FEASIBILITY STUDY OF A NATURAL GAS STORAGE PROSPECT RESERVOIR USING DECLINE CURVE AND HYSTERESIS ANALYSIS

by

Jacob Isaac Kalunakaahele Abraham

A thesis submitted to the faculty of
The University of Utah
in partial fulfillment of the requirements for the degree of

Master of Science

in

Petroleum Engineering

Department of Chemical Engineering

The University of Utah

May 2015

The University of Utah Graduate School

STATEMENT OF THESIS APPROVAL

The thesis of **Jacob Isaac Kalunakaahele Abraham**

has been approved by the following supervisory committee members:

John David McLennan	, Chair	**10/23/2014** Date Approved
Milind Deo	, Member	**10/23/2014** Date Approved
Ian Walton	, Member	**10/23/2014** Date Approved

and by **Milind Deo** , Chair/Dean of

the Department/College/School of **Chemical Engineering**

and by David B. Kieda, Dean of The Graduate School.

ABSTRACT

Underground natural gas baseload storage facilities are a vital part of the world's natural gas infrastructure. These facilities allow Exploration & Production (E&P) and transmission pipeline companies to utilize natural gas assets year round while providing means for consistent gas supply throughout the year. The purpose of this thesis is to present a process in which a feasibility study can be conducted for a prospective baseload storage facility. This was accomplished by explaining 1) the theory of natural gas storage reservoir engineering; 2) geologic consideration for underground storage prospects; 3) design of a new underground baseload facility using decline curve analysis and hysteresis analysis; and 4) a detailed economic analysis of a storage prospect.

A depleted natural gas reservoir was evaluated for its potential to become an underground baseload storage facility for natural gas. For this underground reservoir, it is estimated the Original Gas in Place (OGIP) was 59.4 Billion Cubic Feet (BCF) using hysteresis analysis. The cushion gas requirement was solved to be 50% of the OGIP, or 29.7 BCF. There is currently 7.4 BCF of native gas present in the reservoir. The required injection cushion gas requirement is estimated at 22.3 BCF. The maximum field deliverability was estimated to be 284.3 Thousand Cubic Feet per Day (MCF/D) at a reservoir pressure of 868.5 psia. The minimum field deliverability was estimated to be 83.8 MCF/D at a cushion gas pressure of 434.1 psia. Maximum and minimum deliverabilities assume 30 injection/withdrawal wells are present at 6 different well pads

throughout the field.

After analyzing three different economic scenarios for the prospective storage field it was determined this project is not economically feasible under current market conditions. Recommendations for future work include the operating company conducting a 3D seismic survey and re-evaluating the project using 3D reservoir simulation evaluating the possibilities of 1) using horizontal drilling to minimize number of wells, 2) simulate storage well performance if vertical wells are hydraulically fractured, and/or 3) simulate if the prospective storage facility can be pressurized over the original discovery pressure.

TABLE OF CONTENTS

LIST OF FIGURES

Figures

LIST OF TABLES

Tables

ACKNOWLEDGEMENTS

I would like to thank John David McLennan, Ph.D. for the five years of teaching, mentoring, and friendship. It has been an absolute pleasure. Thank you for remembering higher education is not about the grants, statistics, and business trips; rather it is about your students' success. I have been one of the many beneficiaries of your work at the University of Utah.

I would like to thank Larry Curtis Abraham, M.Ed. and Hazel Luana Nihipali Abraham, M.Ed. for all of your love and support throughout the years. I am proud to be a product of your belief in the public education system. Thank you for all of those late nights editing papers, assisting in science projects, and nurturing my natural curiosity of math and science. Last, thank you for all of your sacrifices in helping me become who I am today.

Lastly, I would like to thank Thaís Branco Pino Abraham, MBA, my dearest wife, friend, and the best editor anyone could have. Thank you for all of the late nights you took to review this and other papers over the years; I am a lucky one. Thank you for your love and support through this incredible academic journey with me. I can truly say I would not be where I am today without you. This degree is not mine, rather it is ours.

CHAPTER 1

INTRODUCTION

Heating residential, commercial, educational, and industrial buildings consume large amounts of gas throughout the world each year. In addition, hundreds of large industrial facilities (i.e., chemical plants, petroleum refineries, manufacturing plants, and electric power plants) burn billions of dekatherms of natural gas in order to provide essential energy, products, and services for a growing world population. In order to meet these ever changing market demands, interstate and intrastate pipeline systems with storage facilities have been constructed to bring natural gas from production fields to end users where it has been deemed economical.

1.1. Economic analysis for pipeline infrastructure and operation

A majority of pipelines worldwide were originally designed by pipeline engineers around the peak energy load case of a given market. In the initial design phase, various Nominal Pipe Sizes (NPS) are considered as well as other pipe characteristics such as material type, wall thickness, and grade. Design's Maximum Allowable Operating Pressures (MAOPs) are calculated using the Barlow formula and additional design/safety factors are applied following regulations from the US Code of Federal Regulations (CFR) 49 Part 192 [Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards]. After considering all combinations of pipe specifications and MAOPs, the most economical solution is selected by the pipeline company's management team such that current market demands are met with a forecasted available pipeline capacity for potential market growth.

Pipelines are designed to meet the peak energy load case for a given market; this assumes all available pipeline flow rate capacity is being utilized by shippers and customers alike. However, it is rare that natural gas pipelines are required to flow at peak rates year round, since high system demands generally occur during the winter season (in North America this is commonly known as the heating season). The length of heating seasons depends on the geographical location/climate. For example, the heating season for the Rocky Mountain region generally begins late in October and goes through mid-April. In order to continually utilize Exploration and Production (E&P) production and pipeline capacity assets, storage facilities are used to supplement excess gas during the off-season.

Figure 1.1 depicts two curves, one is the annual gas supply demand as a function of time and the other is the storage gas in a given pipeline system. On the left hand side, the graph represents that the gas demand during the summer months are less than the amount of gas supply available. During these months, the supply of gas is high and the demand is low, which generally leads the price of natural gas to fall during this time of the year. Excess gas can be purchased and/or produced at a lower price during this part of the season and then injected in an underground storage facility for a small fee. As the winter season approaches the gas stored during the low demand months (shown in the right hand side of Figure 1.1) can then be withdrawn from storage to meet the baseload and peaking demands on an as needed basis.

1.2. What is a natural gas storage facility?

A natural gas storage facility is a facility where large quantities of natural gas are stored at high pressures in naturally occurring or man-made underground reservoirs, or converted to a Liquefied Natural Gas (LNG) via a cryogenic process. These facilities are preferably located close to a large population of natural gas customers. At these facilities, gas is injected or stored during the summer months and withdrawn in the winter months. "Today the [largest] main storage possibilities of natural gas are as follows:

- Underground natural gas storage in depleted fields (if these are available);
- Underground natural gas storage in aquifers;
- LNG storage;
- Underground natural gas storage in man-made caverns." [1]

From the above list, these types of storage facilities can be further categorized into two functional groups: 1) baseload facility and 2) peak shaving facility. A baseload facility is a large facility, usually a depleted natural gas or oil reservoir, which is used for injection/withdrawal of large amounts of gas at a given time. A baseload facility will generally have one injection period (summer months) and one withdrawal period (winter months). The working capacity of a general baseload facility ranges from 35 Billion Cubic Feet (BCF) to 100 BCF of natural gas. A baseload storage facility is commonly used by pipeline transmission companies to facilitate interstate operations. An example of a baseload storage facility is Questar Pipeline Company's Clay Basin facility located in Daggett County in Northeastern Utah.

A peak shaving facility serves a different purpose than its baseload counterpart. A peak shaving facility is typically located closer to a natural gas market (~50 linear miles or less) and is used to meet hourly or daily peak demands. Peaking facilities are generally natural occurring aquifers or LNG facilities. The working capacity of a general peaking facility ranges from 0.25 BCF to 5 BCF of natural gas or natural gas equivalent. Peaking facilities are used to meet short demand peaks where a large volume of natural gas is required for a short period of time. This is better illustrated using Figure 1.2. Notice that it is likely a peak storage facility would be used to increase available system gas during the hours of 5:00 pm to 7:00 pm in this example. Peak shaving storage facilities are generally used by natural gas utility companies or large industrial users who depend on constant flow of gas. An example of a peak shaving facility is Questar Pipeline Company's Chalk Creek facility located in Summit County by Coalville, Utah.

A report published by the U.S. Energy Information Administration (EIA) estimates there are currently 4.33 Trillion Cubic Feet (TCF) of maximum working gas available in the United States as of November 2013 for underground storage facilities. The total design capacity of working gas as of November 2013 is estimated to be 4.68 TCF of natural gas. For more information please refer to [2].

1.3. Purpose of a storage facility feasibility study

Storage facilities provide additional flexibility to operating transmission and distribution companies by ensuring needed peak demands are met during the heating season. As with any large capital project it is recommended a feasibility study be conducted to determine if it is economically viable. For the purposes of this study, general guidelines have been provided for a prospect storage baseload facility. These guidelines have been created as a form of heuristic by referencing available literature and from the author's work experience. These guidelines were used on the feasibility study of

Questar Pipeline Company's latest storage prospect located in the Rocky Mountain region.

1.4. Thesis overview

The following chapters address the theory of subsurface storage reservoir engineering and describe all governing equations and methods used to evaluate storage prospects. Chapter 2 summarizes the theory of storage reservoir engineering and provides a necessary background to perform a feasibility study. Chapter 3 introduces petroleum geology required for storage reservoirs including descriptions of desirable matrix properties (e.g., porosity, permeability, net pay, etc.). Chapter 4 explains the conventional theory used to interpret historical production data in order to estimate the storage reservoirs performance at high inventory levels. Chapter 4 includes considerations that should be made in designing a new storage baseload facility, including maximum deliverability, cushion gas, working gas, well spacing, and deliverability requirements. Chapter 5 explains storage reservoir engineering economics and a detailed cost estimate methodology. Chapter 6 provides conclusions and recommendations for future work.

