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BASIN-CENTERED HYDROCARBON PLAYS: HOW SOURCE, RESERVOIR AND FLUID DEPENDENCIES CONTROL THEIR FORMATION

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Abstract

We use pressure, volume and compositional data from the Viking formation in the Western Canada Sedimentary Basin to show that basin-centered accumulations are a result of dependencies between source, trap, reservoir and timing that do not exist in conventional petroleum accumulations. Specifically, we show that hydrocarbon fluids in these traps carry the load on the system rather than water as in a conventional system. Hydrocarbons carrying the fluid load explains pore pressures less than hydrostatic below the water line. Next, we show that the large pressure gradients at depth in these reservoirs are a consequence of lack of water and pore fluids at saturation pressure, temperature, and composition. Saturated fluids leads to thermodynamic coupling of these fluids, expressed with the Clausius Clapeyron Equation. Uplift of the reservoirs decreases the pressure and temperature on the fluids and places them at saturation conditions and leads to this coupling. Finally, we suggest that basin-centered reservoirs are desiccated during hydrocarbon generation. Source rocks proximal to the reservoirs consume water during generation which makes fluids in these reservoirs unconditionally stable and is in strong contrast to conventional petroleum reservoirs which are unconditionally unstable.

Statement of the background

The tight reservoir, or basin-centered resource opportunity was first made clear by Masters (1979) and Masters (1984) both in terms of the size of the hydrocarbon pools and fields, and also in terms of the large regional setting the play occupies in North America. These early works correctly identified several of the main attributes of basin-centered systems known today including: pervasive hydrocarbon saturation, lack of produced water and an updip waterline which separates wet and porous reservoirs from downdip pay in tight reservoirs in the absence of a clear permeability barrier. However, many of these attributes are descriptive only and lack a physical basis of how they control the formation of this class of play. For example, features such as waterlines are shown schematically in cross section (Masters, 1979; Moore et al., 2016) but they are delineated by drilling and are not observed on seismic data (Masters, 1984) or cannot be associated with a geologic attribute. Pervasive saturation is identified on logs with significant but variable water saturation, however, there is no physical understanding of why so little water is produced. Figure 1 illustrates some of the elements of a basin centered system in the Western Canadian Sedimentary Basin (WCSB) and shows the focus of our paper which is the Viking formation, a basin-centered system and the Leduc Reef Trend, a conventional hydrocarbon system.

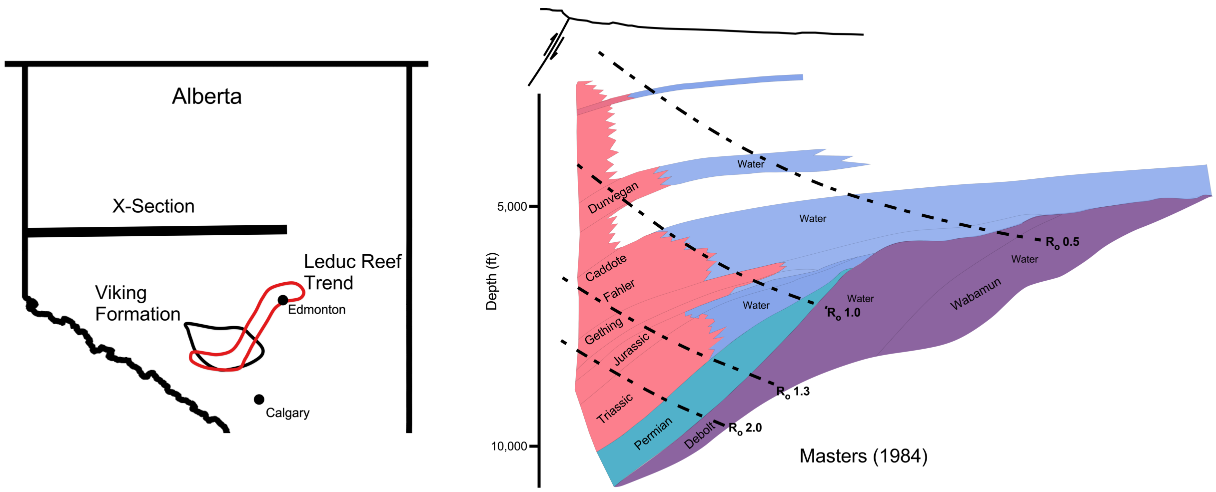

Figure 1: Location map of the data sets used in the Viking formation and the Leduc Reef Trend in the Western Canada Sedimentary Basin. Both polygons encompass approximately 15,000 km^2 but the formations extend well beyond the areas. Within the polygons the Viking formation ranges from 500-1500 m shallower than carbonate Leduc reefs. The right hand plate is modified from Masters (1984) and schematically shows zones of pervasive hydrocarbon saturation and the mid-maturity R_o values that are associated with the waterline.

A summary of the main attributes of basin-centered systems along with representative references include:

- An updip waterline separating downdip pervasive saturated reservoir and updip wet reservoir with no apparent seal or permeability contrast (Masters, 1979; Law, 2002; Sonnenberg, 2011).
- Significant uplift which lowered the pressure and temperature on the reservoir. (Law, 2002; Sonnenberg, 2011; Dembicki, 2016).
- Low permeability reservoir (< 3 mD) (Masters, 1979; Law, 2002).
- Limited volume of produced formation water (Masters, 1979; Law, 2002; Sonnenberg, 2011).
- Lack of gas-oil-water contacts in a single reservoir of the type regularly observed in conventional hydrocarbon systems (Masters, 1979; Law, 2002; Sonnenberg, 2011).
- Abnormal hydrocarbon pressures which may be greater or less than hydrostatic (Masters, 1979; Law, 2002; Sonnenberg, 2011).
- Kerogen of variable TOC proximal to the reservoir and measured vitrinite reflectance greater than 0.8% (Law, 1984; Curtis, 2002; Sonnenberg and Meckel, 2017).

Aims and objectives

In this paper we use PVT data published by the Alberta Energy Regulator to place attributes of basin-centered systems into a physical context. We then use this information to show the dependencies that exist which lead to the formation of basin-centered systems. Appendix A provides a brief introduction to the use of hydrocarbon phase diagrams to understand pressure, temperature and composition controls on oil and gas accumulations in exploration settings.

Materials and methods

Two fundamental controls on the formation of conventional hydrocarbon accumulations are buoyancy and trap style (Sales, 1997). Buoyancy is a control because of the importance of migration in either a two or three phase, water wet system from source to trap. Trap style is a control because it leads to the differential entrapment of oil and gas. Gussow's filled-to-spill trap style (Gussow, 1953), a Sales Class I trap, has properties in which seal capacity exceeds closure and oil is preferentially spilled updip by gas.

