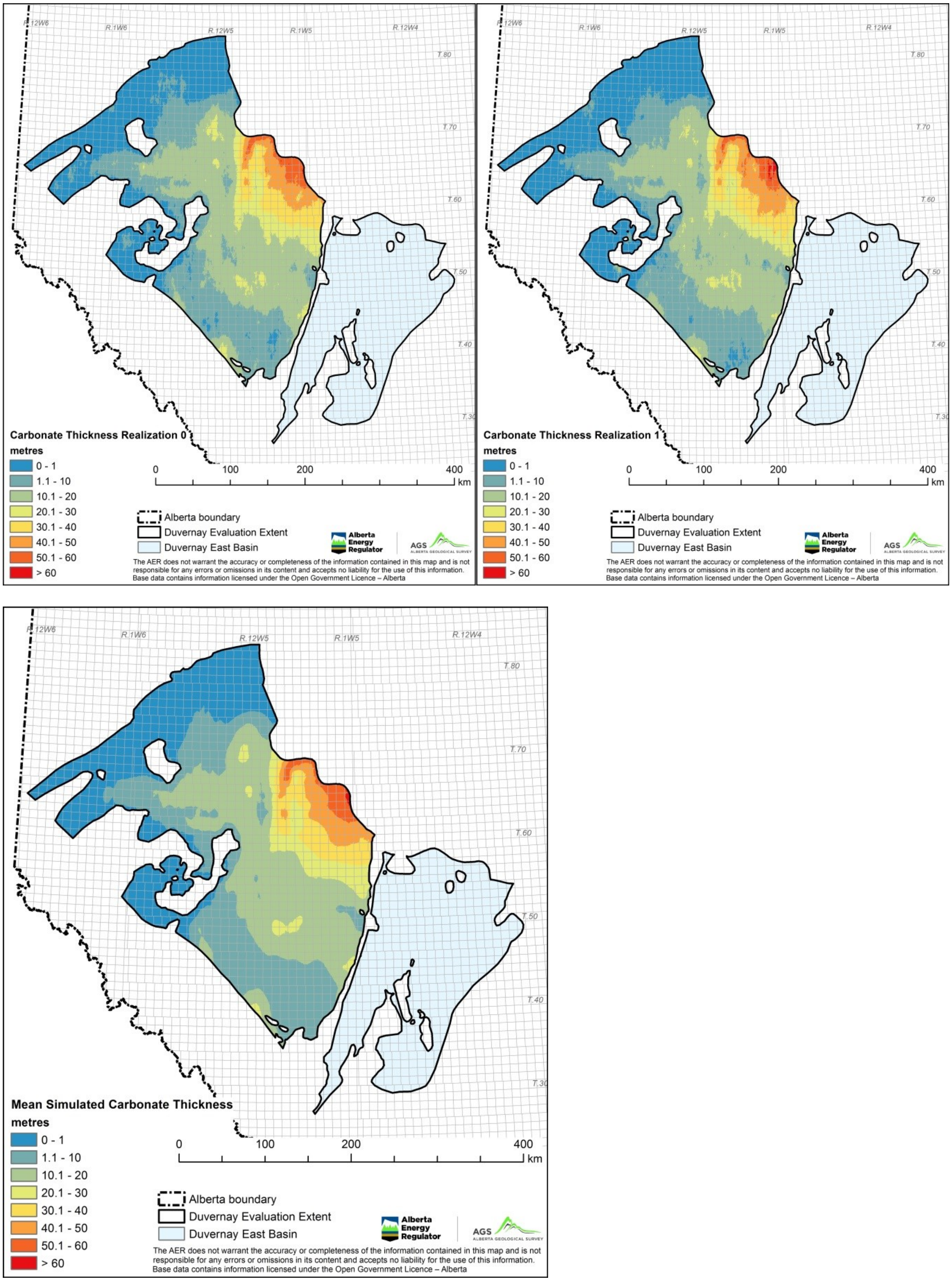

Figure 16. Simulated thickness of the middle carbonate unit. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

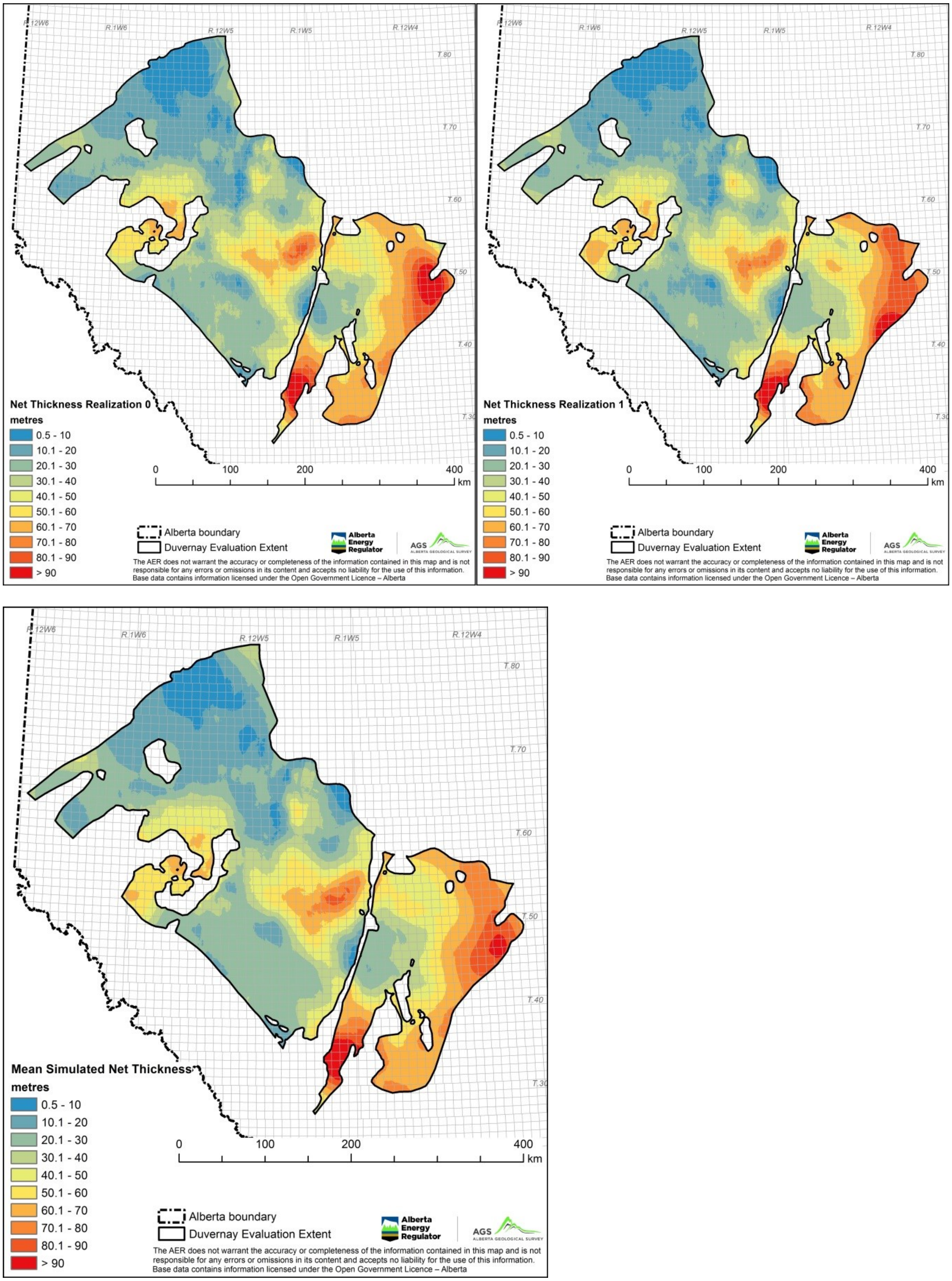

Figure 17. Simulated net thickness of the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

