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The Impact of Shale Gas on Gas Storage Performance

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THE IMPACT OF SHALE GAS ON GAS STORAGE PERFORMANCE

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ABSTRACT

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The advances in technology has resulted in significant gas production from the shale formations across the United States. Marcellus Shale which spans most of the Appalachian Basin is one the most prolific gas producers in the United States. Marcellus Shale gas has a distinctly different composition from the existing Northern Appalachian typical dry natural gas. As gas production from Marcellus shale has increased, so has the amount of the shale gas in the natural gas transportation system in the Appalachian Basin. The composition of the injected gas into a storage reservoir can the storage volumes, pressures, the withdrawal rate, and the pressure drawdown.

The objective of this study is to investigate the impact of storing Marcellus Shale gas on the capacity and deliverability of a gas storage reservoir. In this study, the working gas in the storage was assumed to be a mixture of the Marcellus Shale gas and the original pipeline (storage) gas. The fraction of the shale gas in the mixture was varied from 10 percent to 50 percent to determine the changes in the storage working volume, storage top pressure, withdrawal rate, and pressure drawdown. The results indicate that there is linear relationship between the fraction of the shale gas in the working gas and the changes in mixture storage working volume, storage top pressure, withdrawal rate, and pressure drawdown.

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1. Introduction

The advances in hydraulic fracturing and horizontal well technology have unlocked considerable natural gas reserves contained in the shale formations. Marcellus Shale, a Devonian black shale, spans the majority of the Appalachian Basin from New York through Pennsylvania, West Virginia and also extends into Ohio and Maryland. Marcellus Shale is prolific in size and is located strategically in regards to markets in the Northeastern areas, Eastern Seaboard, and Great Lakes region of the United States. Marcellus Shale in recent years has become the most prolific gas producer in the United States. Marcellus Shale gas has a distinctly different composition than the existing Northern Appalachian typical dry natural gas. Due to lack of processing or blending capabilities, the gas produced from the Marcellus shale wells are transported with pipeline and are mixed with the pipeline gas.

Due to seasonal nature of the gas demand, natural is often stored in underground storage facilities during low demand period and then is withdrawn during the high demand periods. The composition of the injected gas in the storage reservoir can impact the gas compressibility and as a consequence the storage volumes or pressures. Furthermore, the composition of gas influences the viscosity of the gas and therefore the withdrawal rate or the pressure drawdown in the storage reservoir. It is therefore important to investigate the impact of the storing a mixture of shale and pipeline gas in the storage reservoir in the Appalachian basin.

2. Background

2.1 Gas Storage Basics

Natural gas is typically a seasonal fuel, where demand is higher during the winter than it is during warmer months. Due to this, it is necessary to store the gas in times where demand is less, increasing the "base load" in order to meet the supply during short term "Peak Load" demand increases. This is done in various ways; the gas can be stored in underground facilities such as depleted gas reservoirs, aquifers, and salt caverns or stored as liquefied natural gas (LNG) where the natural gas takes up less space and allows for the natural gas to be shipped and stored in liquid form.

As well as meeting base load and peak load demand, gas storage is also used as insurance against disruptions in supply or production. The natural gas is injected into the formation, building pressure and thus becoming a pressurized natural gas container. This pressure is necessary as the higher it is, the more readily available the gas may be extracted. This pressure must remain above that of the wellhead or else there will not be a large enough pressure differential to push the natural gas out of the storage facility. This is referred to as "Base Gas" or "Cushion gas" and must remain in the storage reservoir to maintain the required pressure to extract the remaining gas.

The volume of natural gas in the storage reservoir that can be extracted is called "Working Gas." Working Gas is the gas being stored and withdrawn during normal operations. As this volume is decreased, pressure and deliverability also decrease. This then asks the question of what happens when or if the working gas mixes with the base gas.

Natural gas storage is necessary to maintain a reliable supply of gas to meet the demands of the consumers. Underground storage is an efficient process that can keep up the constant supply from long-distance pipelines with the variable market demand. During warmer months, when the pipeline capacity is greater than the market demand, the natural gas can be placed into underground storage and then during periods of higher supply, typically colder winter months, the gas can be withdrawn and used (Aminian, 2015).

Storage is also used in the industry for commercial reasons to efficiently earn based on the market where factors such as regulations and political climate can dictate the gas price. Storing gas during times when the price is low and withdrawing to sell when prices are high allows for effective economics (NatGas, 2014).

2.2 Types of Underground Storage Reservoirs

There are three main types of underground natural gas storage: depleted reservoirs, aquifers, and salt caverns.

Depleted gas reservoirs are the most common, cheapest, and prominent types of underground storage. These are formations that have already been extracted of all of their recoverable natural gas, and are desirable as they are already proven geologically capable of holding natural gas. Often times the developed reservoir already has the infrastructure for extraction and distribution left over from while the field was in production and can reduce costs when converting to storage purposes. This makes depleted gas reservoirs one of the cheapest storage types to develop, operate and maintain (NatGas, 2014).

Aquifer storage is when natural gas is injected into underground porous, permeable rock formations that act as natural water reservoirs. These formations can be reconditioned and used as natural gas storage facilities, where the gas is injected at the top of the formation and displaces the water down structure (Dietert & Pursell, 2000).

Typically, aquifer storage is used only in areas without any depleted reservoirs, as they are more expensive to develop than depleted reservoirs. This is usually close to the end market user, and only accounts for 10%-15% of total US storage. Another disadvantage with aquifer storage is that their geological characteristics are not as thoroughly understood as those of a depleted reservoir. In order to develop the aquifer into an effective natural gas storage facility, tests must be done to determine the suitability, composition, capacity, and porosity of the formation. These tests add to the cost and time needed to get the aquifer reservoir ready for storage. Additionally, since gas does not naturally occur in the formation, a certain amount of base gas must be added. This base gas requirement can be as high as 80% of the total gas volume, and is often times not recoverable at risk of damaging the formation. These factors mean that the development of storage reservoir from an aquifer formation is both costly and lengthy, in some cases taking up to twice the time of that for a depleted reservoir (NatGas, 2014).

Underground salt formations offer another type of natural gas storage. Formed out of existing salt deposits, these formations are well suited to natural gas storage in that they allow little injected natural gas to escape from the formation unless specifically extracted. The walls of a salt cavern also have the structural strength of steel, making them very resilient to reservoir degradation over time.

Once a suitable salt formation is discovered and suitable for storage it is necessary to develop a “salt cavern” within the formation. Basically this consists of using water to dissolve and extract a certain amount of salt from the deposit resulting in a large empty space in the formation. This is done by drilling a well into the salt formation and cycling large amounts of water through the completed well. Known as ‘salt cavern leaching’ this water dissolves some of the salt in the deposit and, cycled back up the well, leaves a large empty space where some of the salt once was. Salt cavern leaching can be very expensive, but the resulting salt cavern offers an underground gas storage vessel with very high deliverability. In addition, cushion gas requirements are the lowest of all three storage types, with salt caverns only requiring about 33% of total capacity to be used as cushion gas and are best suited for peak load storage.

2.3 Shale Gas

Shale, an organic rich formation, is the source rock as well as the reservoir for a vast majority of the natural gas hydrocarbon production found in the United States. As seen in Figure 1 below, there are shale gas reservoirs covering the north and south regions of the United States including New York, Pennsylvania, West Virginia, Ohio, Wyoming, Colorado, Illinois, Texas, Oklahoma, and New Mexico. The gas is stored in the limited pore space of these formations, as shale is a complicated naturally fractured reservoir. With ultra-low matrix permeability values in the nano-darcy range, unconventional shale reservoirs are not believed to produce economically unless an interconnected fracture system is developed (Garcia-Hernandez, Alvarado, & Ridens, 2015). This is typically achieved through effective placement of horizontal laterals and hydraulic stimulation treatment. The objective of the horizontal wells and stimulation treatment is to create a large, highly fractured, interconnected network allowing for contact to be made with as much of the formation surface as possible and providing access to the hydrocarbons (Elsaig, Aminian, Ameri, & Zamirian, 2016).

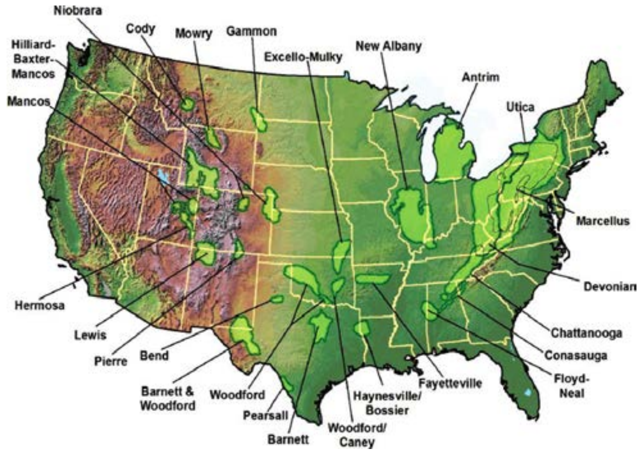

Figure 1 - Shale Basins in Lower 48 States (Stokes & Summers, 2012)

Spanning the majority of the Appalachian Basin, the Marcellus Shale, a Devonian black shale formation extends from New York through Pennsylvania, West Virginia, Ohio and Maryland (Ayers, Aminian, & Ameri, 2012). The Marcellus has tremendous potential, and is relatively shallow at depths of 2,000-8,000 ft. and 300-1,000 ft. thick, seen in Figure 2. Initial production rates show production in the 0.5-4 MMSCFD range, with estimates of 60-100 SCF of gas per ton of shale (Bullin & Krouskop, 2008).

2.4 Gas Composition

Table 1 illustrates typical gas compositions from different sources. As can be seen, Methane is always the major component, typically comprising 60% to 98% of the total.

Table 1 - Typical Raw Gas Composition

Gas Component	Casinghead (Wet) Gas (mol %)	Gas Well (Dry) Gas (mol %)	Condensate Well Gas (mol %)
Carbon Dioxide	0.63	Trace	Trace
Nitrogen	3.73	1.25	0.53
Hydrogen Sulfide	0.57	Trace	Trace
Methane	64.48	91.01	94.87
Ethane	11.98	4.88	2.89
Propane	8.75	1.69	0.92
Iso-Butane	0.93	0.14	0.31
n—Butane	2.91	0.52	0.22
Iso-Pentane	0.54	0.09	0.09
n-Pentane	0.80	0.18	0.06
Hexanes	0.37	0.13	0.05
Heptanes plus	0.31	0.11	0.06
Total	100.00	100.00	100.00

Additionally, natural gas contains significant amounts of ethane, some propane and butane, and typically 1% to 3% of other heavier hydrocarbons. Often, natural gas contains associated and undesirable impurities, such as water, carbon dioxide, nitrogen, and hydrogen sulfide. Although the composition of raw gas varies widely, the composition of gas delivered to commercial pipeline grids is tightly controlled.

In order for the gas producers to meet pipeline specifications, all natural gas requires some treatment even if all that is done is to remove bulk water. Around a fifth of gas extracted requires extensive, and often expensive, treatment, before it can be delivered to the pipeline. Processing of natural gas is therefore, by some considerable margin, the largest industrial gas application. In the U.S., production of natural gas is presently around 22 trillion SCF/Year and expected to increase to more than 31 trillion SCF/Year by 2025. It follows that U.S. production accounts for somewhere in the region of 20% of total Global production making the U.S. a key market both for gas producers, processing equipment, and instrumentation suppliers (Bullin & Krouskop, 2008).

Table 2 – Typical U.S. Tariff Limits (Stokes & Summers, 2012)

Component (molar %)	Minimum	Maximum
Methane	75	-
Ethane	-	18
Propane	-	5
Butane	-	2
Pentane Plus	-	0.5
Nitrogen and other Inert	-	3-4
Carbon Dioxide	-	3-4
Trace Components	-	0.25-1

As most existing Northern Appalachian gas is dry, it does not require removal of Natural Gas Liquids (NGL's) for pipe line transportation. However, the Marcellus gas has sufficient liquids that do require processing. With little CO2 and Nitrogen, the greatest obstacle the Marcellus faces is environmental challenges associated with the terrain of the area. From a gas processing point of view, the Marcellus region does not have the infrastructure as others do to deal with gas blending (Bullin & Krouskop, 2008).

All shale gas is not the same, and composition varies substantially between formation and location. Table 5 shows the gas composition from several Marcellus shale Wells. As it can be observed, Marcellus Shale gas has distinctly different composition than typical natural gas. The key difference is the mole fraction of Ethane, seen in Table 3 Column C2.

Table 3 – Marcellus Shale Gas Composition (Bullin & Krouskop, 2008)

Marcellus Shale Gas Composition					
Well	C1	C2	C3	CO2	N2
1	79.4	16.1	4.0	0.1	0.4
2	82.1	14.0	3.5	0.1	0.3
3	83.8	12.0	3.0	0.9	0.3
4	95.5	3.0	1.0	0.3	0.2

With rapid production growth, shale gas processing requires composition to be determined in order to deal with concerns such as elevated ethane and nitrogen levels across fields.

Some anticipate that the Marcellus shale reserves could hold twice as much gas as the Texas Barnett Shale. If true, gas processing would create substantial volumes of natural gas liquids for the region.

3. Methodology

The objective of this study is to investigate the impact of storing Marcellus Shale gas on the capacity and deliverability of a gas storage reservoir. For the purpose of this study the following steps were developed and implement:

1. Three generic storage reservoirs were considered in this study which represent typical characteristics of different gas storage reservoirs in the Appalachian Basin. The characteristics of these storage reservoir are summarized in Tables 4, 5, and 6 and include an intermediate size and pressure reservoir (Case 1), a small high pressure reservoir (Case 2), and a large low pressure reservoir (Case 3).

Table 4 – Case 1: Intermediate Size and Pressure Reservoir

Case 1		
Working Gas Volume	55	BCF
Base Gas Volume	45	BCF
Maximum Pressure	2250.0	psia
Reservoir Temperature	100	^{o} F
Net Pay	15	ft.
Permeability	150	md
Water Saturation	0.25	
Effective Porosity	12	%
Average Depth	4688	ft.

Table 5 – Case 2: Small High-Pressure Reservoir

Case 2		
Working Gas Volume	4	BCF
Base Gas Volume	4	BCF
Maximum Pressure	2700.0	psia
Reservoir Temperature	120	^{o} F
Net Pay	50	ft.
Permeability	100	md
Water Saturation	0.2	
Effective Porosity	10	%
Average Depth	5625	ft.

Table 6 – Case 3: Large Low-Pressure Reservoir

Case 3		
Working Gas Volume	85	BCF
Base Gas Volume	75	BCF
Maximum Pressure	1100.0	psia
Reservoir Temperature	80	^{o} F
Net Pay	15	ft.
Permeability	120	md
Water Saturation	0.25	
Effective Porosity	12	%
Average Depth	2292	ft.

2. A typical gas composition from gas storage reservoirs in West Virginia was utilized as the base gas composition for all of the cases. This gas composition is provided in Table 7.

Table 7 – Typical Gas Composition for Gas Storage Reservoir

	Storage
Component	Mole Fraction
CO_2	0.001
N_2	0.002
H_2S	0.000
CH_4	0.980
C_2H_6	0.010
C_3H_8	0.003
$i\text{-}C_4H_{10}$	0.002
$n\text{-}C_4H_{10}$	0.0008
$i\text{-}C_5H_{12}$	0.0004
$n\text{-}C_5H_{12}$	0.0003
C_6H_{14}	0.0002
C_7+	0.0003
Total	1.0000

3. A typical Marcellus shale gas composition in West Virginia was utilized for the composition of the injected Marcellus Shale gas for all of the cases. This gas composition is provided in Table 8.

Table 8 – Typical Marcellus Shale Gas Composition

	Shale
Component	**Mole Fraction**
CO_2	0.001
N_2	0.003
H_2S	0.000
CH_4	0.760
C_2H_6	0.150
C_3H_8	0.059
$i\text{-}C_4H_{10}$	0.007
$n\text{-}C_4H_{10}$	0.007
$i\text{-}C_5H_{12}$	0.004
$n\text{-}C_5H_{12}$	0.003
C_6H_{14}	0.002
C_7+	0.004
Total	**1.0000**

4. It was assumed that the entire working gas in the storage reservoir is replaced by a mixture of the Marcellus Shale gas and the original pipeline (storage) gas. The fraction of the shale gas in the mixture was varied from 10 percent to 50 percent.

5. The composition of the working gas after it is injected into the storage reservoir will depend on the level of mixing between the working gas and the base gas. To investigate the impact of the degree of mixing the following scenarios were considered:

   a. No Mixing: This case assumes that no mixing occurs between the injected and the base gas. Two sets of gas properties based on the original base gas and Marcellus gas compositions were determined for further calculations.

b. Full Mixing: This case assumes that the injected gas and the base gas are completely mixed. A single set of gas properties based on the mixture of the base gas and Marcellus shale gas in proportion to the base and working gas were determined for further calculations.

6. For each case described above, the working gas volume required to fill the pore volume of the storage reservoir, excluding the base gas pore volume, at the top storage pressure was determined. The percentage change in working gas volume as compared to the original working gas volume was then determined.

7. For each case described above, a gas volume the same as the original working gas volume was injected into the storage reservoir and the resulting top pressure was determined. The percentage change in top storage pressure compared to the original top storage pressure was then determined.

8. For each case described above, the gas withdrawal rate for a drawdown of 400 psi at the top pressure was determined. The percentage change in withdrawal rate compared to the original withdrawal rate was then determined.