Class III traps have closure that exceeds seal capacity and gas preferentially migrates updip leaving oil behind. Class II traps have properties of both Class I and III traps: they leak hydrocarbons from the seal but are also filled to spill. Class II traps are difficult to identify.

Identification of the trap style in an exploration play is an important step because it is the basis for fluid phase and composition predictions when testing opportunities away from an established play. Figure 2 shows the reservoir pressure, pressure ratio (reservoir pressure to saturation pressure) and composition with depth for Gussow Traps (Class I traps) in a portion of the Leduc Reef Trend (Gussow, 1953). In Figure 2, pressure is plotted with depth instead of elevation as in standard PE plots for basin-centered systems to make clear that pressure in the trend is hydrostatic and downdip hydrocarbons are in communication with regional water systems. The pressure ratio in Figure 2 indicates these fluids are at saturation pressure and pressure is at present day hydrostatic conditions even though hydrocarbon generation ceased at least 20 Ma during the Laramide Orogeny. Finally, Figure 2 shows that hydrocarbon composition trends with depth and that gas has displaced oil updip. Figure 3 shows reservoir pressure, pressure ratio and composition data from Class III traps in the Niger Delta (Matava et al., 2003). These data are from a region that is approximately 10,000 km^2 in area. Pressures in these traps range from hydrostatic to overpressured at depth and fluid composition is generally in equilibrium with present day pressures. Additionally, source rocks in this region are currently generating hydrocarbons and charging traps with fluids. In both Class I and III traps the fluid composition, an extensive thermodynamic variable, is modified to maintain equilibrium with externally set pressures and temperatures which are thermodynamically intensive variables.

Contrasting with Class I and III conventional plays are the pressure, pressure ratio and composition data observed in the unconventional, basin-centered, Viking formation (Figure 4). These data are from an interval approximately 500-1500 m shallower than the Leduc Reef Trend and encompass an area of approximately 15,000 km^2. Hydrocarbon fluids in the Viking formation are generally at or near equilibrium in terms of saturation pressure, but the reservoir pressure is less than hydrostatic and the gradient is approximately three times the hydrostatic gradient. The reservoir fluid composition also varies as much as the conventional plays but over a shorter depth range. Burial history of the Leduc Reef Trend and the Viking formation since generation ceased during uplift has been similar and there is no indication that one reservoir has been uplifted more than another.

Results and discussion

Reservoir pressures in the Viking formation range from underpressured to slightly overpressured and the observed pressure gradient is approximately three times the hydrostatic pressure gradient and near the lithostatic gradient (Figure 4). The fluids are near saturation pressure and are an oil in place indicating pressure, temperature and composition are in equilibrium with present day conditions. To understand these controls on pressure, we first start at the waterline to explain the less than hydrostatic pressures and then explain the large pressure gradient observed in the reservoir.

The simplest explanation for the occurrence of underpressured reservoirs is to assume that the pressure profile results from a hydrocarbon fluid with a density less than water carrying the fluid load. In this case fluid the pressure at depth is

$$P(z) = P_{Z_d} + \int_{Z_d}^{Z_0} \rho_w g dz + \int_{Z_0}^{z} \rho_h g dz \qquad (1)$$

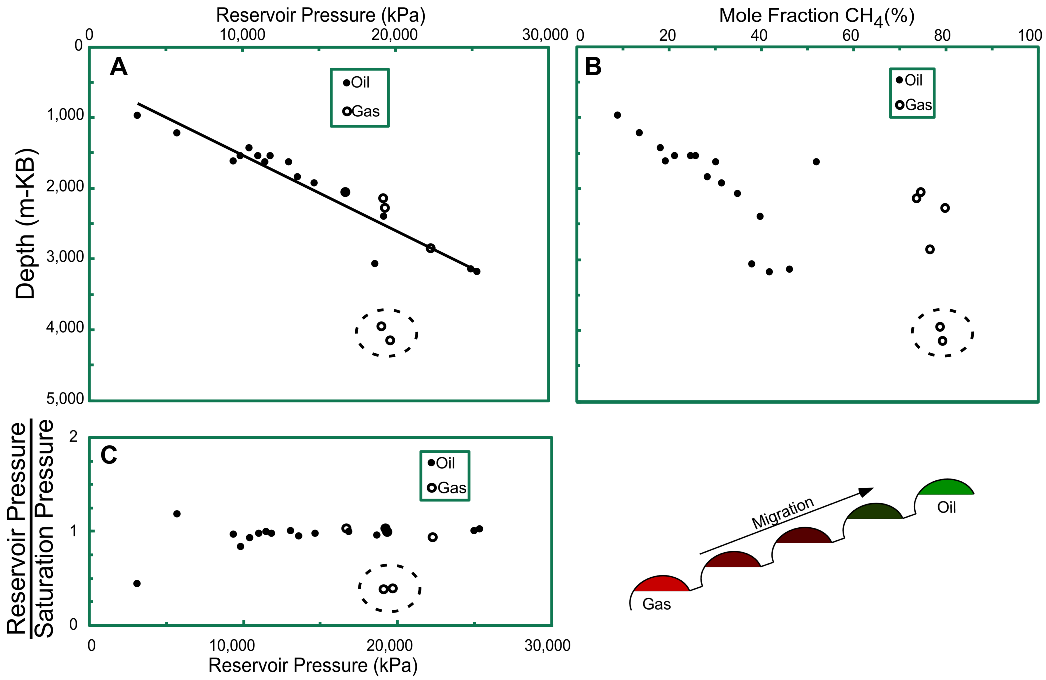

Figure 2: Pressure (A) and composition (B) and pressure ratio (C) for fluids in a 15,000 km^2 part of the Leduc Reef Trend, a series of conventional Class I traps. These data are part Alberta Energy Regulator PVT database (Alberta Energy Regulator, 2017). The solid line in A is the pressure gradient fit to the oil data and suggests fluid density is that of water with an average salinity of 32 PPT (seawater salinity) and is consistent with the view of a conventional filled-to-spill trap style (Gussow,1953). The two data points in A, B and C dash circled are depleted reservoirs at the time of measurement. Appendix A provides a brief introduction of how to interpret oil and gas phase diagrams.

where P is pressure, ρ is the fluid density, g is the gravity term, and Z is depth. Subscripts on the integral limits, d and 0 refer to a shallow depth datum and the waterline depth, respectively. The waterline depth is the top of the hydrocarbon reservoir. Subscripts on the density terms w and h refer to water and the hydrocarbon fluid. A steady vertical pressure profile of water overlying a less dense hydrocarbon, Equation 1, exhibits a hydrostatic pressure profile between the depth datum and the waterline, but in the hydrocarbon reservoir the pressure on the fluids is less than hydrostatic because of the lower hydrocarbon fluid density The difference in pressure profiles between conventional accumulations and basin-centered systems is that hydrocarbons carry the fluid load instead of water. Complicating this simple pressure interpretation is that the depth of the waterline does not follow present day structural dip (McCullagh and Hart, 2010) so a single pressure datum is not present and a range in reservoir pressures are observed below the waterline.