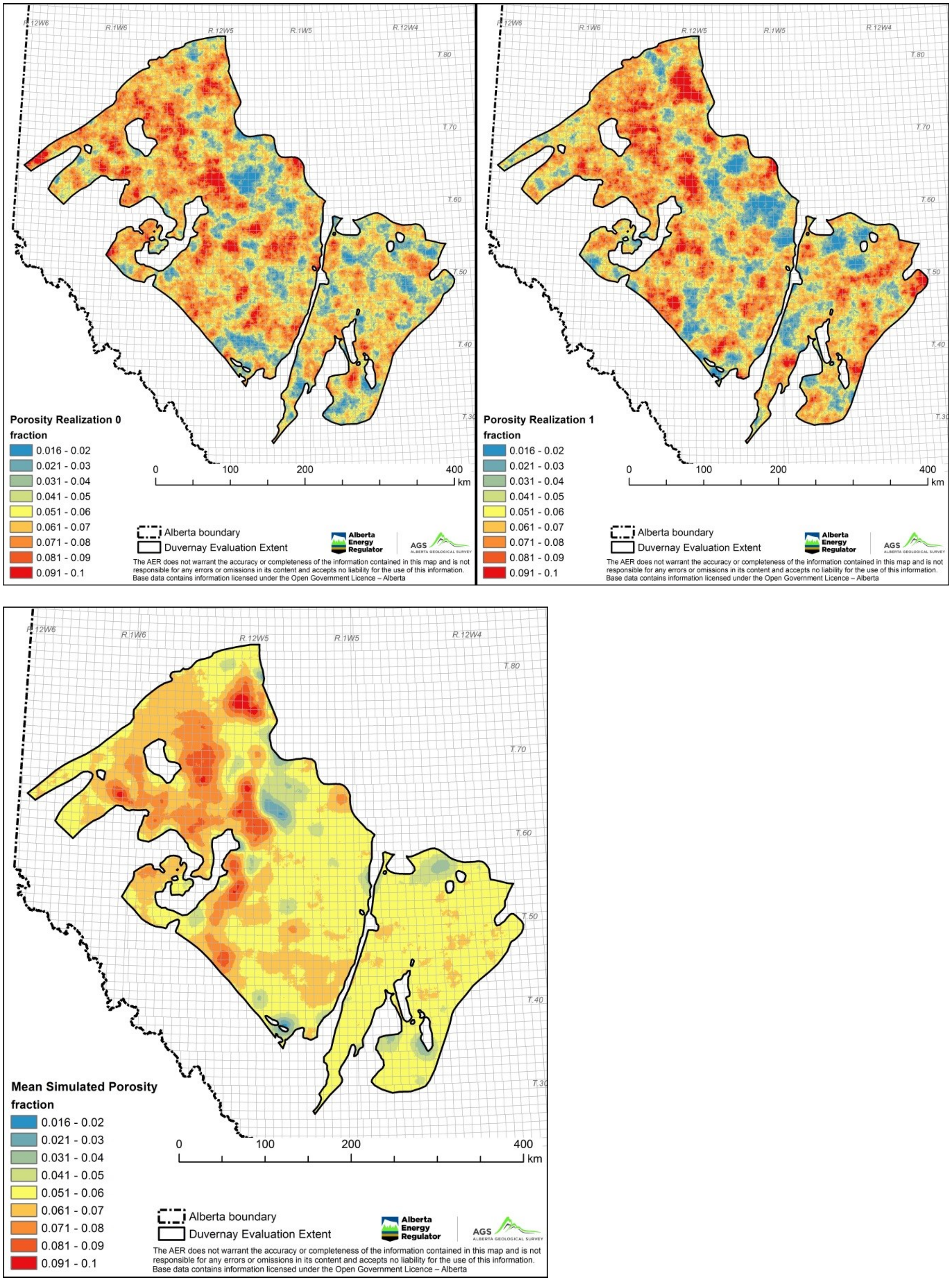

Figure 18. Simulated porosity of the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

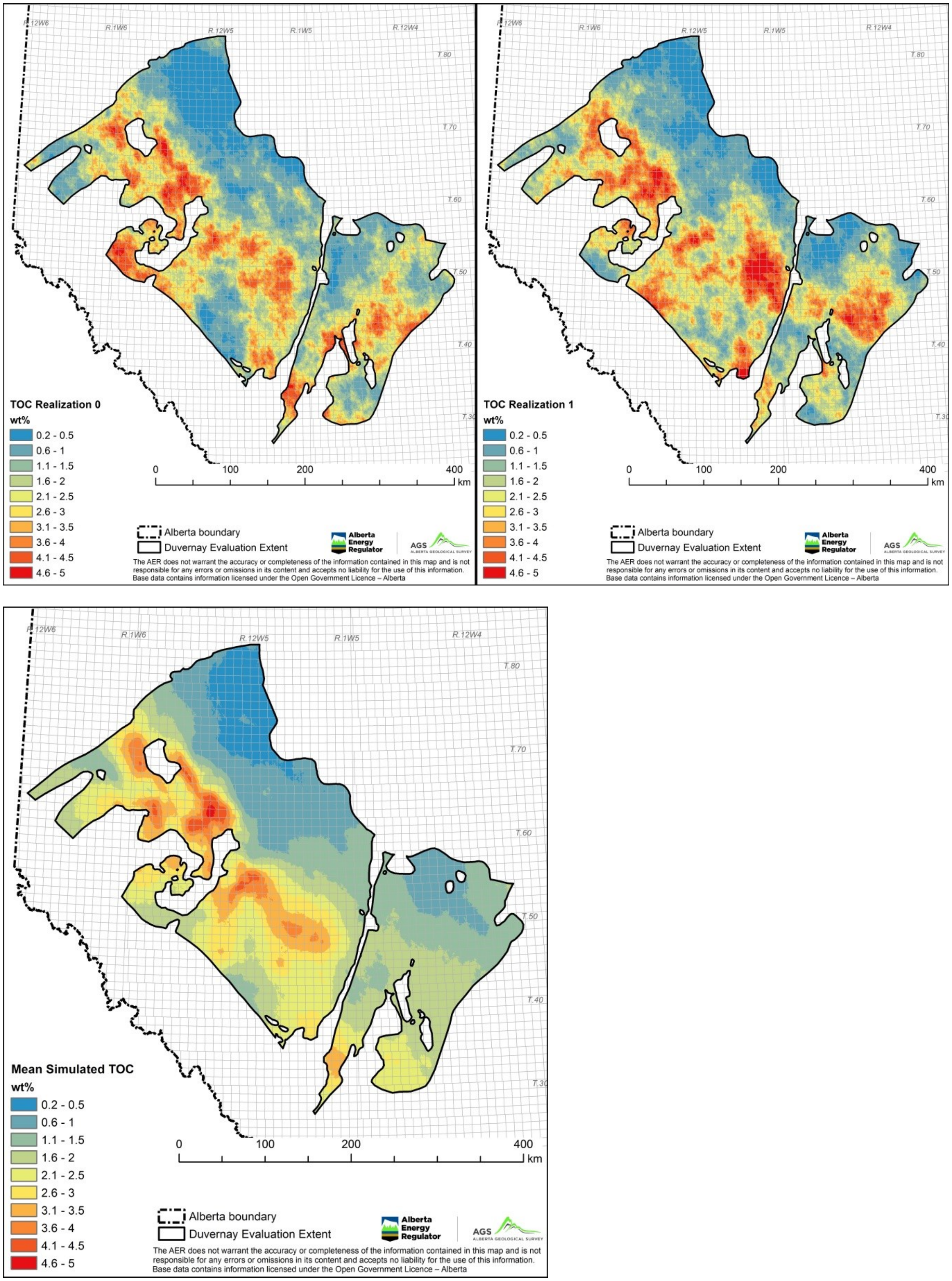

Figure 19. Simulated total organic carbon (TOC) content of the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

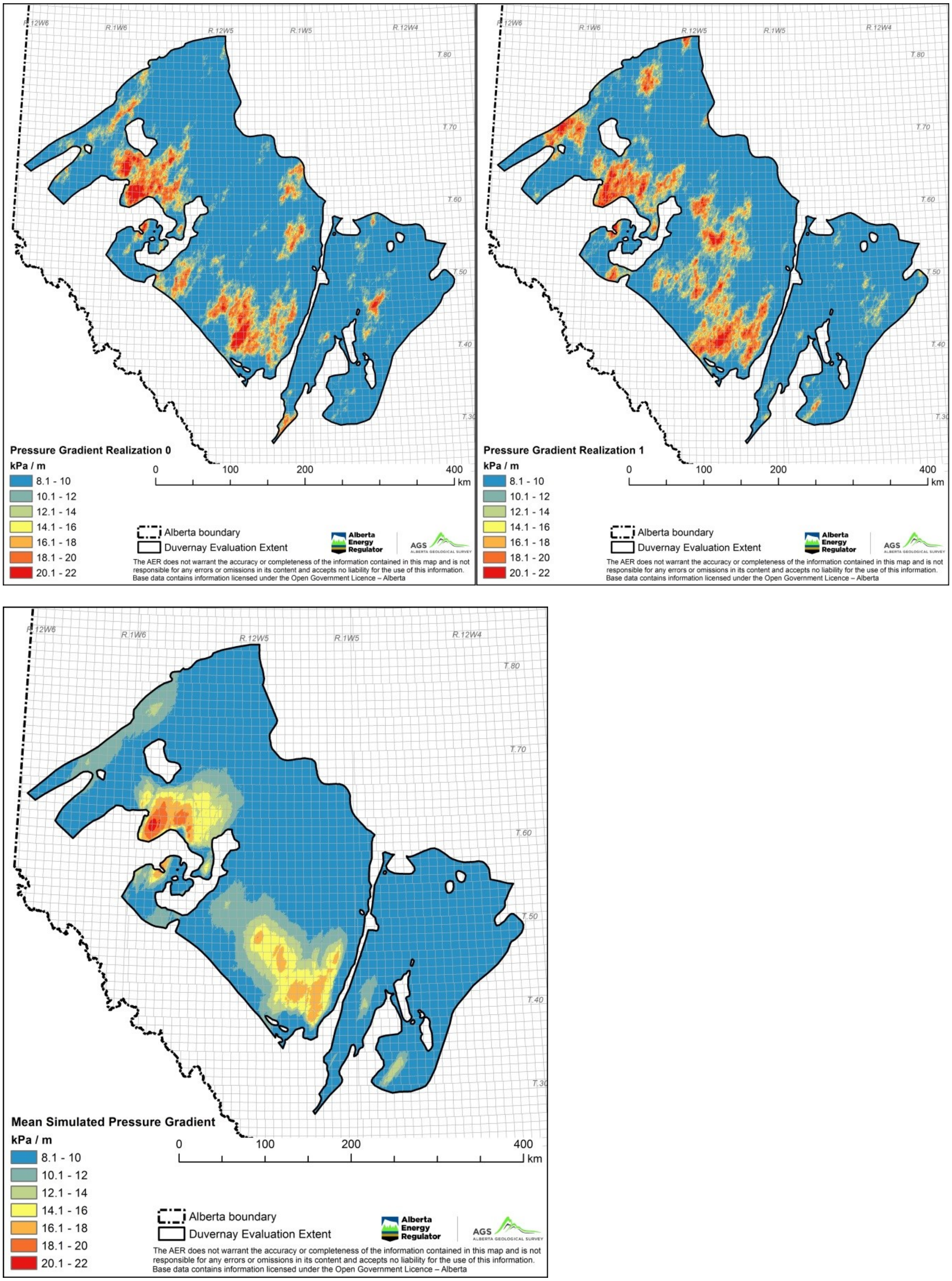

Figure 20. Simulated pressure gradient in the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