9. For each case described above, the drawdown required to achieve the original flow rate (determined based on 400 psi drawdown using the base gas composition) at the top pressure was determined. The percentage change in drawdown compared to the original drawdown (400 psi) was then determined.

4. Results and Discussion

The following sections provide the results for working gas volume, top storage pressure, withdrawal rate, drawdown, and percentage changes for each one as compared to the original reservoir conditions and for 3 reservoir cases.

4.1 Working Gas Volume: Full Mixing

The working gas volume required to fill the pore volume of the storage reservoir, excluding the base gas pore volume, at the top storage pressure for storage reservoir cases 1, 2, and 3 are summarized in Tables 9, 10 and 11. In addition, the percentage change in working gas volume as compared to the original working gas volume are summarized in each table.

Table 9 – Case 1: Full Mix – Volume % Change - Intermediate Size and Pressure Reservoir

Case 1: Full Mix – Volume % Change			
Mix Ratio (Base:Working)	Initial Volume (BCF)	New Volume (BCF)	% Change
90-10	100.00	100.66	0.66%
80-20	100.00	101.32	1.32%
70-30	100.00	102.00	2.00%
60-40	100.00	102.70	2.70%
50-50	100.00	103.40	3.40%

Table 10 – Case 2: Full Mix – Volume % Change - Small High-Pressure Reservoir

Case 2: Full Mix – Volume % Change			
Mix Ratio (Base:Working)	Initial Volume (BCF)	New Volume (BCF)	% Change
90-10	8.00	8.04	0.50%
80-20	8.00	8.09	1.13%
70-30	8.00	8.13	1.63%
60-40	8.00	8.17	2.13%
50-50	8.00	8.22	2.75%

Table 11 – Case 3: Full Mix – Volume % Change - Large Low-Pressure Reservoir

Case 3: Full Mix – Volume % Change			
Mix Ratio (Base:Working)	Initial Volume (BCF)	New Volume (BCF)	% Change
90-10	160.00	160.74	0.46%
80-20	160.00	161.50	0.94%
70-30	160.00	162.28	1.43%
60-40	160.00	163.08	1.93%
50-50	160.00	163.90	2.44%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the volume required to fill the pore volume of the reservoir increased. The percent change increased linearly for every case as illustrated in Figures 2, 3, and 4.

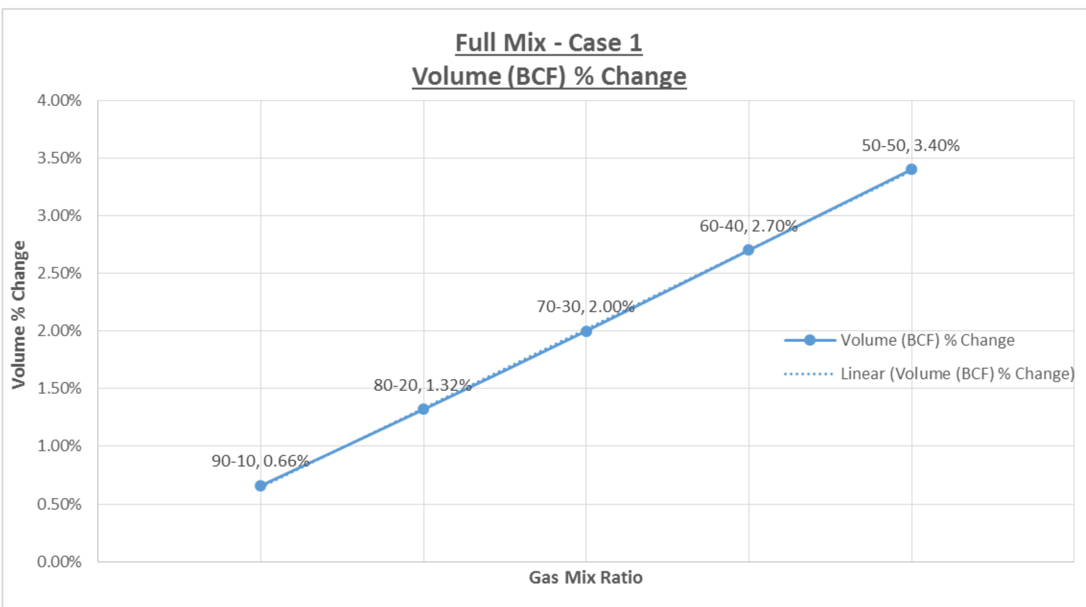

Figure 2 – Case 1: Full Mix – Volume % Change - Intermediate Size and Pressure Reservoir

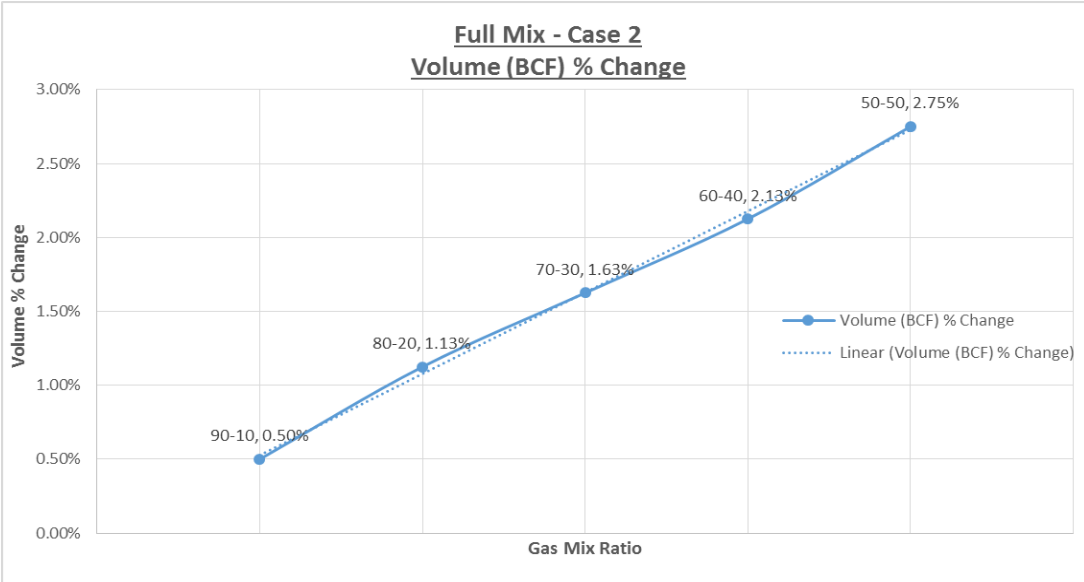

Figure 3 – Case 2: Full Mix – Volume % Change - Small High-Pressure Reservoir

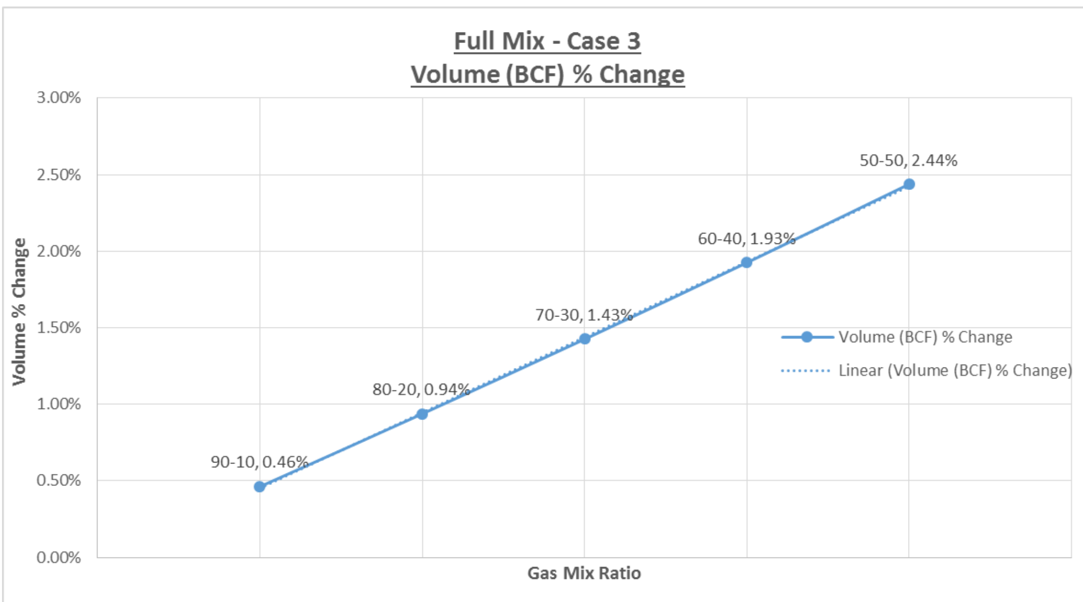

Figure 4 – Case 3: Full Mix – Volume % Change - Large Low-Pressure Reservoir

4.2 Working Gas Volume: No Mixing

The working gas volume required to fill the pore volume of the storage reservoir, excluding the base gas pore volume, at the top storage pressure for storage reservoir cases 1, 2, and 3 are summarized in Tables 12, 13, and 14. In addition, the percentage change in working gas volume as compared to the original working gas volume are summarized in each table.

Table 12 - Case 1: No Mixing - Volume % Change - Intermediate Size and Pressure Reservoir

Case 1: No Mixing - Volume % Change			
Mix Ratio (Base:Working)	Initial Volume (BCF)	New Volume (BCF)	% Change
90-10	55.00	55.66	1.20%
80-20	55.00	56.34	2.44%
70-30	55.00	57.05	3.73%
60-40	55.00	57.79	5.07%
50-50	55.00	58.56	6.47%

Table 13 - Case 2: No Mixing – Volume % Change - Small High-Pressure Reservoir

Case 2: No Mixing – Volume % Change			
Mix Ratio (Base:Working)	Initial Volume (BCF)	New Volume (BCF)	% Change
90-10	4.00	4.04	1.00%
80-20	4.00	4.09	2.25%
70-30	4.00	4.13	3.25%
60-40	4.00	4.18	4.50%
50-50	4.00	4.22	5.50%

Table 14 - Case 3: No Mixing – Volume % Change - Large Low-Pressure Reservoir

Case 3: No Mixing – Volume % Change			
Mix Ratio (Base:Working)	Initial Volume (BCF)	New Volume (BCF)	% Change
90-10	85.00	85.75	0.88%
80-20	85.00	86.53	1.80%
70-30	85.00	87.36	2.78%
60-40	85.00	88.22	3.79%
50-50	85.00	89.13	4.86%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the volume required to fill the pore volume of the reservoir increased. The percent change increased linearly for every case as illustrated in Figures 5, 6, and 7.

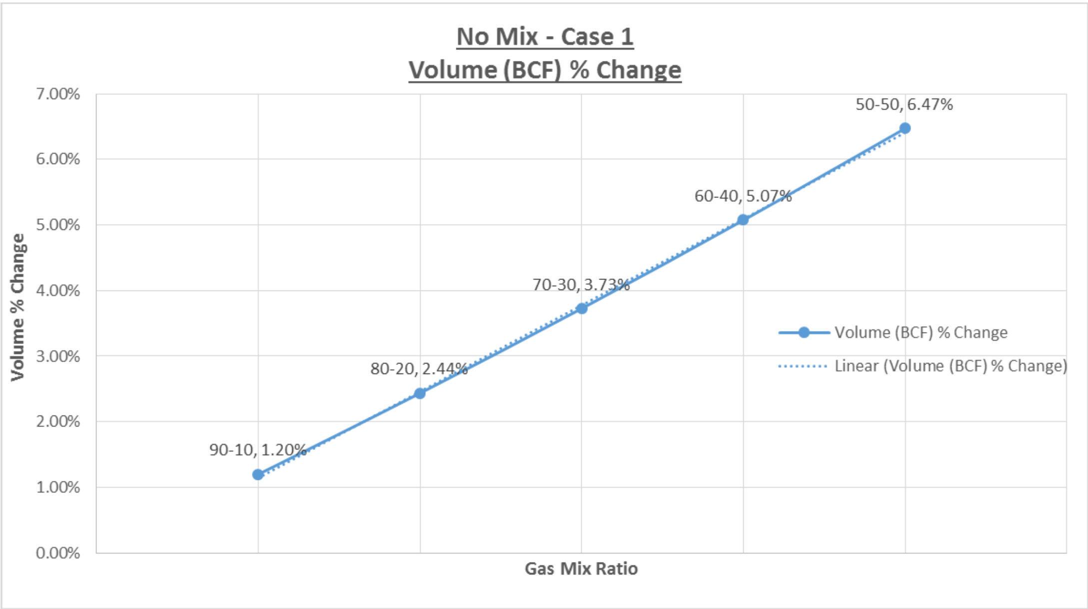

Figure 5 - Case 1: No Mixing – Volume % Change - Intermediate Size and Pressure Reservoir

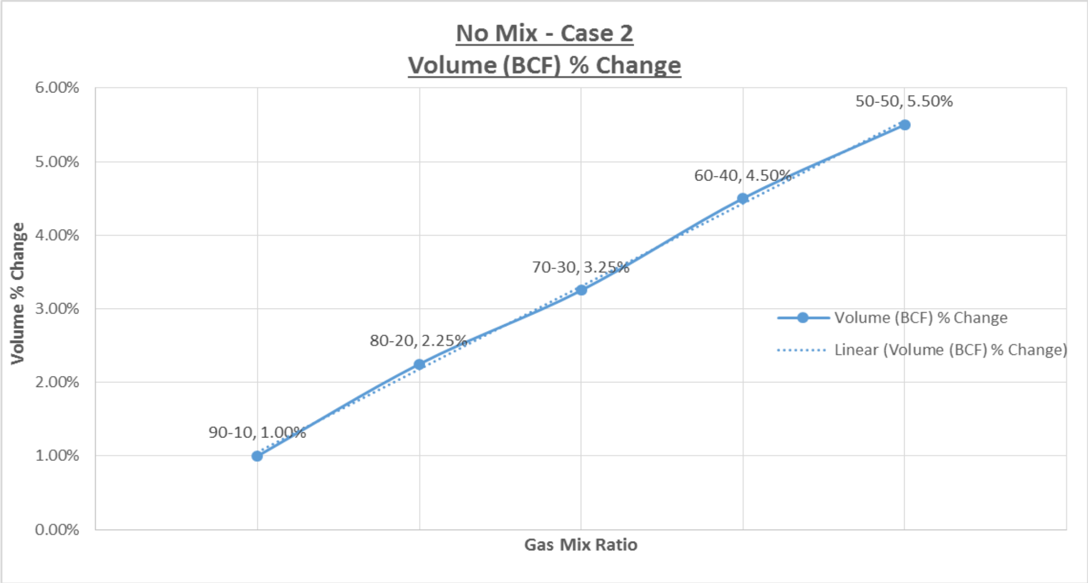

Figure 6 - Case 2: No Mixing – Volume % Change - Small High-Pressure Reservoir

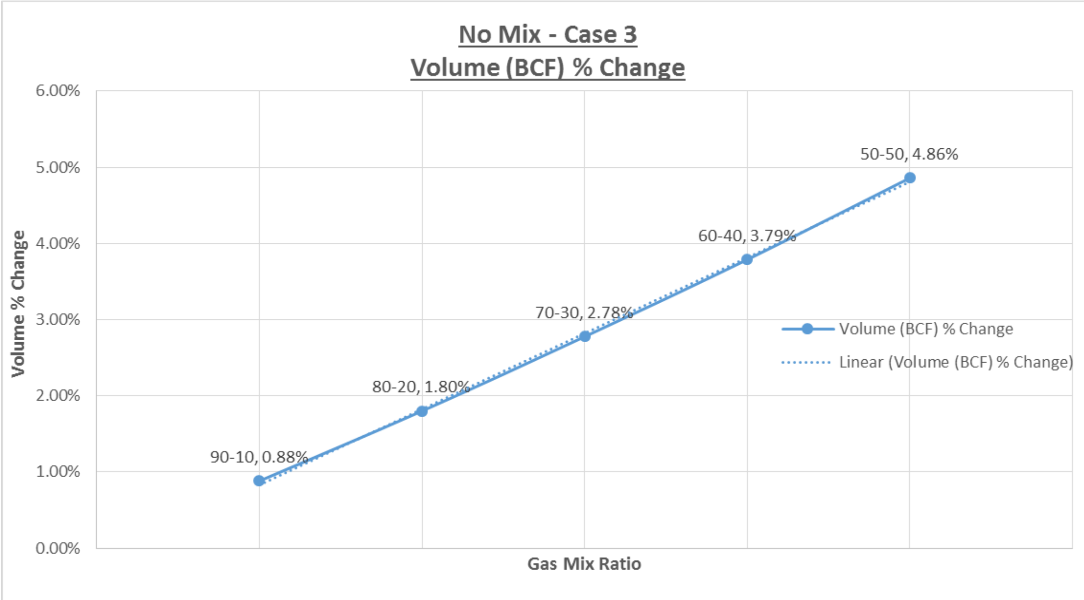

Figure 7 - Case 3: No Mixing – Volume % Change - Large Low-Pressure Reservoir

4.3 Storage Pressure: Full Mixing

The calculated top storage pressure based on the original working gas volume for reservoir cases 1, 2, and 3 are summarized in Table 15, 16, and 17. The percentage change in top storage pressure for the working gas mixture compared to the original top storage pressure are also listed in each table.