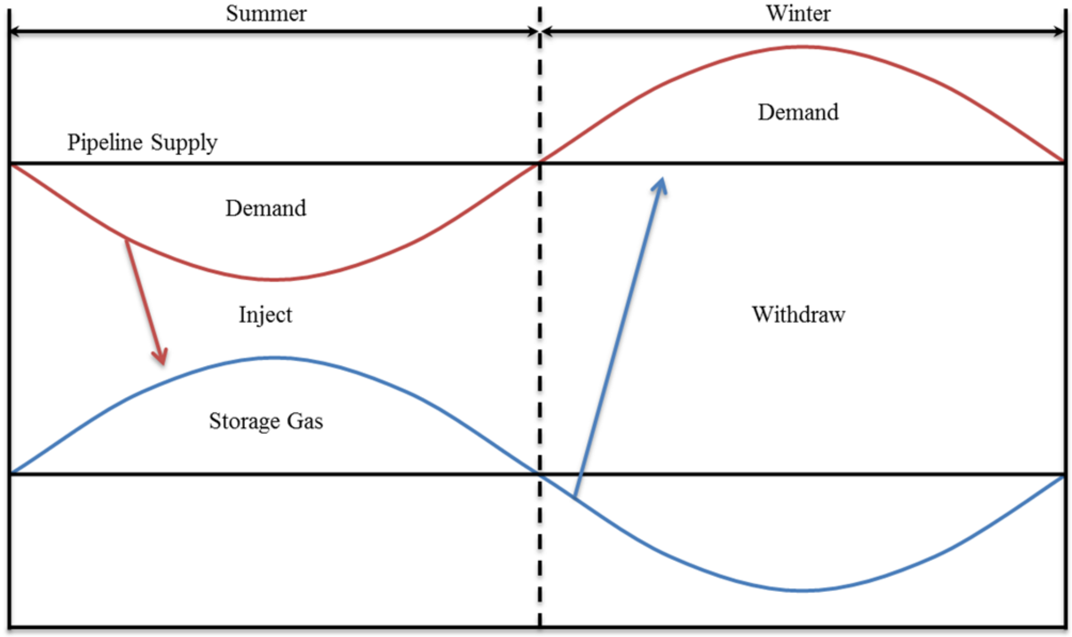

Figure 1.1: Optimization of pipeline capacity by using a storage facility.

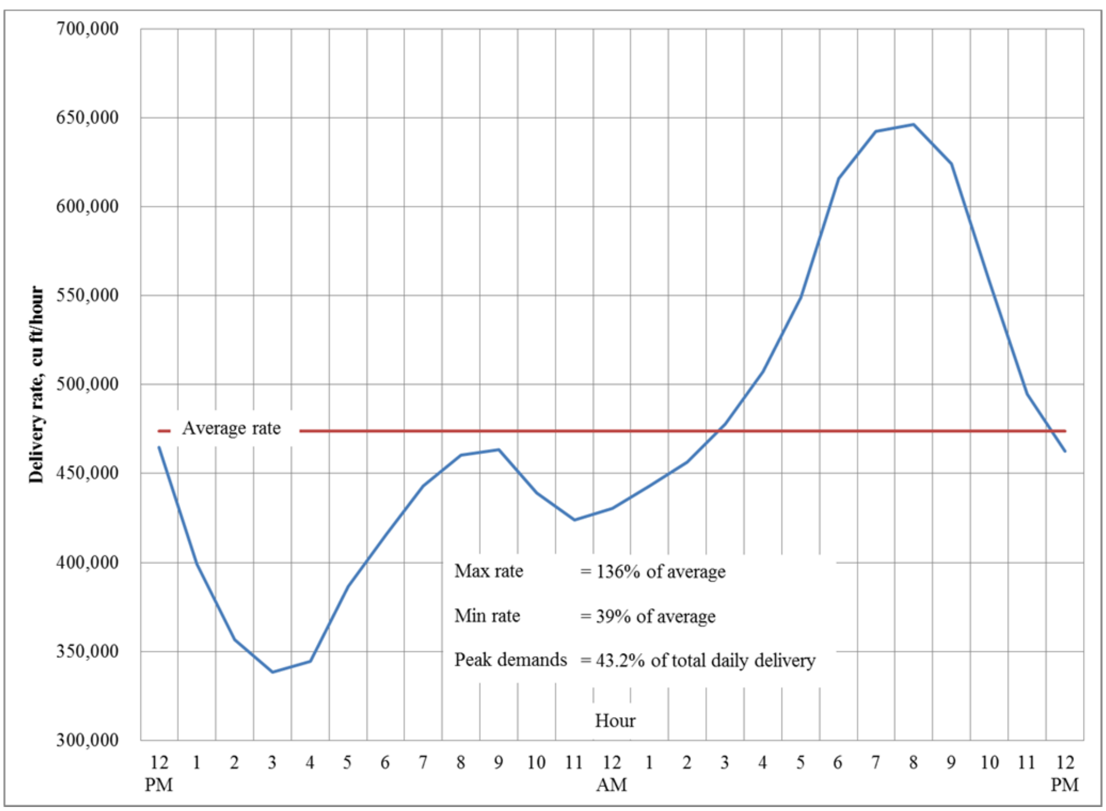

Figure 1.2: Typical natural gas load curve.

CHAPTER 2

UNDERGROUND STORAGE RESERVOIR ENGINEERING THEORY

The theory of underground baseload storage reservoir engineering can be considered as an extension to traditional reservoir engineering literature established in the mid-20th century. For many underground storage reservoirs, the basic mass balance, Darcy's flow, pressure transient analysis, rate transient analysis, and inflow performance equations hold true for gas reservoirs under the following assumptions:

1) Relative gas permeability is greater than 10 mD and less than 100 mD;
2) Porosity is greater than 8% and less than 25%;
3) Finite reservoir boundaries and volumetric cycles;
4) Low amounts of liquids (condensate, oil, and/or water) present within the matrix.

In addition to these traditional methods, storage reservoir engineers have some tools to better characterize reservoir performance and identify potential wells in need of work-overs. Hysteresis analysis, deliverability tests, individual or group well tests, and 3D reservoir simulation are generally used in conjunction with traditional methods to optimize storage operations while minimizing Operation and Maintenance (O&M) costs.

2.1. Underground storage reservoir engineering terminology

Before discussing the tools employed by storage reservoir engineers, it is important to outline the fundamentals of storage reservoir engineering. Understanding these principles is essential to working with peers, customers, operations, and management. Within storage operations, a reservoir has four main natural gas accounts managed by the operator. They are described below and the different accounts are illustrated for additional clarity in Figure 2.1.

1) Native Cushion Gas – Native gas within the given storage reservoir was present before the field was converted to storage. Native gas can be estimated by using a hysteresis plot for a volumetric reservoir.
2) Injected Cushion Gas – Gas which has been injected (intentionally) by the operator of a given storage facility. This gas is used to repressurize the reservoir to enable high deliverability rates from the field during the heating season. The amount of gas injected as cushion gas is considered part of the original capital investment of a new facility.
3) Cushion Gas – The sum of all native cushion gas and injected cushion gas is collectively known as cushion gas. All of this gas is owned by the operator of the facility. Cushion gas allows the storage facility to operate within its designed operating window. Depending on the desired minimum rate deliverability required during the heating season, (often set by the market,) the storage operator will determine how much cushion gas is required. During an annual operation cycle, cushion gas is not put into production, rather this amount of gas will only be used when the storage facility is abandoned.

4) Working Gas – Gas injected into the storage facility within its designed operating window. Working gas is injected throughout the summer or off-season by various storage customers to their contracted working gas capacity. Daily injection rates are determined by multiplying the overall working gas capacity percentage: $\frac{contracted\ working\ gas}{total\ working\ gas}$ * maximum injection rate of storage facility.

2.2. Anatomy of an underground storage facility

With a basic understanding of the different gas accounts in a baseload underground storage facility, it is important to understand what equipment is required for storage operations. When a new storage prospect is found, it is generally a depleted natural gas reservoir. That means the storage reservoir engineer performing the feasibility study needs to review all available assets that have been installed in the area during production. For most baseload storage prospects the following infrastructure is commonly present:

1) Gathering line system;
2) Dehydration unit(s) and/or water knockout tanks;
3) Well casing;
4) Well tubing;
5) Wells perforated in reservoir formation.

In new storage reservoir prospects, all of the items in the list above are essential for successful reservoir conversion. Additional equipment is not required; however, some are highly recommended for optimal storage operation:

1) Compressor(s);
2) Dew-Point processing plant (if condensates or hydrocarbon liquids are present in the storage. BTU content of stored gas should be considered if it exceeds 1050);

3) Modify dehydration piping such that an injection line can bypass the dehydration units en route to the well(s).

After all surface facilities have been considered and installed as part of the reservoir conversion to service; the overall storage facility should resemble [3].

2.2.1. Injection and/or withdrawal wells

Stored natural gas is injected or produced out of wells that have been strategically spaced throughout the storage reservoir. Oftentimes these wells are placed in locations designated by the storage reservoir engineer to be either injection and/or withdrawal wells. During the start of the heating season, working gas is injected into wells located at the top of the reservoir (generally these are the wells completed at the top of the reservoir). As the pressure wave propagates through the reservoir, additional injection wells will be brought online.

During the heating season many injection wells can be used as withdrawal wells for an underground baseload storage facility. In order for this to happen, valves at the surface are actuated such that gas can flow to the surface and then through a dehydration unit. In some reservoirs, storage engineers will designate wells or well groups to be used in directional flow in lieu of bidirectional flow. By doing this, the overall field deliverability will generally decrease; however, stored natural gas can be used as a sweep fluid for enhanced oil recovery. Examples of such a facility would be the Ryckman Creek gas storage project in Southwestern, WY.