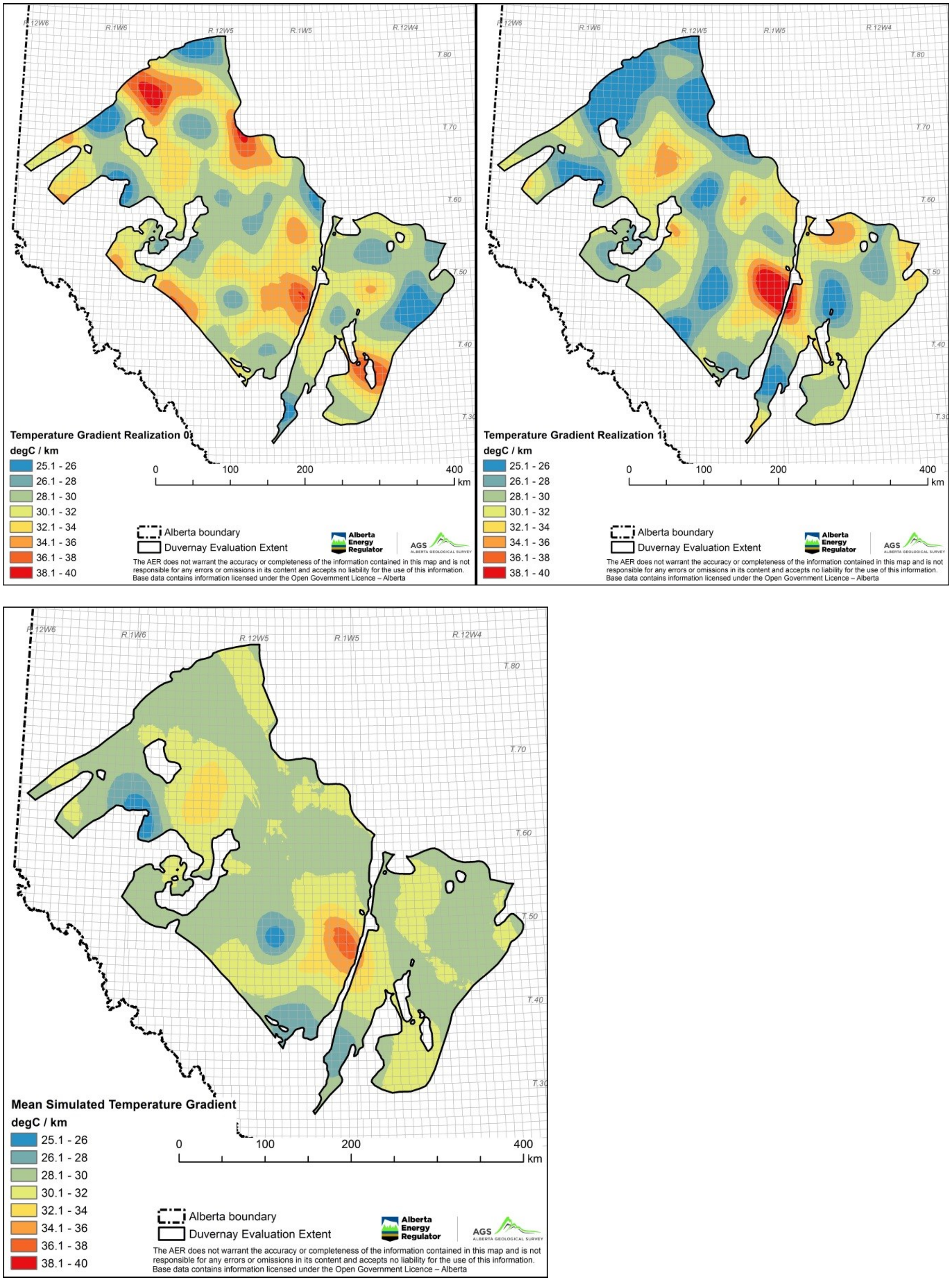

Figure 21. Simulated temperature gradient in the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

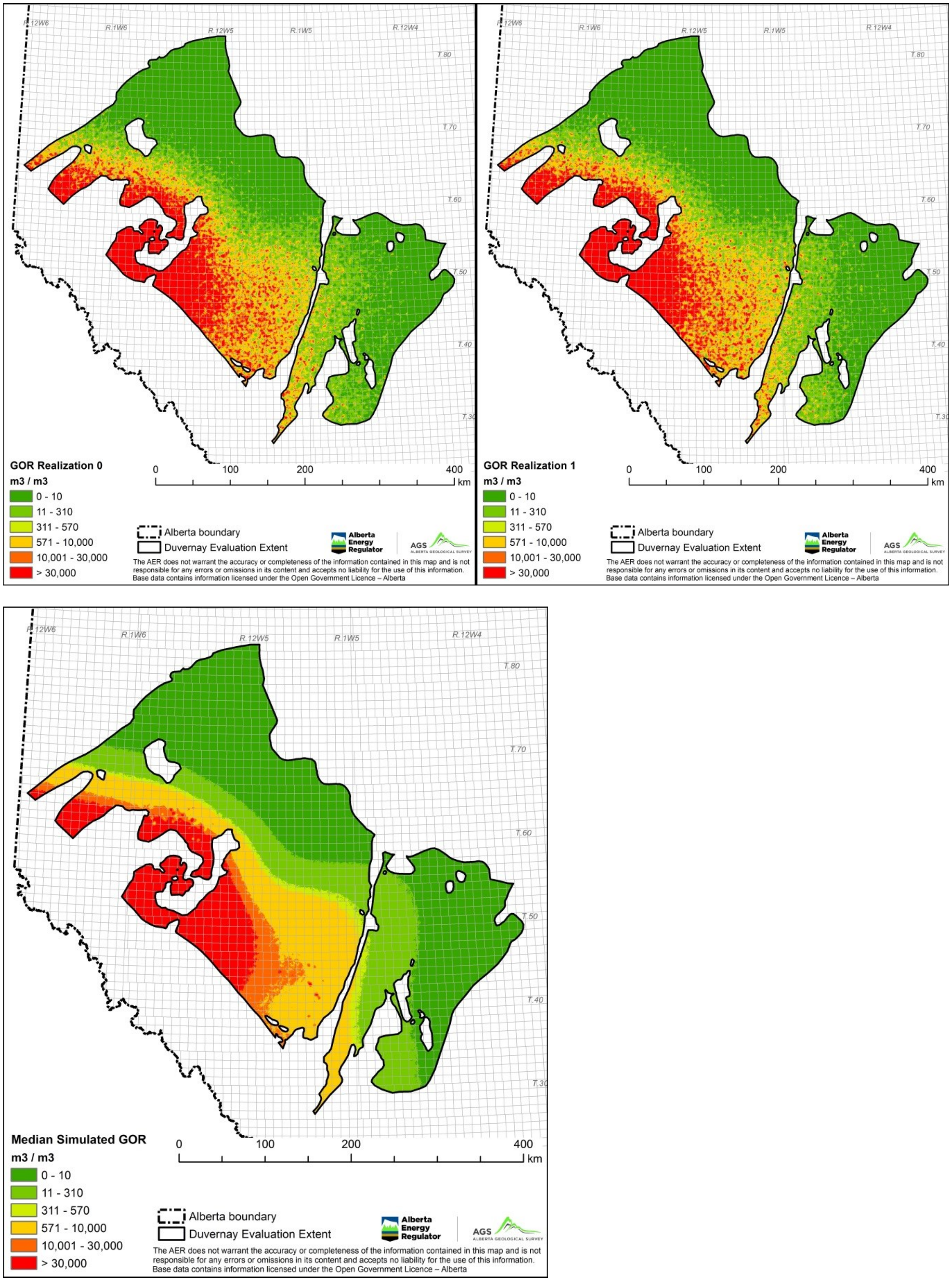

Figure 22. Simulated gas-to-oil ratio in the Duvernay Formation. Top: Two simulated realizations. Bottom: Median of 100 simulated realizations.