Table 15 – Case 1: Full Mix - Pressure % Change – Intermediate Size and Pressure Reservoir

Case 1: Full Mix - Pressure % Change			
Mix Ratio (Base:Working)	Initial Pressure (psia)	New Pressure (psia)	% Change
90-10	2250.00	2236.00	-0.62%
80-20	2250.00	2222.00	-1.24%
70-30	2250.00	2208.00	-1.87%
60-40	2250.00	2194.00	-2.49%
50-50	2250.00	2180.00	-3.11%

Table 16 – Case 2: Full Mix - Pressure % Change – Small High-Pressure Reservoir

Case 2: Full Mix - Pressure % Change			
Mix Ratio (Base:Working)	Initial Pressure (psia)	New Pressure (psia)	% Change
90-10	2700.00	2685.00	-0.56%
80-20	2700.00	2670.00	-1.11%
70-30	2700.00	2657.00	-1.59%
60-40	2700.00	2640.00	-2.22%
50-50	2700.00	2626.00	-2.74%

Table 17 – Case 3: Full Mix - Pressure % Change – Large Low-Pressure Reservoir

Case 3: Full Mix - Pressure % Change			
Mix Ratio (Base:Working)	Initial Pressure (psia)	New Pressure (psia)	% Change
90-10	1100.00	1095.00	-0.45%
80-20	1100.00	1091.00	-0.82%
70-30	1100.00	1086.00	-1.27%
60-40	1100.00	1082.00	-1.64%
50-50	1100.00	1077.00	-2.09%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the percentage change in top storage pressure compared to the original top storage pressure decreased. The percent change decreased linearly for every case as illustrated in Figures 8, 9, 10.

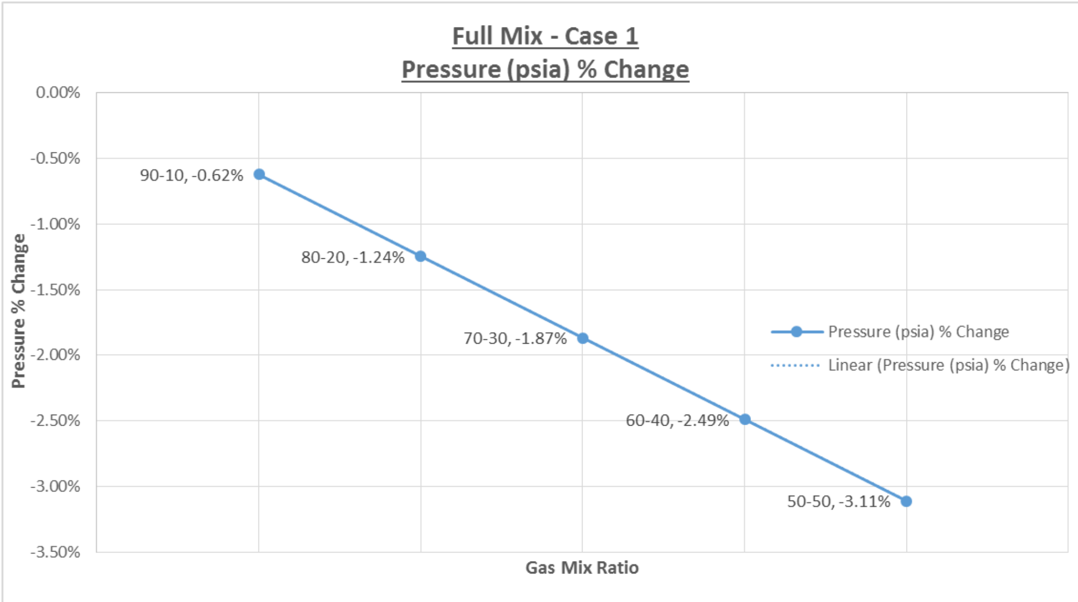

Figure 8 - Case 1: Full Mix - Pressure % Change – Intermediate Size and Pressure Reservoir

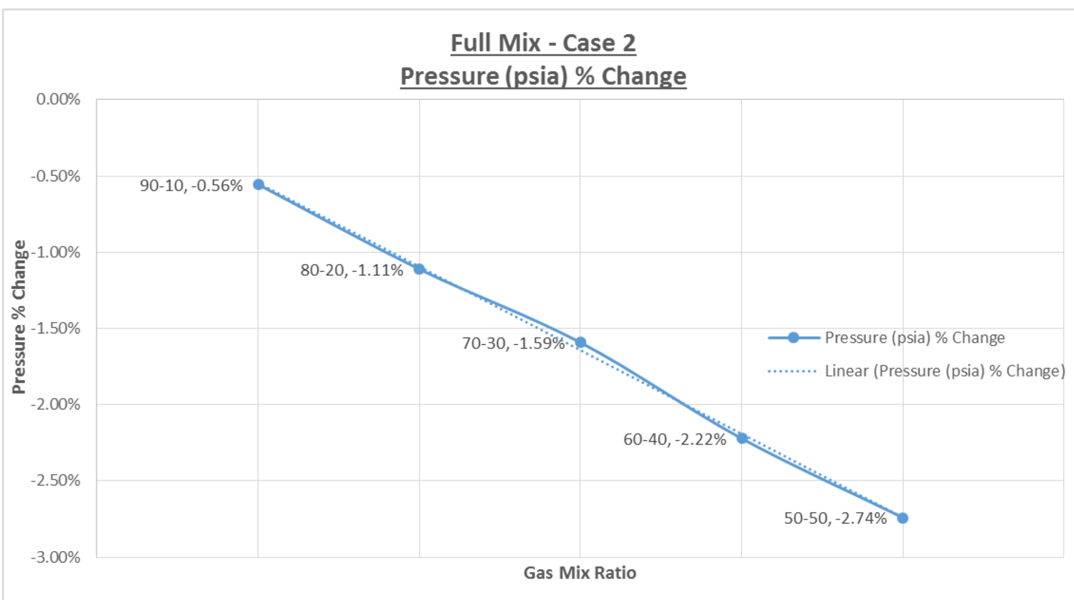

Figure 9 - Case 2: Full Mix - Pressure % Change – Small High-Pressure Reservoir

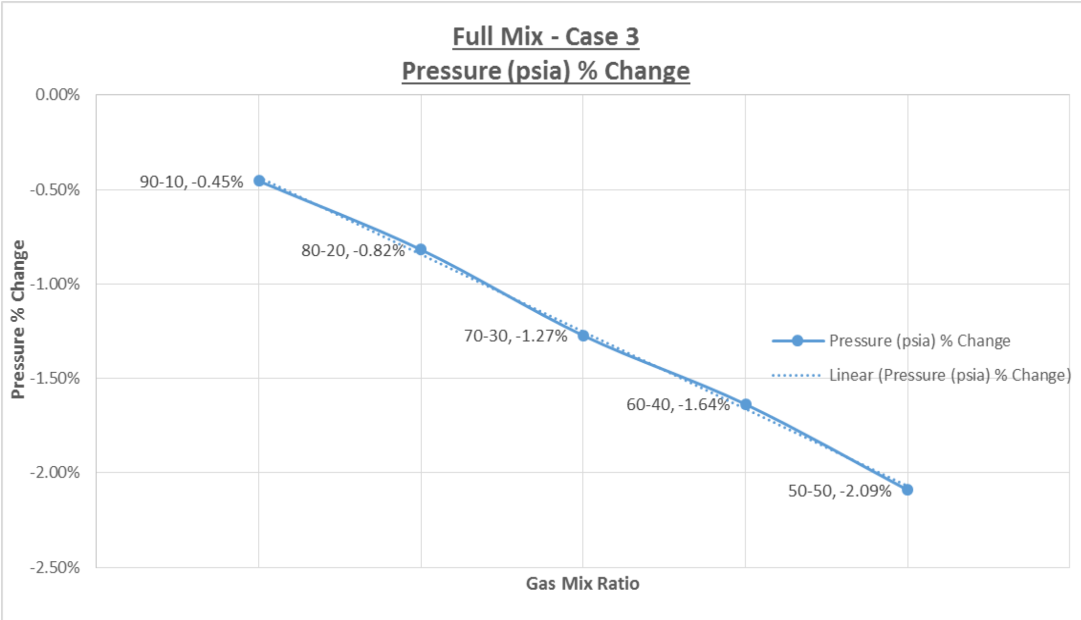

Figure 10 - Case 3: Full Mix - Pressure % Change – Large Low-Pressure Reservoir

4.4 Storage Pressure: No Mixing

The calculated top storage pressure based on the original working gas volume for reservoir cases 1, 2, and 3 are summarized in Table 18, 19, and 20. The percentage changes in top storage pressure for the working gas mixture compared to the original top storage pressure are also listed in each table.

Table 18 - Case 1: No Mixing - Pressure % Change – Intermediate Size and Pressure Reservoir

Case 1: No Mixing - Pressure % Change			
Mix Ratio (Base:Working)	Initial Pressure (psia)	New Pressure (psia)	% Change
90-10	2250.00	2237.00	-0.58%
80-20	2250.00	2220.00	-1.33%
70-30	2250.00	2205.00	-2.00%
60-40	2250.00	2193.00	-2.53%
50-50	2250.00	2179.00	-3.16%

Table 19 - Case 2: No Mixing - Pressure % Change – Small High-Pressure Reservoir

Case 2: No Mixing - Pressure % Change			
Mix Ratio (Base:Working)	Initial Pressure (psia)	New Pressure (psia)	% Change
90-10	2700.00	2690.00	-0.37%
80-20	2700.00	2670.00	-1.11%
70-30	2700.00	2655.00	-1.67%
60-40	2700.00	2642.00	-2.15%
50-50	2700.00	2628.00	-2.67%

Table 20 - Case 3: No Mixing - Pressure % Change – Large Low-Pressure Reservoir

Case 3: No Mixing - Pressure % Change			
Mix Ratio (Base:Working)	Initial Pressure (psia)	New Pressure (psia)	% Change
90-10	1100.00	1096.00	-0.36%
80-20	1100.00	1091.00	-0.82%
70-30	1100.00	1087.00	-1.18%
60-40	1100.00	1082.00	-1.64%
50-50	1100.00	1077.00	-2.09%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the percentage change in top storage pressure compared to the original top storage pressure decreased. The percent change decreased linearly for every case as illustrated in Figures 11, 12, and 13.

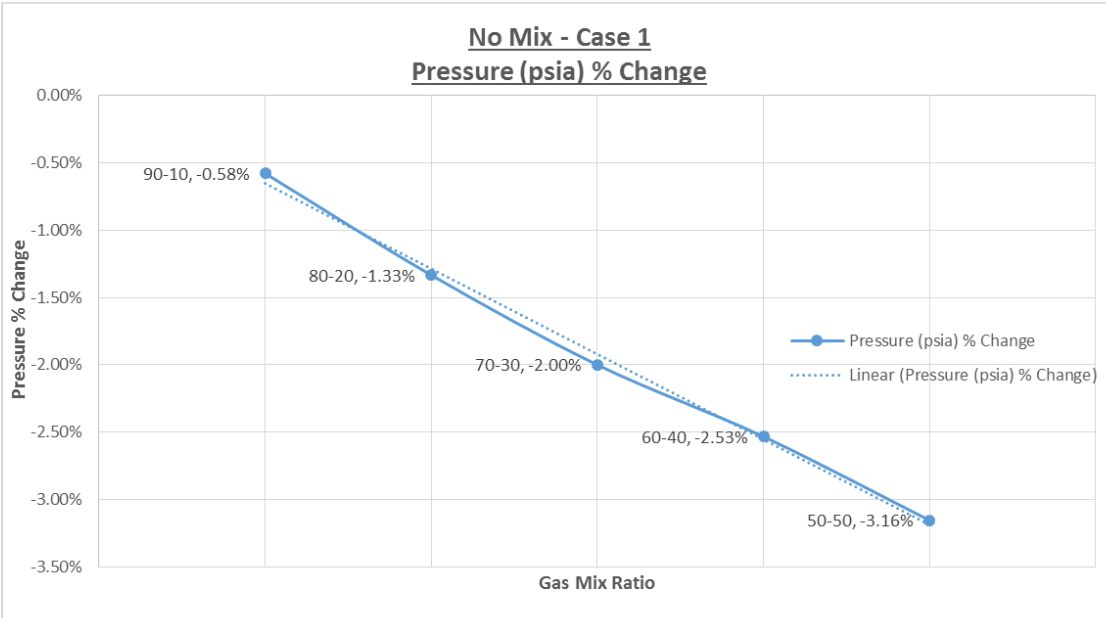

Figure 11 - Case 1: No Mixing - Pressure % Change – Intermediate Size and Pressure Reservoir

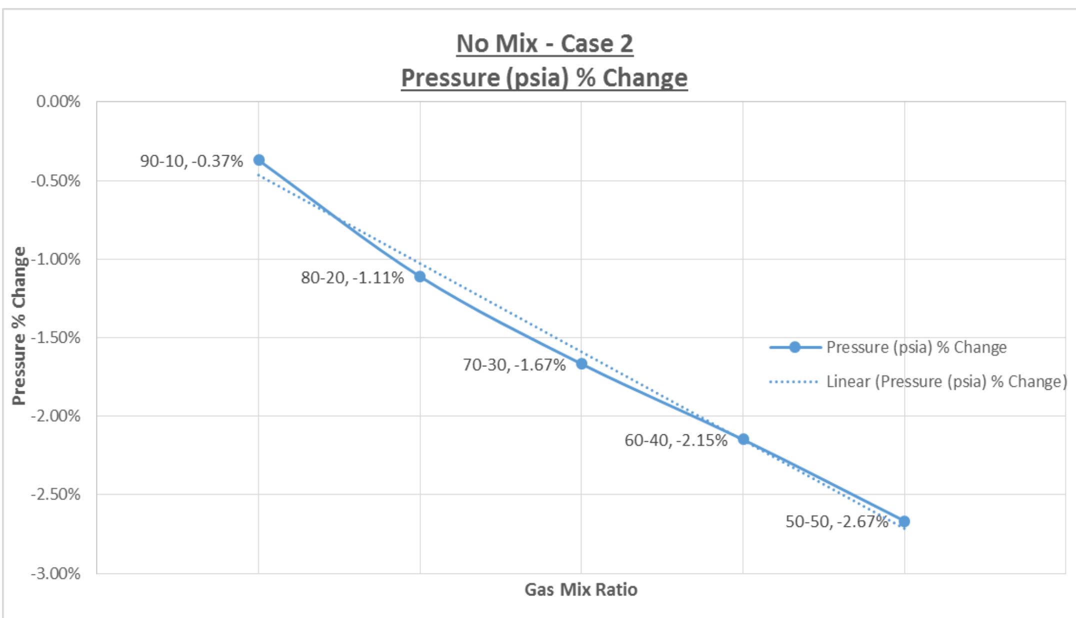

Figure 12 - Case 2: No Mixing - Pressure % Change – Small High-Pressure Reservoir

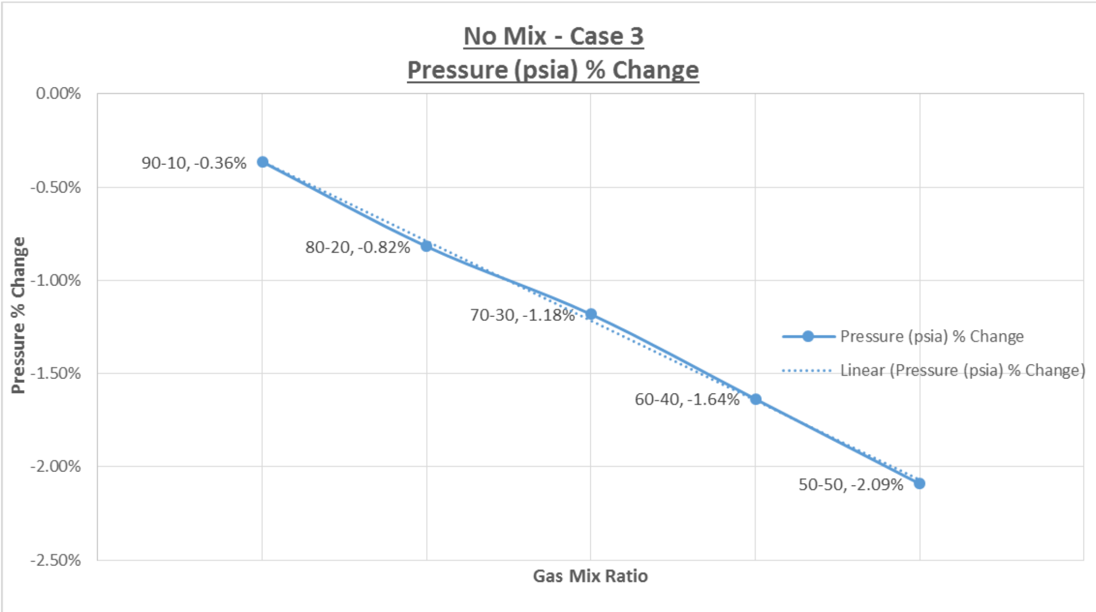

Figure 13 - Case 3: No Mixing - Pressure % Change – Large Low-Pressure Reservoir

4.5 Withdrawal Rate: Full Mix

The calculated gas withdrawal rate for a drawdown of 400 psi at the top storage pressure for the working gas mixture for reservoir cases 1, 2, and 3 are summarized in tables 21, 22, and 23. The percentage changes in withdrawal rate compared to the original withdrawal rate are also listed in each table.