Reservoir data from this part of the Viking formation indicates the hydrocarbon fluids are near saturation suggesting an equilibrium condition exists between liquid and gas over a broad area. In conventional reservoirs, the gas-oil equilibrium condition applies only at the fluid contact separating the phases but basin-centered systems have no observed gas-oil contacts so the equilibrium condition between hydrocarbon liquid and gas mixtures applies to the entire reservoir and is written as

$$\mu_L = \mu_V \tag{2}$$

Where μ is the chemical potential of the liquid, L, and vapor, V, phases of the mixture. The equilibrium condition on the Viking formation fluid leads to the well-known Clausius Clapeyron equation which is a relation between pressure and temperature on the fluids and has the form

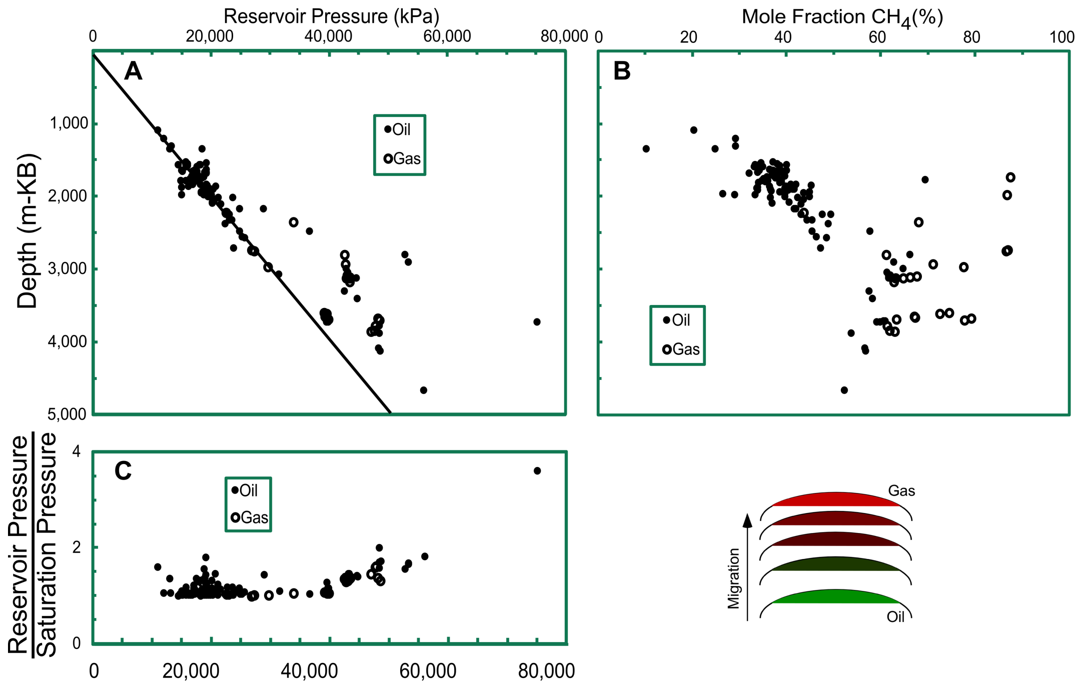

Figure 3: Pressure (A) and composition (B) and pressure ratio (C) for fluids in a 10,000 km^2 portion of the Niger Delta (Matava et al., 2003), a series of conventional Class III traps. The solid line is the hydrostatic gradient and indicates that the majority of the reservoirs are near hydrostatic pressure and near saturation (A and C). These data also show that bubble point and dew point fluids converge to form a near critical state fluid at depth and migration occurs at constant composition. Appendix A provides a brief introduction to interpreting oil and gas phase diagrams.

$$\frac{dP}{dT} = \frac{\Delta H}{T\Delta V} \tag{3}$$

where P is pressure, T is temperature, H is the enthalpy of the phase change and V is the volume of the phase change.

A more general form of Equation 3 uses Frechet derivatives to map gradient fields for pressure and temperature back to their scalar values. This generalization is useful when numerical models are combined with compositional data because the pressure and temperature gradients are not necessarily aligned. This variation of the Clausius Clapeyron Equation has the form

$$\frac{\vec{\nabla}P\cdot\vec{h}}{\vec{\nabla}T\cdot\vec{h}} = \frac{\Delta H}{T\Delta V} \tag{4}$$

where $\vec{\nabla}$ is the gradient operator and $\vec{h}$ is a unit vector.

Application of Equation 3 to fluids from the Viking formation shows that there is a strong dependency between reservoir pressure, temperature and fluid composition. Figure 5 shows measured temperature and pressure from selected wells in the Viking formation. When compositional data were available, they were used with PVTSIM to model the phase envelope of the fluid mixture and then the slope of the phase envelope was calculated at the measured reservoir conditions. The Clapeyron slopes from the bubble point curves line up with the pressure and temperatures in the well.

