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Impact of the Nanopore Size on Estimation of Gas-in-Place for Marcellus Shale Gas Reservoirs

Alexandra Power Stockdale

**Thesis submitted
to the Statler College of Engineering and Mineral Resources
at West Virginia University**

**in partial fulfillment of the requirements for the degree of
Master of Science in
Petroleum and Natural Gas Engineering**

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Pores, Pore Proximity, Critical Temperature, Critical Pressure, Correlations
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ABSTRACT

SIZE EFFECTS OF NANOPORES IN DRY-NATURAL GAS RESERVOIRS OF THE MARCELLUS SHALE ON GAS-IN-PLACE CALCULATIONS

Alexandra Power Stockdale

Nanopores, pores less than 10 nanometers as defined for this study, have significant impact on the flow, production, and storage potential. These impacts, in turn, effect gas-in-place calculations and overall reservoir estimations.

This research studies a dry-gas reservoir in the Marcellus Shale. A dry-gas reservoir exhibits the same behavior as a wet gas reservoir under confinement effects of nanopores. Therefore, the published correlation for estimating the impact of nanopore size on the critical hydrocarbon properties are utilized in this study.

By use of the gas compositional analysis, the effects on the gas-in-place calculations of the confined pores were compared to the traditional reservoir calculations for unconfined pores. After applying the corrections to the critical temperature and pressure, the z-factor was found by the use of a z-factor chart. This z-factor was incorporated into the gas-in-place calculations and created an easily interpreted reservoir result in millions of cubic feet of gas.

Concluding the study, it was found that the gas-in-place calculations deviate by up to 8% when using confined pores versus unconfined pores. The pore sizes of 2nm, 4nm, and 5nm changed the gas-in-place calculation by -8%, 2% and 6% respectively when compared to the unconfined pore size range of 10nm-100nm. The actual field data for the calculations created a simple comparison of gas-in-place calculations of 2nm, 4nm, 5nm, and >10nm pore sizes, yielding 2 MMCF, 2.2 MMCF, 2.3 MMCF and 2.16 MMCF of gas-in-place per acre foot.

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Chapter 1 Introduction

Nanopores have effects on the gas storage and well-life in shale reservoirs that unconfined pores do not. The nanopores may increase or decrease the gas-in-place estimation. There are approximately 354 trillion cubic feet of gas reserves within the Marcellus Shale so it is integral that the United States can have a good estimate of the gas-in-place in each reservoir.

Although there are vast amounts of natural gas in the Marcellus Shale, the changing economic market for the gas in the United States places an importance on knowing the gas-in-place in an area prior to drilling. Previously, when the natural gas prices were high, the production of natural gas was so lucrative that a 10-12% difference in the estimates of natural gas-in-place would not hurt a company economically. With the lower prices in natural gas, the margins to make money become slimmer and it becomes more important to have an accurate estimate of how much gas a reservoir contains.

The properties of the gas like compressibility factor, adsorption, and viscosity will be studied for different size pores. The pore size effects all of these properties and these properties have an impact on gas-in-place estimation. Based on the resultant properties, the gas-in-place will be calculated by applying the volumetric method. Although, this topic has been the focus of previous papers, these papers were looking into gas condensate and oil reservoirs. In the aforementioned gas condensate papers the results revealed that storage potential and well-life were significantly underestimated (Reed & Wang, 2009).

Pore structure determines storage capacities and the flow of gas from the matrix (Curtis, Ambrose, & Sondergeld, 2010). Most of the gas storage occurs in the matrix in fine-grained hydrocarbon reservoirs (Curtis et al., 2010). Pore location, whether the pore is in

the organic or inorganic material, determines the wettability of the shale (Curtis et al., 2010). Along with the pore location, the increase and decrease in pore sizes changes the physics of the fluid flow. Changing the physics of the fluid flow terminates the ability of Darcy's Law to describe fluid flow (Curtis et al., 2010). Small pores, pores a few nanometers in diameter, may have large amounts of adsorbed gas content compared with the free gas content (Ambrose, Hartman, & Akkutlu, 2011). The pores play such a significant role that even the shape of pores can affect the storage. Round pores would be much less prone to collapse from an external pressure than linear or crack-like pores (Curtis et al., 2010).

Deliverability is the tested and proved ability of a well to produce. A realistic expectation of deliverability is hard to conject when the reservoir is 8,000 feet below surface elevation. Deliverability increases with maturity in the reservoir but there is a gas-generation window of thermal maturity. Gas shales contain amounts of organic matter in disparate grades of maturation. The window is different for different shales, but deliverability of shales depends on the composition, porosity and permeability.

Grain size less than 5 micrometers is usually the cut-off to define microstructure in shale. There are many problems with defining shales and their typical or "standard" parameters because the components cannot be identified by simply looking at them. Shale microstructure is mainly explored by use of Scanning Electron Microscopy (SEM), X-ray imaging, Transmission Electron Microscopy (TEM) or Scanning Acoustic Microscopy (SAM). Most recently three dimensional images have been developed with a resolution of 4-5 nm pores (Sondergeld, Ambrose, & Rai, 2010).

Anisotropy, is one thing property inherent to. It causes seismic imaging problems and directly affects AVO (Amplitude Variation with Offset), which tries to identify pore fluid and hydrocarbon interpretations. Estimating gas-in-place and deliverability can prove troublesome owing to pore volume inaccuracies. The pore volumes are usually measured with direct and indirect methods. The direct methods involve visual assessments and can be bounded by two dimensions. Using only two dimensions is a large issue because of the complex nature of the pore structure (Sondergeld et al., 2010). The indirect methods use gas or fluids to flow through the pore space and interpret porosity. Grain size in shales are $<1/256$ millimeters or <39 micrometer and can create challenges in measurement and description (Sondergeld et al., 2010). The NETL (National Energy Technology Laboratory), like many laboratories that specialize in shale gas research, in Morgantown West Virginia has capabilities to go to micrometers but they do not have the ability to see nanometers. Shale has such small grain sizes caused by compaction when it was being formed. This compaction creates lots of anisotropic mechanical, elastic, and transport properties (Sondergeld et al., 2010).

The Marcellus Shale was formed by large amounts of Plankton accumulating on the sea floor and being compacted over approximately 400 million years. This plankton was broken down and decomposed and along with other organic material, like sea plants, it formed kerogen. Kerogen is a mixture of organic materials and the higher the kerogen content the higher the BTU value of the shale. The kerogen content is often reported as Total Organic Content (TOC) as a weight percentage. Organics are important to any economic assessment because they lower density, increase porosity, provide the source

of the gas, impart anisotropy, change wettability and enable adsorption (Sondergeld et al., 2010).