Table 21 - Case 1: Full Mix – Withdrawal Rate % Change – Intermediate Size and Pressure Reservoir

Case 1: Full Mix – Withdrawal Rate % Change			
Mix Ratio (Base:Working)	Initial Withdrawal Rate (MMCFD)	New Withdrawal Rate (MMCFD)	% Change
90-10	36.75	36.44	-0.84%
80-20	36.75	36.14	-1.66%
70-30	36.75	35.85	-2.45%
60-40	36.75	35.57	-3.21%
50-50	36.75	35.30	-3.94%

Table 22 - Case 2: Full Mix – Withdrawal Rate % Change – Small High-Pressure Reservoir

Case 2: Full Mix – Withdrawal Rate % Change			
Mix Ratio (Base:Working)	Initial Withdrawal Rate (MMCFD)	New Withdrawal Rate (MMCFD)	% Change
90-10	41.43	39.32	-5.09%
80-20	41.43	38.96	-5.96%
70-30	41.43	38.63	-6.76%
60-40	41.43	38.27	-7.63%
50-50	41.43	37.95	-8.40%

Table 23 - Case 3: Full Mix – Withdrawal Rate % Change – Large Low-Pressure Reservoir

Case 3: Full Mix – Withdrawal Rate % Change			
Mix Ratio (Base:Working)	Initial Withdrawal Rate (MMCFD)	New Withdrawal Rate (MMCFD)	% Change
90-10	21.65	21.55	-0.46%
80-20	21.65	21.47	-0.85%
70-30	21.65	21.37	-1.31%
60-40	21.65	21.29	-1.68%
50-50	21.65	21.19	-2.13%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the percentage change in withdrawal rate compared to original withdrawal rate decreased. The percent change decreased linearly for every case as illustrated in Figures 14, 15 and 16.

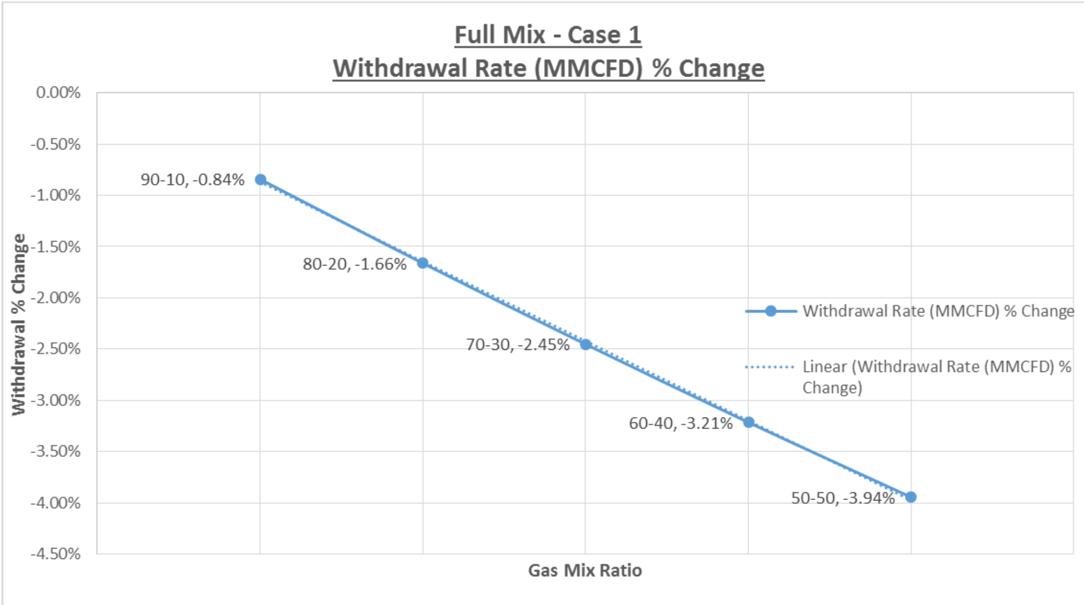

Figure 14 - Case 1: Full Mix – Withdrawal Rate % Change – Intermediate Size and Pressure Reservoir

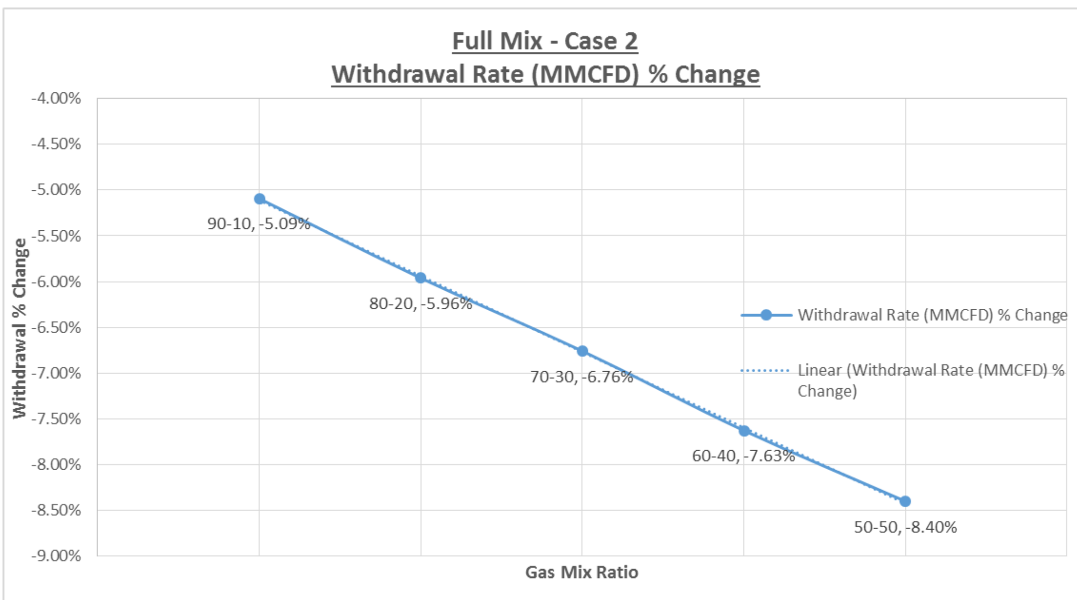

Figure 15 - Case 2: Full Mix – Withdrawal Rate % Change – Small High-Pressure Reservoir

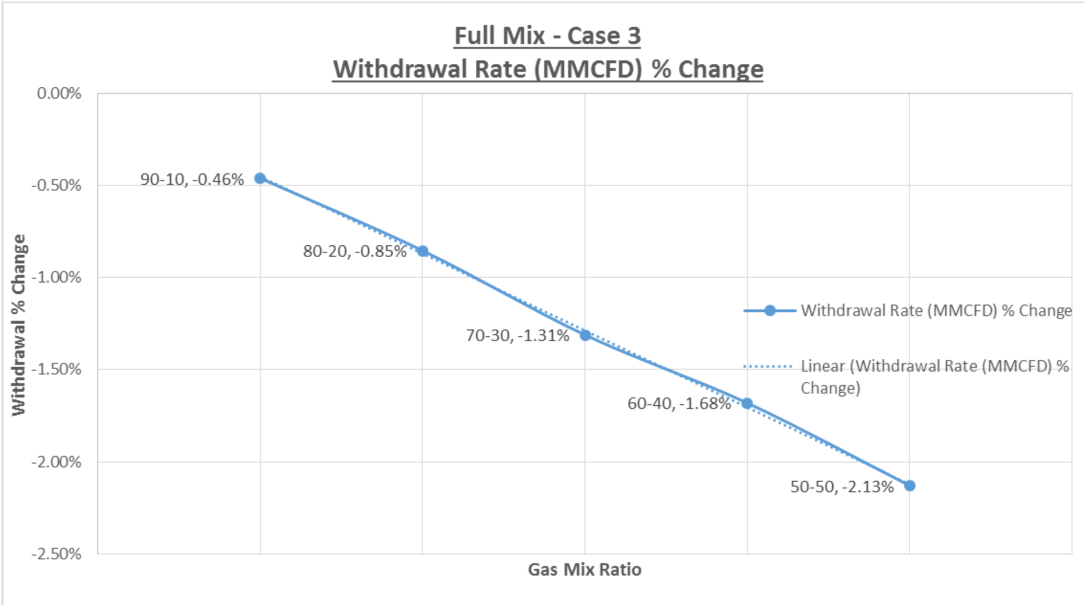

Figure 16 - Case 3: Full Mix – Withdrawal Rate % Change – Large Low-Pressure Reservoir

4.6 Withdrawal Rate: No Mix

The calculated gas withdrawal rate for a drawdown of 400 psi at the top storage pressure for the working gas mixture for reservoir cases 1, 2, and 3 are summarized in tables 24, 25, and 26. The percentage changes in withdrawal rate compared to the original withdrawal rate are also listed in each table.

Table 24 - Case 1: No Mixing – Withdrawal Rate % Change – Intermediate Size and Pressure Reservoir

Case 1: No Mixing – Withdrawal Rate % Change			
Mix Ratio (Base:Working)	Initial Withdrawal Rate (MMCFD)	New Withdrawal Rate (MMCFD)	% Change
90-10	36.75	36.45	-0.82%
80-20	36.75	36.13	-1.68%
70-30	36.75	35.82	-2.54%
60-40	36.75	35.56	-3.24%
50-50	36.75	35.29	-3.97%

Table 25 - Case 2: No Mixing – Withdrawal Rate % Change – Small High-Pressure Reservoir

Case 2: No Mixing – Withdrawal Rate % Change			
Mix Ratio (Base:Working)	Initial Withdrawal Rate (MMCFD)	New Withdrawal Rate (MMCFD)	% Change
90-10	41.43	39.36	-5.00%
80-20	41.43	38.96	-5.96%
70-30	41.43	38.61	-6.80%
60-40	41.43	38.29	-7.58%
50-50	41.43	37.96	-8.38%

Table 26 - Case 3: No Mixing – Withdrawal Rate % Change – Large Low-Pressure Reservoir

Case 3: No Mixing – Withdrawal Rate % Change			
Mix Ratio (Base:Working)	Initial Withdrawal Rate (MMCFD)	New Withdrawal Rate (MMCFD)	% Change
90-10	21.85	21.76	-0.41%
80-20	21.85	21.65	-0.91%
70-30	21.85	21.56	-1.32%
60-40	21.85	21.46	-1.80%
50-50	21.85	21.36	-2.27%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the percentage change in withdrawal rate compared to original withdrawal rate decreased. The percent change decreased linearly for every case as illustrated in Figures 17, 18 and 19.

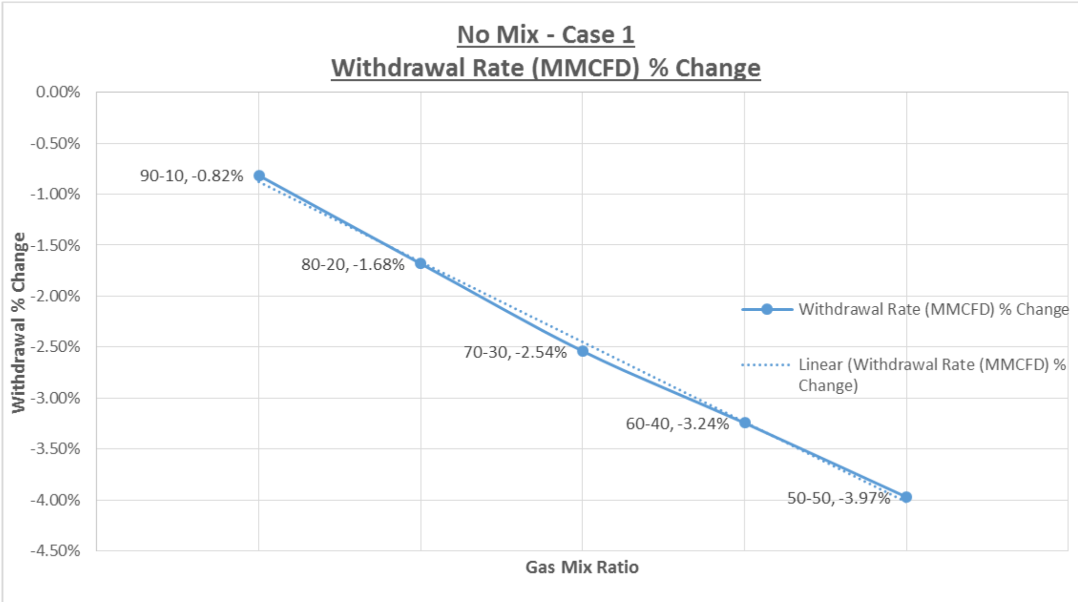

Figure 17 - Case 1: No Mixing – Withdrawal Rate % Change – Intermediate Size and Pressure Reservoir

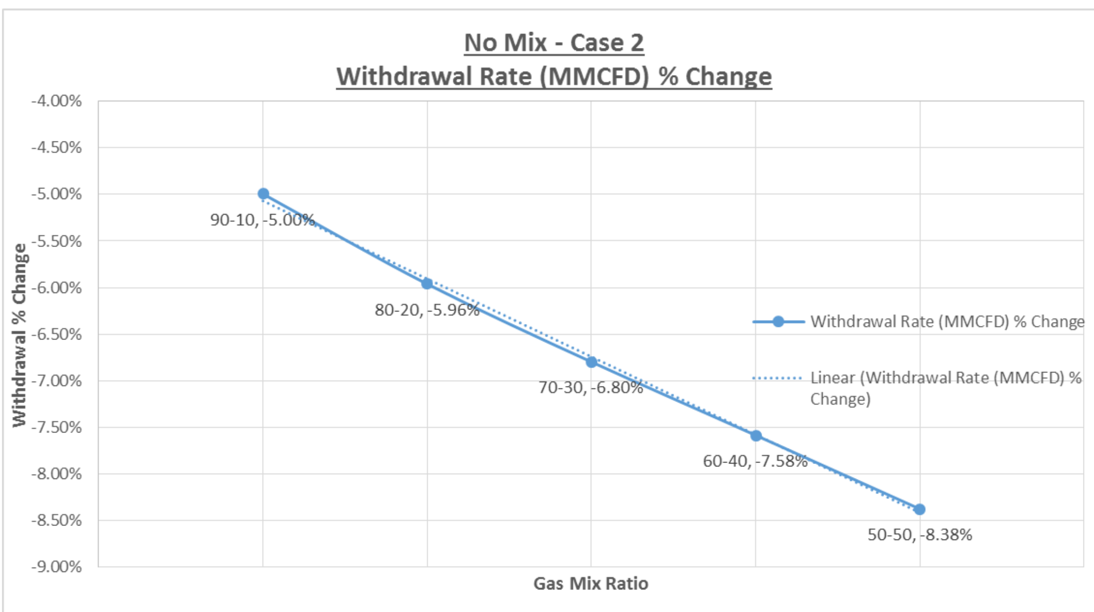

Figure 18 - Case 2: No Mixing – Withdrawal Rate % Change – Small High-Pressure Reservoir

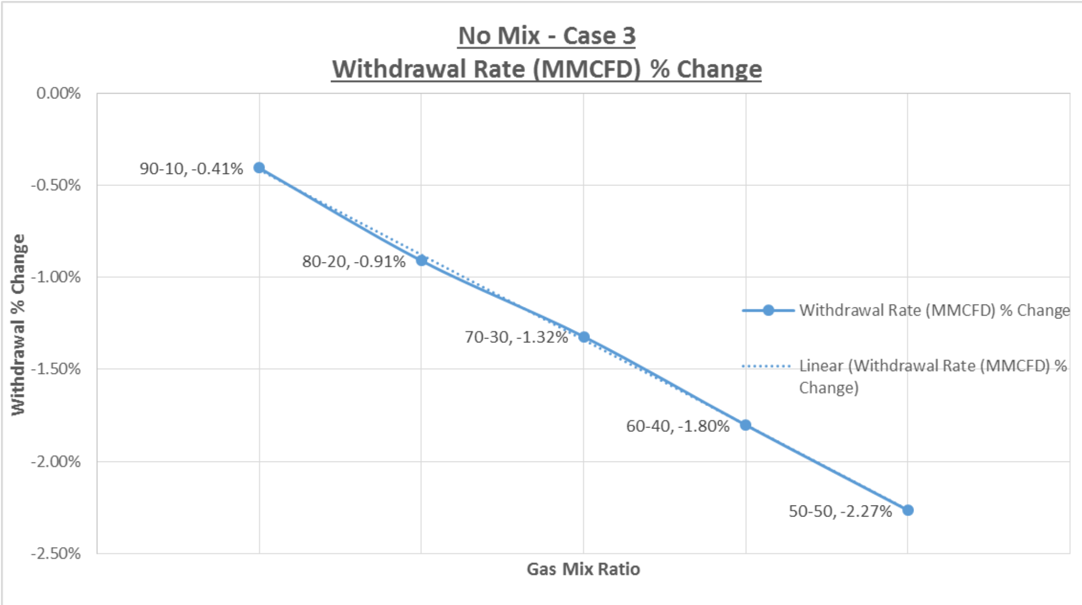

Figure 19 - Case 3: No Mixing – Withdrawal Rate % Change – Large Low-Pressure Reservoir

4.7 Drawdown: Full Mixing

The calculated gas drawdown required to achieve original flow rate (based on 400 psi drawdown using base gas composition) at the top storage pressure for reservoir cases 1, 2, and 3 are summarized in tables 27, 28, and 29. The percentage change in drawdown compared to the original drawdown (400 psi) are also listed in each table.