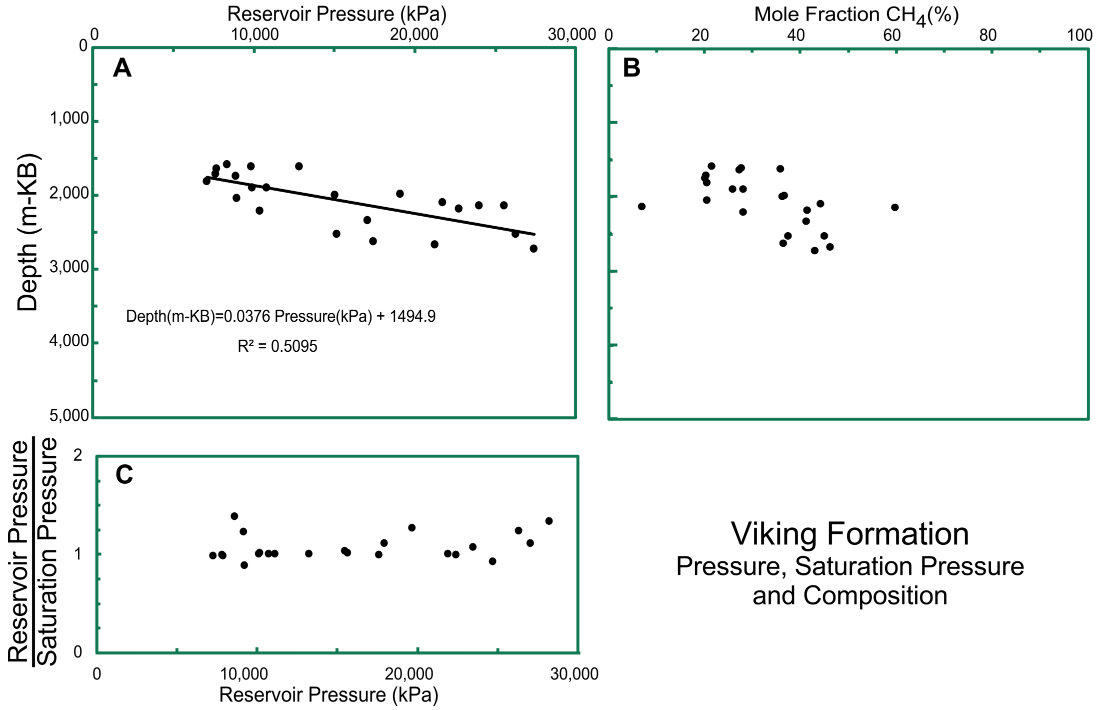

Figure 4: Pressure (A) and composition (B) with depth and pressure ratio (C) with reservoir pressure for fluids in the Viking formation an area encompassing approximately 15,000 km. The Viking formation is composed of a series of basin-centered traps. These data were compiled from the Alberta Energy Regulator PVT database (Alberta Energy Regulator, 2017). The reservoir pressure in these traps is less than hydrostatic but the pressure gradient indicates a fluid density that is equivalent to ~2700 $\frac{kg}{m^3}$. These data show that the Viking formation fluids behave differently than Class I or Class III fluids even though they are still display similar thermodynamic constraints as these traps.

In summary, reservoir pressures observed in basin-centered systems can be explained simply by hydrocarbons carrying the load which is in contrast to conventional accumulations where water carries the load. The large pressure gradients observed in these reservoirs result from an equilibrium condition between pressure, temperature and composition applied to the reservoir. In basin-centered systems, the composition is fixed and the heat flow from the earth is externally set; therefore, the reservoir pressure is the degree of freedom that maintains equilibrium. A consequence of this equilibrium condition is that in basin-centered systems, reservoir pressures are less than hydrostatic pressure near the waterline but large pore pressure gradients exist due to the reservoir temperature and composition of the hydrocarbon fluids. These pressure, temperature and composition dependencies are unique to basin-centered systems.

Formation of a basin-centered hydrocarbon reservoir is more speculative than the present day description because the equilibrium condition between pressure, temperature and composition may not apply throughout the history of the hydrocarbon accumulation. For example, the reservoir may have at some point been a conventional Class I-III type trap or a hydrocarbon migration pathway. However, decreasing reservoir pressure and temperature during uplift is not a likely cause for desiccation of the reservoir because conventional plays do not dehydrate during uplift.

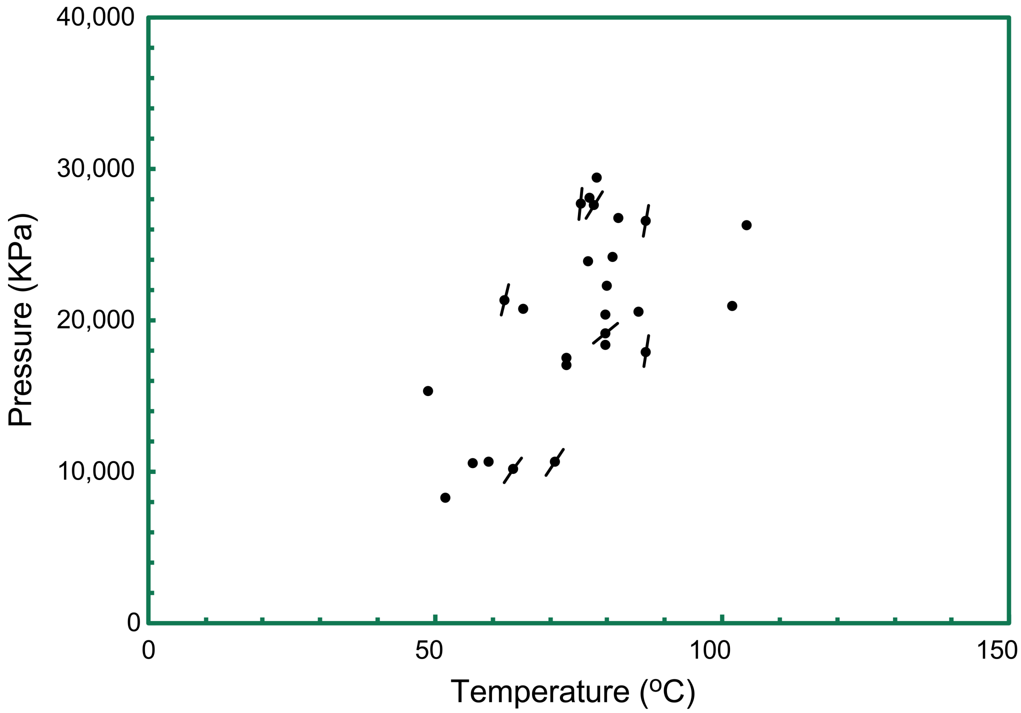

Figure 5: Initial pressure and temperature of basin-centered Viking reservoirs. The Clapeyron Slope calculated using the reservoir P-T conditions and the composition of the sampled fluids is shown with solid lines for samples with available compositional data. These data make clear the relationship between pressure, temperature and composition in a tightly coupled system in thermodynamic equilibrium.

We propose that water consumed during hydrocarbon generation is the mechanism that leads to desiccation of the reservoir and the lack of produced water during production. Helgeson et al. (2009) suggests that the transformation of load-bearing kerogen to a fluid is the result of an equilibrium condition between solid kerogen and hydrocarbon fluid similar to Equation 2. For the kerogen reaction the subscripts are K for the solid kerogen and F is for fluid phase ($\mu_K = \mu_F$). Helgeson et al. (2009) showed that hydrocarbon generation involves hydrolytic disproportionation of kerogen which leads to generation of hydrocarbons through a series of oxidation and reduction reactions which remove hydrogen from water (Price and DeWitt, 2001). As an example, Helgeson et al. (2009) show that a mature type III/IV kerogen undergoing the next increment of irreversible thermal diagenesis has an overall reaction of the form

$$C_{128}H_{68}O_{7\,(K)} + 57.798H_2O_{(L)} \rightarrow 10.864C_{8.8}H_{16.9\,(F)} + 32.99CO_{2\,(V)}$$

where C, H and O represent chemical species of carbon, hydrogen and oxygen and subsrcipts K, F, L and V represent the phase (kerogen solid, hydrocarbon fluid, liquid or vapor). Equation 5, which assumes the system is saturated with CO_2, shows that the formation of a hydrocarbon from a mole of solid kerogen consumes ~58 moles water. Removal of free water during hydrocarbon formation leads to the hydrocarbon fluid carrying the load on the system and is consistent with an attribute of basin-centered systems in that kerogen is present proximal to a reservoir and the waterline with a local maturity of R_o >0.8%.

