Ministry of Energy, Mines and Petroleum Resources

Oil and Gas Division
Resource Development and Geoscience Branch

Regional "Shale Gas" Potential of the Triassic Doig and Montney Formations, Northeastern British Columbia

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Petroleum Geology Open File 2006-02

Abstract

Identifying prospective exploration trends for a shale gas play requires the examination of factors related to gas production and the definition of physical attributes of the shale. The concentration and distribution of organic carbon within the shale, of which gas in place is a direct function, is of particular importance. The Triassic Doig and Montney formations extend over seven million hectares of northeast British Columbia (NEBC), are up to 500 metres thick and are found at depths of 400 to over 4400 metres. Both formations contain significant quantities of organic carbon, which is concentrated in phosphatic shale tens of metres thick or dispersed in low concentration within shale several hundreds of metres thick.

The focus of this study is to evaluate the shale gas potential of the Doig and Montney formations in NEBC through quantifying the potential gas in place via spatial analysis. One aim of this study is to aid shale gas exploration via a series of maps displaying gas-in-place that can be used to focus exploration efforts into delineated high-grade areas. Methods investigated include log derived estimates of total organic carbon (TOC), applying Langmuir isotherms to regional grids and mapping the resultant estimates.

Introduction

As demand for natural gas continues to grow and technology improves, shale gas is becoming an increasingly attractive target for development. Two of the many formations in British Columbia which are thought to have potential for shale gas production are the Triassic Doig and Montney.

The Doig and Montney formations cover over seven million hectares of northeast British Columbia range from 100 to 4400 m deep and combined are up to 500 m thick (Figure 1). They are present through several physiographic zones, such as the foothills, outer-foothills, Peace River Arch and Fort St. John plains, with differing potential and styles of natural fracturing. Major facies include fine-grained shoreface sandstone, shelf siltstone to shale, fine-grained sandstone turbidites and organic-rich phosphatic shale. Limited development of conventional reservoirs in shoreface sandstones, shelf siltstones to fine grained sandstones and turbidites has occurred.

The purpose of this study is to evaluate the shale gas potential of the Doig and Montney formations by quantifying the potential gas-in-place via spatial analysis. A quantitative spatial estimate of gas-in-place was calculated using the variables of depth, formation (shale) isopach, total organic carbon (TOC) estimated from geophysical logs, and estimated adsorption isotherms.

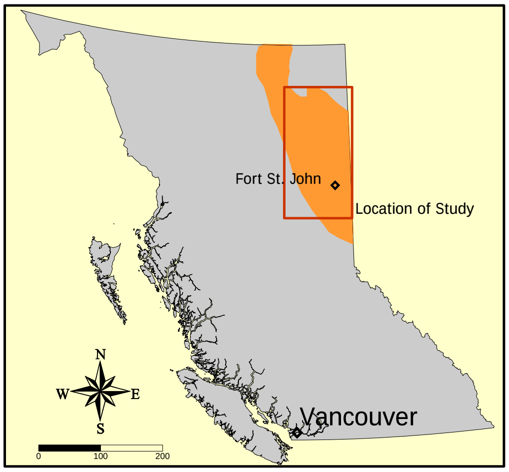

Figure 1. Extent of Triassic Rocks within the study area in northeast British Columbia

This study is the second in a series by the Ministry of Energy, Mines and Petroleum Resources describing the gas potential of shale formations in northeast British Columbia. An earlier report was released in 2005 for Devonian shale formations (MEMPR and CBM Solutions, 2005).

Geologic Setting/Overview of Montney and Doig

The sandstone, siltstone and shale of the Triassic Doig and Montney formations in northeast British Columbia were deposited on a westward prograding shelf on the paleo-continental margin (Edwards *et al.*, 1994).

The Montney Formation marks the first transgressive to highstand cycle of the Triassic, disconformably overlying Permian to Mississippian rocks in northeast British Columbia (Figure 2) (Edwards *et al.*, 1994). Fine grained sandstone and siltstone deposited in shoreface to near shore environments grade westward into deeper water shale. Locally interbedded sandstone and siltstone represent downslope turbidite deposits in the Fort St. John Graben complex. In the east, exploration has concentrated on proximal shoreface sandstone along the subcrop edge where hydrocarbons are trapped by overlying Cretaceous shales in subtle structural and stratigraphic traps. There has also been a focus on distal shoreface and turbidite plays primarily in the Peace River Arch area following a trend of discoveries in Alberta.

The contact between the Montney and the overlying Doig Formation is marked by a major transgression with the basal Doig identified as a distinctive radioactive shale marker containing abundant phosphatic grains. Doig shale grades upwards into a clean shoreface sandstone that in many areas is indistinguishable from the overlying Halfway Formation. Exploration to date has concentrated on thick shoreface sandstones that approximately form north-south oriented linear trends.