Chapter 2 Literature Review

2.1 Pore Size

Methane gas shows the effects of confinement on the critical properties when pore diameters are under 10nm (Rezaveisi, Javadpour, & Sepehrnoori, 2013). Shale gas can be found in pore sizes from 0.5 to 100 nm so the pore proximity must be considered (Devegowda, 2012). Pore proximity is the proximity of a molecule to a molecule or a molecule to a pore wall within the pore. Conventional reservoirs have much larger pore sizes so the interaction between the hydrocarbon molecules and pore walls is insignificant because the pore sizes are larger than molecular mean free paths (Jin, Ma, & Jamili, 2013).

Pore sizes in shales are not homogeneous. This homogeneity is significant because when the sizes of the pores change, the flow within the pores change so using an average pore size when calculating gas-in-place will not be accurate. Beskok and Karniadakis (1999) have attempted to correct this problem by looking at the pores like a bundle of tubes with different diameters (Michel, 2011) (Beskok & Karniadakis, 1999).

Scanning-electron-microscopy was used to confirm pore radii ranging from a few nanometers to tens of nanometers in shales (Curtis et al., 2010). Because Reynolds number is a function of grain diameter and Darcy's Law depends on the Reynolds number, when the grain size gets to a few nanometers the gas flow through porous media can no longer be described under the assumption of no-slip (Darcy's Law). The simplified models with Darcy's Law can underestimate productive well life for infinite acting flow so they must be modified to account for the flow regimes in nanopores. Nanopores have different flows caused by the interaction of the molecules with the pore walls and

transitions from the no-slip to slip regimes (Michel, 2011). The Beskok-Karniadakis Model (1999) is usually selected for describing the transport during production from shale gas formations because it describes all four expected regimes in capillary flow (Michel, 2011).

The permeability of the Marcellus Shale is also affected by pore size. Permeability in the Marcellus Shale decreases with an increase in confining pore pressure (Reed & Wang, 2009). Reduction in porosity creates confining pore pressure and the effect of the confining pore pressure is create by the Klinkenberg (1941) slippage effect (Reed & Wang, 2009). The Klinkenberg (1941) slippage effect says that, “gas flow becomes nonviscous when pore sizes are 1 to 1,000 times larger than the mean free path of gas molecules (Javadpour, Fisher, & Unsworth, 2007).”

2.2 Real Gas Deviation Factor or Z factor

The ideal gas equation, equation 2.1, can also be used to describe natural gas. The natural gas behavior is not drastically different from an ideal gas so a correction factor can be used to adjust the ideal gas equation to suite a real gas. The correction factor that is used is called the z factor or compressibility factor. This factor is also sometimes called the gas deviation factor because it describes the deviation of a real gas from an ideal gas. The z factor can also be expressed as shown in equation 2.2. Equation 2.2 shows that the z-factor is simply the volume actually occupied by a real gas over the volume occupied by an ideal gas at the same pressure and temperature (McCain, 1990).

$$pV = znRT \tag{2.1}$$

$$Z = \frac{V_{real\ gas}}{V_{ideal\ gas}} \quad (2.2)$$

Where, p is pressure, V is volume, z is compressibility, n is the molar mass or number of moles, R is universal gas constant, and T is temperature.

The z factor or real gas deviation factor is calculated with pressure, temperature and the gas constant. Pressure and temperature both change under confined conditions. Therefore, calculations of transport, storage, and gas-in-place can be greatly affected by confinement because of the effects it has on the critical properties. The work of Devegowda (2012) shows the adjustment of critical values changes the real gas deviation factor significantly. Furthermore, a nanoporous reservoir may have enhanced gas transport resulting from the lower viscosity because of confinement effect (Devegowda, 2012).

2.3 Porosity

Hg porosimetry has shown that the porosity of the shales is largely determined in the pore volume development in pores less than 10µm (Bustin et al., 2008). Porosity values of gas-shale systems range from 2 to 15% (Curtis J., 2002). Chesapeake (2008) conducted a study using an assumed porosity of 10% in organic matter, and the total porosity and TOC values for Marcellus Shale in Appalachian Basin as shown in Table 2-1, estimated porosities in organic matter are 1.2% of the bulk volume. That is 18.5% of all pores in the Marcellus Shale are in organic matter. These values increase with the assumed porosity in organic matter.

Table 2-1 General Marcellus Shale Porosity (Chesapeake, 2008).

Item	Marcellus Shale
------	-----------------

Total porosity of shale	6.5%
Assumed Porosity in Natural Fractures	<0.5%
Assumed Porosity in Hydraulic Fractures	<0.2%
Total Organic Content (TOC)	~12% (6 wt %)
Assumed porosity in organic matter	10%
Porosity of organics in shale	~1.2%
Porosity in nonorganic rock matrix	>4.6%

Shales are made up of the nonorganic matter and the organic matter, both forming complicated pore matrices. During stimulation or fracturing, these pore networks may be opened and connected to each other, but they also may not open making the porosity and pore-volume values in natural and hydraulic fractures difficult to measure or estimate. Organic matter pore volumes are usually estimated by assuming they are a function of TOC (total organic content) and the porosity in the organic matter. The porosity in the organic matter can play an important role in the higher-than-expected gas production from shales (Reed & Wang, 2009).

The porosity of shales can be divided into two major groups. The shale with pore sizes from 10 to 1000 nm have little porosity while the pores with sizes less than 10 nm have high porosity (Bustin et al., 2008).

2.4 Adsorption

Adsorption is the accumulation of gases or liquids on the surface of a solid. Shales are made up of four types of solid porous media: nonorganic matrix, organic matter, natural fractures, and hydraulic fractures. Adsorption is commonly noticed in organic matter with pores sizes ranging from 5-1,000nm. Organic matter also has 5 times higher porosity than nonorganic (Reed & Wang, 2009). While adsorbed gas may increase the amount of hydrocarbons in the organic matter, it may actually hinder production because the layer of adsorbed gas increases drag on gas molecules which then decreases permeability (Reed & Wang, 2009).

Although organic matter typically has higher porosity than other matter it sometimes has such small pores that only diffusion will enable flow (Reed and Wang, 2009). Diffusion is defined for this paper as hydrocarbons moving within the solid part of the rock, not as free gas, from high pressure to low pressure. Diffusion is the movement of the hydrocarbons from a high concentration area to a low concentration area.