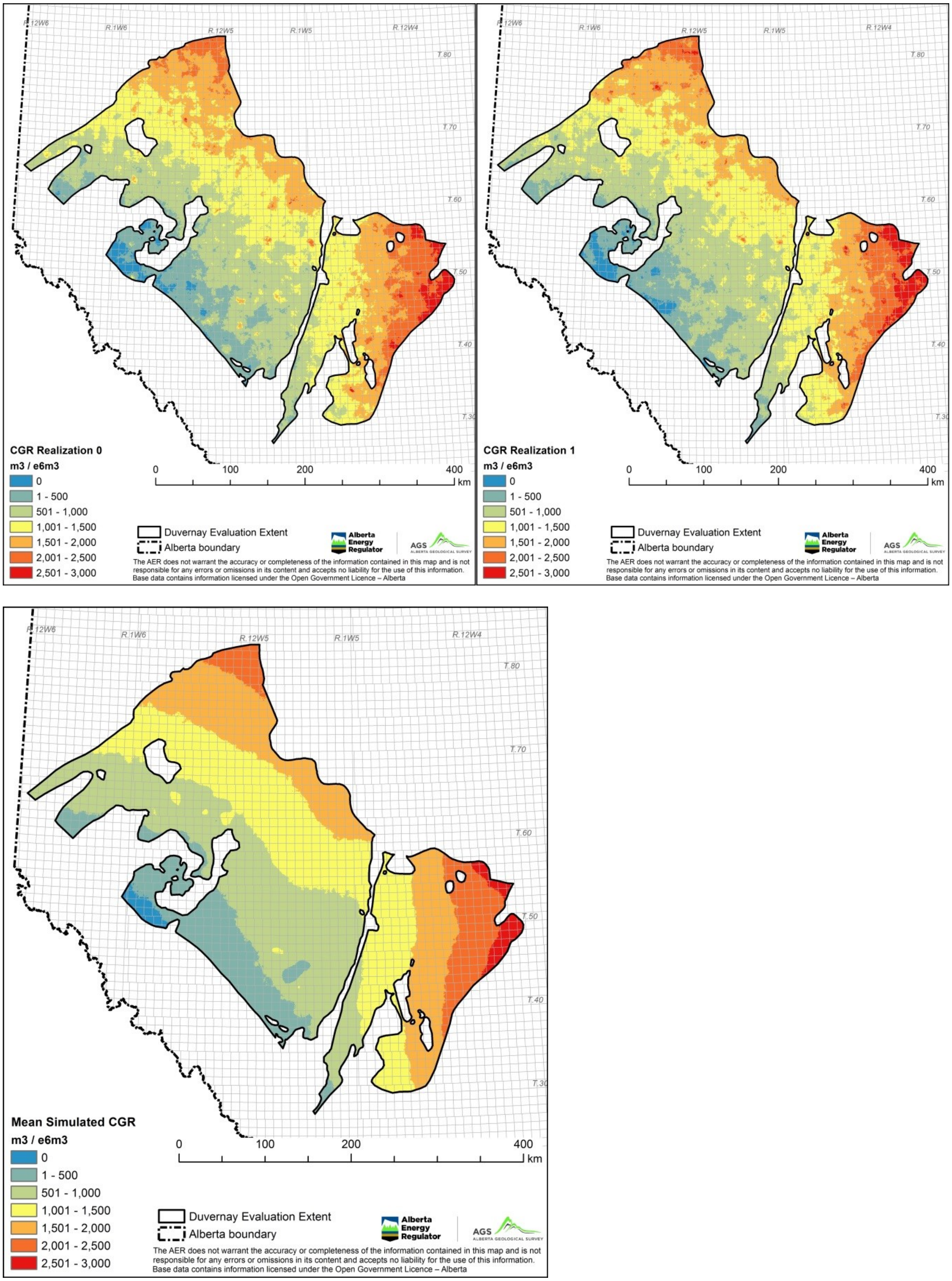

Figure 23. Simulated condensate- to-gas ratio in the Duvernay Formation. Top: Two simulated realizations. Bottom: Mean of 100 simulated realizations.

4 Resource Calculations

Once the variables of interest were simulated, the resource calculations were carried out. Other variables were calculated from the simulated variables, determined through regression of a simulated variable, or simulated from a univariate distribution due to a lack of information. Table 1 shows a summary of the method used to determine each variable.

Table 1. Variables used in resource calculations.

Variable	Abbreviation	Method	Input Variables
Duvernay Thickness	THICK	Simulation	
Carbonate Thickness	CARB	Simulation	
Net Thickness	NET	Calculated	ISO, CARB
Total Organic Carbon	TOC	Simulation	
Langmuir Volume	VL	Regression	TOC
Langmuir Pressure	PL	Regression	TOC
Depth to Top	TOP	Simulation	
Pressure Gradient	PGRAD	Simulation	
Pressure	PRES	Calculation	TOP, PGRAD
Gas Compressibility	ZFAC	Regression	PRES
Temperature Gradient	TGRAD	Simulation	
Temperature	TEMP	Calculation	TOP, TGRAD
Gas:Oil Ratio	GOR	Simulation	
Oil Formation Volume Factor	BOI	Regression	GOR
Gas Fraction	GASFRAC	Calculation	GOR, TEMP, PRES, ZFAC, BOI
Oil Fraction	OILFRAC	Calculation	GASFRAC
Condensate:Gas Ratio	CGR	Simulation	
Porosity	PHI	Simulation	
Water Saturation	SW	Univariate Distribution	

The variables that were calculated directly from others are summarized in the following equations:

$$NET = THICK - CARB$$

$$PRES = 101 + PGRAD \times TOP$$

$$TEMP = 277 + TGRAD \times TOP$$

The fraction of hydrocarbons in the reservoir that are gas and oil are calculated by using the equations:

$$GASFRAC = \frac{\left(GOR \times \frac{101}{PRES} \times \frac{TEMP}{288} \times \frac{ZFAC}{BOI}\right)}{\left(GOR \times \frac{101}{PRES} \times \frac{TEMP}{288} \times \frac{ZFAC}{BOI}\right) + 1}$$

$$OILFRAC = 1 - GASFRAC$$

With all of the necessary values determined, the resources in place could be calculated.

$$GIP_{ads} = NET \times \frac{VL \times PRES}{PL + PRES}$$

$$GIP_{free} = NET \times PHI \times (1 - SW) \times GASFRAC \times \frac{PRES}{101} \times \frac{288}{TEMP} \times \frac{1}{ZFAC}$$

$$GIP_{tot} = GIP_{ads} + GIP_{free}$$

$$NGLIP = GIP_{tot} \times CGR$$

$$OIP = NET \times PHI \times (1 - SW) \times OILFRAC \times \frac{1}{BOI}$$

The resource calculations were done on a township-by-township basis. One hundred realizations were simulated for all of the spatial variables; the calculated and regressed secondary variables were determined based on the primary simulated values.

Figure 24, Figure 25, and Figure 26 show, respectively, the simulated original gas in place (OGIP) in billions of cubic feet (Bcf) per section; the original natural gas liquids in place (NGLIP) in millions of barrels (MMbbls) per section; and the original oil in place (OOIP) in millions of barrels per section. The ranges of uncertainty are shown, with the P10, P50, and P90 estimates for each township and commodity.

The Kaybob area has the greatest resource base for OGIP and NGLIP. The Willesden Green area also has a significant amount of gas and natural gas liquids. The southern tip of the East Shale Basin appears to have the possibility of significant raw resources due to the thickness of the Duvernay Formation in that area. The greatest oil resources are to the northeast of the lighter hydrocarbons, up-dip where the Duvernay is less mature. The simulated results show large quantities of oil to the northeast of Willesden Green and in the south portion of the East Shale Basin.

Figure 27, Figure 28, and Figure 29 show, respectively, the OGIP, NGLIP, and OOIP for the Duvernay Formation in terms of resources per reservoir volume. This corrects for the areas where large volumes of hydrocarbons are driven by the net thickness of the Duvernay, but otherwise have relatively poor reservoir quality. The Kaybob to Willesden Green fairway contains the best reservoir for gas and NGLs, while the far south portion of the East Shale Basin and the thick Duvernay to the northeast of Willesden Green are less prospective than the raw totals would suggest. The most oil resources per reservoir volume are located northeast of the Kaybob area.

Table 2 summarizes the original in-place hydrocarbon resources of the Duvernay, broken down by assessment area and basin. Note that the sum totals over multiple areas are not the simple sums of the smaller areas; this is because the probabilistic distributions were aggregated.

This study's total resources increased from earlier work for several reasons. First, the gross thickness increased in areas that did not previously have data coverage. Figure 30 compares the gross thickness from this study and previous work. Second, the net thickness was better estimated by mapping the middle carbonate unit instead of relying on a simple gamma-ray cutoff. Figure 31 compares the carbonate thickness from the current study and previous work. Figure 32 compares the net thickness of the Duvernay in the current study as well as previous work, accounting for both the differences in gross and carbonate thicknesses. Third, much more data is available to support the overpressured nature of the Duvernay and better direct mapping of the pressure gradient (see Figure 10 and Figure 20).

The increase in NGLs from previous work reflects the previous, conservative estimates of CGR. Industry has since targeted the NGL-rich fairway, and what was previously used as an optimistic value for CGR is now similar to the average. In addition, local estimates of the hydrocarbon mix changed because the GOR and CGR were directly mapped rather than relying on thermal maturity and a correlation to depth. Figure 33 shows a comparison of the fluid zones in this study, using GOR, and the previous work, using thermal maturity correlated to depth as a proxy for the hydrocarbon mix.