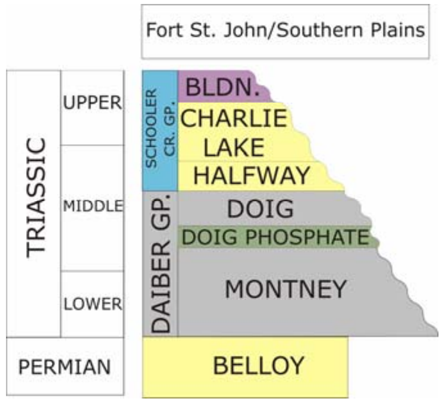

Figure 2. Triassic stratigraphy in the Fort St. John southern plains region of northeast British Columbia

The Montney and Doig formations contain type II kerogen and are prospective source rocks where thermally mature. In previous studies using core and chip samples, the Montney Formation has been found to contain up to 4% TOC and the Doig Formation up to 11% TOC particularly in the radioactive phosphate zone (Ibrahimbas and Riediger, 2004; Faraj *et al*., 2002).

Tops for the Doig, Doig Phosphate, Upper Montney, Lower Montney and Belloy were picked from logs for this study. An example of the stratigraphy is presented in Figure 3.

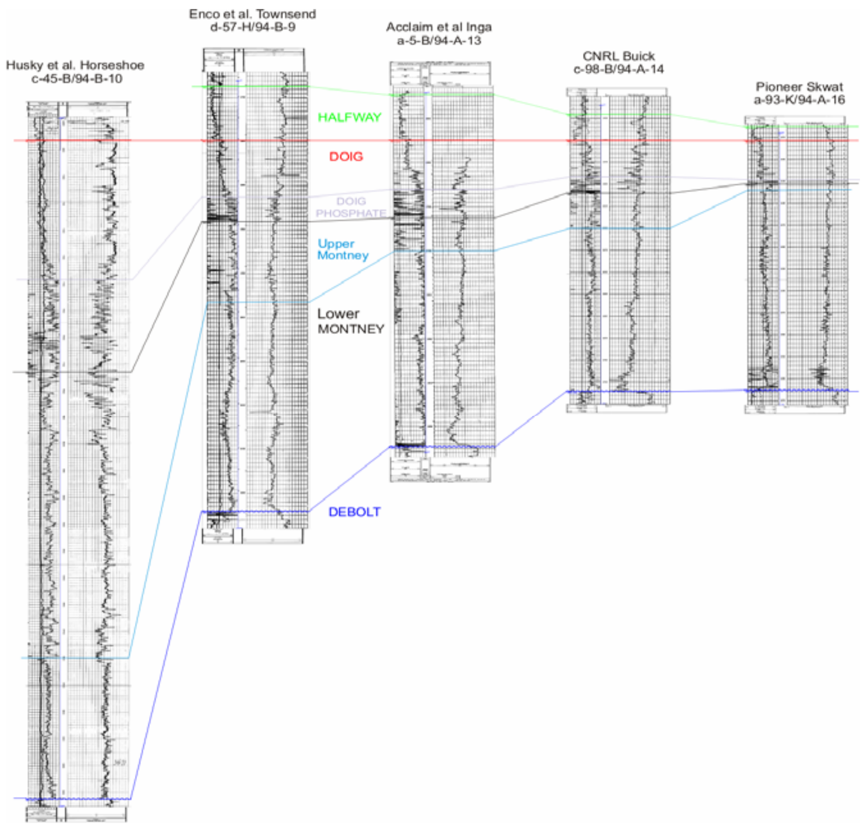

Figure 3. West-East Cross section of the Triassic Doig and Montney formations in northeast British Columbia.

Triassic Shale Industry Activity

Conventional oil and gas exploration in northeast British Columbia of the units described has focused on thick lower Halfway/Doig sandstone and proximal shoreface sandstones of the Montney Formation along the subcrop edge in the Fort St John region (MEMPR, 2006). Industry activity is now shifting to include unconventional reservoirs including the Doig Phosphate in the Groundbirch area and the Montney Formation in the Swan Lake/Bissette, Saturn and Dawson Creek areas.

Fort St. John Region

Groundbirch Area

Duvernay Oil Corp. continues to discover and develop tight gas from the Triassic Doig Formation in the Groundbirch area (in northeast BC's Peace River Block). Duvernay's activity at Groundbirch delineates an 80-kilometre long and three-kilometre wide fairway with additional potential in formations above and below the Doig. Doig gas in the area is interpreted to be in a distal shelf sandstone unit. The basal portion is notable for its phosphate zone, an excellent hydrocarbon source rock and one that may house a potential shale gas target.

In 2005, Duvernay drilled 22 wells in the area targeting Doig gas. Recognized proved, plus probable, reserves in the original Groundbirch Doig discovery grew to 98.9 Bcf to year-end 2005 (Adams et al., 2006).

Saturn Area

In 2003, three development wells were drilled by Duvernay Oil Corp. in the southern portion of the Saturn area. All three wells (11-4-80-19W6, 2-8-80-19W6, 2-5-80-19W6) were perforated in the Montney and are producing average daily gas rates ranging from 128 mcf per day to 344 mcf per day (Adams et al., 2006).

Dawson Creek Area

ARC Energy Trust is the major player of Montney tight gas development in the Dawson area. Production from the field is currently at 20 mmcf per day with 56 wells producing. ARC has implemented new and improved completion techniques which have resulted in wells that have outperformed previous drilling programs. Plans for 2006 were to drill three horizontal wells and six vertical wells, plus install additional field compression to increase production capability (Arc, 2006).