When shale is undisturbed and under a constant pressure or at equilibrium, the hydrocarbon can be distributed throughout the rock as compressed gas, or it may lay on the surface of the kerogen materials as adsorbed gas and dispersed in the kerogen materials as dissolved gas (Bustin et al., 2008). When a reservoir is tapped by drilling a well or inducing a fracture, the equilibrium is disturbed, and molecules start flowing toward the low pressure zone. The molecules do not all flow at once though, first, the free gas or compressed gas is produced. Then, the adsorbed gas on the exterior of the kerogen walls desorb. The desorption allows the gas to expand and increases pore pressure. The gas will then flow from the increased pressure areas to the areas where the gas is being

produced and the pressure is lower. This desorption of gas allows for even the tiniest of pores to produce some gas.

The volume of adsorbed gas in shales is reliant on surface area, pressure, temperature, and sorption affinity (Bustin et al., 2008). With pores in the nanometer size range, the surface area is greatly increased. The smaller pore sizes also mean that the amount of free gas decreases and the adsorbed gas storage capacity increases. Generally, for pores smaller than 0.01 μm , the adsorbed gas storage surpasses the compressed gas storage (Beliveau, 1993). Nanopores with sizes in the 3-100 nm range have a portion of the total pore volume that is occupied by a finite-size adsorption layer and not available for the free gas molecules (Ambrose, Hartman, & Akkutlu, 2011). Adsorption in gas shales is dependent on reservoir temperature and pressure and the abundance, maturity, and type of kerogen (Bustin et al., 2008).

For reservoirs with a large amount of the gas in the form of adsorbed gas, the gas-in-place calculation is usually overestimated. The over-estimation can be as high as 40% (Ambrose et al., 2011).

2.5 Flow

There are four types of fluid flows in gas shales: (1) free gas flow, (2) desorption, (3) diffusion, and (4) imbibition suction. Free gas is the gas that is easily produced from the pores and exists in a gaseous phase and not as a solution or dissolved in reservoir fluids. Free gas flow can be Darcy or Non-Darcy type flow. The Darcy type flow is usually found in natural and hydraulic fractures while the non-Darcy type is found in the matrices as a result of the slippage effect (Reed & Wang, 2009). The slippage effect is a theory to describe the interaction between the pore wall and hydrocarbons that are “slipping” by it.

When the pore size is reduced to be almost the size of the mean free path of a hydrocarbon molecule, then the molecule will have more interaction with the pore wall and may “slip” when it touches the pore wall (Rushing, Newsham, & Fraassen, 2003).

Adsorbed gas is attached to the surface of the pores. When the pressure is lowered in the reservoir, after the free gas is produced, the adsorbed gas is released and desorption occurs. Diffusion is similar to desorption in that when the molecules as free gas and adsorbed gas are produced there is less of a concentration of molecules. So the molecules that are trapped in the matrix, usually in the nanopores, travel from the high concentration areas to the low concentration areas. This occurs through low permeability zones.

Lastly, the imbibition suction occurs when the reservoir has low initial water saturation (subirreducible initial water saturation) (Bennion & Thomas, 1996). This subirreducible initial water saturation can prevent water from being produced and create a suction of water. Although, oil and condensate reservoirs are also subject to imbibition suction, this will not be emphasized in this research because the focus is on dry-gas reservoirs.

2.6 Critical Temperature and Critical Pressure

Natural gas is essentially just an energy source and because temperature is a physical measure of kinetic energy of a material it makes sense to describe a gas reservoir with the temperature (McCain, 1990). Kinetic energy increases when temperature increases and heat is added to a material. Increasing kinetic energy also causes an increase in molecular motion, moving the molecules of gas further apart (McCain, 1990).

Pressure is also used when explaining a reservoir. Pressure increases with confinement because pressure is a description of the number of times the particles of a gas hit the pore wall or wall of the container (McCain, 1990).

Critical temperature and critical pressure are words commonly used when describing gas inside a reservoir. The phases of the gas are defined by the temperature and pressure at which the phases change. The phase diagram in fig. 2-1 should help to clarify where the phases begin and end. The limit where the gas turns to liquid is called the critical point, point C in fig. 2-1. The temperature and pressure at the critical point are called the critical temperature and critical pressure.

Figure 2-1 Typical phase diagram of a pure substance (McCain, 1990).

The reduced temperature and reduced pressure are the temperature and pressure normalized at the critical point. The equations for the critical temperature and critical pressure are shown in equation 2.3 and 2.4 respectively.

$$T_r = \frac{T}{T_c} \quad (2.3)$$

$$p_r = \frac{p}{p_c} \quad (2.4)$$

Where T_r and p_r are reduced temperature and reduced pressure, T is temperature, p is pressure, T_c is critical temperature, and p_c is critical pressure.

$$T_{pc} = \frac{T}{T_{pc}} \quad (2.5)$$

$$p_{pr} = \frac{p}{p_{pc}} \quad (2.6)$$

Equation 2.5 and 2.6 show the pseudocritical temperature and pseudocritical temperature formulas. The pseudocritical temperature and pressure are used to find the compressibility of a natural gas because a natural gas is a mixture of many components. The pseudocritical temperature and pressures are not the critical points for the mixture, but they are the values that are needed to compare the corresponding states of different gases on the z-factor chart (shown in Appendix A).

According to Ma (2013), the critical temperature and critical pressure under nanopore confinement are changed by the molecule-pore wall interactions. He also mentions that when studying pore sizes from 10 to 2 nm the two-phase region of a wet-gas shrinks and makes the wet-gas behave like a dry gas (Ma, Jin, & Jamili, 2013).

Therefore, the work of Devegowda (2012) on the phase behavior and changes to critical properties of gas condensates in shales due to pore proximity effects. Devegowda showed that there are quantified changes in the critical properties from the changing pore sizes and he provided correlations to explain the changes. He used equations 2.7 and 2.8 from the work of Singh et al. (2009) to show the shift of critical temperature and pressure.

$$\Delta T_c = \frac{T_{cb} - T_{cp}}{T_{cb}} \quad (2.7)$$

$$\Delta P_c = \frac{P_{cb} - P_{cp}}{P_{cb}} \quad (2.8)$$

Where P_{cp} and T_{cp} are the critical pressure and temperature in confined pores and P_{cb} and T_{cb} are the corresponding values in bulk.

Devegowda (2012) improves on the work of Singh et al. (2009) and uses the numerical experimental data from Singh et al. (2009) but Devegowda (2012) extrapolated the data to heavier compounds on the basis of their corresponding molecular weights. The figures 2.2 and 2.3 show the extrapolated deviations in critical temperature and pressure for hydrocarbon molecules from methane through n-decane (up to the molecular weight of 250) for pore diameters of 2nm, 4nm, and 5nm (Devegowda, 2012).