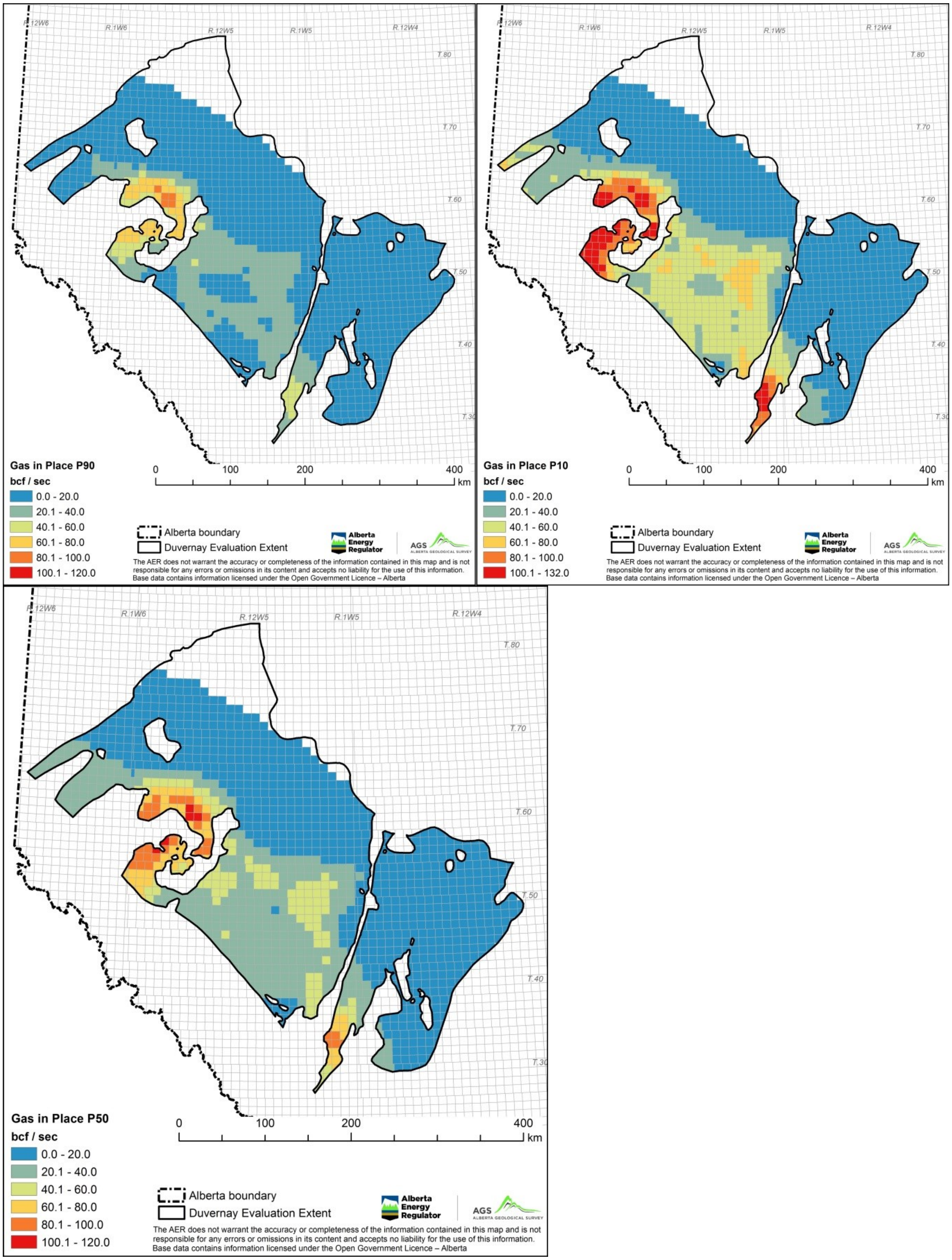

Figure 24. Original gas in place in the Duvernay Formation. Top left: P90, or low, estimates. Top right: P10, or high, estimates. Bottom: P50, or median or best, estimates.

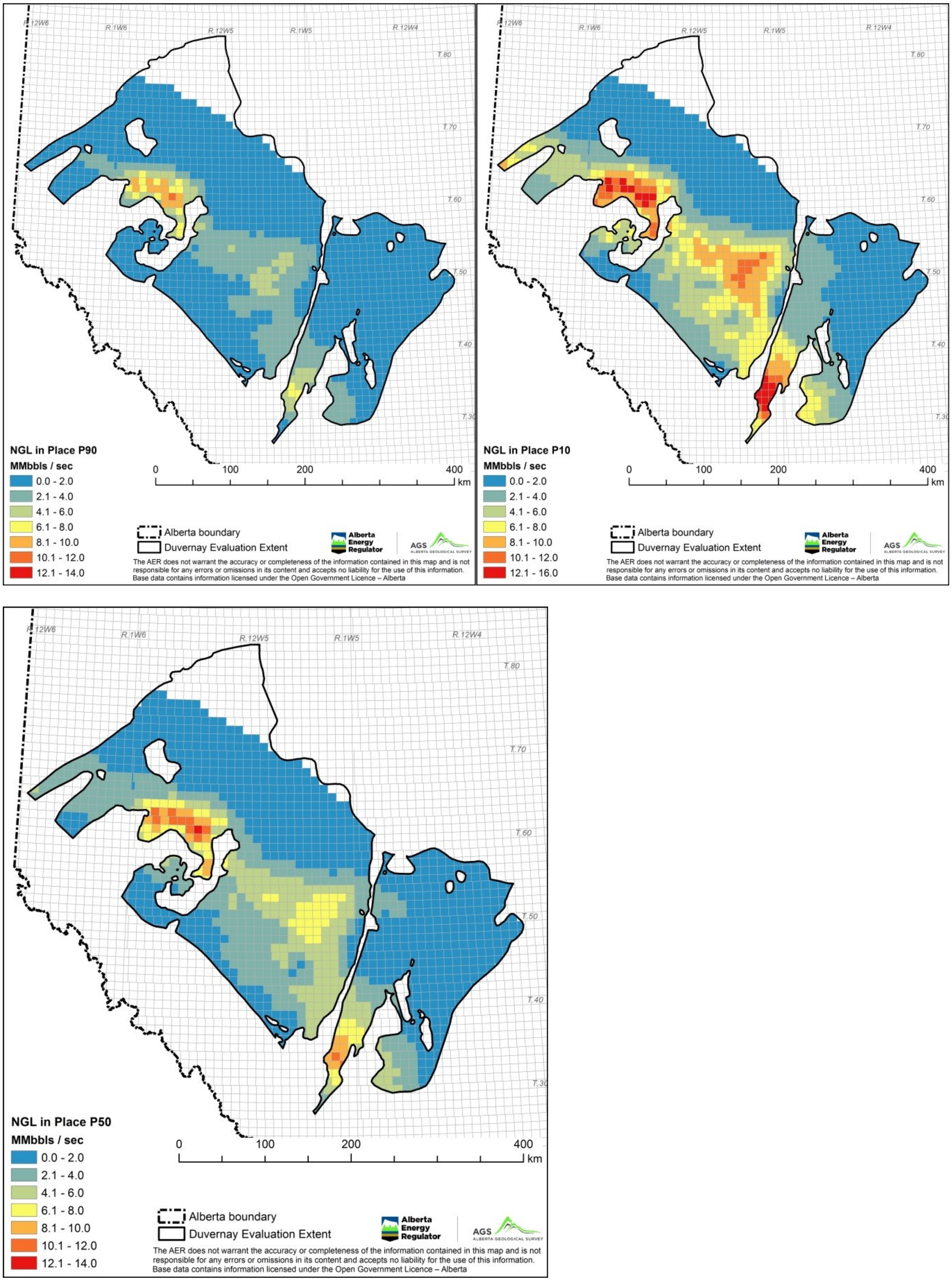

Figure 25. Original natural gas liquids (NGLs) in place in the Duvernay Formation. Top left: P90, or low, estimates. Top right: P10, or high, estimates. Bottom: P50, or median or best, estimates.