Cinch Energy Corp. developed a new exploration program in the Dawson Creek area. There, it has a joint venture in the drilling of two wildcat exploration wells, one of which was completed as a gas well. More seismic work and drilling are being considered for 2006. Cinch holds an interest in 2,350 net hectares in this multi-zone area where the Montney and Doig are considered primary targets (Adams et al., 2006).

Galleon Energy Inc. drilled and cased 18 (14.9 net) Montney natural gas wells in the third quarter of 2006. One significant discovery well flowed at 3.8 mmcf a day (2.7 mmcf per day net) during a production test. The AOF test was 13.1 mmcf a day. The well is expected to be tied in before the end of 2006 with production rates to be determined. The company’s existing 15 mmcf a day natural gas plant is scheduled to be expanded to 30 mmcf per day in late 2006 in anticipation of further production growth in 2007. Galleon has identified over 150 locations in eight separate large gas pools. Up to 15 wells are planned for the fourth quarter of 2006 (Adams et al., 2006).

Deep Basin Region

A total of 232 wells were rig released in the Deep Basin region in 2005. Although the major target interval for operators was the Cadomin, twenty-three wells identified the Doig/Montney as the objective, particularly in the Swan Lake area. Gas production for 2005 from the Doig/Montney was 2.7 Bcf (Adams et al., 2006).

The Cutbank, Kelly, and Noel areas, with 105 rig releases, accounted for 45% of all drilling activity in the Deep Basin region in 2005. The primary objective for producers in these areas was the Cadomin, but other prospective zones such as the Lower Cretaceous Paddy and Falher as well as the Triassic Doig were targets. One of the higher producing wells drilled in the Kelly area in 2005 was drilled by EnCana Corporation. The well, b-13-J/93-P-1, was placed on production in September of 2005 and is producing at an average rate of 4.8 mmcf per day from the Triassic Doig. EnCana estimates that this new Doig discovery contains 350 to 500 Bcf of original gas in place (Adams et al., 2006).

Swan Lake Area/Bissette

EnCana Corporation was the only producer operating in the Bissette/Swan Lake area in 2005. The company continued to develop Triassic shale gas potential from the upper Montney in the area. Fourteen wells were rig released in the area in 2005, 12 of which showed gas production totalling 1.1 Bcf (Adams et al., 2006).

Summary of Previous Studies

In 2002 Faraj *et al.* conducted a study released by the Gas Technology Institute entitled “Shale Gas Potential of Selected Upper Cretaceous, Jurassic, Triassic and Devonian Shale Formations, in the WCSB of Western Canada: Implications for Shale Gas Production”. This work included an assessment of the in-place gas potential of the Doig and Montney formations in Alberta and British Columbia based on isopach mapping, TOC and thermal maturity estimates from core, and adsorbed gas estimates. Total gas-in-place was estimated at 139.7 TCF for the Doig, with the majority of this located in the phosphate zone and 187 TCF for the Montney.

Ibrahimbas and Riediger (2004) conducted an organic geochemical study on several formations including the Doig and Montney. Rock-Eval 6 pyrolysis was used to determine the hydrocarbon source rock potential. In the Montney, TOC values were found to range from 0.51 wt% to 4.18 wt%, with HI values from 43-450 mg HC/g TOC. In the Doig, specifically the “Phosphate Zone”, the TOC values ranged from 1.76 wt% to 10.98 wt% with HI values of 189-489 mg HC/g TOC. These results indicate that the Montney Formation has good to very good source rock potential and the Doig “Phosphate Zone” has excellent source rock potential.

Riediger (1990) also conducted Rock-Eval testing on several formations including the Doig and Montney formations, and the results were released as GSC Open File 2308.

Mineralogy

X-ray diffraction analysis was conducted on three samples of the Montney Formation from two different wells and on one sample of the Doig Formation. All Montney samples showed significant amounts of quartz and the Doig sample displayed moderate to significant amounts of quartz (Table 1.)

Sample	UWI	Depth	Formation	Minerals Contained in Sample	Amount of Mineral
MM-1	D-045-G/094-H-09	909.2 m	Montney	Quartz	Significant
				Illite	Moderate
				Pyrite	Minor
				Dolomite	Minor
				Kaolinite	Minor
MM-2	D-045-G/094-H-09	914.5 m	Montney	Quartz	Significant
				Illite	Moderate
				Pyrite	Minor
				Dolomite	Minor to Moderate
				Kaolinite	Minor
MM-3	D-088-F/094-G-02	2130.8 m	Montney	Quartz	Significant
				Illite	Minor to Moderate
				Pyrite	Minor
				Dolomite	Very Minor
DM-1	D-072-E/094-H-02	1182.9 m	Doig	Quartz	Moderate to Significant
				Calcite	Moderate
				Pyrite	Minor to Moderate
				Illite	Minor
				Dolomite	Minor
				Albite	Trace

Table 1. Mineralogy of selected core samples from the Triassic Doig and Montney formations.