The thermodynamic approach presented by Helgeson et al. (2009) to describe hydrocarbon generation is a significantly different approach than the kinetic models currently in use (Hantschel and Kauerauf, 2009, Chapter 4). Kinetic models are correlations to laboratory pyrolysis data and are based on a first order Arrhenius type reaction. These models conserve mass but do not employ an equilibrium condition and only in special cases do they conserve species (C, H, and O); consequently, they are not useful for modeling the consumption of water during generation and the formation of basin-centered hydrocarbon

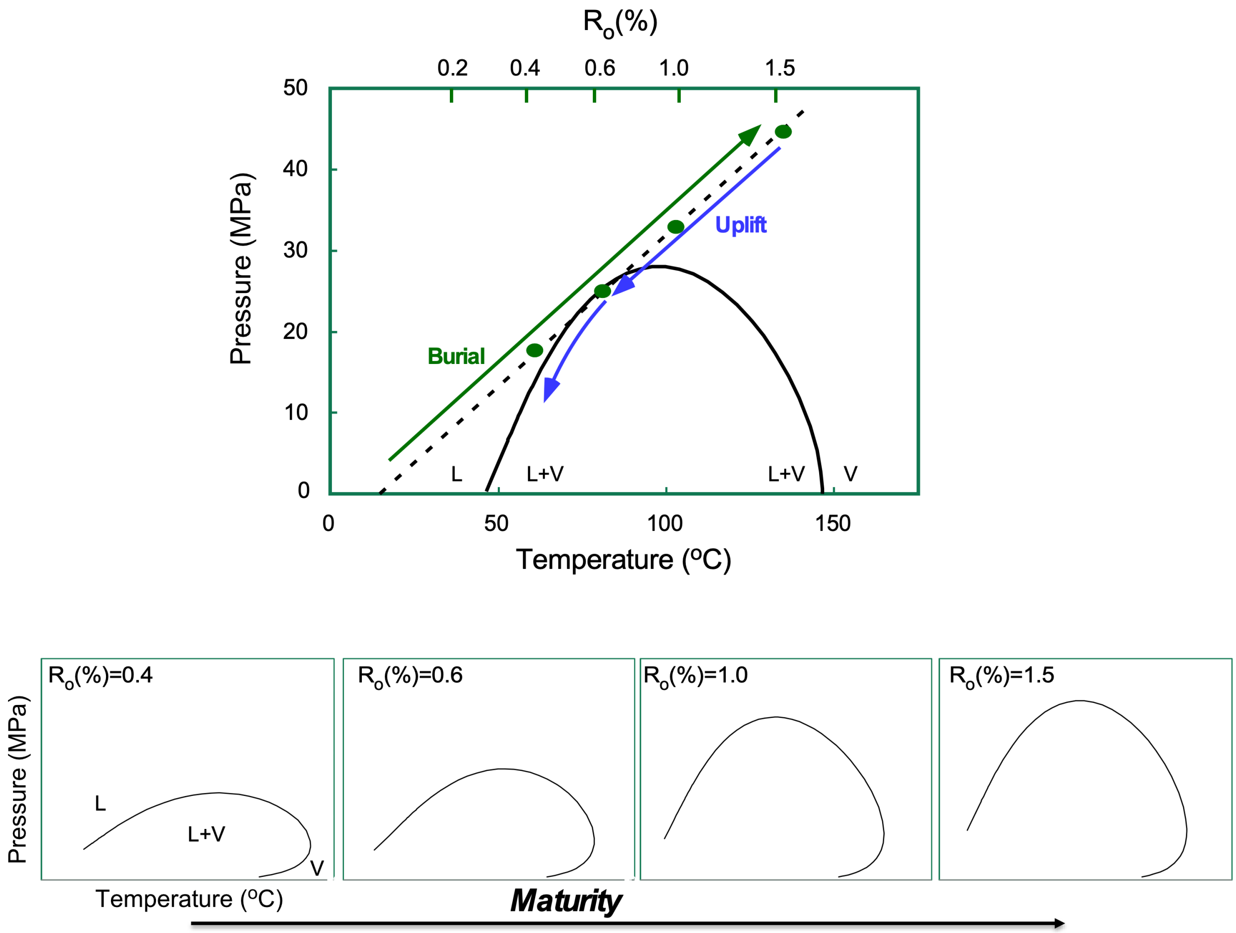

Figure 6: Schematic formation of a basin-centered reservoir. The top plate shows burial leads to an increase in pressure and temperature on the reservoir which, in turn, leads to local maturation of hydrocarbons (top vitrinite scale). As the maturity of the source rock increases, the two phase region of the phase envelope expands (bottom plate). Uplift leads to decreasing reservoir temperature and pressure (blue line) which need not necessarily follow the original burial path. When the reservoir pressure and temperature intersect the bubble point curve, two phases are present; therefore, pressure, temperature and composition are coupled and the slope of the phase envelope controls the pressure on the reservoir (Equation 4). Pressures at the waterline should be continuous (Equation 1).

accumulations.

The formation of a basin-centered hydrocarbon accumulation is shown schematically in pressure and temperature space in Figure 6. Burial leads to increases in reservoir pressure and temperature. A reservoir may initially be part of a migration pathway from deeper hydrocarbons buoyantly migrating to shallower depths. When the pressure and temperature is great enough then hydrocarbons proximal to the reservoir are generated which consumes water from the system. Additional water is removed from the system due to the density difference between load-bearing kerogen and hydrocarbon fluid (kerogen density of 1800 kg m^{-3} and hydrocarbon fluid density of 700 kg m^{-3}). At some point during generation, enough water is consumed that the remaining water becomes bound and hydrocarbons carry the load of the overlying water. When this occurs, buoyant processes cease and the hydrocarbon fluids become unconditionally stable. Uplift decreases the confining stress, fluid pressure and temperature until the hydrocarbon mixture becomes saturated. The two-phase hydrocarbon does not buoyantly separate to form a gas-oil contact due to the tight reservoirs present in basin-centered systems. The two hydrocarbon fluid phases across the reservoir lead to the pressure, temperature and composition coupling as shown in Equation 4, Figure 4 in the broad area shown in Figure 1.

In summary, the evolution and formation of basin-centered systems require a series of dependencies which are not necessary in conventional hydrocarbon accumulations where source, trap, reservoir and seal are considered independent. These dependencies take two forms. First, there is thermodynamic coupling between pressure, temperature and fluid composition. Basin-centered systems lack buoyancy of the pore fluids which makes the hydrocarbons unconditionally stable, and pressure is controlled by the fluid composition and temperature. The second form of dependency is the presence of source rocks of sufficient quality and maturity to desiccate the system of water during generation. Other dependencies are uplift which places the hydrocarbon fluid in saturated conditions and poor reservoir quality so that oil and gas phases cannot separate.