Figure 2-2 Relative deviation of critical pressure (Devegowda, 2012).

Figure 2-3 Relative deviation of critical temperature (Devegowda, 2012).

Chapter 3 Methodology

The estimation of hydrocarbons-in-place can be completed by use of either the material balance method or the volumetric method. For this project, the volumetric method will be used. The volumetric method consists of approximating the volume of the reservoir and then estimating how much hydrocarbon is in that volume. For this study, the hydrocarbons will be estimated for a Marcellus Shale Reservoir. In the Marcellus Shale, the hydrocarbons are found in both an adsorbed form and as free gas. The free gas only exists in pore space so the volume of the pores is important for finding the volume of hydrocarbons. A simplified version of the volumetric method can be seen below:

$$V_b(\text{Bulk Volume}) = A \times h = \text{Area} \times \text{Height} \quad (3.1)$$

$$V_p(\text{Pore Volume}) = A \times h \times \phi = \text{Area} \times \text{Height} \times \text{Porosity} \quad (3.2)$$

$$V_{HC}(\text{Hydrocarbon Volume}) = A \times h \times \phi \times S_{HC} = \text{Area} \times \text{Height} \times \text{Porosity} \times \text{Saturation of Hydrocarbons} \quad (3.3)$$

$$S_{HC} = S_o + S_g = \text{Saturation of Oil} + \text{Saturation of Gas} \quad (3.4)$$

$$S_{HC} = 1 - S_{wi} = 1 - \text{Irreducible Water Saturation} \quad (3.5)$$

In equation 3.1 the bulk volume of the reservoir is found by multiplying the approximate area of the reservoir by the formation height. Equation 3.2 shows the pore volume equation, which includes the bulk volume multiplied by the porosity. Then, in equation 3.3, the hydrocarbon volume is calculated by multiplying the pore volume by the saturation of the hydrocarbons. The saturation of the hydrocarbons, shown in equation

3.4, is found by adding the saturation of oil to the saturation of gas or by using equation 3.5 and subtracting the irreducible water saturation from 1.

The focus of this study is on dry-gas reservoirs, but whether you are examining at oil or gas reservoirs, the hydrocarbon in place calculations depend on area, height, saturation, and porosity. For this study, the absorbed gas volume will be ignored.

The initial gas in place formula is shown below:

$$G(\text{Initial Gas in Place}) = \frac{1.540Ah\phi(1-\overline{S_{wi}})}{T_f} \left(\frac{p}{z}\right), \text{MMCF} \quad (3.6)$$

$$G = \frac{1.540 \cdot V_R \cdot \overline{\phi} \cdot \overline{S_g}}{T_f} \left(\frac{p}{z}\right), \text{MMCF} \quad (3.7)$$

In both equation 3.6 and 3.6, T_f is the formation temperature, p is the formation pressure, and z is the z-factor and $S_{HC} = S_g$. The factors like pressure, saturation, porosity, and temperature must be found by use of core samples, well log data, inferences and a combination of the three. To obtain height, porosity and water saturation, the data must be collected, then interpreted and then finally integrated. Saturation and porosity pose some difficulty in estimation because the reservoirs are heterogeneous. Table 3-1 shows the parameters that were used:

Table 3-1 Reservoir parameters used in the gas-in-place calculations.

Variable		Units
Area (A)	1	acre
height (h)	1	foot
porosity (ϕ)	5	%
Irreducible Water Saturation	20	%

Gas composition also plays a large role in the gas-in-place estimation because the composition effects the critical properties, like critical temperature and critical pressure, which in turn effects the gas compressibility. Table 3-2 shows the components of typical petroleum gases.

Table 3-2 Composition of typical petroleum gases (McCain, 1990).

Components of Typical Petroleum Gases	
Natural Gas	
Hydrocarbon	
Methane	70-98%
Ethane	1-10%
Propane	Trace-5%
Butanes	Trace-2%
Pentanes	Trace-1%
Hexanes	Trace-0.5%
Heptanes +	Trace-0.5%
Nonhydrocarbon	
Nitrogen	Trace-15%
Carbon dioxide	Trace-5%
Hydrogen sulfide	Trace-3%
Helium	Up to 5%, usually trace or none

Two gas compositions for two different areas of the Marcellus Shale will be compared. The first composition is from a compositions analysis of the separator gas in the Mary Field of Wetzel County, West Virginia. The second composition's exact location is unknown because the company that drilled the well did not want to disclose it, but the approximate location is the

Marcellus Shale in Pennsylvania. The comparisons will show how the gas composition effects the gas-in-place. The following compositional data was used in this study:

Table 3-3 Study #1 included separator gas compositional analysis from gas produced in the Marcellus Shale.

Compositional Analysis of Separator Gas				
Sample Date and Time: March 5, 2014 at 1620 hours				
Sampling Conditions: 685psia at 77°F				
Opening Conditions: 788 psia at 120°F				
<i>Component</i>	<i>Mole %</i>	<i>GPM at 14.85 psia</i>	<i>Weight %</i>	<i>Molecular Weight</i>
<i>CO₂(Carbon Dioxide)</i>	<i>0.156</i>	<i>0.00000</i>	<i>0.62800</i>	<i>44.01000</i>
<i>N₂ (Nitrogen Gas)</i>	<i>0.465</i>	<i>0.00000</i>	<i>0.33000</i>	<i>28.01300</i>
<i>H₂S(Hydrogen Sulfide)</i>	<i>0</i>	<i>0.00000</i>	<i>0.00000</i>	<i>34.08200</i>
<i>CH₄ (Methane)</i>	<i>77.299</i>	<i>0.00000</i>	<i>59.77100</i>	<i>16.04300</i>
<i>C₂H₆(Ethane)</i>	<i>14.775</i>	<i>3.97600</i>	<i>21.41200</i>	<i>30.07000</i>
<i>C₃H₈ (Propane)</i>	<i>4.885</i>	<i>1.35700</i>	<i>10.38200</i>	<i>44.09700</i>
<i>i-C₄H₁₀ (Isobutane)</i>	<i>0.573</i>	<i>0.18900</i>	<i>1.60400</i>	<i>58.12300</i>
<i>n-C₄H₁₀(Butane)</i>	<i>1.156</i>	<i>0.36800</i>	<i>3.23900</i>	<i>58.12300</i>
<i>i-C₅H₁₂ (Isopentane)</i>	<i>0.239</i>	<i>0.08800</i>	<i>0.83200</i>	<i>72.15000</i>
<i>n-C₅H₁₂ (Neopentane)</i>	<i>0.23</i>	<i>0.08400</i>	<i>0.80100</i>	<i>72.15000</i>
<i>C₆H₁₄ (Hexane)</i>	<i>0.129</i>	<i>0.05400</i>	<i>0.53500</i>	<i>86.17700</i>
<i>C₇ (Heptanes)</i>	<i>0.053</i>	<i>0.02300</i>	<i>0.24800</i>	<i>96.68200</i>
<i>C₈ (Octanes)</i>	<i>0.027</i>	<i>0.01200</i>	<i>0.13700</i>	<i>107.16300</i>
<i>C₉ (Nonanes)</i>	<i>0.006</i>	<i>0.00300</i>	<i>0.03700</i>	<i>120.09000</i>
<i>C₁₀+ (Decanes Plus)</i>	<i>0.007</i>	<i>0.00400</i>	<i>0.04400</i>	<i>136.61400</i>