Resource Potential

Shale gas reservoirs contain gas both within pore spaces and adsorbed onto the organic carbon contained within the rock. In evaluating the potential of gas shale units, the characteristics and quantitative measures of the organic component of the shales are critical variables in determining total hydrocarbon potential. The resource potential of the Doig and Montney formations were determined through spatial analyses of organic content, isopach and depth combined with regional estimates of porosity, gas saturation, and gas adsorption capacity of the shales. The organic content of the shale and isopach of potential units were estimated using geophysical logs.

Grid-Based Interpolation

Grids were created from the data sets in Golden Software's Surfer© version 8. All of the grids used in this study had a node spacing of 500 m by 500 m, representing an area of 25 ha. Kriging of each dataset was performed with linear or spherical prediction maps with a nugget effect correction to account for measurement error and small scale variations in the data. This has the effect of smoothing the grids to show regional trends over individual points. The grid math functionality of Surfer © was employed for all grid based calculations.

Log Derived TOC estimates

The total organic carbon (TOC) content of shale is commonly determined through laboratory analyses (Rock-Eval pyroloysis) of core or chip samples from prospective horizons. Where core coverage is poor, or for regional analysis, log derived methods have the advantage (over lab-based methods) of increased resolution both vertically, within a well bore, and aerially because average or summary data from many wells can be incorporated. Several methods to determine TOC from wireline logs are available. For this study, TOC curves and estimates were generated from over 1000 wells in northeast British Columbia based on published methods described by Passey *et al.* (1990) and Issler *et al.* (2002) (Appendix A).

The Passey *et al.* (1990) method relies on an estimation of the Level of Maturity (LOM) (Hood *et al.*, 1975). Regional thermal maturity map data (Tmax), compiled from Ibrahimbas and Riediger (2004) and Riediger (1990), were converted to LOM (Appendix C). For the Triassic, a trend of increasing thermal maturity to the west is evident. It is crucial to be aware of this thermal maturity gradient when regionally applying the Passey method. Otherwise the TOC will be either over-estimated or under-estimated.

Summary data for each well are included in Appendix A. For each well this data includes the total thickness of carbon, total "shale thickness" and maximum TOC produced by the Passey *et al.* (1990) method. For the Issler *et al.* (2002) method summary data includes the total carbon isopach and maximum TOC. Note that anomalies in the data set identified by maximum percent TOC (greater than 15%) were deleted as these are likely caused by poor log quality or calibration error. Appendix A also contains the TOC logs for each well.

As a preliminary test of the applicability of these methods, several wells with TOC values determined from core or chip samples have been compared to the log-derived estimates (Appendix B). A more detailed comparison and analysis of these methodologies is beyond the scope of this report.

Gas in Place Calculations

The potential gas-in-place for each of the four units was calculated as adsorbed gas (methane adsorbed onto organic matter) and free gas (porosity). Two slightly different methods were employed to calculate adsorbed gas-in-place (see below for free gas), based on the two different log-derived TOC methods.

Adsorbed Gas in Place

Method One

The first method utilizes log-derived total organic carbon estimates following the procedure outlined by Passey *et al.* (1990). For each well the TOC content is summarized as a total carbon thickness and total "shale thickness". Total carbon thickness is defined as the total thickness of organic carbon within the stratigraphic unit if concentrated to one hundred percent, whereas "shale thickness" is defined as having a total organic content greater than zero percent. The average TOC for the unit is the total carbon thickness divided by the total shale thickness.

Method Two

The second method employs the total carbon isopach estimated from logs using the procedure described by Issler *et al.* (2002). However, instead of using "shale thickness" the total isopach of each stratigraphic unit was used.

Calculations

Gas adsorbed onto organic material represents a significant potential resource for shale gas plays. The volume of gas adsorbed onto organic matter contained within a mass or volume of shale can be easily described at different pressures using the Langmuir equation if the Langmuir properties of the shale are known. (Note: For simplicity, in this study it is assumed that the only gas present is methane). The following equation is used:

Volume of Gas Adsorbed = VL*Pressure/(PL+Pressure) * Rock Mass

where VL is the Langmuir Volume (defined as the maximum amount of gas that can be adsorbed) and PL is the Langmuir Pressure (defined as the pressure at which half of the VL is adsorbed).

By using grids for factors of pressure, shale volume (or mass) and the Langmuir properties of the shale, the estimation of adsorbed gas-in-place can be made regionally on a per unit area basis. The first step is to define Langmuir properties of the shale regionally. For this study, the Langmuir volume for each grid was related to average TOC. Unfortunately, no desorption/adsorption data are currently available for Triassic aged shale in northeast British Columbia. However, adsorption isotherms and desorption analyses are available for several other formations and these data were plotted against sample TOC values (Figure 4). These composite data display a roughly linear trend with a large degree of scatter (y=0.25x; R^2= 0.366). Several factors relating to data collection, sample preparation and shale properties likely contribute to the poor correlation. In order to reflect this variability and to determine a reasonable range of gas-in-place estimates, three Langmuir volumes were calculated using a linear relationship to TOC. These are referred to as the high, middle and low cases (Table 2 and Figure 5).