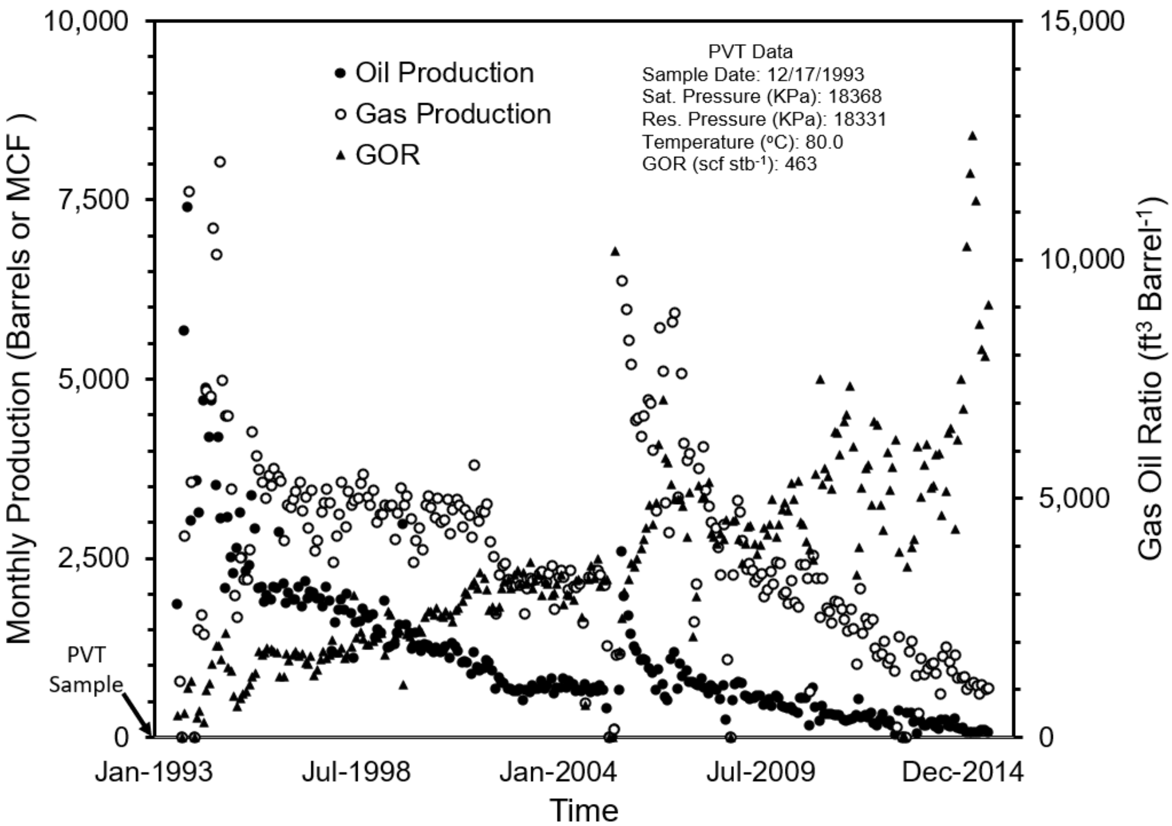

Figure 7: Monthly oil, and gas production with GOR for a Montney well. Fluids in this well were initially at bubble point pressure and the GOR (460 $\frac{SCF}{STB}$) indicates a mature oil from an oil prone source interval. For a large part of the early life of this well production was a volatile oil in place, however, the last half of the production has been wet and dry gas.

These data indicate that many basin-centered reservoirs are oil in place at or near the bubble point prior to production. Figure 7 is a Montney well with the reservoir pressure originally at bubble point pressure. The well produced oil early but later, with decreased reservoir pressure, produced progressively drier gas. Capturing the value of the fluid in place means recovering as much liquids as possible during production.

Conclusions

We use data from the Western Canadian Sedimentary Basin and the Niger Delta to show how basin-centered reservoirs differ from conventional Gussow traps (Sales Class I traps) and Class III traps. We show that well known attributes of basin-centered accumulations are a result of a physical setting in which hydrocarbons carry the fluid load in the system and hydrocarbon fluid coupling over large areas leads to pressure gradients in the reservoir that are approximately three times hydrostatic gradients and approach lithostatic. Basin-centered systems require several dependencies in order to form which can lead to large hydrocarbon accumulations of unconditionally stable fluids when all the elements are in place. The dependencies include: a source rock proximal to the reservoir with sufficient maturity and quality to desiccate the reservoir of free water; sufficient uplift to place the hydrocarbon fluid in a two-phase region; and reservoir quality that is poor enough that two hydrocarbon phases cannot buoyantly separate to form gas-oil contacts as they would in conventional reservoirs. Finally, this work shows that much of the fluids in tight reservoirs are initially oils which is consistent with the main source intervals in the basin. Gas production from these intervals is a result of gas being the mobile phase which leaves the oil behind.

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Appendix A: Oil and Gas Phase Diagram in Exploration

In this appendix we provide a short summary of hydrocarbon phase diagrams for oil and gas exploration. When two hydrocarbon phases are in equilibrium then gas is saturated with oil and oil is saturated with gas. For example, decreasing the pressure on a saturated oil will produce an oil saturated gas phase (Figure A.1). The equilibrium condition is expressed through the chemical potential of the liquid, L, and vapor, V, phases ($\mu_L = \mu_V$, Equation 2) and the degrees of freedom in the system (pressure, temperature and composition) are reduced by 1 allowing composition to be plotted with depth. Composition-depth curves are useful for understanding fundamental controls on fluids and can be used to delineate trap style.