Table 27- Case 1: Full Mix – Drawdown % Change – Intermediate Size and Pressure Reservoir

Case 1: Full Mix – Drawdown % Change			
Mix Ratio (Base:Working)	Initial Drawdown (psia)	New Drawdown (psia)	% Change
90-10	400.00	405.00	1.25%
80-20	400.00	410.00	2.50%
70-30	400.00	415.00	3.75%
60-40	400.00	420.00	5.00%
50-50	400.00	425.00	6.25%

Table 28- Case 2: Full Mix – Drawdown % Change – Small High-Pressure Reservoir

Case 2: Full Mix – Drawdown % Change			
Mix Ratio (Base:Working)	Initial Drawdown (psia)	New Drawdown (psia)	% Change
90-10	400.00	432.00	8.00%
80-20	400.00	438.00	9.50%
70-30	400.00	444.00	11.00%
60-40	400.00	450.00	12.50%
50-50	400.00	456.00	14.00%

Table 29 - Case 3: Full Mix – Drawdown % Change – Large Low-Pressure Reservoir

Case 3: Full Mix – Drawdown % Change			
Mix Ratio (Base:Working)	Initial Drawdown (psia)	New Drawdown (psia)	% Change
90-10	400.00	403.00	0.75%
80-20	400.00	406.00	1.50%
70-30	400.00	409.00	2.25%
60-40	400.00	412.00	3.00%
50-50	400.00	415.00	3.75%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the percentage change in drawdown compared to original drawdown increased. The percent change increased linearly for every case as illustrated in Figures 20, 21 and 22.

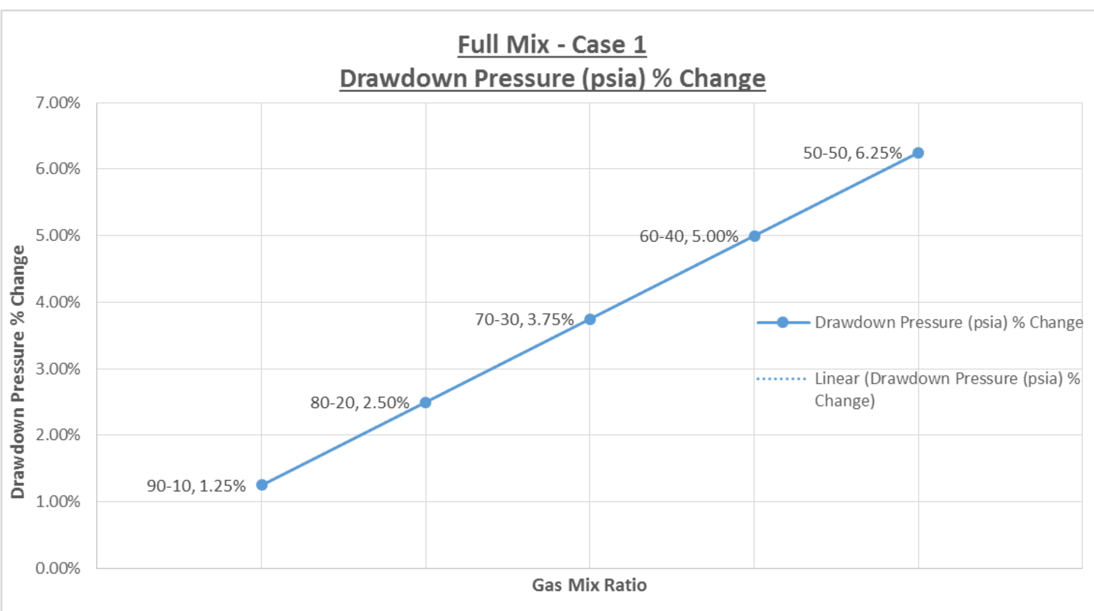

Figure 20 - Case 1: Full Mix – Drawdown % Change – Intermediate Size and Pressure Reservoir

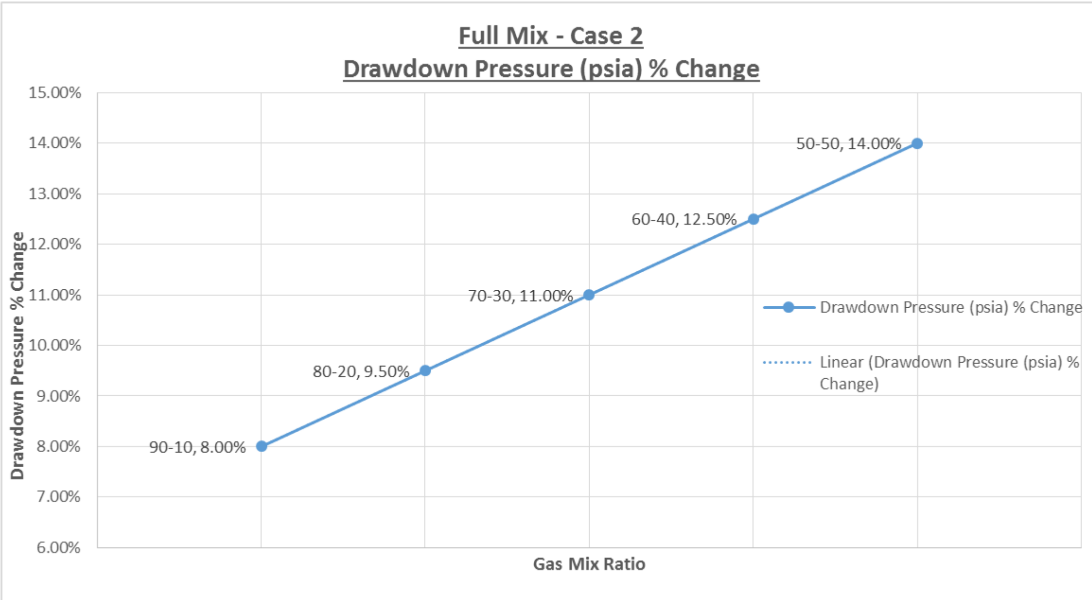

Figure 21 - Case 2: Full Mix – Drawdown % Change – Small High-Pressure Reservoir

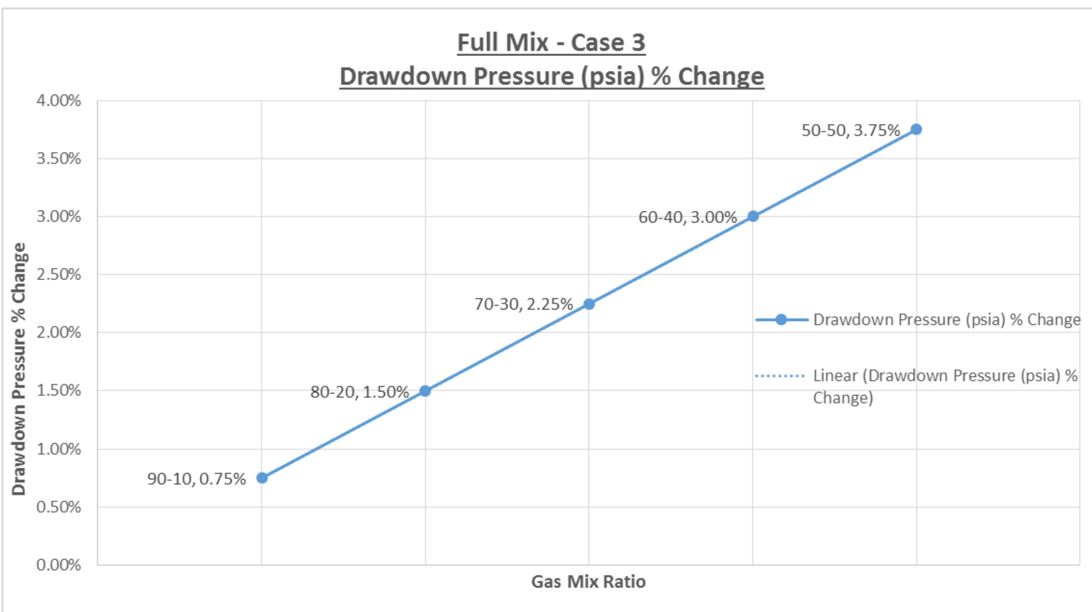

Figure 22 - Case 3: Full Mix – Drawdown % Change – Large Low-Pressure Reservoir

4.8 Drawdown: No Mix

The calculated gas drawdown required to achieve original flow rate (based on 400 psi drawdown using base gas composition) at the top storage pressure for reservoir cases 1, 2, and 3 are summarized in tables 30, 31, and 32. The percentage change in drawdown compared to the original drawdown (400 psi) are also listed in each table.

Table 30 - Case 1: No Mixing – Drawdown % Change – Intermediate Size and Pressure Reservoir

Case 1: No Mixing – Drawdown % Change			
Mix Ratio (Base:Working)	Initial Drawdown (psia)	New Drawdown (psia)	% Change
90-10	400.00	405.00	1.25%
80-20	400.00	410.50	2.63%
70-30	400.00	416.00	4.00%
60-40	400.00	420.50	5.13%
50-50	400.00	425.50	6.38%

Table 31 - Case 2: No Mixing – Drawdown % Change – Small High-Pressure Reservoir

Case 2: No Mixing – Drawdown % Change			
Mix Ratio (Base:Working)	Initial Drawdown (psia)	New Drawdown (psia)	% Change
90-10	400.00	431.50	7.88%
80-20	400.00	439.00	9.75%
70-30	400.00	444.00	11.00%
60-40	400.00	450.00	12.50%
50-50	400.00	456.00	14.00%

Table 32 - Case 3: No Mixing – Drawdown % Change – Large Low-Pressure Reservoir

Case 3: No Mixing – Drawdown % Change			
Mix Ratio (Base:Working)	Initial Drawdown (psia)	New Drawdown (psia)	% Change
90-10	400.00	403.00	0.75%
80-20	400.00	406.00	1.50%
70-30	400.00	409.00	2.25%
60-40	400.00	413.00	3.25%
50-50	400.00	416.00	4.00%

For all following cases, as the ratio of shale gas to the original gas in the mixture (working gas) was increased, the percentage change in drawdown compared to original drawdown increased. The percent change increased linearly for every case as illustrated in Figures 23, 24 and 25.

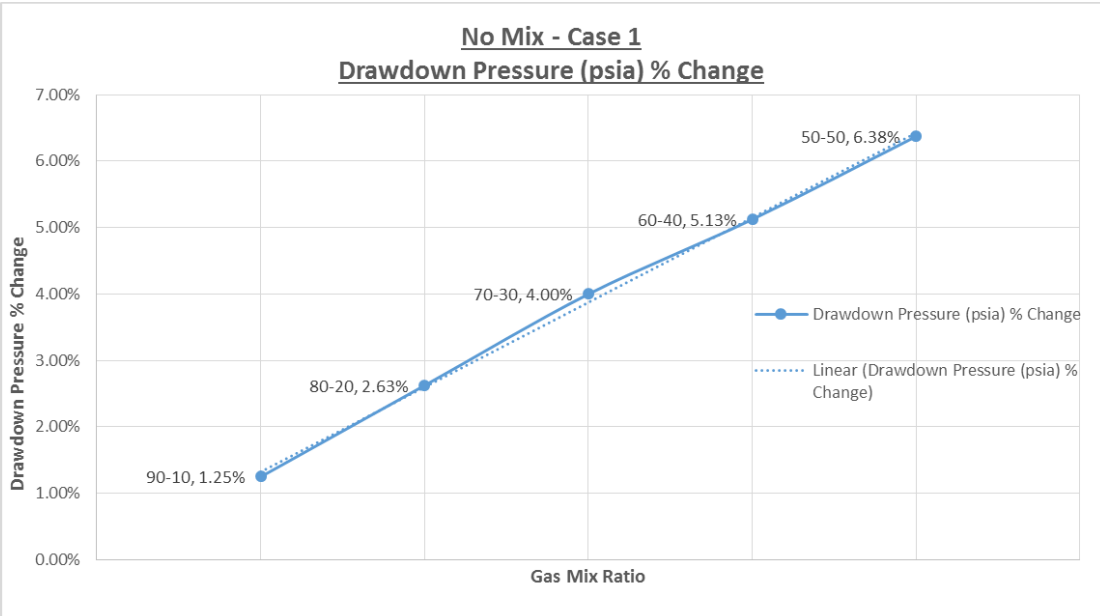

Figure 23 - Case 1: No Mixing – Drawdown % Change – Intermediate Size and Pressure Reservoir

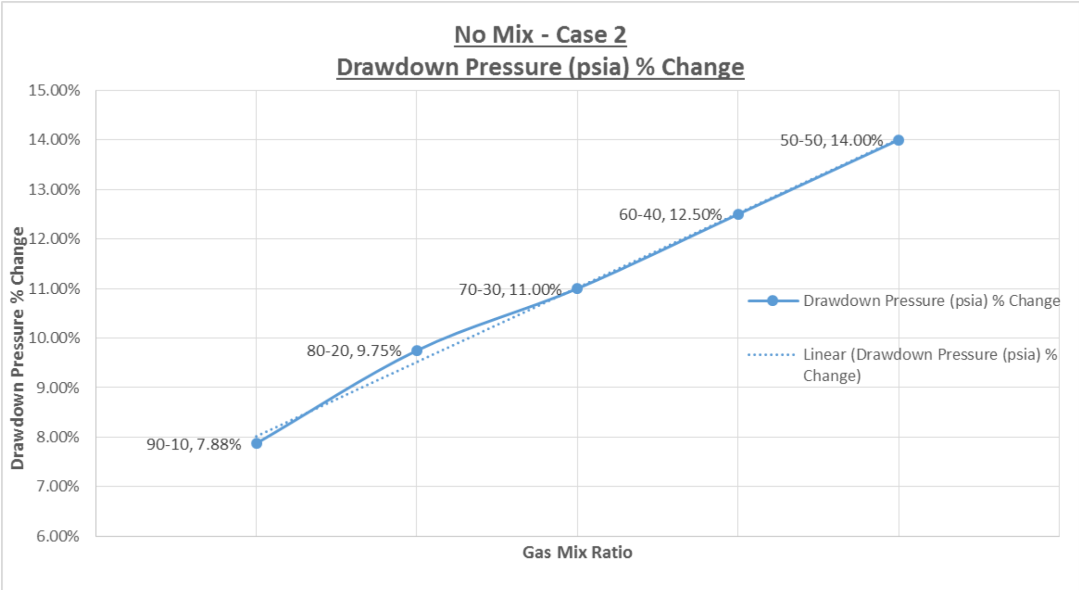

Figure 24 - Case 2: No Mixing – Drawdown % Change – Small High-Pressure Reservoir

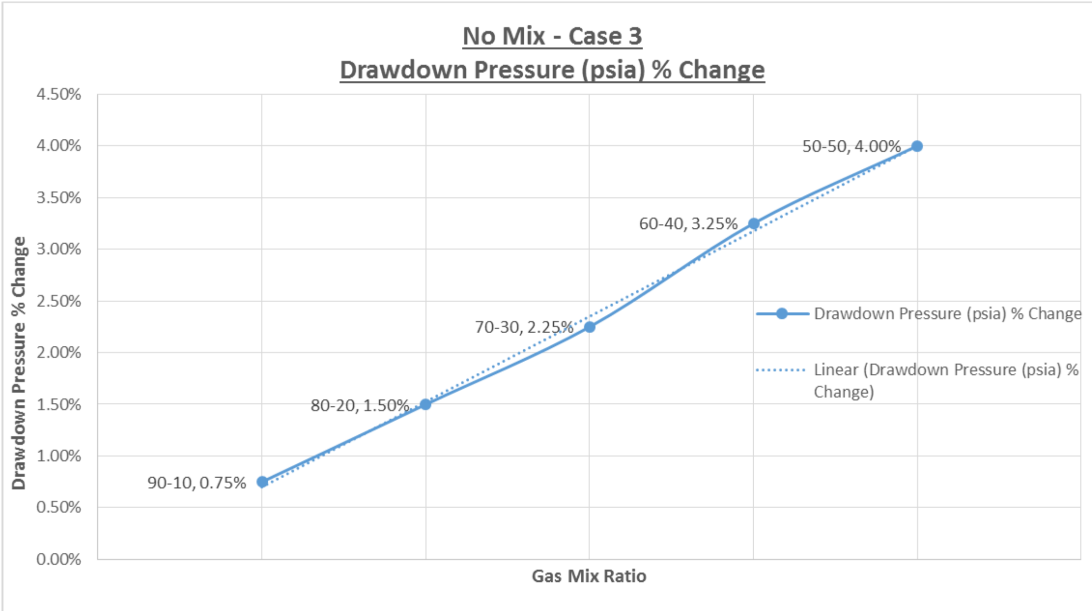

Figure 25 - Case 3: No Mixing – Drawdown % Change – Large Low-Pressure Reservoir

5. Conclusions

The following conclusions were reached for all the storage reservoir cases in this study:

1. The volume required to fill the pore volume of the reservoir increased as the percentage of the shale gas in the working gas was increased for both full mixing and no mixing cases.
2. The percent change in the volume was found to change linearly with the percentage of the shale gas in the working gas.
3. The top pressure in the reservoir after injecting a gas volume the same as the original working gas volume decreased as the percentage of shale gas in the working gas was increased for both full mixing and no mixing cases.
4. The percent change in top storage pressure was found to change linearly with the percentage of the shale gas in the working gas.
5. The gas withdrawal rate for a drawdown of 400 psi decreased as the percentage of shale gas in the working gas increased for both full mixing and no mixing cases.
6. The percent change in gas withdrawal rate was found to change linearly with the percentage of the shale gas in the working gas.
7. The drawdown required to achieve original reservoir flow rate at top pressure increased as the percentage of shale gas in the working gas increased for both full mixing and no mixing cases.
8. The percent change in gas withdrawal rate was found to change linearly with the percentage of the shale gas in the working gas.