2.2.2. Observation wells

Additional wells are sometimes drilled in baseload storage reservoirs on the outer edges of the geometric anticline to measure casing and tubing pressures at strategic locations. This type of well is known as an observation well. Unlike normal wells that are drilled, completed, and tied into gathering systems, these wells are used by storage reservoir engineers to understand where the underground gas is being stored and to observe reservoir pressure waves. For new storage facilities, it is highly recommended to have at least one observation well located at the known spill point of the reservoir for operations, and monitoring of potential reservoir over pressuring, and/or gas migration.

Additional observation wells are oftentimes considered depending on the geology above and/or below the target storage reservoir. If naturally occurring aquifers are present, than observation wells are drilled and monitored in order to ensure gas migration is not occurring through the seal rock. If pressure begins to increase at these observation wells, then that indicates a break in the seal of the cap rock. These observation wells are then used by storage reservoir engineers to determine if mitigation techniques can be used to prevent unwanted flow or if the storage facility is no longer viable.

2.2.3. Compression facilities

For many underground baseload storage facilities, compression is installed to help inject storage gas at high rates during the off-season. In many cases the reservoir is considered to be full when the reservoir pressure is equal to the original discovery pressure. Without compression facilities it is difficult to reach the original discovery pressure, unless the prospective storage facility is shallow (less than 2,500 ft deep), and trunk line pressures from nearby transmission facilities are high. Compressors are generally designed by facilities engineers to run in parallel, thus given the operator flexibility in meeting the injection demand of a given day.

Compression facilities can also be used by operators during the heating season to put a given reservoir on compressed withdrawal. By utilizing these compressors in a reverse mode, declining natural gas deliverabilities from the storage reservoir can be increased in order to meet the minimum rate deliverability of a given storage field. While on compression, the operator is allowed to induce a higher ΔP to the reservoir, thus increasing flow rates. Compressed withdrawal mode adds cost to the operator; however, it ensures customers' needs are met.

2.2.4. Ancillary facilities

In addition to meeting storage customers' demands, it is important for a storage reservoir and facilities engineer to consider the quality of gas being stored and withdrawn from the field. In order to have a storage prospect become a fully functioning facility, it is important to verify gas quality pipeline specs can be met for each of the storage customers. The amount of storage capacity held by a single or group of customers could influence the operating company to install ancillary facilities to meet contractual obligations such as 1) Cricondentherm Hydrocarbon Dew Point (CHDP), and/or 2) percent of inert gas present in a gas stream.

2.2.4.1. Lowering CHDP for downstream corrosion control

Most natural gas transmission companies strive to keep liquids out of their pipeline systems to mitigate internal pipeline corrosion. One of the methods to do this is by limiting the amount of potential liquids that enter into the pipeline. In storage fields liquids are a concern if heavy gas is injected into the reservoir and condense within the formation. These liquids can cause potential liquid loading problems or can dropout in pipeline systems when gas is produced to the surface. Another cause of liquids may be some incremental amounts of Enhanced Oil Recovery (EOR) if a storage field is located in a historical oil or retrograde condensate reservoir.

A dew-point processing plant can be considered in order to help control the CHDP of an incoming or outgoing gas stream at a storage facility. The basis of this facility is to reduce the temperature of a gas stream such that any heavier hydrocarbons condense into a liquid phase. The gas and liquid is then separated gravimetrically into two different streams. The processed gas is then reheated and introduced into the transmission mainlines that will route it to different contracted customers. The liquids stream will be sent to a pressurized vessel for storage and can be sold as a condensate at a later time. All liquids collected at a storage facility are owned by the operator and therefore any revenue generated from liquids production will help increase the storage facility's bottom line.

2.2.4.2. H_2S removal facilities

Sometimes storage facilities are created in sour gas reservoirs, or sometimes these reservoirs become contaminated with sulfur reducing bacteria during drilling or work overs. If Hydrogen Sulfide (H_2S) is present within a storage field, than a H_2S removal facility can be installed to prevent abandoning the storage reservoir. Although this will add capital costs to the facility, it will prevent the operation from having to plug and abandon the field. If H_2S levels are low to moderate (below 100 ppm), then a simple two tower Sulfa Treat scrubber system can be installed. If H_2S levels are above 100 ppm and there is a projected high throughput of gas, then a Selexol facility should be installed.

2.3. Storage reservoir engineering theory and tools

With a background in storage engineering terminology the theory behind storage reservoir engineering can be discussed. For the purposes of this paper, it is assumed the reader has an understanding of conventional reservoir engineering principles such as: basic mass balance, Darcy's flow, pressure transient analysis, rate transient analysis, and inflow performance equations. The theory of the tools used by storage reservoir engineers are an extension of afore mentioned topics and are unique for feasibility study and maintenance of storage reservoirs. One benefit about storage reservoir engineering is that for many baseload facilities the original production data, geology studies, and reservoir models are available, create deliverability models, and allow for inventory verifications.

2.3.1. Hysteresis analysis

Hysteresis analysis is one of the fundamental tools used in storage reservoir engineering when performing a feasibility study of a new prospective reservoir or to verify operating parameters and inventory during storage utilization. Hysteresis analysis utilizes historical pseudobottomhole pressures and their respective Cumulative Gas Production (Gp). It is important to note hysteresis analysis is not a function of reservoir flowrate or time; rather, it is an overall review of the produced field's ability to be re-pressurized and reused for storage operation. The hysteresis analysis is performed by plotting known pseudopressures vs. Gp. An example of a hysteresis plot can be seen in Figure 2.2.

For a volumetric natural gas reservoir with no water drive, the data can be trended using a straight line approximation. The y-intercept of this straight line will estimate the initial reservoir pressure if that point was not previously recorded. The x-intercept estimates what is the total original gas in place of the reservoir. Using the example provided in Figure 2.2, the estimated total gas in place for this reservoir is 58.5 BCF. A linear relationship for the pseudobottomhole pressure vs. Gp can be constructed and used by a storage reservoir engineer as a method of estimating potential storage capacity at a given pressure.

When conducting a feasibility study of a prospective storage field, the hysteresis analysis is oftentimes used to determine the necessary amount of cushion gas to maintain a minimum storage reservoir pressure. Determining how much cushion gas will be required for the underground storage facility is vital in determining a cost estimate. The Darcy flow equation can be used to estimate field deliverability at different reservoir pressures in conjunction with the hysteresis analysis as a second order method of determining cushion gas requirements. After the cushion gas requirement is selected, then the working gas capacity is calculated by taking the estimated total gas in place and then subtract the cushion gas requirement. With this information, the working gas capacity can be used in the economic analysis to calculate what the internal rate of return is for the facility.

Last, the hysteresis analysis can be used for active storage facilities as a method of inventory verification and reservoir integrity. By using the linear relationship for BHP/Z vs. Gp, annual or bi-annual tests can be conducted at the end of the heating season and/or at the end of the off-season and these points plotted on the hysteresis chart. If the points fall on or relatively close to where the linear equation predicts, then the overall storage inventory can be confirmed. If the data point(s) fall below the linear line it indicates that either 1) the reservoir was not given sufficient time to equalize, or 2) that inventory has been lost. Lost inventory is indicative of when high inventory levels correspond to low pressures. Data points above the line indicate there is likely a measurement error present within the operator's Supervisory Control and Data Acquisition (SCADA) system; that would indicate the reservoir has higher pressures with lower inventories. This case is possible if the measured flows going downhole are less than the actual values. Possible causes of this could be 1) instruments need to be calibrated, or 2) improper accounting of compressor and dehydration fuels.

Proper measurement is vital in ensuring the longevity of assets in a storage facility. Hysteresis analysis allows storage reservoir engineers to monitor the reservoir's performance and watch trends that indicate if improper measurement or potential gas leaks are present at the subsurface. If inventory verification is not checked on a consistent cycle (at minimum once a year) it is possible for the operator to lose its customers' gas and to have to buy new gas at market value, oftentimes resulting in a great financial loss. If reservoirs continue to demonstrate leaks it is possible for the Federal Energy Regulatory Commission (FERC) to decommission the facility unless mitigations are put into place and proven effective over a period of time.

2.3.2. Decline curve analysis

Decline Curve Analysis (DCA) is an empirical or semi-empirical method of predicting future production and estimating reserves of a new well or well group. Classical decline curve analysis assumes production of a field will occur under constant well drawdown for many years. This is a simplified assumption, as in most practical applications gas wells can be shut-in during the off-season when demands are low and sometimes are not flown at a constant drawdown. DCA is powerful because it uses real production data to forecast future production and estimate ultimate recovery from a well or well group.

DCA was first documented by J. J. Arps in 1944 while analyzing flow rate vs. time plots. Arps noted that after a traditional well, a different slope of the decline curve or type curve represent different reservoir behaviors. Arps developed a variety of different heuristics that have been employed by the oil and gas industry for many years explaining different flow regimes occurring subsurface.

Upon analyzing various different data sets, Arps determined wells declined at a constant rate. This is known as the b factor as illustrated below:

$$b = \frac{d\frac{1}{D}}{dt} = -\frac{\left(\frac{1}{D^2}\right)dD}{dt} = constant \tag{1}$$

$$D = -\frac{dq/dt}{q} \tag{2}$$

Integrating (2) twice provides the Arps decline rate relations as written below:

$$D = \frac{D_i}{1+bD_it} \tag{3}$$

$$q = \frac{(q_i)}{(1+bD_it)^{1/b}} \tag{4}$$

where q is equal to the flow rate, q_i is equal to the Initial Production (IP) of a well, and D_i is the decline rate for the well.