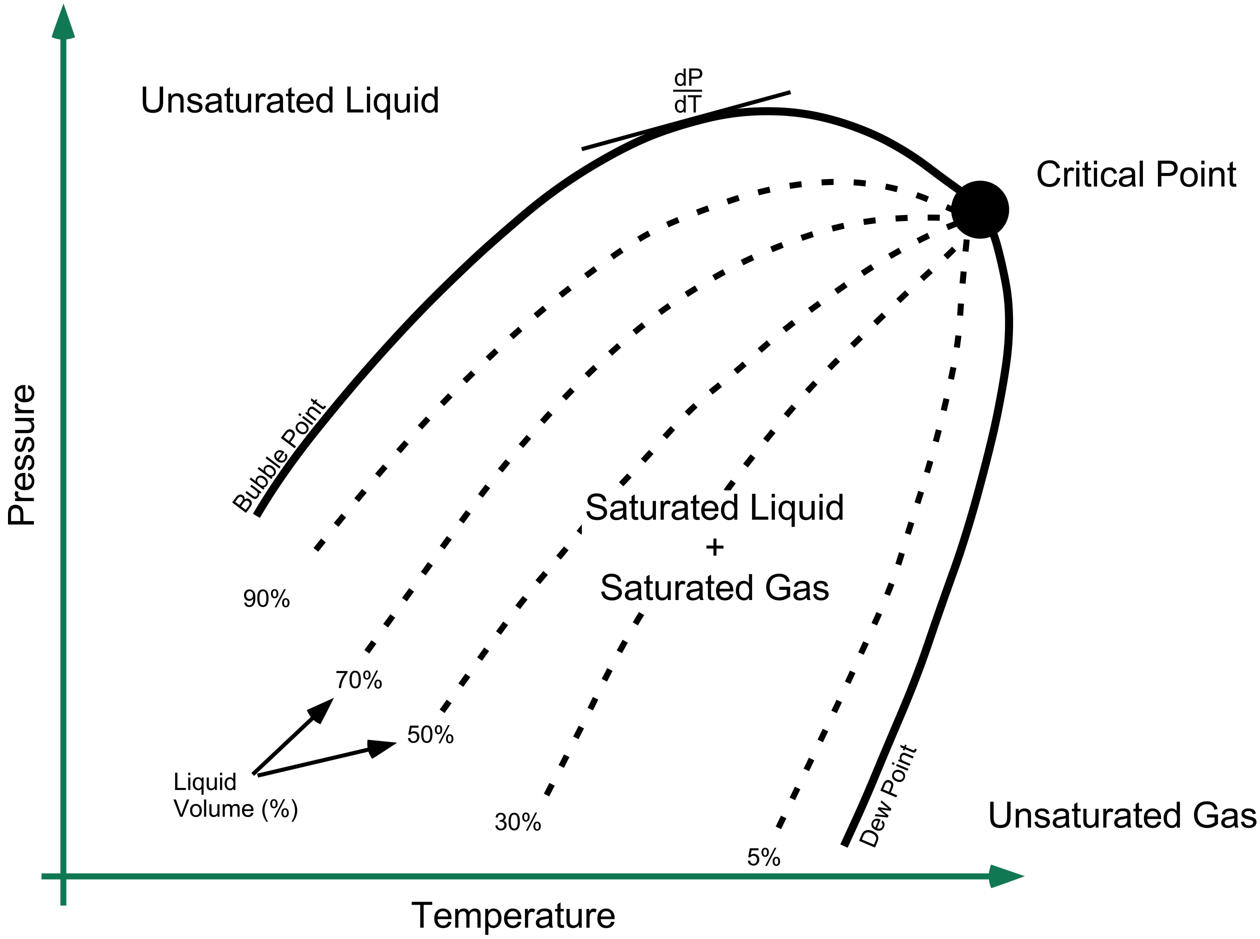

Figure A.1: Phase envelope for a normal hydrocarbon fluid. The phase envelope consists of bubble point and dew point curves connected at a critical point. At pressures and temperature outside the phase envelope the fluids are undersaturated while at pressures and temperatures inside the phase envelope the fluids are in equilibrium and are saturated. The equilibrium condition between a liquid and vapor occurs when the chemical potential of the liquid is the same as the vapor (Equation 2). The tangent to the bubble point curve, $\frac{dP}{dT}$, is the Clapeyron Slope due to a phase change from liquid to vapor in a closed system (Equation 3).

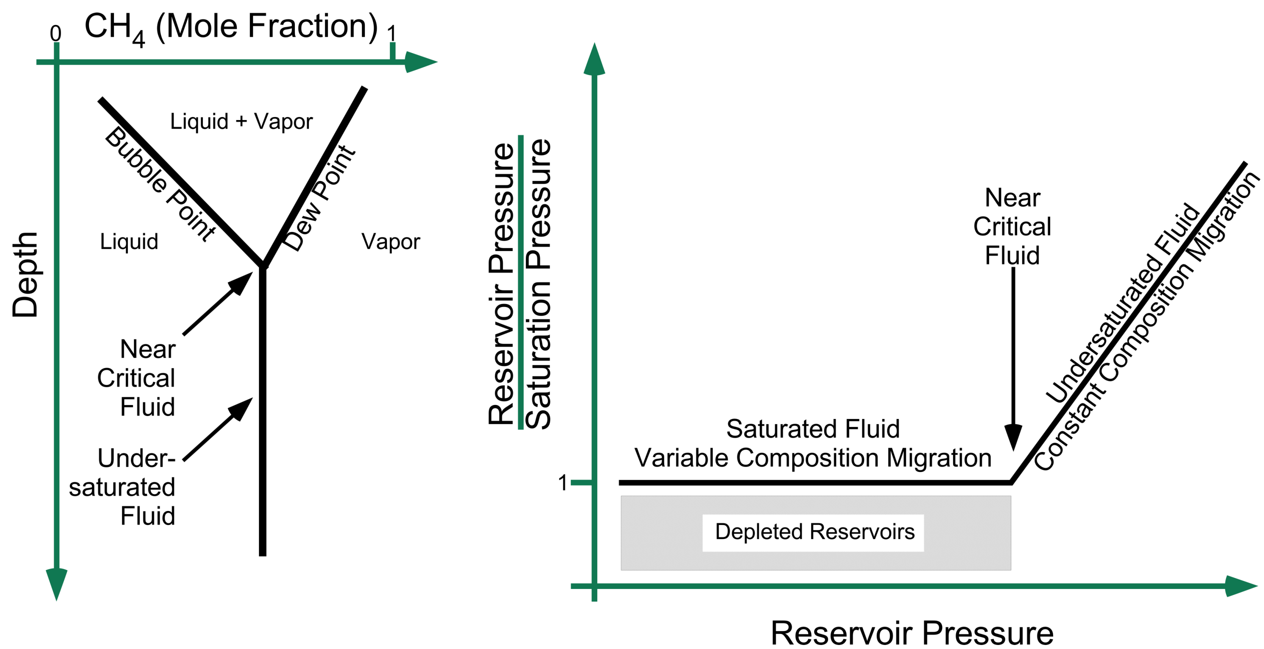

Figure A.2: Compositional phase diagram and the reservoir pressure ratio. At depths or pressures above the critical point the fluids are undersaturated. Migration processes in this region are constant composition. At depths shallower than the critical point the fluids split into two phases and compositions follow a bubble point or dew point curves and the ratio of reservoir pressure to saturation pressure is close to 1. Depleted reservoirs have pressure ratios less than 1.

Figure A.1 is a typical phase diagram found in any petroleum engineering book and is also typical of the phase diagram constructed from a bottom hole sample prior to production such as the sample obtained in Figure 7. The phase envelope is constructed using data obtained from a laboratory PVT (Pressure-Volume-Temperature), compositional analysis of the sample in conjunction with a numerical PVT simulator such as PVTSIM. The phase envelope consists of bubble point and dew point curves which bound the saturated liquid plus trace gas (bubble point) or a saturated gas plus trace liquid (dew point). Connecting bubble and dew point curves is a critical point. Also shown in Figure A.1 is the tangent to the bubble point curve. This tangent is $\frac{dP}{dT}$ and calculated from right hand side of Equations 3 and 4 and is called the Clapeyron slope of the phase diagram so it is a property of the fluid mixture.