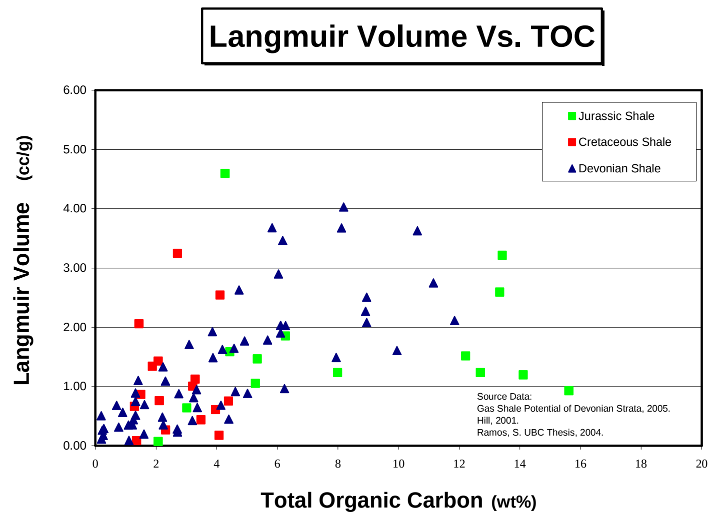

Figure 4. Langmuir volume data versus total organic carbon.

	Low Case	Middle Case	High Case
TOC * Langmuir Volume (cc/g)	TOC * 0.1 (cc/g)	TOC * 0.2 (cc/g)	TOC * 0.3 (cc/g)

Table 2. Linear relationships used for estimating Langmuir volume as a function of TOC.

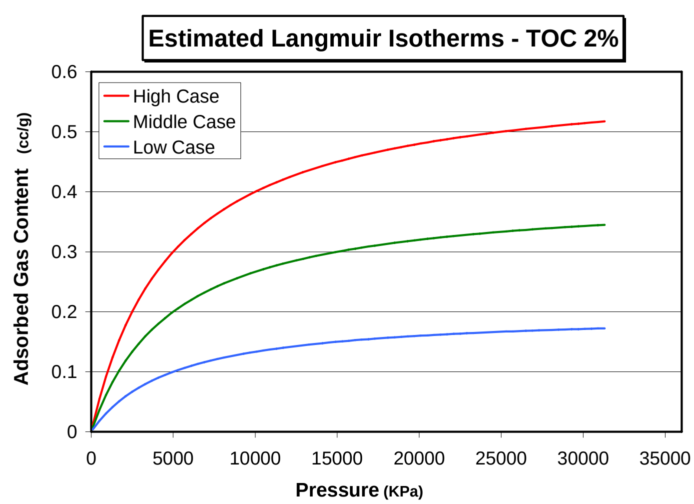

Figure 5. Representative isotherms for Langmuir volumes at a TOC of 2% (Langmuir Pressure 5000 kPa).

Langmuir pressure does not affect the theoretical limit of gas adsorbed by the organic matter contained within the shale but it does affect the rate at which the gas is adsorbed. As PL increases there is a decrease in the amount of adsorbed gas at lower pressure. This can also greatly affect the producibility of the adsorbed gas (*i.e.* at a lower PL more pressure drawdown will be required to desorb the gas). A single Langmuir pressure of 5000 kPa was used for each case as this was the average of the data from several studies. A more detailed investigation of the Langmuir pressure is beyond the scope of this study.

Rock volume for each unit was estimated from the shale thickness and an estimated average density. An average density of 2650 kg/m^3, estimated from the density logs of several wells, was used to convert the rock volume to mass.

A grid of reservoir pressures was estimated from the grid of depth to the Montney Formation top, using a gradient of 9.792 kPa/m. The grid-based calculation was done in metric units with the results in E^3 m^3/25 ha. This allowed the mean of each grid and the number of grid nodes to be recorded. From this the total value of the grid could be calculated, thus, giving the total gas-in-place estimate (Table 2). Depth cut-offs were then applied to the resultant grids corresponding to the Montney Formation top at 1500 m, 2000 m, and 2500 m and using a thermal maturity cut-off of Tmax 455 °C (Table 3). For ease of use and display purposes the grids were converted to billions of cubic feet per gas spacing unit (260 ha) (Bcf/GSU) (see Appendix D).

	Method one				Method Two			
	Area Ha	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf	Area Ha	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf
Adsorbed Gas Total								
Doig	4,427,000	39,794	79,589	119,383	4,197,425	20,583	41,166	61,750
Doig Phosphate	4,427,000	21,617	43,234	64,851	4,197,425	15,509	31,018	46,526
Upper Montney	4,922,525	26,735	53,470	80,205	4,197,425	37,248	74,496	111,744
Lower Montney	4,922,525	47,624	95,249	142,873	4,197,425	98,101	196,203	294,304
Adsorbed Gas Total								
After 1500m&Tmax455ºC Cuttoffs								
Doig	884,750	7,296	14,591	21,887	801,325	3,004	6,008	9,012
Doig Phosphate	884,750	4,303	8,607	12,910	801,325	2,699	5,399	8,098
Upper Montney	877,475	6,651	13,302	19,953	801,325	6,222	12,445	18,667
Lower Montney	877,475	7,304	14,608	21,912	801,325	19,000	37,999	56,999
Adsorbed Gas Total								
After 2000m&Tmax455ºC Cuttoffs								
Doig	2,094,275	18,209	36,417	54,626	2,007,950	8,717	17,434	26,151
Doig Phosphate	2,094,275	11,484	22,969	34,453	2,007,950	8,141	16,281	24,422
Upper Montney	2,087,000	13,964	27,928	41,892	2,007,950	18,681	37,361	56,042
Lower Montney	2,087,000	20,607	41,213	61,820	2,007,950	55,398	110,795	166,193
Adsorbed Gas Total								
After 2500m&Tmax455ºC Cuttoffs								
Doig	2,712,900	31,490	62,981	94,471	2,572,000	15,768	31,536	47,304
Doig Phosphate	2,712,900	16,154	32,308	48,462	2,572,000	12,409	24,817	37,226
Upper Montney	2,690,050	20,999	41,997	62,996	2,572,000	31,584	63,167	94,751
Lower Montney	2,690,050	27,102	54,204	81,305	2,572,000	71,334	142,667	214,001