For simplicity, there are three commonly accepted decline curves that have been classified for b values that are at 0, 0.5, and 1, respectively. A b-factor of 0 represents an exponential decline for a well; this is considered to be the most conservative estimate for traditional applications. A b-factor of 0.5 represents a hyperbolic decline for a given well, this is considered to be a moderate estimate for traditional plays. Finally, a b-factor of 1 is considered to be a harmonic decline for a given well; this is generally an aggressive estimate for traditional reservoirs and it can sometimes lead to overestimation of reserves. The gas reservoir drive mechanisms for an array of b-factor values are provided in Table 2.1.

When using DCA for feasibility studies for prospective storage reservoirs, it is recommended that reservoir engineers use the exponential decline assumption to estimate well and field deliverabilities at higher inventories. By designing a facility for this worst case scenario, it should ensure that signed contracts by future customers will likely be met. An example of an exponential DCA plot for a prospective storage reservoir can be seen in Figure 2.3. Please note that the blue data points from Figure 2.3 represent measured values, the red data points indicate the theoretical well decline assuming exponential decline as modeled, assuming the b-factor is equal to 0. Notice when rate is plotted on a semilog plot, as seen in Figure 2.4, the curve will appear to be linear; this is another diagnostic that can be used to determine if the exponential decline assumption is valid.

By assuming exponential decline (4) is reduced to:

$$q = q_1 * \exp(-D_i t) \tag{5}$$

where q is equal to the flow rate [Thousands of Cubic Feet per Day] (MCFD) at a given time (days), D_i is equal to the decline rate, and q_1 is equal to the initial production in (MCFD). (5) can be further modified to solve for the cumulative production of the field at a given time as shown below:

$$Q(t) = \frac{q_i - q_t}{D_i} \tag{6}$$

2.3.3. 2D or 3D simulation with history matching

The last tool that can be used for conducting a feasibility study is either 2D or 3D simulation with history matching. Models of a given reservoir can be constructed by geologists and storage reservoir engineers to recreate the field's production, in order to refine the geophysical properties of the reservoir matrix, using history matching. After history matching is completed and the geophysical properties have been confirmed within the rock matrix, then simulations can be run to repressurize the reservoir back to maximum inventory.

For historical storage reservoirs, computer simulation has been used by storage reservoir engineers to confirm expected reservoir deliverabilities at different inventories and at different reservoir pressures. For example, Questar Pipeline Company's Clay Basin storage facility was modeled using 2D simulation back in the 1970s before construction of the physical asset. Details of how Questar's simulation work was used are well explained by J.L. Baird in SPE publication 7171. For Questar's Clay Basin storage field the results of the 2D simulation in conjunction with DCA helped drive the company to drill additional wells within the reservoir formation such that market deliverabilities could be met.

Similarly to how Questar Pipeline Company used 2D modeling to help drive design criteria, 3D simulation can be leveraged as well. However, in addition to 2D modeling, 3D simulations can help explain if the reservoir can be considered contiguous or if reservoir compartmentalization is likely occurring. Simulated deliverabilities at different reservoir pressures will also help storage reservoir engineers determine the amount of cushion gas required within the new facility. The remaining gas can be sold to potential storage customers as firm storage working gas capacity.

Utilizing 3D simulation also helps reservoir engineers understand the deliverability at the current number of existing wells and make guided recommendations if new wells need to be drilled. By using their model, new wells can be "drilled and produced" in different areas of the reservoir. By using these results, a storage reservoir engineer can optimize the number of wells (and their geometries) to meet the designed deliverability requirements of a new facility.

2.4. Economic theory

As with many oil and gas projects it is important to note that economics will ultimately decide if a new prospective storage facility will be installed. Unlike traditional oil and gas facilities, storage facilities do not make a profit by producing hydrocarbons out of the ground and then selling them at a market or cost of service price. Rather, storage tariffs are put into place, allowing for a moderate rate of return to the operator. These tariffs are oftentimes approved by the FERC and are normally written as a cost per dekatherm of gas stored per month. In addition, there are usage fees for injecting and withdrawing working gas inventory from the reservoir. Lists of storage tariffs and rates can be found by contacting the operator of a storage field or on the operator's website. Questar Pipeline's tariffs for their Clay Basin storage facility can be found at www.questarpipeline.com.

The economic feasibility of storage facilities is generally governed by the required capital investment and the internal rate of return. A heuristic and reasonable internal rate of return to design for is about 10% for 10 years. For facilities with high capital costs, the tariff for these facilities will generally be high. As long as the price to store gas remains less than the price of gas during the peak winter months, then often the project will be viable. However, if the forward price curves do not indicate a seasonal and off-seasonal price differential larger than the annual rate, then storage facilities will oftentimes struggle of utilize all capacity and will fall short on their internal rate of return. These should be considered by the storage reservoir engineer and the management before a new storage project is finalized.

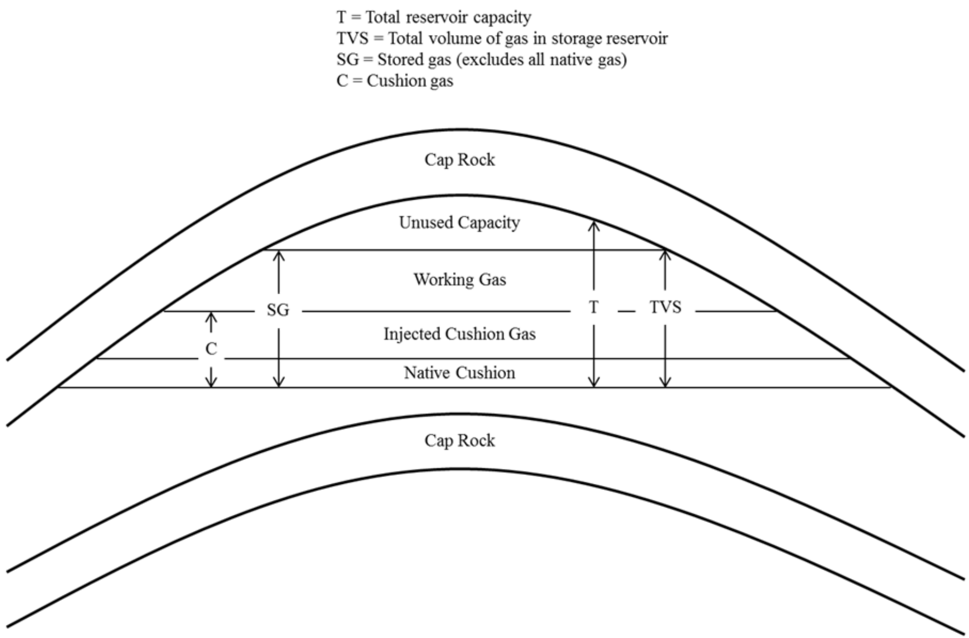

Figure 2.1: Schematic diagram of a storage reservoir.

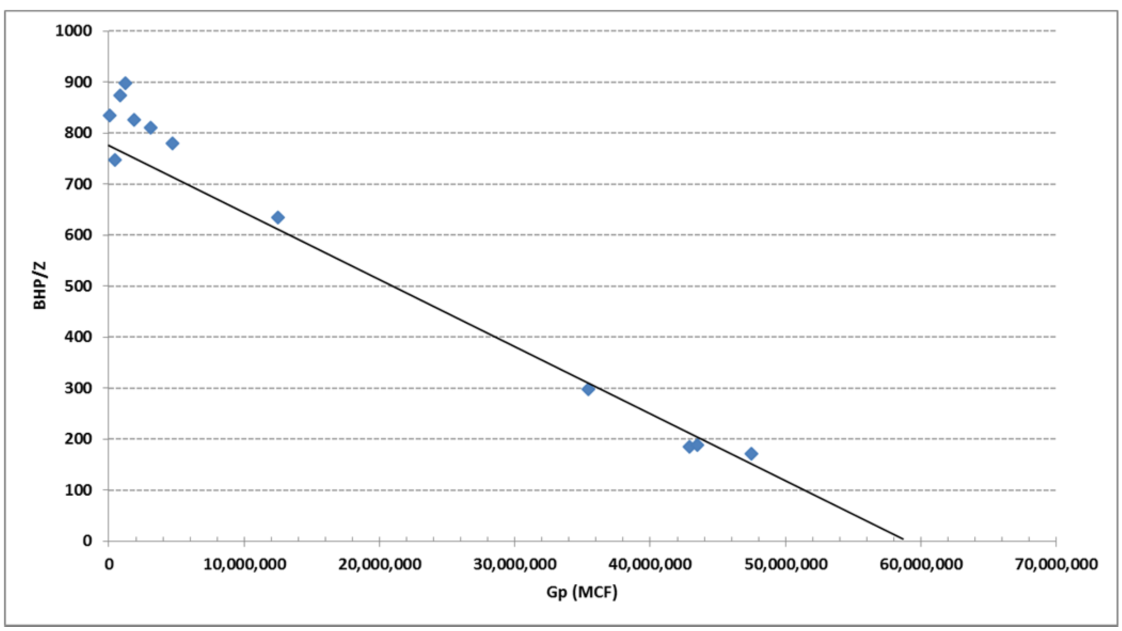

Figure 2.2: Hysteresis plot of a prospective storage reservoir.