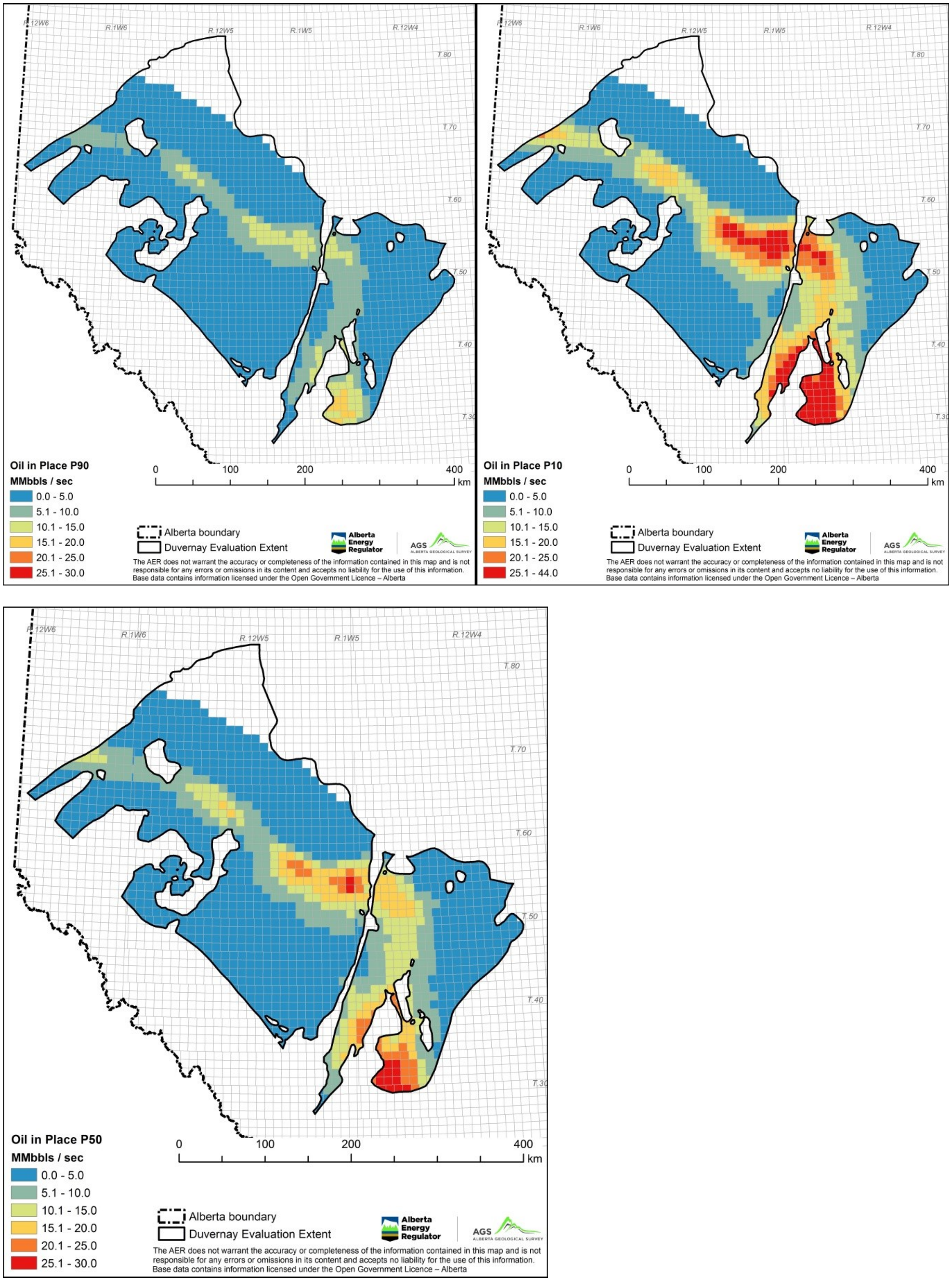

Figure 26. Original oil in place in the Duvernay Formation. Top left: P90, or low, estimates. Top right: P10, or high, estimates. Bottom: P50, or median or best, estimates.

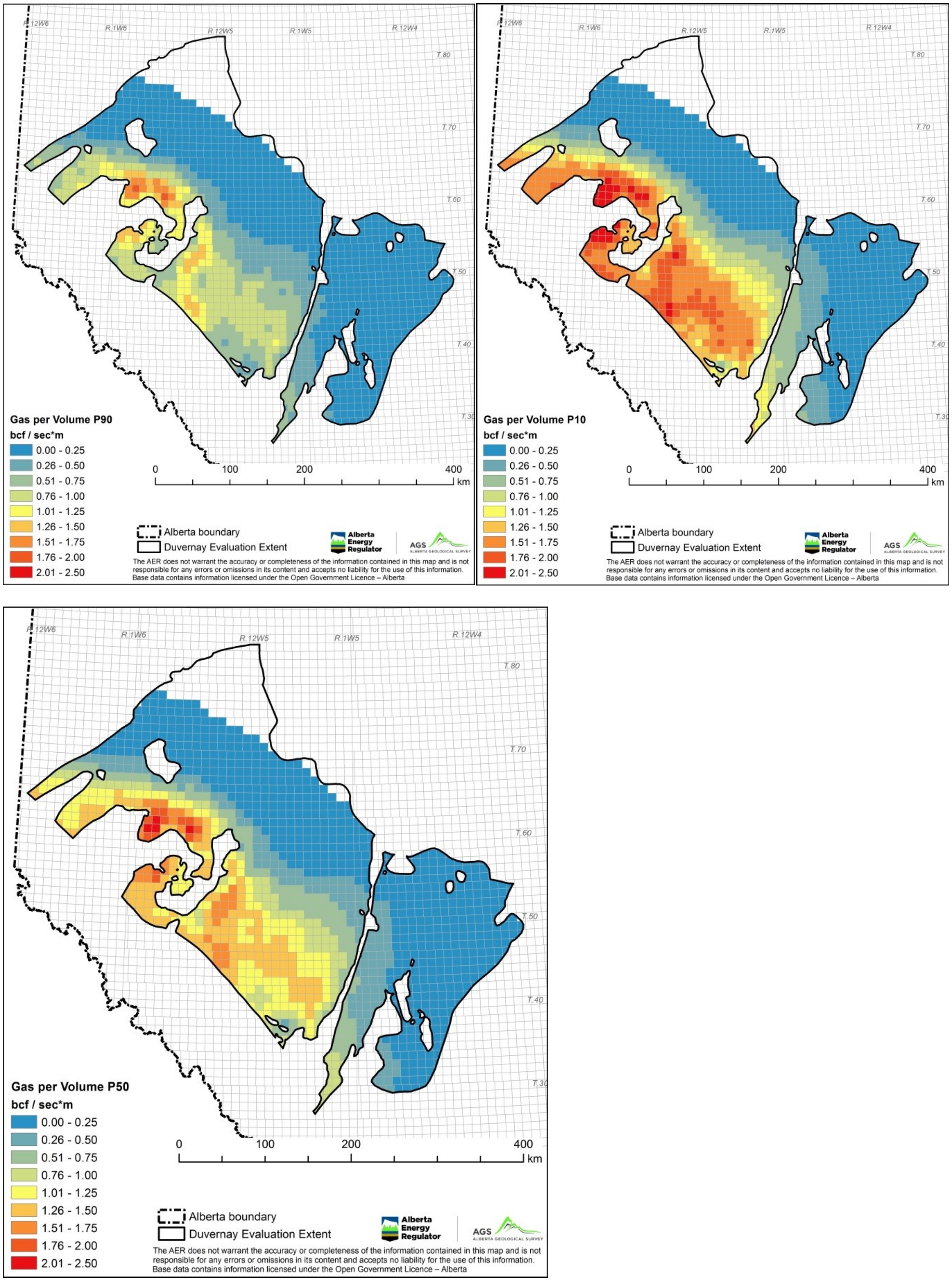

Figure 27. Original gas in place per volume in the Duvernay Formation. Top left: P90, or low, estimates. Top right: P10, or high, estimates. Bottom: P50, or median or best, estimates.

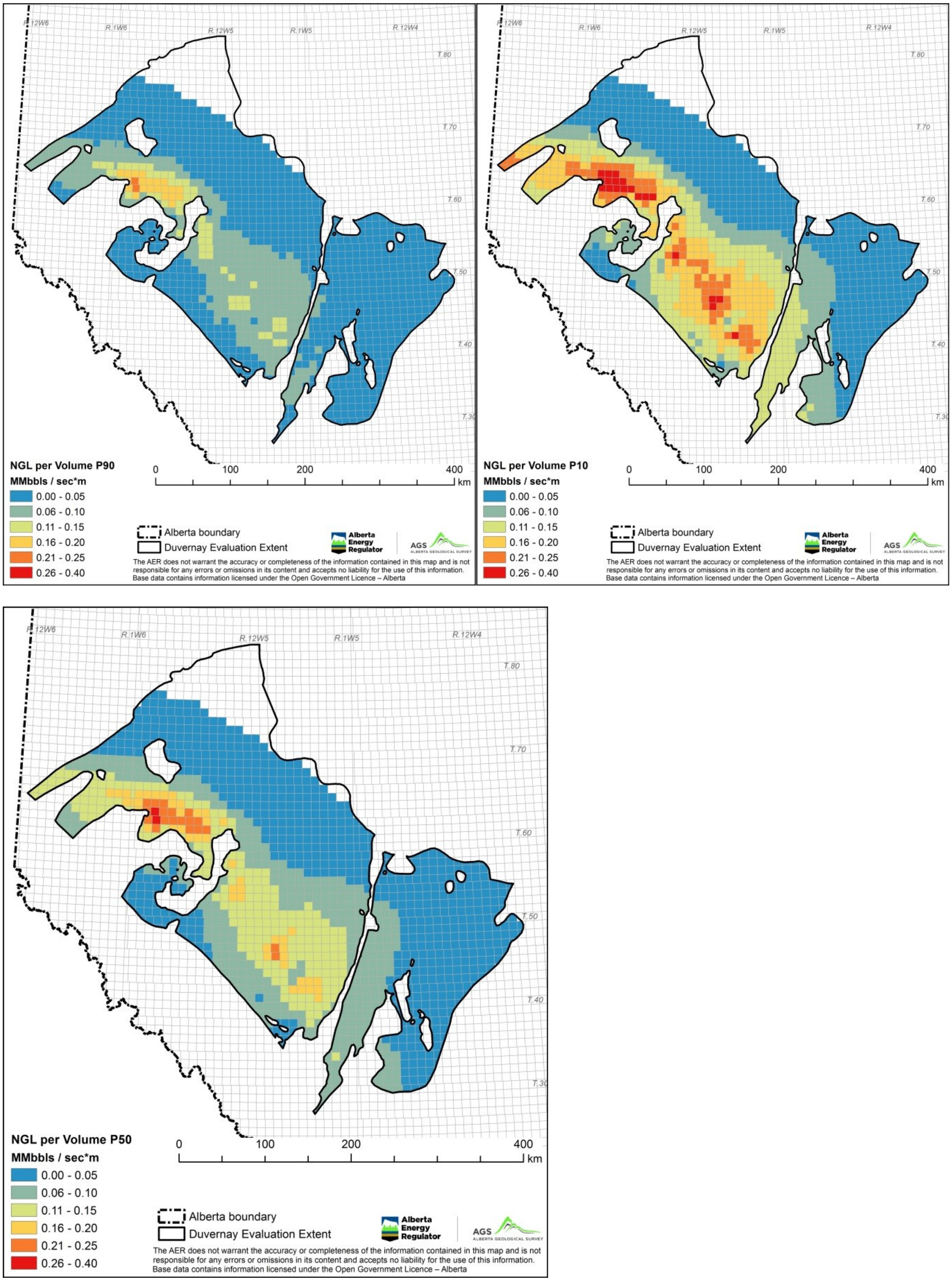

Figure 28. Original NGLs in place per volume in the Duvernay Formation. Top left: P90, or low, estimates. Top right: P10, or high, estimates. Bottom: P50, or median or best, estimates.