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7. Appendix

Appendix A – Shale Gas and Storage Gas Compositions and properties

Table 33 - Typical Marcellus Shale Gas (Working Gas) Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×TC	P_c, psia	y×PC	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.003	0.00300	227.0	0.6810	493.0	1.479	28.01	0.08
H_2S	0.000	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.760	0.76000	343.3	260.9080	673.1	511.556	16.04	12.1904
C_2H_6	0.150	0.15000	549.8	82.4700	708.3	106.245	30.07	4.51
C_3H_8	0.059	0.05900	666.0	39.2940	617.4	36.4266	44.10	2.60
i-C_4H_{10}	0.007	0.00700	734.7	5.1429	529.1	3.7037	58.12	0.41
n-C_4H_{10}	0.007	0.00700	765.3	5.3571	550.7	3.8549	58.12	0.41
i-C_5H_{12}	0.004	0.00400	829.8	3.3192	483.0	1.932	72.15	0.22
n-C_5H_{12}	0.003	0.00300	845.6	2.5368	489.5	1.4685	72.15	0.14
C_6H_{14}	0.002	0.00200	914.0	1.8280	439.7	0.8794	86.18	0.17
C_7+	0.004	0.00400	1098.1	4.3925	428.8	1.71533	120.00	0.5
	1.00000	**1.00000**		**406.48**		**670.33**		**21.2576**

Table 34 - Typical Marcellus Storage Gas Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×TC	P_c, psia	y×PC	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002	0.00200	227.0	0.4540	493.0	0.986	28.01	0.06
H_2S	0.000	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.980	0.98000	343.3	336.4340	673.1	659.638	16.04	15.7192
C_2H_6	0.010	0.01000	549.8	5.4980	708.3	7.083	30.07	0.30
C_3H_8	0.003	0.00300	666.0	1.9980	617.4	1.8522	44.10	0.13
i-C_4H_{10}	0.002	0.00200	734.7	1.4694	529.1	1.0582	58.12	0.12
n-C_4H_{10}	0.0008	0.00080	765.3	0.6122	550.7	0.44056	58.12	0.05
i-C_5H_{12}	0.0004	0.00040	829.8	0.3319	483.0	0.1932	72.15	0.02
n-C_5H_{12}	0.0003	0.00030	845.6	0.2537	489.5	0.14685	72.15	0.01
C_6H_{14}	0.0002	0.00020	914.0	0.1828	439.7	0.08794	86.18	0.02
C_7+	0.0003	0.00030	1098.1	0.3294	428.8	0.12865	120.00	0.0
	1.00000	**1.00000**		**348.11**		**672.69**		**16.5043**

Table 35 - Compositions of Storage Gas and Shale Gas Mixtures

	Storage	Shale	Mix				
Component	Mole Fraction	Mole Fraction	90-10	80-20	70-30	60-40	50-50
CO_2	0.001	0.001	0.001	0.001	0.001	0.001	0.001
N_2	0.002	0.003	0.0021	0.0022	0.0023	0.0024	0.0025
H_2S	0.000	0.000	0	0	0	0	0
CH_4	0.980	0.760	0.958	0.936	0.914	0.892	0.870
C_2H_6	0.010	0.150	0.024	0.038	0.052	0.066	0.080
C_3H_8	0.003	0.059	0.0086	0.0142	0.0198	0.0254	0.031
i-C_4H_{10}	0.002	0.007	0.0025	0.003	0.0035	0.004	0.0045
n-C_4H_{10}	0.0008	0.007	0.00142	0.00204	0.00266	0.00328	0.0039
i-C_5H_{12}	0.0004	0.004	0.00076	0.00112	0.00148	0.00184	0.0022
n-C_5H_{12}	0.0003	0.003	0.00057	0.00084	0.00111	0.00138	0.00165
C_6H_{14}	0.0002	0.002	0.00038	0.00056	0.00074	0.00092	0.0011
C_7+	0.0003	0.004	0.00067	0.00104	0.00141	0.00178	0.00215
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

Appendix B – Case 1 Storage Reservoir: Full Mix Data

Table 36 - Case 1: Shale Gas 90-10 Full Mix Ratio Composition

	90-10 Working Gas	Storage	Mix
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0021	0.002	0.002055
H_2S	0	0.000	0
CH_4	0.958	0.980	0.9679
C_2H_6	0.024	0.010	0.0177
C_3H_8	0.0086	0.003	0.00608
$i\text{-}C_4H_{10}$	0.0025	0.002	0.002275
$n\text{-}C_4H_{10}$	0.00142	0.0008	0.001141
$i\text{-}C_5H_{12}$	0.00076	0.0004	0.000598
$n\text{-}C_5H_{12}$	0.00057	0.0003	0.0004485
C_6H_{14}	0.00038	0.0002	0.000299
C_7+	0.00067	0.0003	0.0005035
	1.00000	1.00000	1.00000

Table 37 - Case 1 Storage Reservoir: 90-10 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002055	0.00206	227.0	0.4665	493.0	1.01312	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.9679	0.96790	343.3	332.2801	673.1	651.493	16.04	15.5251
C_2H_6	0.0177	0.01770	549.8	9.7315	708.3	12.5369	30.07	0.53
C_3H_8	0.00608	0.00608	666.0	4.0493	617.4	3.75379	44.10	0.27
$i\text{-}C_4H_{10}$	0.002275	0.00228	734.7	1.6714	529.1	1.2037	58.12	0.13
$n\text{-}C_4H_{10}$	0.001141	0.00114	765.3	0.8732	550.7	0.62835	58.12	0.07
$i\text{-}C_5H_{12}$	0.000598	0.00060	829.8	0.4962	483.0	0.28883	72.15	0.03
$n\text{-}C_5H_{12}$	0.0004485	0.00045	845.6	0.3793	489.5	0.21954	72.15	0.02
C_6H_{14}	0.000299	0.00030	914.0	0.2733	439.7	0.13147	86.18	0.03
C_7+	0.0005035	0.00050	1098.1	0.5529	428.8	0.21592	120.00	0.1
	1.00000	1.00000		351.32		672.56		16.7657

Table 38 - Case 1: Shale Gas 80-20 Full Mix Ratio Composition

	80-20 Working Gas	Storage	Mix
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0022	0.002	0.00211
H_2S	0	0.000	0
CH_4	0.936	0.980	0.9558
C_2H_6	0.038	0.010	0.0254
C_3H_8	0.0142	0.003	0.00916
$i\text{-}C_4H_{10}$	0.003	0.002	0.00255
$n\text{-}C_4H_{10}$	0.00204	0.0008	0.001482
$i\text{-}C_5H_{12}$	0.00112	0.0004	0.000796
$n\text{-}C_5H_{12}$	0.00084	0.0003	0.000597
C_6H_{14}	0.00056	0.0002	0.000398
C_7+	0.00104	0.0003	0.000707
	1.00000	1.00000	1.00000

Table 39 - Case 1 Storage Reservoir: 80-20 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y{\times}T_c$	P_c, psia	$y{\times}P_c$	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.00211	0.00211	227.0	0.4790	493.0	1.04023	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.9558	0.95580	343.3	328.1261	673.1	643.349	16.04	15.331
C_2H_6	0.0254	0.02540	549.8	13.9649	708.3	17.9908	30.07	0.76
C_3H_8	0.00916	0.00916	666.0	6.1006	617.4	5.65538	44.10	0.40
$i\text{-}C_4H_{10}$	0.00255	0.00255	734.7	1.8735	529.1	1.34921	58.12	0.15
$n\text{-}C_4H_{10}$	0.001482	0.00148	765.3	1.1342	550.7	0.81614	58.12	0.09
$i\text{-}C_5H_{12}$	0.000796	0.00080	829.8	0.6605	483.0	0.38447	72.15	0.04
$n\text{-}C_5H_{12}$	0.000597	0.00060	845.6	0.5048	489.5	0.29223	72.15	0.03
C_6H_{14}	0.000398	0.00040	914.0	0.3638	439.7	0.175	86.18	0.03
C_7+	0.000707	0.00071	1098.1	0.7764	428.8	0.30319	120.00	0.1
	1.00000	1.00000		354.53		672.43		17.0271

Table 40 - Case 1: Shale Gas 70-30 Full Mix Ratio Composition

	70-30 Working Gas	Storage	Mix
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0023	0.002	0.002165
H_2S	0	0.000	0
CH_4	0.914	0.980	0.9437
C_2H_6	0.052	0.010	0.0331
C_3H_8	0.0198	0.003	0.01224
$i\text{-}C_4H_{10}$	0.0035	0.002	0.002825
$n\text{-}C_4H_{10}$	0.00266	0.0008	0.001823
$i\text{-}C_5H_{12}$	0.00148	0.0004	0.000994
$n\text{-}C_5H_{12}$	0.00111	0.0003	0.0007455
C_6H_{14}	0.00074	0.0002	0.000497
C_7+	0.00141	0.0003	0.0009105
	1.00000	1.00000	1.00000

Table 41 - Case 1 Storage Reservoir: 70-30 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002165	0.00217	227.0	0.4915	493.0	1.06735	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.9437	0.94370	343.3	323.9722	673.1	635.204	16.04	15.1369
C_2H_6	0.0331	0.03310	549.8	18.1984	708.3	23.4447	30.07	1.00
C_3H_8	0.01224	0.01224	666.0	8.1518	617.4	7.55698	44.10	0.54
$i\text{-}C_4H_{10}$	0.002825	0.00283	734.7	2.0755	529.1	1.49471	58.12	0.16
$n\text{-}C_4H_{10}$	0.001823	0.00182	765.3	1.3951	550.7	1.00393	58.12	0.11
$i\text{-}C_5H_{12}$	0.000994	0.00099	829.8	0.8248	483.0	0.4801	72.15	0.05
$n\text{-}C_5H_{12}$	0.0007455	0.00075	845.6	0.6304	489.5	0.36492	72.15	0.04
C_6H_{14}	0.000497	0.00050	914.0	0.4543	439.7	0.21853	86.18	0.04
C_7+	0.0009105	0.00091	1098.1	0.9998	428.8	0.39045	120.00	0.1
	1.00000	1.00000		357.74		672.30		17.2886

Table 42 - Case 1: Shale Gas 60-40 Full Mix Ratio Composition

	60-40 Working Gas	Storage	Mix
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0024	0.002	0.00222
H_2S	0	0.000	0
CH_4	0.892	0.980	0.9316
C_2H_6	0.066	0.010	0.0408
C_3H_8	0.0254	0.003	0.01532
$i\text{-}C_4H_{10}$	0.004	0.002	0.0031
$n\text{-}C_4H_{10}$	0.00328	0.0008	0.002164
$i\text{-}C_5H_{12}$	0.00184	0.0004	0.001192
$n\text{-}C_5H_{12}$	0.00138	0.0003	0.000894
C_6H_{14}	0.00092	0.0002	0.000596
C_7+	0.00178	0.0003	0.001114
	1.00000	1.00000	1.00000

Table 43 - Case 1 Storage Reservoir: 60-40 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.00222	0.00222	227.0	0.5039	493.0	1.09446	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.9316	0.93160	343.3	319.8183	673.1	627.06	16.04	14.9429
C_2H_6	0.0408	0.04080	549.8	22.4318	708.3	28.8986	30.07	1.23
C_3H_8	0.01532	0.01532	666.0	10.2031	617.4	9.45857	44.10	0.68
$i\text{-}C_4H_{10}$	0.0031	0.00310	734.7	2.2776	529.1	1.64021	58.12	0.18
$n\text{-}C_4H_{10}$	0.002164	0.00216	765.3	1.6561	550.7	1.19171	58.12	0.13
$i\text{-}C_5H_{12}$	0.001192	0.00119	829.8	0.9891	483.0	0.57574	72.15	0.06
$n\text{-}C_5H_{12}$	0.000894	0.00089	845.6	0.7560	489.5	0.43761	72.15	0.04
C_6H_{14}	0.000596	0.00060	914.0	0.5447	439.7	0.26206	86.18	0.05
C_7+	0.001114	0.00111	1098.1	1.2233	428.8	0.47772	120.00	0.1
	1.00000	1.00000		360.95		672.17		17.55

Table 44 - Case 1: Shale Gas 50-50 Full Mix Ratio Composition

	50-50 Working Gas	Storage	Mix
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0025	0.002	0.002275
H_2S	0	0.000	0
CH_4	0.87	0.980	0.9195
C_2H_6	0.08	0.010	0.0485
C_3H_8	0.031	0.003	0.0184
$i\text{-}C_4H_{10}$	0.0045	0.002	0.003375
$n\text{-}C_4H_{10}$	0.0039	0.0008	0.002505
$i\text{-}C_5H_{12}$	0.0022	0.0004	0.00139
$n\text{-}C_5H_{12}$	0.00165	0.0003	0.0010425
C_6H_{14}	0.0011	0.0002	0.000695
C_7+	0.00215	0.0003	0.0013175
	1.00000	1.00000	1.00000

Table 45 - Case 1 Storage Reservoir: 50-50 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×TC	P_c, psia	y×PC	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002275	0.00228	227.0	0.5164	493.0	1.12158	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.920	0.91950	343.3	315.6644	673.1	618.915	16.04	14.7488
C_2H_6	0.049	0.04850	549.8	26.6653	708.3	34.3526	30.07	1.46
C_3H_8	0.0184	0.01840	666.0	12.2544	617.4	11.3602	44.10	0.81
$i\text{-}C_4H_{10}$	0.003375	0.00338	734.7	2.4796	529.1	1.78571	58.12	0.20
$n\text{-}C_4H_{10}$	0.002505	0.00251	765.3	1.9171	550.7	1.3795	58.12	0.15
$i\text{-}C_5H_{12}$	0.00139	0.00139	829.8	1.1534	483.0	0.67137	72.15	0.08
$n\text{-}C_5H_{12}$	0.0010425	0.00104	845.6	0.8815	489.5	0.5103	72.15	0.05
C_6H_{14}	0.000695	0.00070	914.0	0.6352	439.7	0.30559	86.18	0.06
C_7+	0.0013175	0.00132	1098.1	1.4468	428.8	0.56499	120.00	0.2
	1.00000	1.00000		364.16		672.04		17.8114

Appendix C – Case 2 Storage Reservoir: Full Mix Data

Table 46 - Case 2: Shale Gas 90-10 Full Mix Ratio Composition

	90-10 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0021	0.002	0.00205
H_2S	0	0.000	0
CH_4	0.958	0.980	0.969
C_2H_6	0.024	0.010	0.017
C_3H_8	0.0086	0.003	0.0058
$i\text{-}C_4H_{10}$	0.0025	0.002	0.00225
$n\text{-}C_4H_{10}$	0.00142	0.0008	0.00111
$i\text{-}C_5H_{12}$	0.00076	0.0004	0.00058
$n\text{-}C_5H_{12}$	0.00057	0.0003	0.000435
C_6H_{14}	0.00038	0.0002	0.00029
C_7+	0.00067	0.0003	0.000485
	1.00000	1.00000	1.00000

Table 47 - Case 2 Storage Reservoir: 90-10 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.00205	0.00205	227.0	0.4654	493.0	1.01065	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.969	0.96900	343.3	332.6577	673.1	652.234	16.04	15.5428
C_2H_6	0.017	0.01700	549.8	9.3466	708.3	12.0411	30.07	0.51
C_3H_8	0.0058	0.00580	666.0	3.8628	617.4	3.58092	44.10	0.26
$i\text{-}C_4H_{10}$	0.00225	0.00225	734.7	1.6531	529.1	1.19048	58.12	0.13
$n\text{-}C_4H_{10}$	0.00111	0.00111	765.3	0.8495	550.7	0.61128	58.12	0.06
$i\text{-}C_5H_{12}$	0.00058	0.00058	829.8	0.4813	483.0	0.28014	72.15	0.03
$n\text{-}C_5H_{12}$	0.000435	0.00044	845.6	0.3678	489.5	0.21293	72.15	0.02
C_6H_{14}	0.00029	0.00029	914.0	0.2651	439.7	0.12751	86.18	0.02
C_7+	0.000485	0.00049	1098.1	0.5326	428.8	0.20798	120.00	0.1
	1.00000	1.00000		351.03		672.57		16.7419

Table 48 - Case 2: Shale Gas 80-20 Full Mix Ratio Composition

	80-20 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0022	0.002	0.0021
H_2S	0	0.000	0
CH_4	0.936	0.980	0.958
C_2H_6	0.038	0.010	0.024
C_3H_8	0.0142	0.003	0.0086
$i\text{-}C_4H_{10}$	0.003	0.002	0.0025
$n\text{-}C_4H_{10}$	0.00204	0.0008	0.00142
$i\text{-}C_5H_{12}$	0.00112	0.0004	0.00076
$n\text{-}C_5H_{12}$	0.00084	0.0003	0.00057
C_6H_{14}	0.00056	0.0002	0.00038
C_7+	0.00104	0.0003	0.00067
	1.00000	1.00000	1.00000