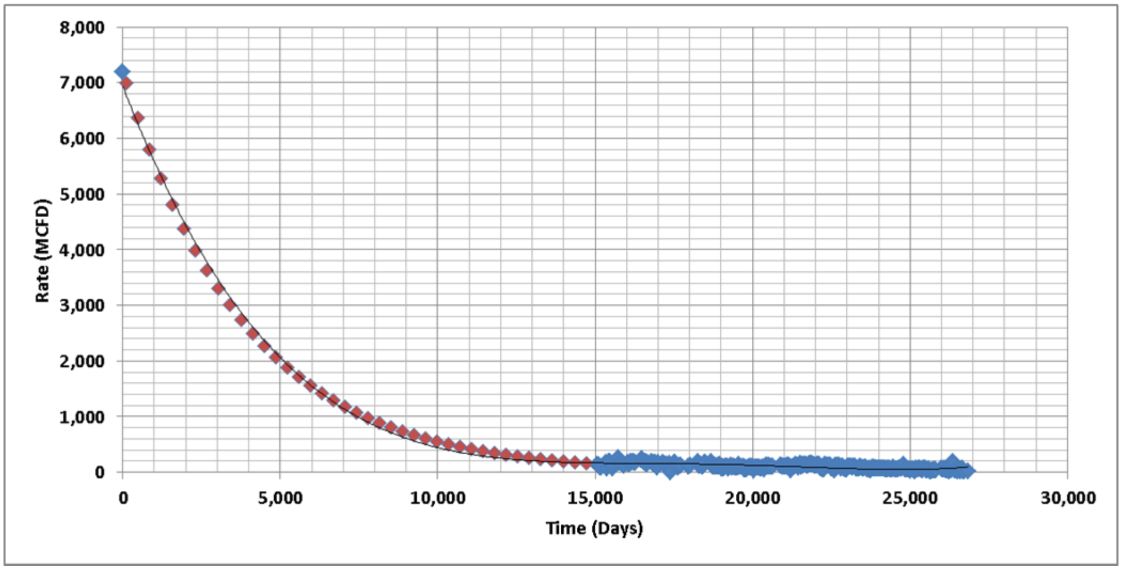

Figure 2.3: Example of a DCA plotting rate vs. time of a prospective storage well.

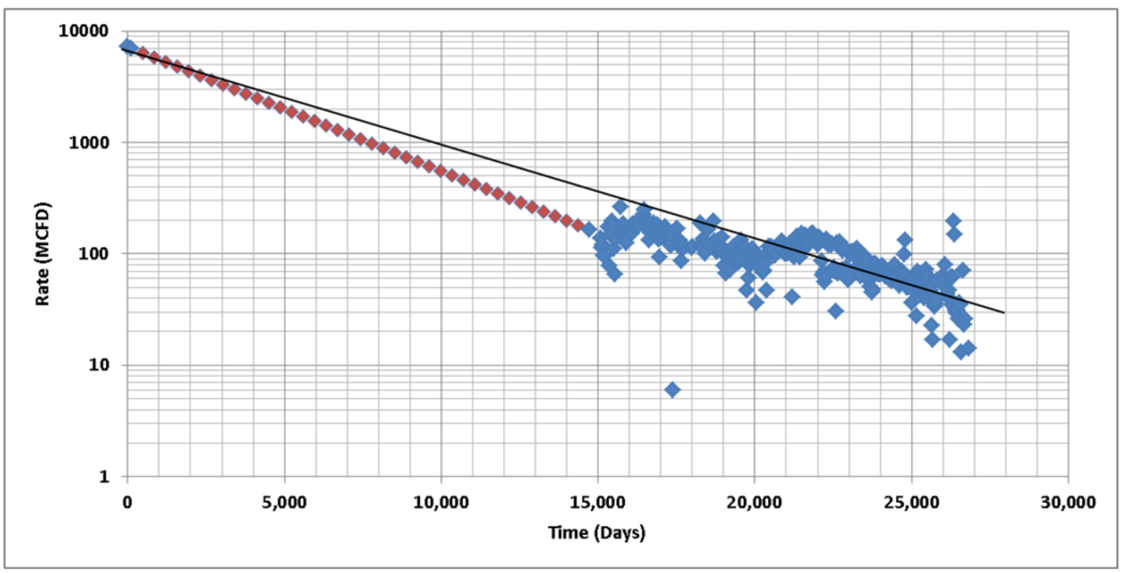

Figure 2.4: Example of a DCA plotting rate vs. time on a semilog plot.

Table 2.1: Reservoir drive mechanisms for various b-factors, modified from [4].

b-factor	Reservoir Drive Mechanism
0	Single phase gas expansion at high pressure
0.1 – 0.4	Solution gas drive
0.4 – 0.5	Single phase gas expansion
0.5 – 1.0	Layered reservoirs
> 1	Transient (Tight Gas)

CHAPTER 3

GEOLOGY OF AN UNDERGROUND STORAGE PROSPECT

The subsurface geology of an underground storage prospect is the most vital part of a baseload storage facility and it is oftentimes an area quickly overlooked. The reason for this is that a typical storage operator who is looking to open or acquire additional storage facilities is more interested in the economics and the engineering study than in the geologic study. In many cases, the management falls in love with the project before all of the facts are available. Before any high level engineering calculations are made, it is recommended a professional geologist prepare a detailed report focusing on the following areas:

1) Subsurface tectonics of the reservoir;
2) Stratigraphy;
3) Historical oil and/or gas background of the reservoir;
4) Petroleum system.

The analysis should contain figures and/or tables providing support about the geologist's conclusions, such as:

1) Evolution of structure maps of the field;
2) Time event chart;
3) Burial history chart;
4) Historical isopach map;

5) Stratigraphy of reservoir.

3.1. Subsurface tectonics of the reservoir

The first area that the petroleum geologist will need to understand is the subsurface tectonics of the reservoir; this is a vital step in understanding what bounds the perspective storage reservoir and to determine if the reservoir is continuous, or if there are areas compartmentalized. By analyzing previous geologic studies from other geologists, available logs, and 2D or 3D seismic surveys, if available, the geologist will interpret whether the reservoir should or should not be considered for storage operations. If the reservoir has a predominant fault within its boundaries, it is imperative to understand if it is a sealing fault; if it is not, then the storage field will lose inventory at the fault interface.

In most storage reservoirs, the subsurface geometry will either be a symmetrical anticline or an asymmetrical anticline with a sealing fault. After the internal field tectonics are understood, the geologist will work outward to draw the boundaries of the reservoir. Oftentimes these boundaries are important as it will define where the potential spill points within the reservoir are located and at what depths gas loss can occur. Lastly, existing well logs will need to be correlated to verify if the reservoir is continuous throughout its defined area, or if normal or reserve faults are present, disconnecting the reservoir sands from each other. This will ensure the proper placement of new storage wells within the known reservoir limits and not risk drilling in small reservoir compartments that will act independently of the main reservoir matrix. After the basin tectonics are confirmed, the geologist will determine if the historical structure maps are representative of the field or will create an updated structure map with their interpretation. An example of a structure map is illustrated in [5].

If the geologist concludes there is not enough information for their interpretation it is likely they will recommend a seismic survey be conducted by the operator. If the operator considers creating a 3D model of the potential storage field, a 3D seismic survey will be helpful in creating the underlying geologic model used in the reservoir simulations. An example of a 3D structure map comprised of 3D seismic interpretations can be seen in [6].

3.2. Reservoir stratigraphy

After the subsurface tectonics have been determined, the next step is for the geologist to determine the stratigraphy of the subsurface. In order to do this, it is important to use gamma ray and resistivity logs to determine the location and depth of sandstones, limestones, shales, and siltstones. In many cases, the geologist will reference the work of other geologists in surrounding hydrocarbon fields or at formation outcrops. Stratigraphic tables and/or charts will show the different layers of rock formation under the surface with their respective thicknesses, identifying which formations are either hydrocarbon and/or water bearing. Geologic unconformities are also noted in the stratigraphic interpretation, helping geologists and engineers make decisions about the age of the formation and how long potential source rocks have been thermally maturating. An example of a subsurface stratigraphy section is illustrated in Table 3.1.

Within the stratigraphic description of the reservoir formation, it is important to note if there are unconformities within a given reservoir rock. An example of this is the Frontier sandstone, located in Southwestern Wyoming. The lower part of the Frontier sandstone was deposited in a fluvial depositional environment flowing toward the

Cretaceous Mancos Sea. Within these fluvial channels, the sands are well sorted with high porosity and permeability. As the Mancos Sea continued to expand, the Frontier formation transitioned from a fluvial to a shoreface depositional environment. At this point the Frontier became poorly sorted and became a tight sandstone with lower porosity and permeability, compared to its lower levels. This transition has been classified by geologists as the Turonian unconformity. It is important for unconformities within reservoir formations to be documented in this phase in order to help drilling and reservoir engineers plan on drilling depths and completion zones. After the stratigraphic column is completed, the next step is to categorize the depositional environments of all potential gas storage formations. For a complete stratigraphic description the following items should be included:

1) Deposition environment(s) i.e., fluvial, shoreface, marine etc.;
2) Average reservoir porosity;
3) Average reservoir permeability;
4) Sorting quality of reservoir formation.

3.2.1. E.g., of a stratigraphic description for Clay Basin

The Frontier formation is sandstone from the Upper Cretaceous Period that lies underneath the Mancos shale formation and above the Mowry shale formation. The Frontier sandstones were deposited in two well defined benches and have been identified by Mountain Fuel geologists to be of predominantly fluvial shoreline type deposits [8]. The fluvial deposits most likely occurred between marine transgressions of the Cretaceous Sea. A marine transgression is a geologic event in which the sea level rises, moving the shoreline to a higher elevation. Evidence of the marine transgressions can be seen in the depositions of the Mancos shale and the Mowery shale.

The recorded thickness of the Frontier formation varies throughout Clay Basin and has a recorded maximum thickness of 81 ft. and a minimum of 40 ft. It was determined by Mountain Fuel geologists that the average total sand thickness for the Frontier formation is 59 ft. [8]. The Frontier sandstone deposition was recorded as irregular. This suggests it was in a high energy flow regime of the historical fluvial area; this has led the sandstone sorting to be poor. In typical Frontier sandstone within Clay Basin, the average estimated porosity is 12% and the average estimated permeability of 10 mD [8]. With a porosity of 12% and a permeability of 10 mD, the Frontier sandstone can be characterized as a fair reservoir using metrics provided by [9]. The Frontier sandstone beds are located on average at 5,400 ft [5]. Due to poor sorting and a reasonable poroperm, it has been found that the Frontier sandstone is broadly tight with the exception of Unit Well No. 1, and it has been classified as a mediocre gas producer in wells that have not been stimulated using sand-oil fracturing [8]. Gas wells that employed sand-oil fracturing, a precursor to hydraulic fracturing that is a common occurrence in modern wells, enabling operators to achieve higher volume production rates leading to economic field developments.