Table 3-4 Compositional data used in Study #2.

Component	Mole Fraction
CO₂(Carbon Dioxide)	0.00089
N₂ (Nitrogen Gas)	0.00354
H₂S(Hydrogen Sulfide)	0.00000
CH₄ (Methane)	0.74305
C₂H₆(Ethane)	0.15185
C₃H₈ (Propane)	0.05874
i-C₄H₁₀ (Isobutane)	0.00713
n-C₄H₁₀(Butane)	0.01717
i-C₅H₁₂ (Isopentane)	0.00370
n-C₅H₁₂ (Neopentane)	0.00537
C₆H₁₄ (Hexane)	0.00500
C₇+	0.00351
M.W. C₇+	136.00000

The gas compositions then must be corrected for mole fractions because not all of the components are found in each sample. The corrected compositions are shown below:

Table 3-5: Corrected compositions for Study #1 for mole fractions.

Component	Mole Fraction	Corrected Mole Frac.
CO2(Carbon Dioxide)	0.00156	0.00156
N2 (Nitrogen Gas)	0.00465	0.00465
H2S(Hydrogen Sulfide)	0.00000	0.00000
CH4 (Methane)	0.77299	0.77299
C2H6(Ethane)	0.14775	0.14775
C3H8 (Propane)	0.04885	0.04885
i-C4H10 (Isobutane)	0.00573	0.00573
n-C4H10(Butane)	0.01156	0.01156
i-C5H12 (Isopentane)	0.00239	0.00239
n-C5H12 (Neopentane)	0.00230	0.00230
C6H14 (Hexane)	0.00129	0.00129
C7+	0.00093	0.00093

Table 3-6: Corrected compositions for Study #2 for mole fractions.

Component	Mole Fraction	Corrected Mole Frac.
CO2(Carbon Dioxide)	0.00089	0.00089
N2 (Nitrogen Gas)	0.00354	0.00355
H2S(Hydrogen Sulfide)	0.00000	0.00000
CH4 (Methane)	0.74305	0.74308
C2H6(Ethane)	0.15185	0.15185
C3H8 (Propane)	0.05874	0.05874
i-C4H10 (Isobutane)	0.00713	0.00714
n-C4H10(Butane)	0.01717	0.01717
i-C5H12 (Isopentane)	0.00370	0.00370
n-C5H12 (Neopentane)	0.00537	0.00537
C6H14 (Hexane)	0.00500	0.00500
C7+	0.00351	0.00351

The corrections shown in Table 3-4 and 3.5 are performed to because the data for composition #1 includes Heptanes, Octanes, Nonanes, Decanes Plus, whereas the composition #2 data includes only up to C7+. To make the data sets comparable the mole fractions were adjusted. Once the corrected compositional data is obtained, the next step is to assess the critical temperature and pressure for the unconfined pore size (10-100nm), 2nm pore size, 4nm pore size, and 5nm pore size. Please see appendix A for the critical temperature and pressure results. The correlations for the critical temperature and pressure due to confinement were found using the correlations by Deepak illustrated in the following Figures:

Figure 3-1: Critical Pressure Correlation for Molecular Weight (Devegowda, 2012).

Figure 3-2: Critical Temperature Correlation for Molecular Weight (Devegowda, 2012).

Where P_{cp} and T_{cp} are the critical pressure and temperature in confined pores and P_{cb} and T_{cb} are the corresponding values in bulk. The results of the temperature and pressure correlations are shown in Appendix A. Next, the summated critical temperature and pressure are found. To find the summated critical pressure, the corrected mole fraction for each component is multiplied by the correlated critical pressure of each component. These multiplied results are then added together, which is why the result is called the summated critical pressure but it essentially representative of a weighted average. To find the summated critical temperature the corrected mole fraction for each component is multiplied by the correlated critical temperature of each component. These multiplied results are then added together. Then the summated critical temperature (in Rankin) and pressure (in psia) are adjusted by the formation temperature and pressure to get the pseudo reduced temperature and pressure respectively. The pseudo reduced

temperature and pressure are used on the compressibility chart or z-factor chart. This chart is shown in appendix A.

Once the z-factors are found for each condition they are applied to the gas-in-place calculation. The formation pressure and temperature for the Marcellus Shale are usually between 3000-4000psia and 115-135°F. The same methodology for each of the pore sizes was completed for each of the following formation temperatures and pressures:

Table 3-7 Formation pressures and temperatures used for both of the compositions.

Formation Pressure (psia)	Formation Temperature (°F)
3000	115
3100	117
3200	119
3300	121
3400	123
3500	125
3600	127
3700	129
3800	130
3900	133
4000	135

Using these 11 pressure and temperature conditions plus the 4 pore size conditions and the two different compositions there will be about 88 scenarios for comparison for the Marcellus Shale. These comparisons will be shown in the results section.

Chapter 4 Results and Discussion

This section describes the results of the study on the size effects of the nanopores on the gas-in-place calculation. It is important to compare the results of the different Marcellus Shale regions to see the effects that the depths of the reservoir have and also the compositions. The organization of these results are most simply shown in the figure below:

Figure 4-1 Flow chart and organization for the study of nanopore effects on gas-in-place.

4.1 Nanopore Size Effects on the Pseudo Reduced Temperatures and Pressures

The formation temperature for each of the locations was studied for the pore size effects and formation pressure effects when the temperature changes from 115-135 degrees Fahrenheit and from 3000 psia to 4000 psia formation pressure. These formation temperatures were then used to calculate the effects on the pseudo reduced pressure of the two different gas compositions of the two Marcellus Shale locations.