Table 3. Total gas-in-place estimates for adsorbed gas. See Appendix D.

Free Gas

An estimate of the free gas component associated with the potential shale gas reservoir zones was calculated for each interval. The grid-based calculation used a standard as-in-place equation:

$$\text{Gas in place} = \frac{\text{Area} * \text{Isopach} * \text{Porosity} * \text{Saturation} * \text{Pressure}}{\text{Constant} * \text{Temperature} * \text{Gas Compressibility (z-factor)}}$$

Grids of shale thickness were used to determine reservoir isopach and the area was calculated on each grid space, representing an area of 25 ha. The same grid of pressure, based on the depth to the top of the Montney Formation described previously, was used. A formation temperature grid was estimated, also using the depth to the top of the Montney Formation and an average geothermal gradient of 2.5 °C/100 m derived from bottom hole temperatures of several wells (Figure 6).

As with the calculations for adsorbed gas, low, medium and high cases were calculated. This was accomplished by varying the porosity and saturation. A log-normal distribution was assumed for porosity and gas saturation (Table 4).

	Low Case	Middle Case	High Case
Porosity	1 %	2.4 %	6 %
Gas Saturation	30 %	46 %	70 %

Table 4. Range of porosity and gas saturation values used in free gas calculations.

The z-factor (compressibility of gas) was calculated for the gridded area assuming the gas is 100 percent methane.

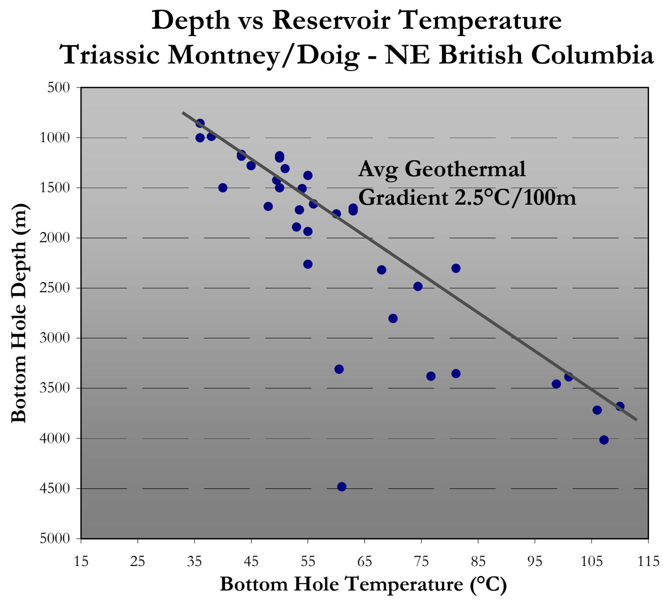

Figure 6. An average geothermal gradient of 2.5 °C per 100 m for the Doig and Montney formations was estimated from bottom hole temperatures (BHT) recorded on geophysical logs. Anomalously low BHTs are likely due to fluids in the bore hole not having enough time to equilibrate to temperatures in the reservoir.

As with the adsorbed gas-in-place calculations, area was calculated based on a 25 ha area for each grid space and tabulated (Table 4). Similarily, cut-offs were applied to the grids for each zone at depths of 1500 m, 2000 m and 2500 m for the Montney Formation top and using a thermal maturity cut-off of Tmax 455 °C (Table 4). Finally, following the adsorbed gas-in-place procedure, the grids were converted to billions of cubic feet per grid spacing unit (Bcf/GSU) (see Appendix D).