Table 49 - Case 2 Storage Reservoir: 80-20 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y{\times}T_c$	P_c, psia	$y{\times}P_c$	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0021	0.00210	227.0	0.4767	493.0	1.0353	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.958	0.95800	343.3	328.8814	673.1	644.83	16.04	15.3663
C_2H_6	0.024	0.02400	549.8	13.1952	708.3	16.9992	30.07	0.72
C_3H_8	0.0086	0.00860	666.0	5.7276	617.4	5.30964	44.10	0.38
$i\text{-}C_4H_{10}$	0.0025	0.00250	734.7	1.8368	529.1	1.32275	58.12	0.15
$n\text{-}C_4H_{10}$	0.00142	0.00142	765.3	1.0867	550.7	0.78199	58.12	0.08
$i\text{-}C_5H_{12}$	0.00076	0.00076	829.8	0.6306	483.0	0.36708	72.15	0.04
$n\text{-}C_5H_{12}$	0.00057	0.00057	845.6	0.4820	489.5	0.27902	72.15	0.03
C_6H_{14}	0.00038	0.00038	914.0	0.3473	439.7	0.16709	86.18	0.03
C_7+	0.00067	0.00067	1098.1	0.7357	428.8	0.28732	120.00	0.1
	1.00000	1.00000		353.95		672.45		16.9796

Table 50 - Case 2: Shale Gas 70-30 Full Mix Ratio Composition

	70-30 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0023	0.002	0.00215
H_2S	0	0.000	0
CH_4	0.914	0.980	0.947
C_2H_6	0.052	0.010	0.031
C_3H_8	0.0198	0.003	0.0114
$i\text{-}C_4H_{10}$	0.0035	0.002	0.00275
$n\text{-}C_4H_{10}$	0.00266	0.0008	0.00173
$i\text{-}C_5H_{12}$	0.00148	0.0004	0.00094
$n\text{-}C_5H_{12}$	0.00111	0.0003	0.000705
C_6H_{14}	0.00074	0.0002	0.00047
C_7+	0.00141	0.0003	0.000855
	1.00000	1.00000	1.00000

Table 51 - Case 2 Storage Reservoir: 70-30 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.00215	0.00215	227.0	0.4881	493.0	1.05995	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.947	0.94700	343.3	325.1051	673.1	637.426	16.04	15.1899
C_2H_6	0.031	0.03100	549.8	17.0438	708.3	21.9573	30.07	0.93
C_3H_8	0.0114	0.01140	666.0	7.5924	617.4	7.03836	44.10	0.50
$i\text{-}C_4H_{10}$	0.00275	0.00275	734.7	2.0204	529.1	1.45503	58.12	0.16
$n\text{-}C_4H_{10}$	0.00173	0.00173	765.3	1.3240	550.7	0.95271	58.12	0.10
$i\text{-}C_5H_{12}$	0.00094	0.00094	829.8	0.7800	483.0	0.45402	72.15	0.05
$n\text{-}C_5H_{12}$	0.000705	0.00071	845.6	0.5961	489.5	0.3451	72.15	0.03
C_6H_{14}	0.00047	0.00047	914.0	0.4296	439.7	0.20666	86.18	0.04
C_7+	0.000855	0.00086	1098.1	0.9389	428.8	0.36665	120.00	0.1
	1.00000	1.00000		356.87		672.33		17.2173

Table 52 - Case 2: Shale Gas 60-40 Full Mix Ratio Composition

	60-40 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0024	0.002	0.0022
H_2S	0	0.000	0
CH_4	0.892	0.980	0.936
C_2H_6	0.066	0.010	0.038
C_3H_8	0.0254	0.003	0.0142
$i\text{-}C_4H_{10}$	0.004	0.002	0.003
$n\text{-}C_4H_{10}$	0.00328	0.0008	0.00204
$i\text{-}C_5H_{12}$	0.00184	0.0004	0.00112
$n\text{-}C_5H_{12}$	0.00138	0.0003	0.00084
C_6H_{14}	0.00092	0.0002	0.00056
C_7+	0.00178	0.0003	0.00104
	1.00000	1.00000	1.00000

Table 53 - Case 2 Storage Reservoir: 60-40 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, ^oR	$y{\times}T_c$	P_c, psia	$y{\times}P_c$	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0022	0.00220	227.0	0.4994	493.0	1.0846	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.936	0.93600	343.3	321.3288	673.1	630.022	16.04	15.0134
C_2H_6	0.038	0.03800	549.8	20.8924	708.3	26.9154	30.07	1.14
C_3H_8	0.0142	0.01420	666.0	9.4572	617.4	8.76708	44.10	0.63
$i\text{-}C_4H_{10}$	0.003	0.00300	734.7	2.2041	529.1	1.5873	58.12	0.17
$n\text{-}C_4H_{10}$	0.00204	0.00204	765.3	1.5612	550.7	1.12343	58.12	0.12
$i\text{-}C_5H_{12}$	0.00112	0.00112	829.8	0.9294	483.0	0.54096	72.15	0.06
$n\text{-}C_5H_{12}$	0.00084	0.00084	845.6	0.7103	489.5	0.41118	72.15	0.04
C_6H_{14}	0.00056	0.00056	914.0	0.5118	439.7	0.24623	86.18	0.05
C_7+	0.00104	0.00104	1098.1	1.1420	428.8	0.44599	120.00	0.1
	1.00000	1.00000		359.78		672.22		17.4549

Table 54 - Case 2: Shale Gas 50-50 Full Mix Ratio Composition

	50-50 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0025	0.002	0.00225
H_2S	0	0.000	0
CH_4	0.87	0.980	0.925
C_2H_6	0.08	0.010	0.045
C_3H_8	0.031	0.003	0.017
$i\text{-}C_4H_{10}$	0.0045	0.002	0.00325
$n\text{-}C_4H_{10}$	0.0039	0.0008	0.00235
$i\text{-}C_5H_{12}$	0.0022	0.0004	0.0013
$n\text{-}C_5H_{12}$	0.00165	0.0003	0.000975
C_6H_{14}	0.0011	0.0002	0.00065
C_7+	0.00215	0.0003	0.001225
	1.00000	1.00000	1.00000

Table 55 - Case 2 Storage Reservoir: 50-50 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, ^oR	y×TC	P_c, psia	y×PC	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.00225	0.00225	227.0	0.5108	493.0	1.10925	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.925	0.92500	343.3	317.5525	673.1	622.618	16.04	14.837
C_2H_6	0.045	0.04500	549.8	24.7410	708.3	31.8735	30.07	1.35
C_3H_8	0.017	0.01700	666.0	11.3220	617.4	10.4958	44.10	0.75
$i\text{-}C_4H_{10}$	0.00325	0.00325	734.7	2.3878	529.1	1.71958	58.12	0.19
$n\text{-}C_4H_{10}$	0.00235	0.00235	765.3	1.7985	550.7	1.29415	58.12	0.14
$i\text{-}C_5H_{12}$	0.0013	0.00130	829.8	1.0787	483.0	0.6279	72.15	0.07
$n\text{-}C_5H_{12}$	0.000975	0.00098	845.6	0.8245	489.5	0.47726	72.15	0.05
C_6H_{14}	0.00065	0.00065	914.0	0.5941	439.7	0.28581	86.18	0.06
C_7+	0.001225	0.00123	1098.1	1.3452	428.8	0.52532	120.00	0.1
	1.00000	1.00000		362.70		672.10		17.6926

Appendix D – Case 3 Storage Reservoir: Full Mix Data

Table 56 - Case 3: Shale Gas 90-10 Full Mix Ratio Composition

	90-10 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0021	0.002	0.002053125
H_2S	0	0.000	0
CH_4	0.958	0.980	0.9683125
C_2H_6	0.024	0.010	0.0174375
C_3H_8	0.0086	0.003	0.005975
$i\text{-}C_4H_{10}$	0.0025	0.002	0.002265625
$n\text{-}C_4H_{10}$	0.00142	0.0008	0.001129375
$i\text{-}C_5H_{12}$	0.00076	0.0004	0.00059125
$n\text{-}C_5H_{12}$	0.00057	0.0003	0.000443438
C_6H_{14}	0.00038	0.0002	0.000295625
C_7+	0.00067	0.0003	0.000496563
	1.00000	1.00000	1.00000

Table 57 - Case 3 Storage Reservoir: 90-10 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002053125	0.00205	227.0	0.4661	493.0	1.01219	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.9683125	0.96831	343.3	332.4217	673.1	651.771	16.04	15.5317
C_2H_6	0.0174375	0.01744	549.8	9.5871	708.3	12.351	30.07	0.52
C_3H_8	0.005975	0.00598	666.0	3.9794	617.4	3.68897	44.10	0.26
$i\text{-}C_4H_{10}$	0.002265625	0.00227	734.7	1.6646	529.1	1.19874	58.12	0.13
$n\text{-}C_4H_{10}$	0.001129375	0.00113	765.3	0.8643	550.7	0.62195	58.12	0.07
$i\text{-}C_5H_{12}$	0.00059125	0.00059	829.8	0.4906	483.0	0.28557	72.15	0.03
$n\text{-}C_5H_{12}$	0.000443438	0.00044	845.6	0.3750	489.5	0.21706	72.15	0.02
C_6H_{14}	0.000295625	0.00030	914.0	0.2702	439.7	0.12999	86.18	0.03
C_7+	0.000496563	0.00050	1098.1	0.5453	428.8	0.21294	120.00	0.1
	1.00000	1.00000		351.21		672.56		16.7568

Table 58 - Case 3: Shale Gas 80-20 Full Mix Ratio Composition

	80-20 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0022	0.002	0.00210625
H_2S	0	0.000	0
CH_4	0.936	0.980	0.956625
C_2H_6	0.038	0.010	0.024875
C_3H_8	0.0142	0.003	0.00895
$i\text{-}C_4H_{10}$	0.003	0.002	0.00253125
$n\text{-}C_4H_{10}$	0.00204	0.0008	0.00145875
$i\text{-}C_5H_{12}$	0.00112	0.0004	0.0007825
$n\text{-}C_5H_{12}$	0.00084	0.0003	0.000586875
C_6H_{14}	0.00056	0.0002	0.00039125
C_7+	0.00104	0.0003	0.000693125
	1.00000	1.00000	1.00000

Table 59 - Case 3 Storage Reservoir: 80-20 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.00210625	0.00211	227.0	0.4781	493.0	1.03838	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.956625	0.95663	343.3	328.4094	673.1	643.904	16.04	15.3443
C_2H_6	0.024875	0.02488	549.8	13.6763	708.3	17.619	30.07	0.75
C_3H_8	0.00895	0.00895	666.0	5.9607	617.4	5.52573	44.10	0.39
$i\text{-}C_4H_{10}$	0.00253125	0.00253	734.7	1.8597	529.1	1.33928	58.12	0.15
$n\text{-}C_4H_{10}$	0.00145875	0.00146	765.3	1.1164	550.7	0.80333	58.12	0.08
$i\text{-}C_5H_{12}$	0.0007825	0.00078	829.8	0.6493	483.0	0.37795	72.15	0.04
$n\text{-}C_5H_{12}$	0.000586875	0.00059	845.6	0.4963	489.5	0.28728	72.15	0.03
C_6H_{14}	0.00039125	0.00039	914.0	0.3576	439.7	0.17203	86.18	0.03
C_7+	0.000693125	0.00069	1098.1	0.7611	428.8	0.29724	120.00	0.1
	1.00000	1.00000		354.31		672.44		17.0093

Table 60 - Case 3: Shale Gas 70-30 Full Mix Ratio Composition

	70-30 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0023	0.002	0.002159375
H_2S	0	0.000	0
CH_4	0.914	0.980	0.9449375
C_2H_6	0.052	0.010	0.0323125
C_3H_8	0.0198	0.003	0.011925
$i\text{-}C_4H_{10}$	0.0035	0.002	0.002796875
$n\text{-}C_4H_{10}$	0.00266	0.0008	0.001788125
$i\text{-}C_5H_{12}$	0.00148	0.0004	0.00097375
$n\text{-}C_5H_{12}$	0.00111	0.0003	0.000730313
C_6H_{14}	0.00074	0.0002	0.000486875
C_7+	0.00141	0.0003	0.000889688
	1.00000	1.00000	1.00000

Table 61 - Case 3 Storage Reservoir: 70-30 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002159375	0.00216	227.0	0.4902	493.0	1.06457	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.9449375	0.94494	343.3	324.3970	673.1	636.037	16.04	15.1568
C_2H_6	0.0323125	0.03231	549.8	17.7654	708.3	22.8869	30.07	0.97
C_3H_8	0.011925	0.01193	666.0	7.9421	617.4	7.3625	44.10	0.53
$i\text{-}C_4H_{10}$	0.002796875	0.00280	734.7	2.0549	529.1	1.47983	58.12	0.16
$n\text{-}C_4H_{10}$	0.001788125	0.00179	765.3	1.3685	550.7	0.98472	58.12	0.10
$i\text{-}C_5H_{12}$	0.00097375	0.00097	829.8	0.8080	483.0	0.47032	72.15	0.05
$n\text{-}C_5H_{12}$	0.000730313	0.00073	845.6	0.6176	489.5	0.35749	72.15	0.04
C_6H_{14}	0.000486875	0.00049	914.0	0.4450	439.7	0.21408	86.18	0.04
C_7+	0.000889688	0.00089	1098.1	0.9770	428.8	0.38153	120.00	0.1
	1.00000	1.00000		357.41		672.31		17.2618

Table 62 - Case 3: Shale Gas 60-40 Full Mix Ratio Composition

	60-40 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0024	0.002	0.0022125
H_2S	0	0.000	0
CH_4	0.892	0.980	0.93325
C_2H_6	0.066	0.010	0.03975
C_3H_8	0.0254	0.003	0.0149
$i\text{-}C_4H_{10}$	0.004	0.002	0.0030625
$n\text{-}C_4H_{10}$	0.00328	0.0008	0.0021175
$i\text{-}C_5H_{12}$	0.00184	0.0004	0.001165
$n\text{-}C_5H_{12}$	0.00138	0.0003	0.00087375
C_6H_{14}	0.00092	0.0002	0.0005825
C_7+	0.00178	0.0003	0.00108625
	1.00000	1.00000	1.00000

Table 63 - Case 3 Storage Reservoir: 60-40 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y \times T_c$	P_c, psia	$y \times P_c$	M	$y \times M$
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0022125	0.00221	227.0	0.5022	493.0	1.09076	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.93325	0.93325	343.3	320.3847	673.1	628.171	16.04	14.9693
C_2H_6	0.03975	0.03975	549.8	21.8546	708.3	28.1549	30.07	1.20
C_3H_8	0.0149	0.01490	666.0	9.9234	617.4	9.19926	44.10	0.66
$i\text{-}C_4H_{10}$	0.0030625	0.00306	734.7	2.2500	529.1	1.62037	58.12	0.18
$n\text{-}C_4H_{10}$	0.0021175	0.00212	765.3	1.6205	550.7	1.16611	58.12	0.12
$i\text{-}C_5H_{12}$	0.001165	0.00117	829.8	0.9667	483.0	0.5627	72.15	0.06
$n\text{-}C_5H_{12}$	0.00087375	0.00087	845.6	0.7388	489.5	0.4277	72.15	0.04
C_6H_{14}	0.0005825	0.00058	914.0	0.5324	439.7	0.25613	86.18	0.05
C_7+	0.00108625	0.00109	1098.1	1.1928	428.8	0.46582	120.00	0.1
	1.00000	1.00000		360.51		672.19		17.5144

Table 64 - Case 3: Shale Gas 50-50 Full Mix Ratio Composition

	50-50 Working Gas	Storage	Mix 2
Component	Mole Fraction	Mole Fraction	Mole Fraction
CO_2	0.001	0.001	0.001
N_2	0.0025	0.002	0.002265625
H_2S	0	0.000	0
CH_4	0.87	0.980	0.9215625
C_2H_6	0.08	0.010	0.0471875
C_3H_8	0.031	0.003	0.017875
$i\text{-}C_4H_{10}$	0.0045	0.002	0.003328125
$n\text{-}C_4H_{10}$	0.0039	0.0008	0.002446875
$i\text{-}C_5H_{12}$	0.0022	0.0004	0.00135625
$n\text{-}C_5H_{12}$	0.00165	0.0003	0.001017188
C_6H_{14}	0.0011	0.0002	0.000678125
C_7+	0.00215	0.0003	0.001282813
	1.00000	1.00000	1.00000

Table 65 - Case 3 Storage Reservoir: 50-50 Full Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×TC	P_c, psia	y×PC	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.002265625	0.00227	227.0	0.5143	493.0	1.11695	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.922	0.92156	343.3	316.3724	673.1	620.304	16.04	14.7819
C_2H_6	0.047	0.04719	549.8	25.9437	708.3	33.4229	30.07	1.42
C_3H_8	0.017875	0.01788	666.0	11.9048	617.4	11.036	44.10	0.79
$i\text{-}C_4H_{10}$	0.003328125	0.00333	734.7	2.4452	529.1	1.76091	58.12	0.19
$n\text{-}C_4H_{10}$	0.002446875	0.00245	765.3	1.8726	550.7	1.34749	58.12	0.14
$i\text{-}C_5H_{12}$	0.00135625	0.00136	829.8	1.1254	483.0	0.65507	72.15	0.07
$n\text{-}C_5H_{12}$	0.001017188	0.00102	845.6	0.8601	489.5	0.49791	72.15	0.05
C_6H_{14}	0.000678125	0.00068	914.0	0.6198	439.7	0.29817	86.18	0.06
C_7+	0.001282813	0.00128	1098.1	1.4087	428.8	0.55011	120.00	0.2
	1.00000	1.00000		363.61		672.06		17.7669

Appendix E – Storage Reservoir: No Mix Data (Cases 1, 2, & 3)