Figure 4-2 Study #1 Pseudo reduced temperature results for the changing reservoir pressures.

Figure 4-3 Study #2 Pseudo reduced temperature results for the changing reservoir pressures.

The conclusion is made that the higher the formation temperature the higher the pseudo reduced pressure will be because of the calculation for the pseudo reduced pressure which is shown below:

$$\text{Pseudo Reduced Temperature} = \frac{\text{Formation Temperature } (^{\circ}\text{R})}{\text{Critical Temperature}}$$

The pore size shows that the pseudo reduced temperature increases with the reduction in pore size. This is due to the increases in pressure on the hydrocarbons that occurs in a confined space. Although, the results from the two compositions are slightly different, they follow the same trend.

Figure 4-4 Study #1 Pseudo reduced pressure results for the changing reservoir pressures and pore sizes.

Figure 4-5 Study #2 Pseudo reduced pressure results for the changing reservoir pressures and pore sizes.

The pseudo reduced pressure shows a trend that is different from the pseudo reduced temperature. The pseudo-reduced pressure still has the trend of the pressure increasing with the increased reservoir pressure but the pore size does not follow the same trend as the pseudo-reduced temperature. The 2nm pore size has the highest pseudo-reduced pressure, the unconfined pore size has the next highest pseudo-reduced pressure, the 4nm has the next highest and the 5nm pore size has the lowest pseudo reduced pressure. Comparing the two compositions from the two different locations there is almost no difference in the pseudo-reduced pressure.

4.2 Pore Size Effects on Compressibility and Gas-in-Place

When calculating the compressibility of a gas there are many ways to do so. The method that was chosen uses the critical temperature and pressure in the calculation because this allows the compressibility to show the changes in critical temperature and pressure with confinement effects.

The z-factor calculation was explained in the methodology section. This section will present the results of the calculation and introduce the effects that confinement has had on the gas compressibility. In the chart below the pore size effects on compressibility are plotted with a changing reservoir pressure for four different pore sizes: unconfined, 2nm, 4nm and 5nm.

Figure 4-6 Study #1 Compressibility results for the changing reservoir pressures and pore sizes.

Figure 4-7 Study #2 Compressibility results for the changing reservoir pressures and pore sizes.

The pore size of 5nm has the lowest gas compressibility and the 2nm pore size has the highest compressibility. The 4nm pore size is the second lowest with the unconfined pore size only slightly above it. The effects on the compressibility for the changing compositions is almost nothing.

Figure 4-8 Study #1 gas-in-place results for the changing reservoir pressures and pore sizes.

Figure 4-9 Study #2 gas-in-place results for the changing reservoir pressures and pore sizes.

The gas-in-place is effected most by the 5nm pore size and the 2nm pore size. The 4nm pore size behaves closely to the unconfined pore size. The changing pore sizes compared to the changing compositions are shown in the tables below:

Table 4-1 Percent change of the gas-in-place comparing the composition #1 and #2 when increasing the formation pressure from 3000 psia to 4000 psia.

Percent Change of Gas-in-Place from 3000 to 4000 psia							
Composition #1 (lighter gas)				Composition #2 (heavier gas)			
Gas-in-Place				Gas-in-Place			
2 nm	4nm	5nm	unconfined	2 nm	4nm	5nm	Unconfined
0.146%	3.739%	6.008%	-0.288%	-1.087%	0.796%	5.756%	-0.787%

As the pressure increases from 3000 psia to 4000 psia the lighter gas shows an increase in gas-in-place (excluding the unconfined pore size which shows almost no change). The heavier gas does not follow the same trend, the 2nm pore size, 4nm pore size and unconfined case show almost no change to in gas-in-place as the pressure increases but the 5nm pore size shows a 5% increase in gas-in-place as the reservoir pressure increases from 3000 psia to 4000 psia.

Table 4-2 Percent change of gas-in-place between composition #1 and #2.

Percent Change of Gas-in-Place Between the Changing Compositions					
Temperature	Pressure	2 nm	4nm	5nm	unconfined
115	3000	1%	5%	4%	2%
117	3100	1%	6%	4%	2%
119	3200	1%	5%	5%	3%
121	3300	0%	6%	4%	3%
123	3400	1%	4%	5%	3%
125	3500	0%	5%	5%	2%
127	3600	0%	4%	4%	3%
129	3700	0%	4%	5%	2%
130	3800	0%	4%	5%	1%
133	3900	0%	2%	4%	2%
135	4000	0%	2%	4%	2%

When comparing the change in the gas-in-place when the compositions change, the heavier gas shows an increase in gas-in-place which is why the percentages in the above table are positive. The 4nm and 5nm pore sizes exhibit a higher change of gas-in-place than the 2nm and unconfined cases. Lastly, the comparison of the gas-in-place for each composition for each pore size is shown in the table below:

Table 4-3 Comparison of the changes to the gas-in-place for the changing composition and pore size.

% Change of Gas in Place for the Change in Pore Size							
Temperature	Pressure	Composition #1 (lighter gas)			Composition #2 (heavier gas)		
		2nm	4nm	5nm	2nm	4nm	5nm
115	3000						
117	3100	-9%	1%	2%	-10%	4%	4%
119	3200	-8%	-1%	3%	-9%	3%	5%
121	3300	-9%	1%	4%	-11%	3%	5%
123	3400	-8%	1%	5%	-11%	5%	6%
125	3500	-9%	2%	5%	-11%	3%	7%
127	3600	-9%	1%	5%	-10%	5%	8%
129	3700	-9%	4%	7%	-11%	5%	9%
130	3800	-8%	4%	6%	-11%	5%	9%
133	3900	-8%	2%	6%	-10%	5%	10%
135	4000	-8%	5%	8%	-11%	5%	10%
		-8%	5%	8%	-10%	5%	10%

The change of the gas-in-place for the lighter gas shows that there is a about a 9% decrease in the 2nm pore size but in the 4 nm there is almost no change and in the 5nm pore size there is up to a 7% increase. For the heavier gas there is about a 10% increase in the gas-in-place in the 2nm pore size but the 4nm and 5nm pore sizes shown about a 6% decrease.

Chapter 5 Conclusion

The objective of this study was to decide if the nanopores found in the Marcellus Shale have an impact on the gas-in-place calculation. To perform the study the unconfined pore formula for gas-in-place was compared to the formula accounting for pore size.

In summary, the results of this study have shown that confined pores do have an effect on the gas-in-place estimates. The greatest effects are seen in the 5nm pore size and the 2nm pore size. The gas-in-place shows up to an -8% change for the 2nm pore size when compared to the unconfined case.