The Dakota sandstone located at Clay Basin has been determined to be predominantly of fluvial to lower costal-plain channel and over bank deposits. [5] The top layer of the Dakota sandstones was slightly reworked by marine transgression upon the entrance of the Mowry shale formation. [9] The Dakota sandstone represents an environmental shift between the underlying continental deposits of the Cedar Mountain formation to overlying marine deposits of Mowry shale. [5] The Dakota sandstone is composed of four separate formation benches with a maximum thickness of 60 ft., with overlapping benches, and a minimum of 15 ft. of total sand, and one isolated bench [5]. The average total of sand thickness per well in the Dakota sandstone is ~40 ft. [5].

Through the development of the Dakota sandstone it is noted that the sand quality varies considerably from well to well; however, it tends to deteriorate northward across the field [8]. On average, the porosity of the Dakota sandstone in Clay Basin was determined to be 16% with a permeability of 24 mD. This means the Frontier sandstone can be characterized as a good reservoir using metrics provided by [9]. The upper interval of the Dakota sandstone was historically the dominate gas producing reservoir. It was converted to natural gas storage by Mountain Fuel back in 1976 to help minimize gas shortages in the Wasatch Front.

3.3. Historical oil and/or gas background of the reservoir

Before engineering calculations are run on a new storage prospect it is important for the storage reservoir engineers and management to understand the historical background of a given depleted field. Within this section of the geology report, the following information should be noted if readily available:

1) Date of the original hydrocarbon discovery;
2) Initial production at discovery;
3) Installation of pipeline transmission facilities (i.e., pipelines);
4) Estimated ultimate recovery of the reservoir;
5) Reservoir recovery factor;
6) Exploratory deep wells in the field, results of drill-stem test(s);
7) Gas in place at current reservoir pressure.

Some of this information can be difficult to locate; however, much of the production history as well as initial discoveries are oftentimes documented by geologists in American Associate of Petroleum Geologists (AAPG) publications, or records kept at the specific state's division of oil, gas, and mines. For the State of Texas, records will be located at the Railroad Commission of Texas. An example of a historical background is provided in section 3.3.1 for Questar's Clay Basin storage field.

3.3.1. E.g., of a historical background for Clay Basin

Natural gas was originally discovered in 1927 with the successful drilling of the R.D. Murphy Well No. 1 in the Frontier sandstone and the R.D. Murphy Well No. 2 in the Dakota sandstone in 1935. Shortly after completion, it was determined that Murphy No. 1 had an initial rate of 3 MMCF/D of dry gas and Murphy No. 2 had an initial rate of 32 MMCF/D. After initial hydrocarbons were located, both wells were shut in until 1937 with the completion of the Mountain Fuel pipeline connecting Clay Basin to other main pipelines that served the Salt Lake Valley [5]. The Frontier formation produced a constant supply of natural gas from seventeen wells throughout Clay Basin and has produced 76 BCF of natural gas up to December 31, 2003. The Dakota formation produced 104.3 BCF from nine wells before being converted to gas storage in 1976. At that time it was estimated that the gas in place in the Dakota sands was 11.8 BCF, suggesting there was an estimated ultimate recovery of 116.1 BCF (Utah Division of Oil, Gas and Mining 1975 hearing files, cause 164-1). As of December 31st, 2003, Clay Basin has produced more than 180.3 BCF of natural gas and 380 Mbbl of oil with a 3.7 BCF over estimation; the corrected total was 176 BCF. A detailed annual gas production of the Clay Basin field can be observed in [5].

Mountain Fuel explored a number of different geologic formations older than the Cretaceous Period. During the initial drilling of Murphy No. 2, the Jurassic Entrada sandstone was penetrated at a Total Vertical Depth (TVD) of 6,799 ft. for exploration purposes. A drill-stem test was performed at that depth and water was recovered. Shortly after, the well was plugged and completed back in the Dakota sandstone. Another exploration attempt in 1946, the R.D. Murphy Well No. 11, was drilled to a TVD of 9,355 ft. which penetrated 330 ft. of Pennsylvanian Weber sandstone. A drill-stem test of the Weber sandstone gauged ~ 8.5 MMCF/D of noncombustible gas [5]. After this test, the Weber sandstone was plugged and completed in the Dakota sandstone. This well was reentered in 1969 and drilled to 11,778 ft. TVD, penetrating 598 ft. of Cambrian Lodore sandstone. A drill-stem test of the Mississippian Humbug formation and Madison Limestone revered 10,100 ft^3 of brine water [5]. The well was recompleted in the Dakota sandstone and continued to produce until converted into gas storage in 1976.

Recently, QEP (formally known as Questar Exploration and Production) has applied for permits to drill new wells in Clay Basin to expand on previous exploration efforts by Mountain Fuel. As of 2013, QEP drilled at least one wildcat well to reevaluate formations below the Dakota formation such as the Entrada sandstone, Nugget sandstone, and the Weber sandstone; they are seeking new potential hydrocarbon reservoirs. The results of the QEP wildcat well discovered new sour gas hydrocarbon reserves below Questar Pipeline Company's Clay Basin storage facility. Depending on market demand it is possible that the pipeline and facility system surrounding Clay Basin may be further developed in the years to come to accommodate these new reserves.

3.4. Classification of the reservoir petroleum system

The last part of the geologic report is the classification of the reservoir petroleum system. Within the petroleum system analysis, the professional geologist will identify the following areas and discuss each in detail:

1) Time event chart;
2) Source rock formation(s);
3) Reservoir rock formation(s);
4) Cap/Seal rock formation(s).

The most important section for a storage reservoir prospect is 4) the cap/seal rock formation(s) above and below the proposed storage formation. This is where a storage reservoir engineer will want to spend most of his/her attention when evaluating the engineering feasibility of the storage project. If the geologist determines, either through cap rock core analysis or log correlation, that the cap/seal rock is indeed an impermeable barrier at the original reservoir pressure, then the project should continue to be evaluated. If it is deemed the cap rock is unstable or if an existing fracture network exists above the reservoir formation, then it is recommended the prospect be discontinued. If the storage reservoir pressures are designed to exceed the original reservoir pressure, then the geologist will likely recommend a geotechnical study be conducted by a third party to evaluate the rock mechanics of the cap rock at the designed reservoir pressures to ensure it does not exceed the formation breakdown/fracture pressure. During this geotechnical analysis it is important for the perspective storage operator to consider the possibilities of overpressuring the reservoir beyond its virgin reservoir pressure to store additional working gas volumes in the future.

3.4.1. Example of a petroleum system analysis for Clay Basin

Although a number of geologic surveys and prospect analysis were performed at Clay Basin by a number of Mountain Fuel and government geologists over the years, there has been little focus on characterizing the total petroleum system that exists in the subsurface. Instead, there has been a one-dimensional approach to understand Clay Basin's anticline structure and reservoir stratigraphy. For the purposes of this paper, the total petroleum system will be explored for this basin with an emphasis on its original source rocks and petroleum expulsion; an enhanced discussion of reservoir rocks and economic production, and its proven cap rocks is provided.

As detailed above, Clay Basin is a foreland basin located just north of the Uinta Basin fault. Due to folding caused by the thrust faults in the area, the structure of Clay Basin can be depicted as a traditional anticline. Clay Basin is unique since there are two different source rock formations, two reservoir rock formations, and two different types of cap rocks in the same subsurface structure. The timing of when these formations occurred is best illustrated using a time event chart as in Figure 3.1.

3.4.1.1. Source rock formations at Clay Basin

After researching for a number of months throughout the vast amounts of available literature available for Clay Basin, no resource located made a determination of its source rock formation(s) or when its critical moment occurred. Using what was presented in the University of Utah in Chemical Engineering 6163, Petroleum Geoscience course, a detailed hypothesis of the source rock formations and hydrocarbon generation is presented by the author. The first thing to be considered for source rock quality is the kerogen type that generated the hydrocarbons at Clay Basin. Based on the historical production data provided by [5], there has been 176 BCF of natural gas produced with only 380 Mbbl of oil. Based on these data, it is hypothesized that the kerogen in the source rock is Type I or from marine origin. In addition to the kerogen type, it is vital to understand which formation(s) acts as the source rock for the Clay Basin field. Drilling records and later electric logs established the TVD of the Dakota sandstone formation is located around 5,600 ft. to 5,800 ft.

After recreating the different stratigraphic formation layers in MS Excel with their respective thicknesses, the subsurface temperature was estimated using

$$T_{subsurface} = 18^{o}C + \frac{25^{o}C}{km} * (x\ km) \tag{7}$$

assuming a constant surface temperature of 18º C. The purpose of plotting this data was to determine which potential source rock formations entered the gas generation zone and when. Using the provided TVD from Questar Pipeline, it was determined none of the formations entered into the gas generation zone or exceeded a subsurface temperature of 120º C to 150º C. This exercise proved to be quite puzzling as it is known the hydrocarbon reserves migrated from somewhere to the Clay Basin anticline. After reviewing Mountain Fuel production records from the '50s – '60s, it was determined the origin of the natural gas was not formed through biogenic processes. Therefore, some geologic event must have removed the source rock formations from the gas generation zone.

Upon researching surrounding basins in the southwestern parts of Wyoming and the northwestern parts of Colorado with similar formations, which yielded some promising information, it was discovered that the Dakota sandstone is located at a variety of different depths throughout the larger Uinta-Piceance province [10]. Using one of the isopach maps provided by the U.S. Geological Survey, it was determined the actual TVD at Clay Basin before upliftment was ~7,000 ft., as illustrated Figure 3.2.