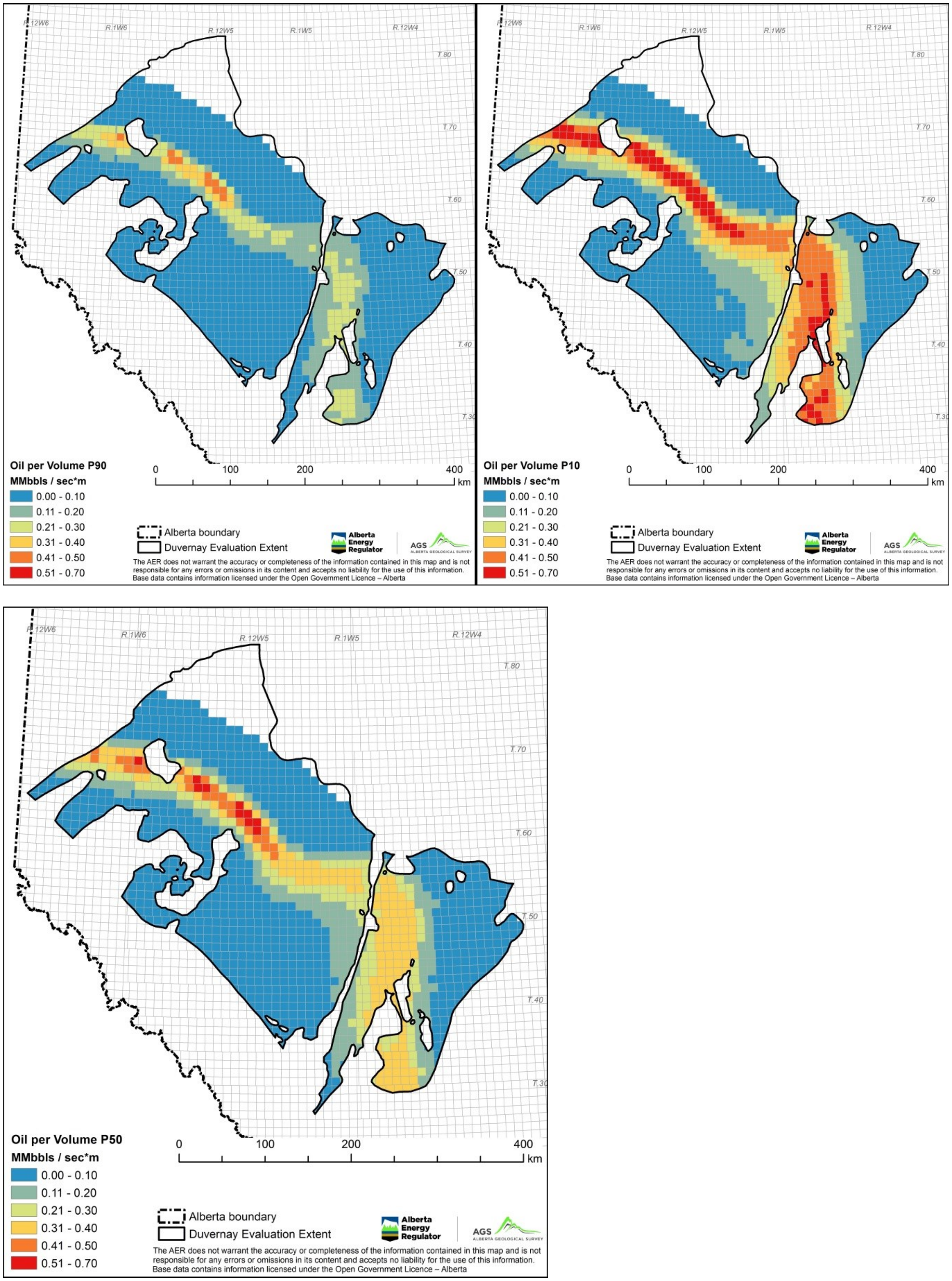

Figure 29. Original oil in place per volume in the Duvernay Formation. Top left: P90, or low, estimates. Top right: P10, or high, estimates. Bottom: P50, or median or best, estimates.

Table 2. Summary of in-place hydrocarbon resources in the Duvernay Formation. Upper: SI units. Lower: imperial units.

Area	Gas (10^{12} m^3)			NGLs (10^9 m^3)			Oil (10^9 m^3)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10
Kaybob AA	4.6	4.9	5.1	2.9	3.1	3.3	2.4	2.7	2.9
Edson-Willesden Green AA	7.2	7.7	8.2	4.5	4.8	5.2	2.4	2.6	3.0
West Shale Basin AA Total	12.0	12.6	13.3	7.5	7.9	8.4	4.9	5.3	5.7
West Shale Basin Total	18.7	19.8	20.8	11.2	11.7	12.3	15.2	16.3	17.7
Innisfail AA	1.8	2.0	2.1	2.0	2.2	2.4	9.4	10.5	11.4
East Shale Basin Total	3.1	3.3	3.6	3.2	3.4	3.7	15.6	16.9	18.0
All Assessment Areas Total	13.9	14.6	15.2	9.6	10.2	10.6	14.7	15.7	16.9
DUVERNAY TOTAL	**22.1**	**23.1**	**24.2**	**14.6**	**15.2**	**15.8**	**31.5**	**33.1**	**34.9**

Area	Gas (Tcf)			NGLs (Bbbls)			Oil (Bbbls)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10
Kaybob AA	163	174	181	18.4	19.4	20.7	15.3	16.8	18.0
Edson-Willesden Green AA	256	273	291	28.2	30.3	33.0	15.1	16.6	18.6
West Shale Basin AA Total	425	449	471	47.1	50.0	52.9	31.1	33.6	35.8
West Shale Basin Total	665	703	737	70.4	73.9	77.7	95.8	102.4	111.1
Innisfail AA	62	70	76	12.3	13.9	15.0	59.1	66.0	71.6
East Shale Basin Total	111	118	129	20.1	21.7	23.4	98.1	106.1	113.4
All Assessment Areas Total	494	518	541	60.4	64.1	67.0	92.3	98.9	106.1
DUVERNAY TOTAL	**784**	**820**	**858**	**91.7**	**95.9**	**99.4**	**198.2**	**208.4**	**219.7**

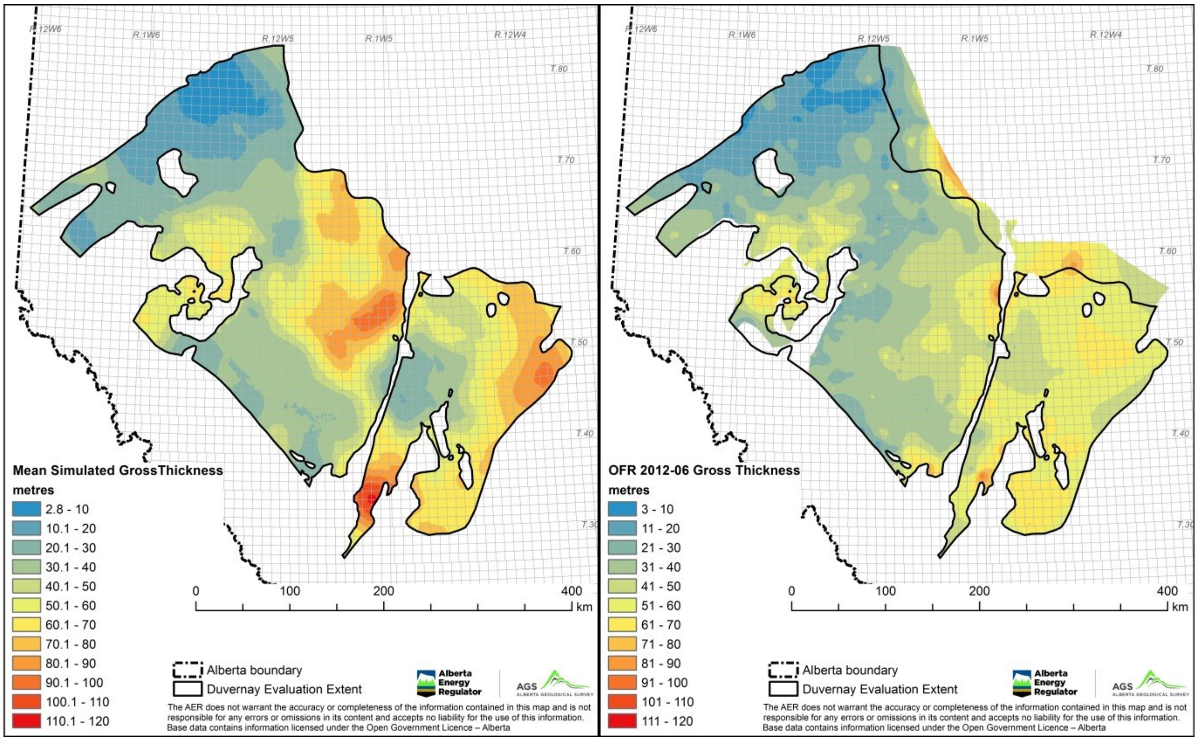

Figure 30. Mean simulated gross thickness of the Duvernay Formation. Left: from the current report using the new data. Right: from previous work (Rokosh et al., 2012).