Table 5-1 Percent change of the gas-in-place found in the Marcellus Shale from the unconfined pore size condition.

Gas-in-Place Results			% Change from Unconfined
G (MMCF)	2.001	for 2 nm	-8%
	2.223	for 4 nm	2%
	2.308	for 5 nm	6%
	2.169	for Normal	

These are the recommendations for future work:

1. Further work should be done to improve this study like adding an absorption factor to the gas-in-place formula.
2. This work could also be expanded if more pore sizes were included and more compositions from different shales.
3. There could also be an enhancement made on the formula to account for many different sized pores.

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Appendix A:

Table 1-A Study #1 critical temperature and pressure for unconfined pores.

<i>Component</i>	<i>Critical Temperature, °R</i>	<i>Critical Pressure, psia</i>
<i>CO₂ (Carbon Dioxide)</i>	<i>547.7</i>	<i>1073.0</i>
<i>N₂ (Nitrogen Gas)</i>	<i>227.0</i>	<i>493.0</i>
<i>H₂S (Hydrogen Sulfide)</i>	<i>672.0</i>	<i>1306.0</i>
<i>CH₄ (Methane)</i>	<i>343.3</i>	<i>673.1</i>
<i>C₂H₆ (Ethane)</i>	<i>549.8</i>	<i>708.3</i>
<i>C₃H₈ (propane)</i>	<i>666.0</i>	<i>617.4</i>
<i>i-C₄H₁₀ (isobutane)</i>	<i>734.7</i>	<i>529.1</i>
<i>n-C₄H₁₀ (butane)</i>	<i>765.3</i>	<i>550.7</i>
<i>i-C₅H₁₂ (isopentane)</i>	<i>829.8</i>	<i>483.0</i>
<i>n-C₅H₁₂ (neopentane)</i>	<i>845.6</i>	<i>489.5</i>
<i>C₆H₁₄ (hexane)</i>	<i>914.0</i>	<i>439.7</i>
<i>C₇+</i>	<i>1070.3</i>	<i>369.6</i>

Table 2-A Study #1 critical temperature and pressure correlation results for the 2nm pore size.

2 nm Pore Size Tc and Pc Correlation		
Component	T_c, °R	P_c, psia
CO_2 (Carbon Dioxide)	985.9	854.5
N_2 (Nitrogen Gas)	217.4	405.6
H_2S (Hydrogen Sulfide)	1209.6	1306.0
CH_4 (Methane)	330.7	572.1
C_2H_6 (Ethane)	525.5	580.8
C_3H_8 (propane)	696.3	491.7
$i-C_4H_{10}$ (iso-butane)	725.5	432.0
$n-C_4H_{10}$ (butane)	696.3	414.7
$i-C_5H_{12}$ (isopentane)	783.3	379.3
$n-C_5H_{12}$ (neopentane)	799.0	378.2
C_6H_{14} (hexane)	861.5	364.4
C_7+	1005.0	276.2

Table 3-A Study #1 critical temperature and pressure correlation results for the 4nm pore size.

4 nm Pore Size Tc and Pc Correlation		
Component	T_c, °R	P_c, psia
CO_2 (Carbon Dioxide)	536.8	1341.7
N_2 (Nitrogen Gas)	223.2	589.0
H_2S (Hydrogen Sulfide)	1209.6	19198.2
CH_4 (Methane)	338.1	755.5
C_2H_6 (Ethane)	540.0	853.7
C_3H_8 (propane)	652.5	772.4
$i-C_4H_{10}$ (isobutane)	719.1	683.7
$n-C_4H_{10}$ (butane)	749.2	712.2
$i-C_5H_{12}$ (isopentane)	810.3	649.8
$n-C_5H_{12}$ (neopentane)	826.5	647.8
C_6H_{14} (hexane)	892.4	644.2
C_7+	863.7	519.6

Table 4-A Study #1 critical temperature and pressure correlation results for the 5nm pore size.

5 nm Pore Size Tc and Pc Correlation		
Component	T_c, °R	P_c, psia
CO₂ (Carbon Dioxide)	540.0	1613.9
N₂ (Nitrogen Gas)	224.4	701.1
H₂S(Hydrogen Sulfide)	1209.6	19198.2
CH₄ (Methane)	339.6	895.4
C₂H₆ (Ethane)	542.9	1016.7
C₃H₈ (propane)	656.5	922.8
i-C₄H₁₀ (isobutane)	723.7	819.0
n-C₄H₁₀ (butane)	754.1	853.1
i-C₅H₁₂ (isopentane)	815.8	779.9
n-C₅H₁₂ (neopentane)	832.2	777.6
C₆H₁₄ (hexane)	898.7	774.6
C₇+	1051.7	627.1

Table 5-A Study #1 critical temperature and pressure results for the unconfined pore size.

Component	TC, oR	PC, psia
CO2 (Carbon Dioxide)	547.7	1073.0
N2 (Nitrogen Gas)	227.0	493.0
H2S(Hydrogen Sulfide)	672.0	1306.0
CH4 (Methane)	343.3	673.1
C2H6 (Ethane)	549.8	708.3
C3H8 (propane)	666.0	617.4
i-C4H10 (isobutane)	734.7	529.1
n-C4H10 (butane)	765.3	550.7
i-C5H12 (isopentane)	829.8	483.0
n-C5H12 (neopentane)	845.6	489.5
C6H14 (hexane)	914.0	439.7
C7+	1070.3	369.6

Table 6-A Study #2 Critical Temperature and Pressure correlation results.

Component	2 nm		4 nm		5 nm	
	Critical Temperature °R	Critical Pressure psia	Critical Temperature °R	Critical Pressure psia	Critical Temperature °R	Critical Pressure psia
CO₂	520.9	520.9	536.8	536.8	540.0	540.0
N₂	217.4	217.4	223.2	223.2	224.4	224.4
H₂S	0.0	0.0	0.0	0.0	0.0	0.0
CH₄	330.7	330.7	338.1	338.1	339.6	339.6
C₂H₆	525.5	525.5	540.0	540.0	542.9	542.9
C₃H₈	633.2	633.2	652.5	652.5	656.5	656.5
i-C₄H₁₀	696.3	696.3	719.1	719.1	723.7	723.7
n-C₄H₁₀	725.5	725.5	749.2	749.2	754.1	754.1
i-C₅H₁₂	783.3	783.3	810.3	810.3	815.8	815.8
n-C₅H₁₂	799.0	799.0	826.5	826.5	832.2	832.2
C₆H₁₄	861.5	861.5	892.4	892.4	898.7	898.7
C₇+	1003.5	1003.5	1043.1	1043.1	1051.2	1051.2

Table 7-A Pseudo critical temperature and pressure for the unconfined case in study #1.