	Method one				Method Two			
	Area Ha	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf	Area Ha	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf
Free Gas Total								
Doig	4,372,975	55,872	153,648	419,041	4,192,700	156,793	431,180	1,175,945
Doig Phosphate	4,372,975	23,932	65,819	179,506	4,192,700	23,706	65,192	177,795
Upper Montney	4,864,300	51,470	141,542	386,023	4,192,700	66,369	182,515	497,769
Lower Montney	4,864,300	125,434	344,942	940,752	4,192,700	156,971	431,669	1,177,279
Free Gas Total								
After 1500m&Tmax455ºC Cuttoffs								
Doig	884,750	8,645	23,773	64,836	801,325	26,790	73,673	200,928
Doig Phosphate	884,750	3,895	10,711	29,211	801,325	3,366	9,256	25,243
Upper Montney	877,475	18,329	50,404	137,466	801,325	8,101	22,277	60,757
Lower Montney	877,475	9,607	26,420	72,055	801,325	26,861	73,867	201,456
Free Gas Total								
After 2000m&Tmax455ºC Cuttoffs								
Doig	2,094,275	23,719	65,228	177,893	2,007,950	76,047	209,129	570,351
Doig Phosphate	2,094,275	11,159	30,686	83,690	2,007,950	10,840	29,810	81,300
Upper Montney	2,087,000	23,489	64,595	176,168	2,007,950	26,868	73,887	201,511
Lower Montney	2,087,000	56,634	155,744	424,758	2,007,950	76,123	209,337	570,920
Free Gas Total								
After 2500m&Tmax455ºC Cuttoffs								
Doig	2,712,900	44,690	122,898	335,177	2,572,000	99,731	274,261	747,985
Doig Phosphate	2,712,900	18,015	49,542	135,114	2,572,000	17,634	48,492	132,252
Upper Montney	2,690,050	41,775	114,882	313,315	2,572,000	48,482	133,327	363,618
Lower Montney	2,690,050	80,382	221,052	602,868	2,572,000	99,839	274,557	748,792

Table 4. Total gas-in-place estimates for free gas. See Appendix D.

Total Gas in Place

Summation of the estimated adsorbed gas-in-place and free gas-in-place for each unit results in an estimate of total gas-in-place. The products for each case are presented in Table 5. Total gas maps for low, medium and high cases are in Appendix D and are displayed in Bcf/GSU. The most obvious difference between the two methods employed is use of total "shale thickness" in method one versus the total unit thickness of method two. This resulted in a much greater adsorbed estimates by method two and higher average TOC estimates for method one.

Identification of trends or "play fairways" where the units have the highest potential for shale gas development can be interpreted by either clearing the grids of low prospective areas (*i.e.* too deep) or by combining the gas-in-place grids with others through logic statements. As an example, to identify "play fairways" the factors of gas-in-place per gas spacing unit, average TOC, depth and thermal maturity were combined. This was accomplished through mathematically overlying the maps using a logic statement (*i.e.* IF statement) to identify areas satisfying the different cut-offs. For this study the total potential shale gas-in-place is defined as the play area with greater than 5 Bcf/GSU and an average TOC greater than 1.5 percent for method one and one percent for method two. A summary of the total gas in-place is presented in Table 5 Appendix E contains maps for each unit where the gas-in-place and average TOC contents meets the criteria selected.

	Method one				Method Two			
	Area Ha	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf	Area Ha	Low TGIP-Bcf	Middle TGIP-Bcf	High TGIP-Bcf
Total Gas In place								
Doig	8,799,975	95,666	233,237	538,424	8,390,125	177,376	472,346	1,237,695
Doig Phosphate	8,799,975	45,549	109,053	244,357	8,390,125	39,215	96,209	224,322
Upper Montney	9,786,825	78,205	195,012	466,228	8,390,125	103,617	257,011	609,513
Lower Montney	9,786,825	173,058	440,191	1,083,625	8,390,125	255,072	627,872	1,471,583
Total Gas In Place								
After 1500m&Tmax455ºC Cuttoffs								
Doig	1,769,500	15,940	38,364	86,723	1,602,650	29,794	79,682	209,940
Doig Phosphate	1,769,500	8,198	19,318	42,121	1,602,650	6,065	14,654	33,341
Upper Montney	1,754,950	24,980	63,706	157,419	1,602,650	14,323	34,722	79,424
Lower Montney	1,754,950	16,911	41,028	93,967	1,602,650	45,860	111,866	258,455
Total Gas In Place								
After 2000m&Tmax455ºC Cuttoffs								
Doig	4,188,550	41,928	101,645	232,519	4,015,900	84,764	226,563	596,503
Doig Phosphate	4,188,550	22,643	53,655	118,143	4,015,900	18,981	46,091	105,722
Upper Montney	4,174,000	37,453	92,523	218,060	4,015,900	45,549	111,248	257,552
Lower Montney	4,174,000	77,241	196,958	486,578	4,015,900	131,520	320,133	737,114
Total Gas In Place								
After 2500m&Tmax455ºC Cuttoffs								
Doig	5,425,800	76,181	185,879	429,648	5,144,000	115,499	305,797	795,289
Doig Phosphate	5,425,800	34,169	81,850	183,576	5,144,000	30,042	73,309	169,477
Upper Montney	5,380,100	62,774	156,880	376,311	5,144,000	80,066	196,494	458,369
Lower Montney	5,380,100	107,484	275,255	684,173	5,144,000	171,173	417,224	962,793

Table 5. Total gas-in-place estimates for sum of adsorbed and free gas. See Appendix D.

Doig

Within the play area defined, the Doig Formation likely contains a total in-place shale gas potential of approximately 40 Tcf to 200 Tcf (Table 6). Of the two methods used, the first yielded a much higher estimation of total gas in-place. This is primarily due to a higher estimated average TOC determined by the Passey *et al.* (1990) log-derived TOC estimation. Interestingly, the second method resulted in a determination of a much higher free gas component, as a result of using the entire formation isopach in the analysis.