Saturated fluid compositions are determined exactly the same way as geologic phase diagrams describing solid and liquid melts and these are shown in Figure A.2. Composition of the liquid and vapor follow bubble point and dew point curves. The depth that the two saturation curves intersect is typically referred to as a near critical region in reference to Figure A.1 but can actually be far from the real critical point. At depths greater than the near critical region, the fluids are undersaturated and migration of hydrocarbons along this pathway occurs at constant composition.

In conventional traps pressure and temperature are set externally. Temperature is determined by heat flow and thermal conductivity according to Fourier's heat law. Pressure on the hydrocarbon phase is the pressure on the water phase plus the buoyant pressure on the hydrocarbons which is typically small compared to the water pressure. The composition of saturated migrating hydrocarbons changes along pathways to maintain equilibrium with the externally set pressures and temperatures (Figure A.2).

Pressure ratio, the reservoir pressure divided by the saturation pressure, is used to determine if the fluid is saturated, undersaturated or if the reservoir is depleted (Figure A.2). Undersaturated fluids have a reservoir pressure that is greater than the saturation pressure and are at depths greater than the critical region. Migration from source to a trap is a constant composition process for undersaturated fluids. When the depth is less than the critical point, liquid and vapor phases are in equilibrium and composition of the oil follows the bubble point curve and the gas composition follows the dew point curve. Composition-

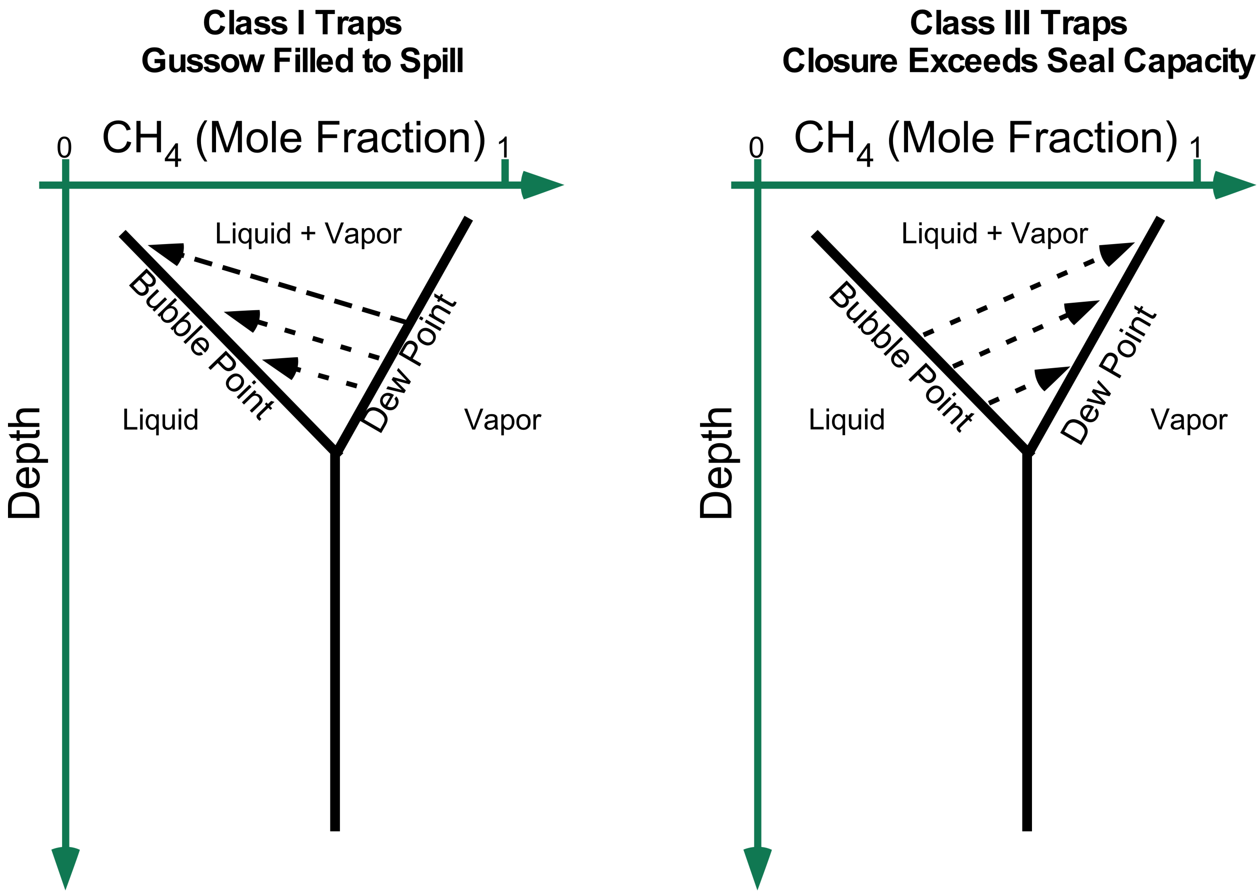

Figure A.3: Fluid compositions in the saturated region are on the bubble point and dew point curves. Fluid compositions between these bubble point and dew point curves cannot occur in equilibrium conditions just like solid-liquid phase diagrams of geologic materials. At depths greater than the critical point the fluids are unsaturated. Detailed geochemical analysis of oils and gases in a play can be used to determine the trap style in conventional accumulations based on the geochemical relationships.

depth charts show how the phases partition along migration pathways. Finally, depleted reservoirs have reservoir pressure to saturation pressures less than 1. Depleted reservoirs are identified using PVT test data obtained prior to production.

Trap style for conventional reservoirs can be determined by geochemically finger printing oils and gases in the traps and is data supplementary to PVT data. Figure A.3 shows how oil and gas typing is used to identify Gussow traps (Sales Class I traps) which spill oil updip and Class III traps where gas migrates shallower faster than oil. A large number of geochemical and PVT samples are required to demonstrate trap style from composition-depth differences. Mapping fluid contacts and spill points is the other way to determine trap style and is the method used by Gussow (1953).

In practice, and in the data shown in the text, a significant amount of noise is present in the compositional data, reservoir pressure data and saturation pressure data. Contributing to this noise in the gas phase is an additional phase diagram which includes the methane saturated pore fluids. A good example of this noise is shown in Figure 3 in the body of the paper. In these cases there is usually a strong overprint of biogenic gas, either secondary or primary, on the thermogenic fluids.

Fluids in the Viking formation are distinct from the Class I and Class III fluids because they have been placed in a saturated condition during uplift which cooled and decreased the pressure on the fluids.

Basin-centered systems form their own class of reservoir that is compositionally distinct from conventional reservoirs.