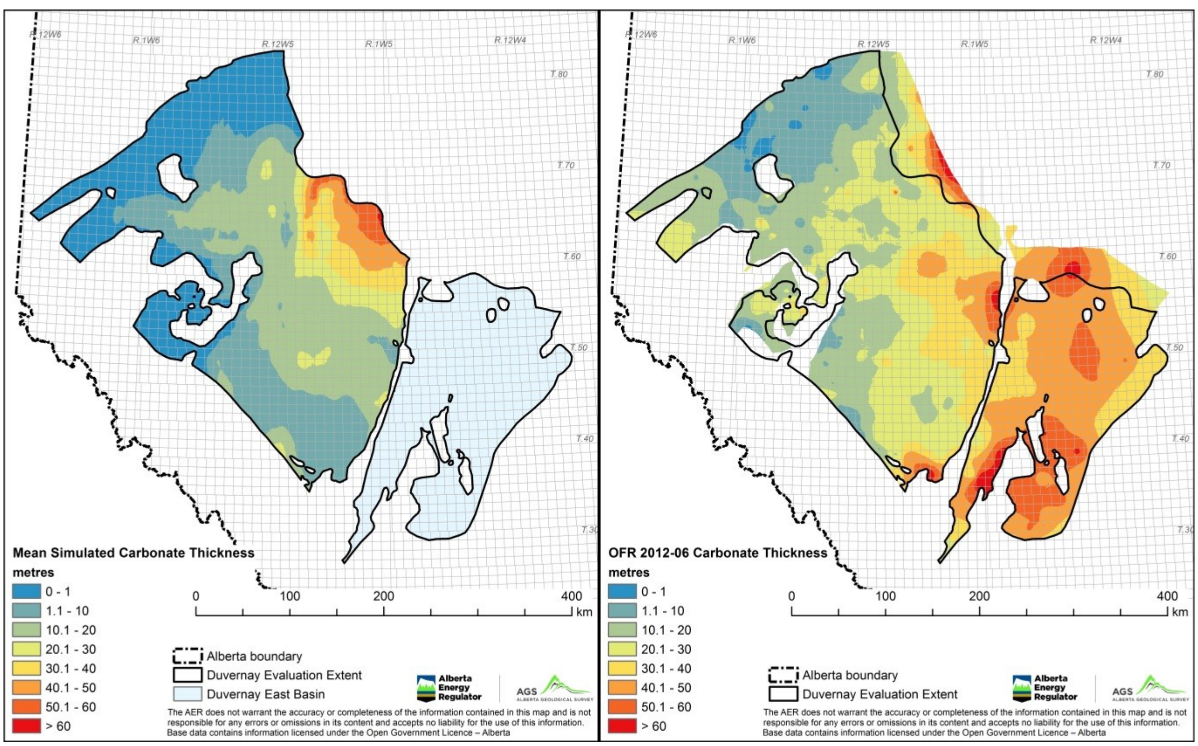

Figure 31. Mean simulated carbonate thickness of the Duvernay Formation. Left: from the current report using the new data. Right: from previous work (Rokosh et al., 2012).

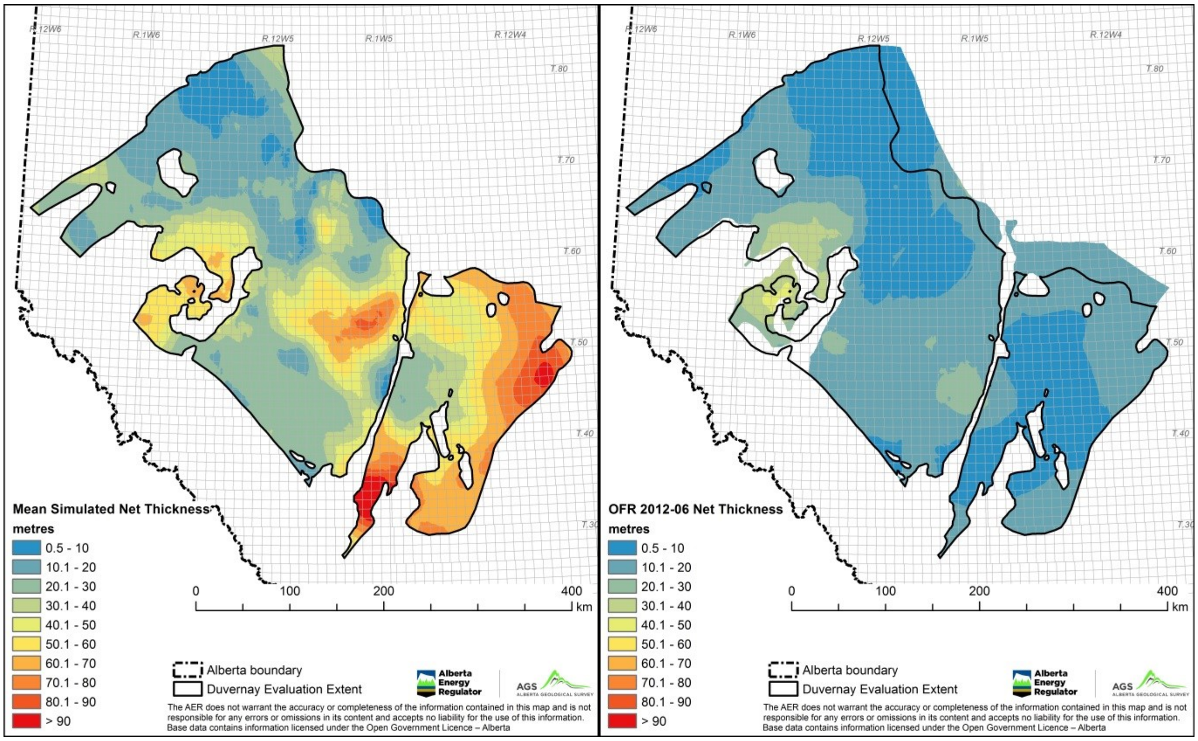

Figure 32. Mean simulated net thickness of the Duvernay Formation. Left: from the current report using the new data and assumptions. Right: from previous work (Rokosh et al., 2012).

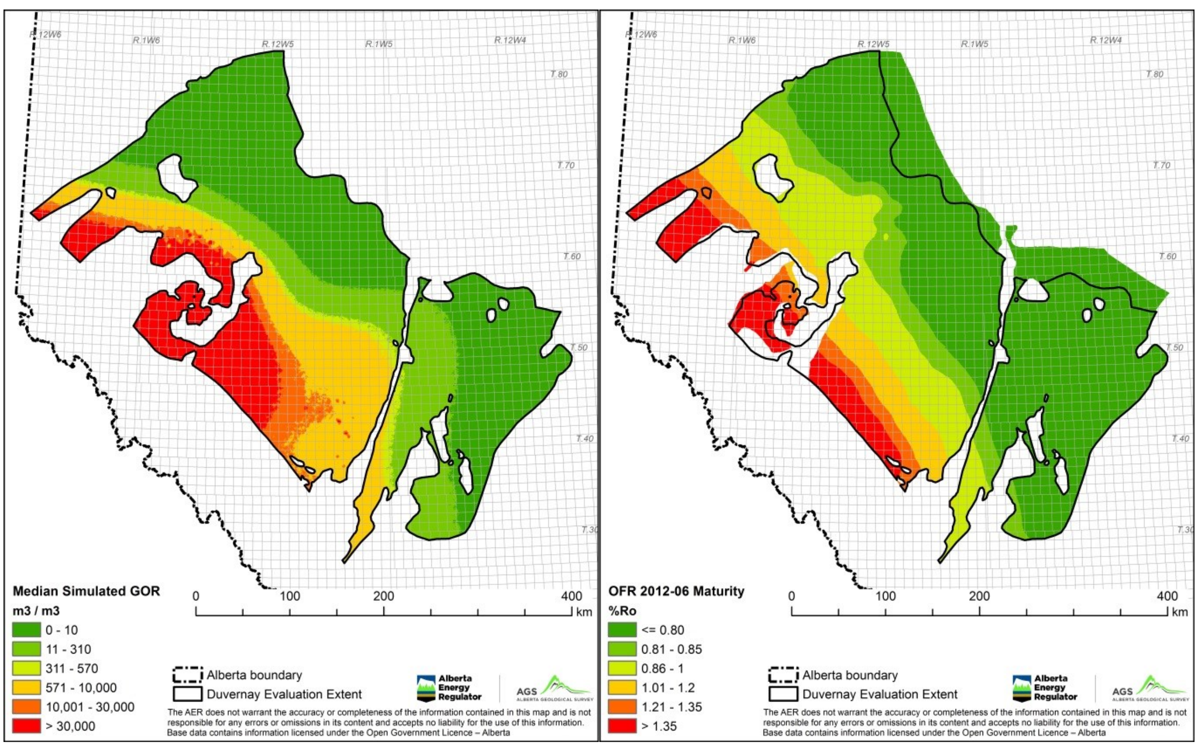

Figure 33. Fluid zones in the Duvernay Formation. Left: from the current report using well GOR. Right: from previous work based on thermal maturity (Rokosh et al., 2012).

5 Conclusions

New data has enabled a more detailed look at the hydrocarbon resource potential of the Duvernay Formation. An increase in the total resource estimates from previous work is a result of the availability of new pick data in previously unmapped areas, the mapping of the middle carbonate and the subsequent change to the calculation of the net pay thickness, and new pressure gradient data allowing the mapping of high pressure gradients directly. The prospective areas around Kaybob and Willesden Green are now more certain to contain large quantities of in-place hydrocarbons. The Innisfail area also shows some promise, although there is less certainty and the large quantities estimated are more related to the overall thickness of the Duvernay rather than reservoir quality. A few fringe areas have been identified as having the potential for hosting significant hydrocarbon resources, although the uncertainty is higher than within the currently identified prospective areas.

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