Table 66 - Case 1 Storage Reservoir: 90-10 No Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y{\times}T_c$	P_c, psia	$y{\times}P_c$	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0021	0.00210	227.0	0.4767	493.0	1.0353	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.958	0.95800	343.3	328.8814	673.1	644.83	16.04	15.3663
C_2H_6	0.024	0.02400	549.8	13.1952	708.3	16.9992	30.07	0.72
C_3H_8	0.0086	0.00860	666.0	5.7276	617.4	5.30964	44.10	0.38
$i\text{-}C_4H_{10}$	0.0025	0.00250	734.7	1.8368	529.1	1.32275	58.12	0.15
$n\text{-}C_4H_{10}$	0.00142	0.00142	765.3	1.0867	550.7	0.78199	58.12	0.08
$i\text{-}C_5H_{12}$	0.00076	0.00076	829.8	0.6306	483.0	0.36708	72.15	0.04
$n\text{-}C_5H_{12}$	0.00057	0.00057	845.6	0.4820	489.5	0.27902	72.15	0.03
C_6H_{14}	0.00038	0.00038	914.0	0.3473	439.7	0.16709	86.18	0.03
C_7+	0.00067	0.00067	1098.1	0.7357	428.8	0.28732	120.00	0.1
	1.00000	**1.00000**		**353.95**		**672.45**		**16.9796**

Table 67 - Case 1 Storage Reservoir: 80-20 No Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	$y{\times}T_c$	P_c, psia	$y{\times}P_c$	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0022	0.00220	227.0	0.4994	493.0	1.0846	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.936	0.93600	343.3	321.3288	673.1	630.022	16.04	15.0134
C_2H_6	0.038	0.03800	549.8	20.8924	708.3	26.9154	30.07	1.14
C_3H_8	0.0142	0.01420	666.0	9.4572	617.4	8.76708	44.10	0.63
$i\text{-}C_4H_{10}$	0.003	0.00300	734.7	2.2041	529.1	1.5873	58.12	0.17
$n\text{-}C_4H_{10}$	0.00204	0.00204	765.3	1.5612	550.7	1.12343	58.12	0.12
$i\text{-}C_5H_{12}$	0.00112	0.00112	829.8	0.9294	483.0	0.54096	72.15	0.06
$n\text{-}C_5H_{12}$	0.00084	0.00084	845.6	0.7103	489.5	0.41118	72.15	0.04
C_6H_{14}	0.00056	0.00056	914.0	0.5118	439.7	0.24623	86.18	0.05
C_7+	0.00104	0.00104	1098.1	1.1420	428.8	0.44599	120.00	0.1
	1.00000	**1.00000**		**359.78**		**672.22**		**17.4549**

Table 68 - Case 1 Storage Reservoir: 70-30 No Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×T_c	P_c, psia	y×P_c	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0023	0.00230	227.0	0.5221	493.0	1.1339	28.01	0.06
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.914	0.91400	343.3	313.7762	673.1	615.213	16.04	14.6606
C_2H_6	0.052	0.05200	549.8	28.5896	708.3	36.8316	30.07	1.56
C_3H_8	0.0198	0.01980	666.0	13.1868	617.4	12.2245	44.10	0.87
i-C_4H_{10}	0.0035	0.00350	734.7	2.5715	529.1	1.85185	58.12	0.20
n-C_4H_{10}	0.00266	0.00266	765.3	2.0357	550.7	1.46486	58.12	0.15
i-C_5H_{12}	0.00148	0.00148	829.8	1.2281	483.0	0.71484	72.15	0.08
n-C_5H_{12}	0.00111	0.00111	845.6	0.9386	489.5	0.54335	72.15	0.05
C_6H_{14}	0.00074	0.00074	914.0	0.6764	439.7	0.32538	86.18	0.06
C_7+	0.00141	0.00141	1098.1	1.5483	428.8	0.60466	120.00	0.2
	1.00000	**1.00000**		**365.62**		**671.98**		**17.9303**

Table 69 - Case 1 Storage Reservoir: 60-40 No Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×T_c	P_c, psia	y×P_c	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0024	0.00240	227.0	0.5448	493.0	1.1832	28.01	0.07
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.892	0.89200	343.3	306.2236	673.1	600.405	16.04	14.3077
C_2H_6	0.066	0.06600	549.8	36.2868	708.3	46.7478	30.07	1.98
C_3H_8	0.0254	0.02540	666.0	16.9164	617.4	15.682	44.10	1.12
i-C_4H_{10}	0.004	0.00400	734.7	2.9388	529.1	2.1164	58.12	0.23
n-C_4H_{10}	0.00328	0.00328	765.3	2.5102	550.7	1.8063	58.12	0.19
i-C_5H_{12}	0.00184	0.00184	829.8	1.5268	483.0	0.88872	72.15	0.10
n-C_5H_{12}	0.00138	0.00138	845.6	1.1669	489.5	0.67551	72.15	0.07
C_6H_{14}	0.00092	0.00092	914.0	0.8409	439.7	0.40452	86.18	0.08
C_7+	0.00178	0.00178	1098.1	1.9546	428.8	0.76332	120.00	0.2
	1.00000	**1.00000**		**371.46**		**671.75**		**18.4056**

Table 70 - Case 1 Storage Reservoir: 50-50 No Mix Composition

Component	Mole Fraction	Corrected Mole Frac.	T_c, °R	y×TC	P_c, psia	y×PC	M	y×M
CO_2	0.001	0.00100	547.7	0.5477	1073.0	1.073	44.01	0.04401
N_2	0.0025	0.00250	227.0	0.5675	493.0	1.2325	28.01	0.07
H_2S	0	0.00000	672.0	0.0000	1306.0	0	34.08	0.00
CH_4	0.870	0.87000	343.3	298.6710	673.1	585.597	16.04	13.9548
C_2H_6	0.080	0.08000	549.8	43.9840	708.3	56.664	30.07	2.41
C_3H_8	0.031	0.03100	666.0	20.6460	617.4	19.1394	44.10	1.37
$i\text{-}C_4H_{10}$	0.0045	0.00450	734.7	3.3062	529.1	2.38095	58.12	0.26
$n\text{-}C_4H_{10}$	0.0039	0.00390	765.3	2.9847	550.7	2.14773	58.12	0.23
$i\text{-}C_5H_{12}$	0.0022	0.00220	829.8	1.8256	483.0	1.0626	72.15	0.12
$n\text{-}C_5H_{12}$	0.00165	0.00165	845.6	1.3952	489.5	0.80768	72.15	0.08
C_6H_{14}	0.0011	0.00110	914.0	1.0054	439.7	0.48367	86.18	0.09
C_7+	0.00215	0.00215	1098.1	2.3609	428.8	0.92199	120.00	0.3
	1.00000	1.00000		377.29		671.51		18.881

Appendix F – Viscosity Composition

Table 71 - Shale Gas Viscosity Composition

Component	y_i	M_i	T_c (°R)	P_c (psia)	μ_{i1}, cp	Tc * yi	Pc * yi	$\mu_i*y_i*M_i$^0.5	y_i*M_i^0.5
CO2	0.001	44.01	548	1072	0.016	0.548	1.072	0.000106144	0.006634003
N2	0.003	28.01	227	492	0.019	0.681	1.476	0.00030167	0.015877342
C1	0.760	16.04	344	673	0.012	261.44	511.48	0.036525572	3.043797628
C2	0.150	30.07	550	709	0.0102	418	538.84	0.04250896	4.167545081
C3	0.059	44.1	666	618	0.009	99.9	92.7	0.008965057	0.996117463
i-C4	0.007	58.12	733	530	0.0083	43.247	31.27	0.0037333	0.449795198
n-C4	0.007	58.12	766	551	0.008	5.362	3.857	0.000426924	0.053365532
i-C5	0.004	72.12	830	482	0.0072	5.81	3.374	0.000428014	0.059446446
n-C5	0.003	72.15	847	485	0.007	3.388	1.94	0.000237835	0.033976462
C6	0.002	86.18	915	434	0.0066	2.745	1.302	0.00018381	0.027849955
C7+	0.004	100.21	973	397	0.0062	1.946	0.794	0.00012413	0.020020989
Total	**1.000**					843.067	1188.11	**0.093541416**	**8.8744261**
μ_{g1}	0.01054056								

Table 72 - Storage Gas Viscosity Composition

Component	y_i	M_i	T_c (°R)	P_c (psia)	μ_{i1}, cp	Tc * yi	Pc * yi	$\mu_i*y_i*M_i$^0.5	y_i*M_i^0.5
CO2	0.001	44.01	548	1072	0.016	0.548	1.072	0.000106144	0.006634003
N2	0.002	28.01	227	492	0.019	0.454	0.984	0.000201113	0.010584895
C1	0.980	16.04	344	673	0.012	337.12	659.54	0.047098763	3.924896941
C2	0.010	30.07	550	709	0.0102	539	694.82	0.054814185	5.373939709
C3	0.003	44.1	666	618	0.009	6.66	6.18	0.00059767	0.066407831
i-C4	0.002	58.12	733	530	0.0083	2.199	1.59	0.000189829	0.022870942
n-C4	0.0008	58.12	766	551	0.008	1.532	1.102	0.000121978	0.015247295
i-C5	0.0004	72.12	830	482	0.0072	0.664	0.3856	4.89159E-05	0.00679388
n-C5	0.0003	72.15	847	485	0.007	0.3388	0.194	2.37835E-05	0.003397646
C6	0.0002	86.18	915	434	0.0066	0.2745	0.1302	1.8381E-05	0.002784996
C7+	0.0003	100.21	973	397	0.0062	0.1946	0.0794	1.2413E-05	0.002002099
Total	**1.000**					888.985	1366.08	**0.103233176**	**9.435560237**
μ_{g1}	0.01094086								

Appendix G – Compressibility Factor (z-chart)

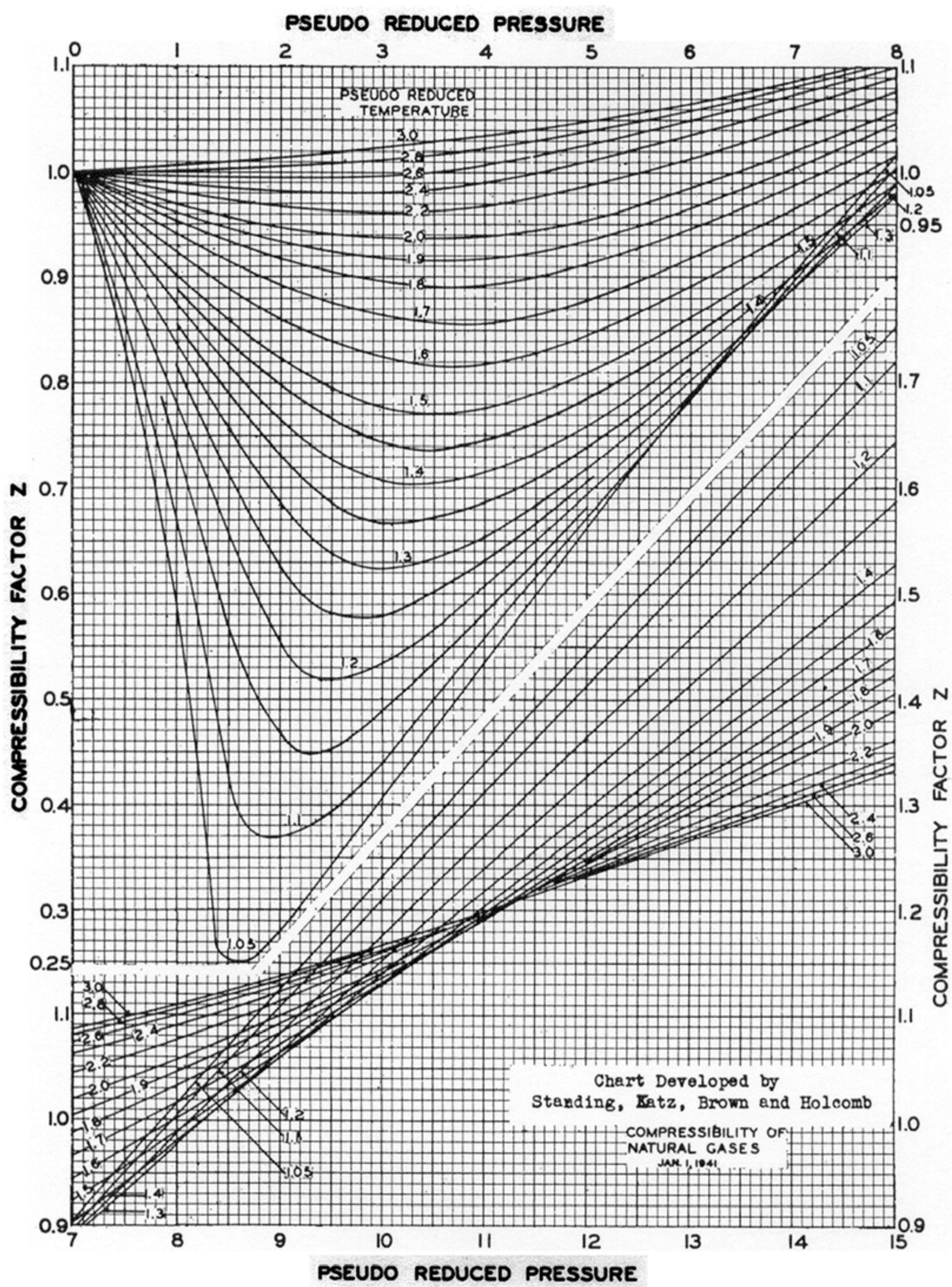

Figure 26 - Compressibility Factor (z-chart)

Appendix H – Viscosity Ratio Chart

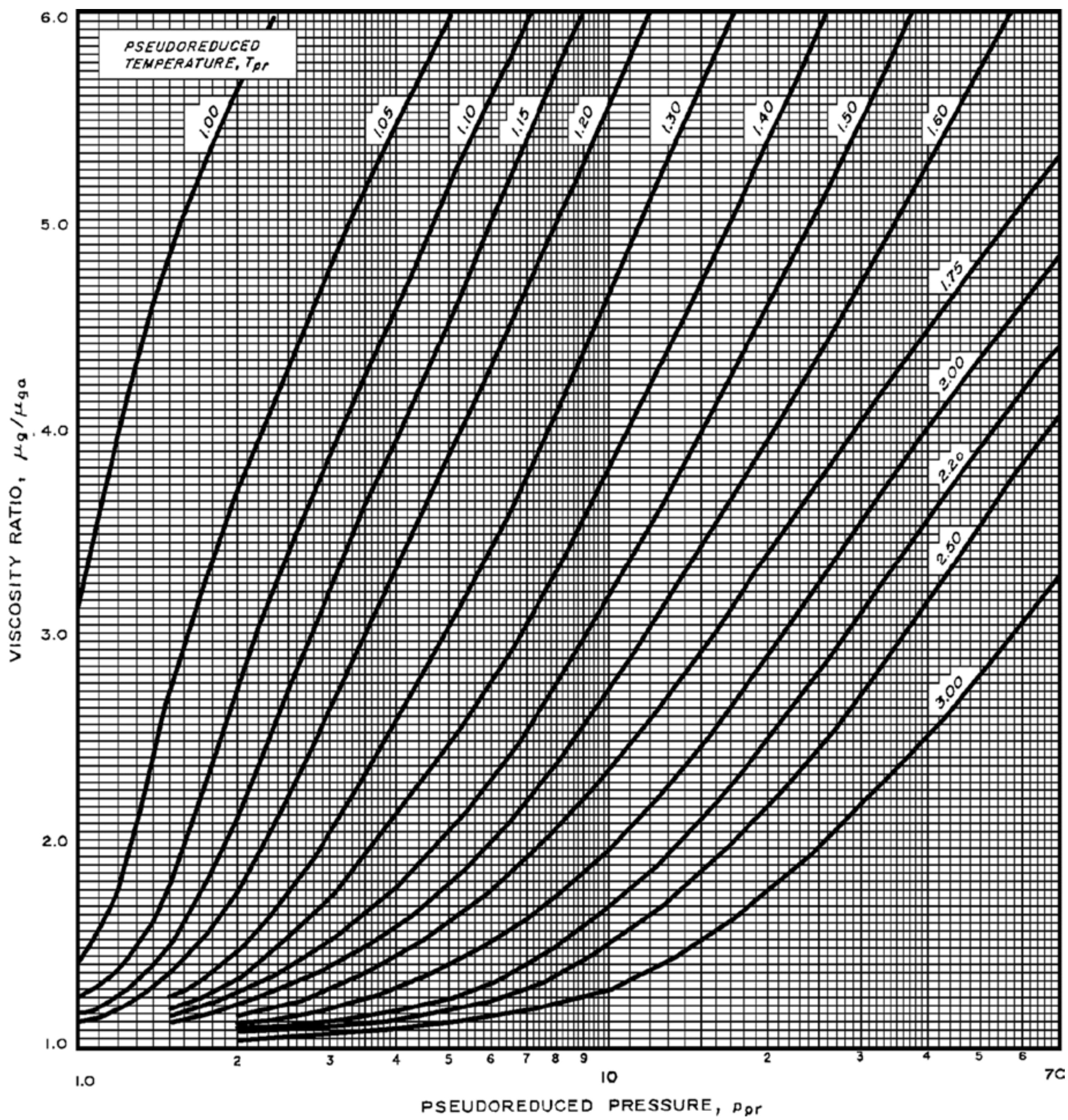

Figure 27 - Viscosity Ratio Chart