Applying an understanding of the Dakota formation's initial depth to Clay Basin's anticline structure indicates that there is at least one adjacent syncline that was buried at the same time. This hypothesis is illustrated in Figure 3.3. If folding did occur to create the Clay Basin anticline, then it is probably the same part of the Dakota formation that was buried by the approximately same change in height. By recalculating the temperature profile using (7) and placing the depth of the Dakota formation at 8,500 ft., there were two organic formations entered into the gas window: the Morgan and Doughnut shales with an absolute thickness of 539 ft. and 40 ft., respectively. The Morgan formation is from the early Pennsylvanian Period and the Doughnut formation is from the late-Pennsylvanian Period. From Figure 3.1 it is estimated the critical moment for Clay Basin occurred ~80 Ma years ago when the Morgan formation entered into the gas window. Gas generation began in the adjacent syncline until the slip point was reached and the formation yielded, migrating to the more permeable Dakota and Frontier formations, respectively.

3.4.1.2. Reservoir rock formations at Clay Basin

Shortly after the Doughnut and the Morgan formations entered into the gas window, hydrocarbons formed and began to migrate. As geologic time progressed, a significant amount of hydrocarbons built up to a sizable pressure and were able to fracture the shale formations in which they were entrained and through secondary migration moved to more favorable reservoir rock formations. The two reservoir formations located in Clay Basin are the Frontier sandstone and the Dakota sandstone. Detailed descriptions of these two formations can be found in sections 3.1 and 3.2 of this paper, respectively.

From historical papers, it is recorded that the average initial reservoir pressures of the Frontier and Dakota formations were 2,433 psig and 2,536 psig [11]. By assuming a hydrostatic pressure gradient in the same formation, the following equation can be used to estimate the pore pressure:

$$P_{pore} = 0.433\frac{psi}{ft} * \Delta h_{Dakota} = 0.433\frac{psi}{ft}(5{,}600ft) = 2{,}425\ psig \qquad (8)$$

By comparing the initial reservoir pressure provided by [11] and the result from (8) it can be assumed the Frontier and Dakota formations are normally pressured. Currently, Clay Basin's Dakota formation is being operated by Questar Pipeline as a storage reservoir; its rated maximum operating pressure is 2,600 psig.

3.4.1.3. Cap rock formations at Clay Basin

As mentioned above there are two reservoir formations located within Clay Basin, the Frontier and the Dakota sandstones. The larger petroleum bearing formation is the Dakota, which has a net reservoir pay of ~40 ft. As hydrocarbons migrated from the Doughnut and the Morgan formations upward, they reached the Dakota sandstone and some of the gas began to be trapped by the Mowry shale formation, which was deposited during the marine transgression of the Mowry Sea. This cap rock did not begin sealing upon being deposited; however, a reasonable amount of gas can be found in the Frontier formation above. The presence of a similar quality of natural gas in the Frontier formation as the Dakota suggests that both share a common source, the Morgan shale formation.

In order for the gas quality to be similar in both reservoir rocks, it is hypothesized the Mowry shale formation did not act as a perfect cap rock initially. Rather, there were some minor channels in the formation that allowed small amounts of natural gas to bypass and enter into the Frontier formation. The sizes of the channels were small, so only a limited amount of gas was allowed to leak from the Dakota to the Frontier formation. As geologic time passed, the Mowry shale formation became more compacted as the weight of the Mancos shale was added to Clay Basin. Finally, the Mowry shale formation compacted, closing any channels that connected the two sandstone reservoirs, forming the cap rock for the Dakota formation. The Mowry shale formation has been a proven cap rock since Mountain Fuel converted the Dakota formation into a natural gas storage reservoir. As gas was re-injected into the Dakota sandstone, no increase of gas production rates was observed in the Frontier sandstone, suggesting that there is no reservoir connectivity via the Mowry shale formation.

The other cap rock located at Clay Basin in the Mancos shale formation overlies the Frontier formation. The Mancos shale formation was deposited upon the marine transgression of the Cretaceous Sea. The overall surface and drilled thickness of the Mancos shale formation was recorded by Mountain Fuel to be ~6,200 ft. [5]. Due to the thickness and low permeability of this cap rock, a large portion of natural gas that migrated to the Frontier formation stayed in place. The Mancos shale formation is a relatively young shale that appears to be a light gray in color. Based on analysis of an available core sample from Questar Pipeline Company, it is observed that the Mancos shale is an immature source rock. However; if the Mancos shale is buried and given time to undergo catagenesis (shale becomes thermally mature through earth's thermal gradient as a function of depth) it is possible it could generate a large supply of hydrocarbons in the future.

3.5. Importance of geologic considerations in a storage prospect

As mentioned at the beginning of this chapter, the geology of the storage reservoir prospect is the most important step in a storage feasibility study and oftentimes it is overlooked by the storage reservoir engineer. After all geologic considerations have been made the last step that needs to be completed is a formal meeting with the storage reservoir engineer and the management. If the following conclusions are presented in the geologist's summary, than this is an indicator the project should be passed on to engineering for further technical review:

1) Basin tectonics indicate minimum faulting within reservoir boundaries;
2) Basin tectonics indicate continuous reservoir formation within storage boundaries with minimum to no compartmentalization;
3) Spill point(s) are documented and are located outside of the storage boundaries;
4) Stratigraphy indicates favorable geomechanical properties;
5) Cap/seal formation indicate an impermeable barrier to prevent natural gas seepage.

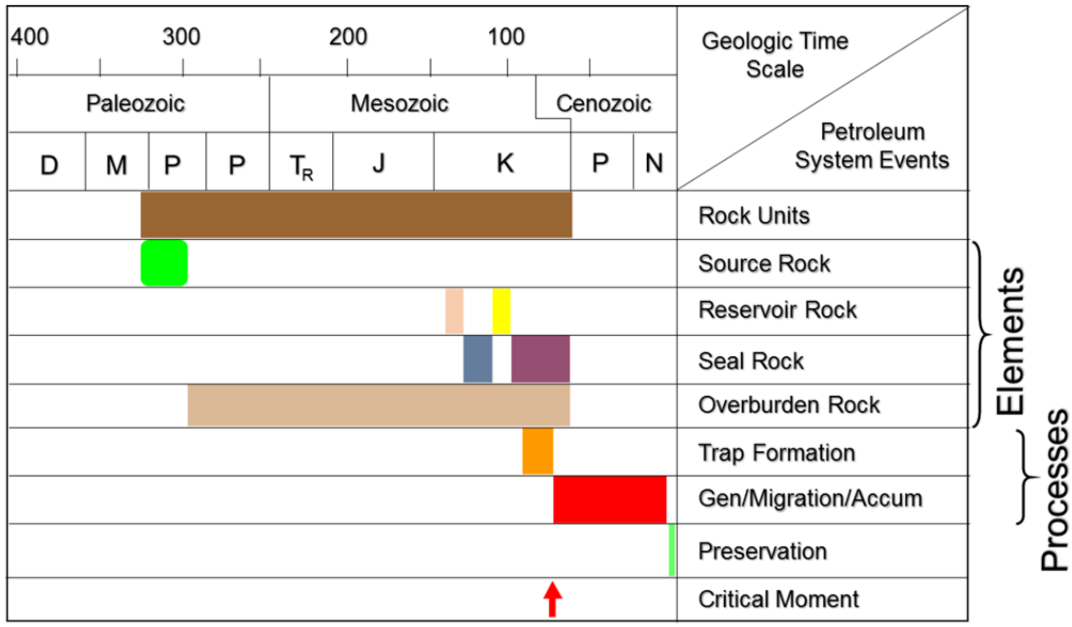

Figure 3.1: Time event chart for Clay Basin, Daggett County (UT).