Component	Mole Fraction	Corrected Mole Frac.	T _c , °R	y×TC	P _c , psia	y×PC
CO₂ (Carbon Dioxide)	0.00156	0.00156	547.7	0.8544	1073.0	1.67388
N₂ (Nitrogen Gas)	0.00465	0.00465	227.0	1.0556	493.0	2.29245
H₂S (Hydrogen Sulfide)	0.00000	0.00000	672.0	0.0000	1306.0	0
CH₄ (Methane)	0.77299	0.77299	343.3	265.3675	673.1	520.29957
C₂H₆ (Ethane)	0.14775	0.14775	549.8	81.2330	708.3	104.65133
C₃H₈ (propane)	0.04885	0.04885	666.0	32.5341	617.4	30.15999
i-C₄H₁₀ (isobutane)	0.00573	0.00573	734.7	4.2098	529.1	3.031743
n-C₄H₁₀ (butane)	0.01156	0.01156	765.3	8.8469	550.7	6.366092
i-C₅H₁₂ (isopentane)	0.00239	0.00239	829.8	1.9832	483.0	1.15437
n-C₅H₁₂ (neopentane)	0.00230	0.00230	845.6	1.9449	489.5	1.12585
C₆H₁₄ (hexane)	0.00129	0.00129	914.0	1.1791	439.7	0.567213
C₇+	0.00093	0.00093	1070.3	0.9954	369.6	0.3437168
	1.00000	1.00000		400.20		671.67

Table 8-A Pseudo critical temperature and pressure for the 2nm pore size case in study #1.

Component	Mole Fraction	Corrected Mole Frac.	$T_c, ^\circ R$	$y \times TC$	P_c, psia	$y \times PC$
CO_2 (Carbon Dioxide)	0.00156	0.00156	985.9	1.5379	854.5	1.3330142
N_2 (Nitrogen Gas)	0.00465	0.00465	217.4	1.0107	405.6	1.8862699
H_2S (Hydrogen Sulfide)	0.00000	0.00000	1209.6	0.0000	1306.0	0
CH_4 (Methane)	0.77299	0.77299	330.7	255.5927	572.1	442.20716
C_2H_6 (Ethane)	0.14775	0.14775	525.5	77.6429	580.8	85.808847
C_3H_8 (propane)	0.04885	0.04885	696.3	34.0132	491.7	24.021671
$i-C_4H_{10}$ (iso-butane)	0.00573	0.00573	725.5	4.1568	432.0	2.4754034
$n-C_4H_{10}$ (butane)	0.01156	0.01156	696.3	8.0490	414.7	4.7942473
$i-C_5H_{12}$ (isopentane)	0.00239	0.00239	783.3	1.8722	379.3	0.9065568
$n-C_5H_{12}$ (neopentane)	0.00230	0.00230	799.0	1.8377	378.2	0.8698065
C_6H_{14} (hexane)	0.00129	0.00129	861.5	1.1114	364.4	0.4701212
C_7+	0.00093	0.00093	1005.0	0.9346	276.2	0.2568603
	1.00000	1.00000		387.76		565.03

Table 9-A Pseudo critical temperature and pressure for the 4nm pore size case in study #1.

Component	Mole Fraction	Corrected Mole Frac.	$T_c, ^\circ R$	$y \times TC$	P_c, psia	$y \times PC$
CO_2 (Carbon Dioxide)	0.00156	0.00156	536.8	0.8374	1341.7	2.0930268
N_2 (Nitrogen Gas)	0.00465	0.00465	223.2	1.0379	589.0	2.73903
H_2S (Hydrogen Sulfide)	0.00000	0.00000	1209.6	0.0000	1919.2	0
CH_4 (Methane)	0.77299	0.77299	338.1	261.3456	755.5	583.96761
C_2H_6 (Ethane)	0.14775	0.14775	540.0	79.7792	853.7	126.12864
C_3H_8 (propane)	0.04885	0.04885	652.5	31.8756	772.4	37.730176
$i-C_4H_{10}$ (isobutane)	0.00573	0.00573	719.1	4.1203	683.7	3.917818
$n-C_4H_{10}$ (butane)	0.01156	0.01156	749.2	8.6607	712.2	8.233343
$i-C_5H_{12}$ (isopentane)	0.00239	0.00239	810.3	1.9366	649.8	1.5529829
$n-C_5H_{12}$ (neopentane)	0.00230	0.00230	826.5	1.9009	647.8	1.490028
C_6H_{14} (hexane)	0.00129	0.00129	892.4	1.1512	644.2	0.8310453
C_7+	0.00093	0.00093	863.7	0.8032	519.6	0.4832333
	1.00000	1.00000		393.45		769.17

Table 10-A Pseudo critical temperature and pressure for the 5nm pore size case in study #1.

Component	Mole Fraction	Corrected Mole Frac.	$T_c, ^\circ R$	$y \times TC$	P_c, psia	$y \times PC$
CO_2 (Carbon Dioxide)	0.00156	0.00156	540.0	0.8424	1613.9	2.5176864
N_2 (Nitrogen Gas)	0.00465	0.00465	224.4	1.0435	701.1	3.2601692
H_2S (Hydrogen Sulfide)	0.00000	0.00000	1209.6	0.0000	19198.2	0
CH_4 (Methane)	0.77299	0.77299	339.6	262.5111	895.4	692.17133
C_2H_6 (Ethane)	0.14775	0.14775	542.9	80.2145	1016.7	150.2117
C_3H_8 (propane)	0.04885	0.04885	656.5	32.0688	922.8	45.079448
$i-C_4H_{10}$ (isobutane)	0.00573	0.00573	723.7	4.1470	819.0	4.6926699
$n-C_4H_{10}$ (butane)	0.01156	0.01156	754.1	8.7170	853.1	9.8617045
$i-C_5H_{12}$ (isopentane)	0.00239	0.00239	815.8	1.9499	779.9	1.8639813
$n-C_5H_{12}$ (neopentane)	0.00230	0.00230	832.2	1.9139	777.6	1.7884188
C_6H_{14} (hexane)	0.00129	0.00129	898.7	1.1594	774.6	0.9992268
C_7+	0.00093	0.00093	1051.7	0.9780	627.1	0.5831619
	1.00000	1.00000		395.55		913.03

Figure 1-Z-Factor or compressibility chart.