Doig Phosphate

The Doig Phosphate play area is extensive with a total of approximately 70 Tcf in-place (Table 6). The two methods used to determine gas-in-place returned very different results for all the units except the Doig Phosphate, with the only appreciable difference being that the Passey *et al.* (1990) method resulted in higher average TOC values.

Upper Montney

The defined play area is very similar between the two methods. However, calculations following the procedure of Issler *et al*. (2002) resulted in a much higher average gas in-place estimate due to larger free gas component and a higher estimated average TOC. Total shale gas potential is 30 – 200 Tcf in-place (Table 6).

Lower Montney

This unit had the greatest discrepancy of gas-in-place as determined by the two methods. Free gas estimated by method two (based on Issler *et al.* (2002)) resulted in a much higher estimate than method one (from Passey *et al*. (1990). Notionally, this is a result of using the total isopach versus the shale isopach determined in method one. In addition, method two appears to yield a much higher estimate of average TOC. This is likely a result of the log derived Passey *et al.* (1990) method requiring a barren zone which was usually picked within the Montney. Total in-place shale gas potential is estimated between 50 – 500 Tcf (Table 6).

		Based on TGIP Middle Case					
		Method One			Method Two		
Doig		TOC>1.5	TOC>2	TOC>3	TOC>1	TOC>2	TOC>3
Bcf> 5	Area Ha	2,961,750	1,968,475	199,850	373,400	95,600	19,100
	TGIP-Bcf	184,277	114,124	10,077	38,507	10,231	2,279
Bcf> 10	Area Ha	1,667,950	960,000	82,725	373,400	95,600	19,100
	TGIP-Bcf	148,490	86,359	7,378	38,507	10,231	2,279
Doig Phosphate							
Bcf> 5	Area Ha	2,142,525	1,786,250	666,300	1,900,475	875,325	0
	TGIP-Bcf	70,893	58,989	19,826	67,454	32,246	0
Bcf> 10	Area Ha	586,950	495,475	155,475	522,500	242,175	0
	TGIP-Bcf	27,778	23,382	6,801	28,273	13,686	0
Upper Montney							
Bcf> 5	Area Ha	1,354,725	458,875	17,825	2,483,975	864,075	103,950
	TGIP-Bcf	59,221	15,327	544	207,214	79,084	7,757
Bcf> 10	Area Ha	521,925	126,500	2,700	1,833,425	699,500	71,450
	TGIP-Bcf	36,372	6,254	121	188,980	74,201	6,792
Lower Montney							
Bcf> 5	Area Ha	444,725	170,900	6,350	3,289,100	1,216,650	35,675
	TGIP-Bcf	47,525	17,825	592	538,850	214,282	5,368
Bcf> 10	Area Ha	430,225	169,850	6,350	3,289,100	1,216,650	35,675
	TGIP-Bcf	47,094	17,796	592	538,850	214,282	5,368

Table 6. Total gas-in-place estimates for “play fairways” based on the middle case of each method.

Other Play Types

Other play types and potential trends can be identified using different criteria. For example, the current production from the upper Montney Formation in the areas around the Dawson, Swan, and Saturn fields are from silt rich shale (Walsh *et al.*, 2006). These reservoirs which are considered “tight” reservoirs (Arc, 2006) are comprised of silt to clay sized mudstone (Fritz and Moore, 1988). Production is generally from intervals greater than 1800m depth and high reservoir temperatures (greater than 70°C). As a result the contribution of adsorbed gas is likely minor in comparison to the free gas component.

The free gas grids from method two were cleared using a depth cut-offs of greater than 1800m and less than 2700m (the approximate depth range encompassing the producing fields mentioned). The resultant maps are in Appendix E and the total gas-in-place estimates are in Table 7.

	Based on Free Gas Totals		
	Method Two		
	Limits: >1800m <2700m		
Upper Montney	Low	Middle	High
Area Ha	1,080,950	1,080,950	1,080,950
Mean	8	23	62
TGIP-Bcf	34,542	94,991	259,066

Table 7. Free gas-in-place total (Bcf), area (ha) and grid mean (Bcf/GSU) for the upper Montney in the depth range of 1800m to 2700m corresponding to the upper Montney pools at Dawson and Swan.

Summary

This study confirms previous work (Faraj *et al*, 2002) that the shale gas potential of the Triassic Doig and Montney formations is large. However gas-in-place estimates however must be taken in context and not compared directly with gas-in-place estimates for conventional plays. Many critical reservoir characteristics are currently poorly understood. Future consideration must be given to estimate pool distribution and to more accurately estimate the total potential of the units discussed.

Acknowledgements

I would like to thank Dr. Barry Ryan for his thoughtful insights, Cassandra Lee for assistance in producing this study and earlier drafts. Jessica Neal for her work on preparing the maps and tables. This report has benefited greatly from reviews by Alf Hartling, Dr. Vic Levson, and Fil Ferri.

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Appendix A.
Log derived TOC data file and comma separated data files of TOC log data for each well.

Appendix B.
Comparison of log derived TOC data to sample data for several wells.

Appendix C.
Maps of input grids for calculations.

Appendix D.
Gas in Place Maps
Free gas, adsorbed gas and total gas in-place for each method

Appendix E.