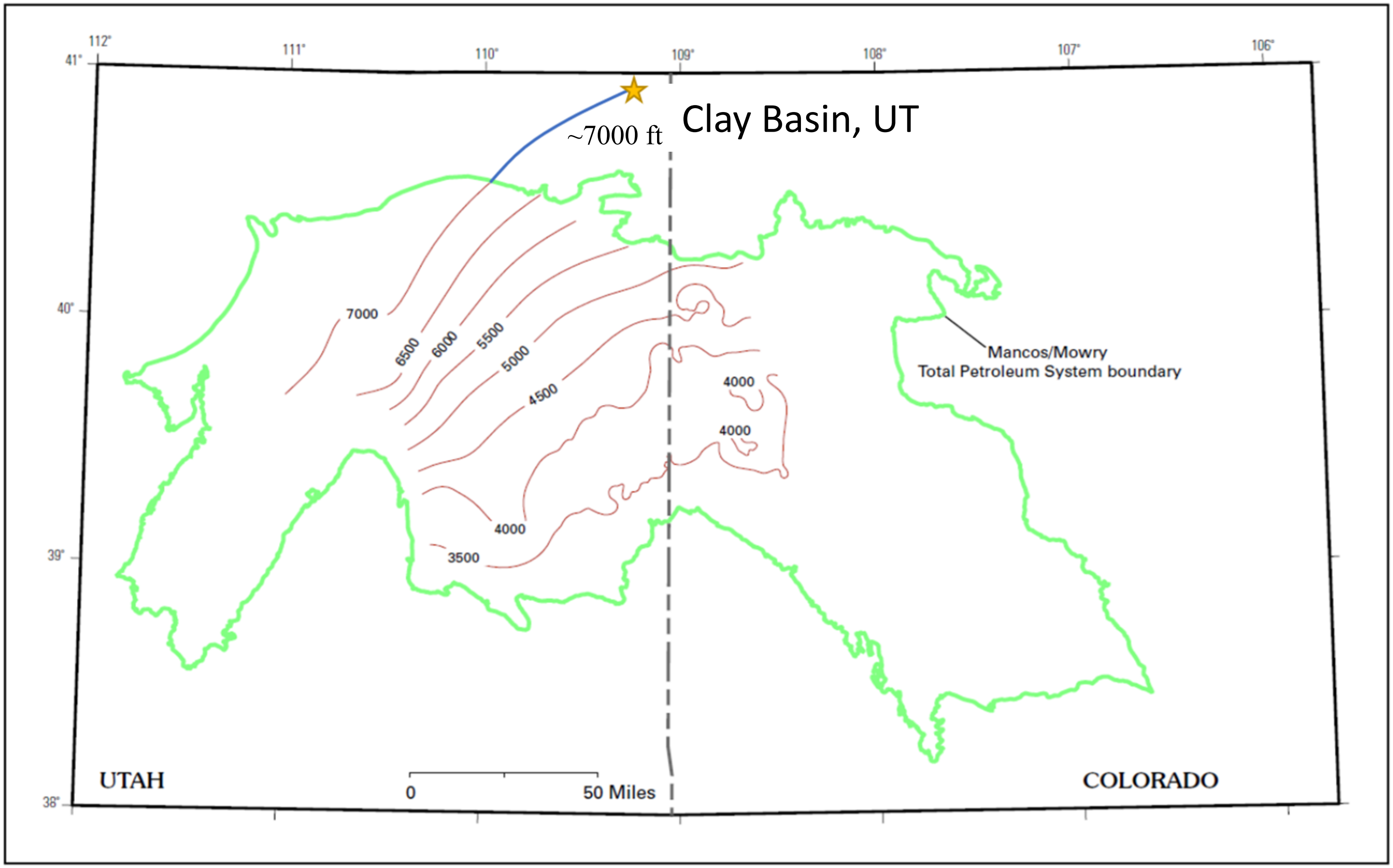

Figure 3.2: Isopach map of the Uinta-Piceance basins. Blue line indicates extrapolated value by the author. Modified from [10].

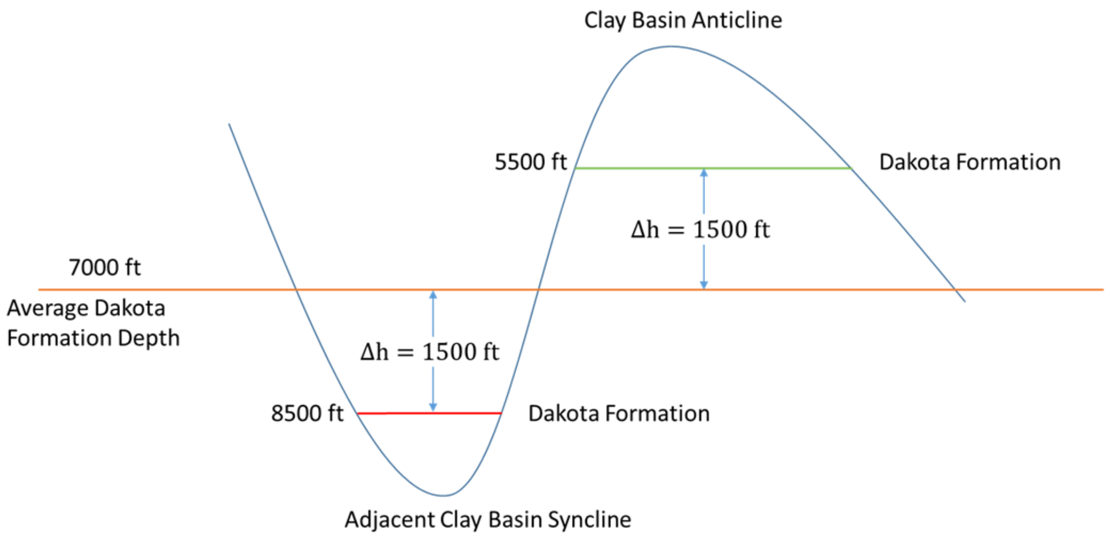

Figure 3.3: Proposed subsurface structure of the Dakota formation at Clay Basin.

Table 3.1: Subsurface stratigraphic section at Clay Basin storage field, modified from [5].

Age and Formation or Member	Thickness (ft)
CRETACEOUS	
Mancos Shale (surface + drilled thickness)	*6200*
Frontier Formation (gas producer) ★	*120*
Mowry Shale	*245*
Dakota Sandstone (gas producer/storage) ★	*125*
Unconformity	
JURASSIC	
Cedar Mountain & Morrison Formations	*600*
Stump Formation	*175*
Entrada Sandstone (water bearing)	*100*
Carmel Formation	*110*
Nugget Sandstone	*780*
Unconformity	
TRIASSIC	
Chinle Formation	*210*
Garta Mbr of Chinle Fm (water bearing)	*40*
Moenkopi Formation	*750*
Dinwoody Formation	*190*
PERMIAN	
Park City Formation	*180*
PENNSYLVANIAN	
Weber Sandstone (noncombustible gas)	*1029*
Morgan Formation	*539*
MISSISSIPPIAN	
Doughnut Formation	*40*
Humbug Formation	*190*
Madison Limestone (water bearing)	*390*
Unconformity	
CAMBRIAN	
Lodore Sandstone	*598+*

CHAPTER 4

DESIGN OF A NEW BASELOAD STORAGE FACILITY

After a new underground baseload storage facility prospect has passed the initial review from a professional geologist, it is sent to the storage reservoir engineer for the designing phase. The engineer will work closely with the geologist to gain an understanding of the subsurface before beginning his/her design work. The purpose of this chapter will be to demonstrate how a storage reservoir feasibility study should be conducted using available data from governmental and industry sources. This will be demonstrated in the sections below by using data from a depleted natural gas reservoir located in the Rocky Mountains. Due to confidentiality agreements the name of the facility or its location are not disclosed.

4.1. Solve for storage facility specs using hysteresis analysis

The first step in the design of a new storage facility is determining the reservoir specifications such as total volume, native cushion gas available, required cushion gas required for injection, and the remaining volume that can be sold to customers as contracted working gas. The total volume of the reservoir can be estimated as the Original Gas in Place (OGIP). This value is normally estimated by the current operator of the field, it can also be estimated using hysteresis analysis by plotting P/Z vs. Gp as shown in Figure 4.1.

For a volumetric natural gas reservoir, the hysteresis plot will yield a straight line correlation. By trending the data using a linear model, the OGIP is estimated by solving for the x-intercept. Using the trended equation from Figure 4.1 the OGIP is estimated to be 59.4 BCF. The operating company of this field has produced 52.0 BCF as of 2011 when the field was shut-in due to the loss of compression. The booked reserves or Estimated Ultimate Recovery (EUR) is 53.4 BCF. The remaining reserves for the field are 1.4 BCF and the total amount of native gas is approximately 7.4 BCF. The recovery factor for the reservoir is calculated by taking the EUR and dividing it by the OGIP. For this perspective storage field the recovery factor is 53.4 BCF / 59.0 BCF = 90.0%. The field shut-in pseudo-pressure is estimated using the trended equation from Figure 4.1 as illustrated below:

$$\frac{P_a}{Z}(psia) = -14.626 * x(BCF) + 868.53 \tag{9}$$

Using (9) the final shut-in pseudo pressure is estimated to be, $\frac{P_a}{Z} = -14.626 * 52\,BCF + 868.53 = 108\,psia$. The discovery pseudo-pressure is estimated using: $\frac{P_i}{Z} = -14.626 * 0\,BCF + 868.53 = 868.53\,psia$.

Once the maximum and minimum limits of the reservoir are calculated for pseudo-pressures and inventories, the next step is calculating the amount of cushion gas required for the storage prospect. As a general heuristic, the cushion gas requirement can be estimated by multiplying the OGIP by ~50%. Thus, the cushion gas requirement is estimated to be 29.7 BCF. This value can either be increased or decreased after surface facilities are considered. If additional capital is invested in surface facilities, then the cushion gas requirement is decreased; this will, however, increase the O&M costs of the facility. The working gas capacity can be estimated using the cushion gas requirement of

29.7 BCF. This is done by taking the OGIP and subtracting the cushion gas to equation 29.7 BCF. By using (9) the minimum storage reservoir pseudo-pressure is calculated to be $\frac{P}{Z} = -14.626 * 29.7\ BCF + 868.53 = 434\ psia.$

4.2. Assess the integrity of existing wellbores

The majority of the underground baseload storage facilities will be located in a depleted oil or gas reservoir. Within these fields, the storage reservoir engineer should consider the possibility of reusing existing wells to reduce the drilling and completion costs of the storage facility. The storage reservoir engineer will have three options for determining wellbore integrity within an existing reservoir, they are: 1) run caliper, 2) multifrequency electromagnetic thickness tools to evaluate for casing metal loss, and 3) temperature log. Running these tools require a workover rig and have been estimated to cost $100,000 per well for each of the existing wellbores in the prospective storage field. These vertical wells have been completed at an average depth of 2430 ft. Drilling a new deviated well from a pad has been estimated to cost $600,000 per new well. If large amounts of metal loss are observed after integrity tools are run, the well will need to be Plug and Abandoned (P&A) and a new well will need to be drilled adjacently. The estimated cost to P&A a well is $100,000 for this given area.

Analyzing if existing wellbores can be reused is a calculated risk; however, the rewards could yield considerable cost savings to the storage prospect. Consider the prospective field has 10 existing wells, if the wells are reused that would result in a capital savings of $700,000 per well ([$600,000 new well + $100,000 for P&A] per well). If all 10 wells are reused, that would translate into a capital savings of $7,000,000. The shortfall is that integrity tools will need to be run down each of the wells in order to verify if the wellbore can be reused. That will add \$100,000 per well. Assuming all wells can be reused after the integrity tools have been run, the overall capital savings results in \$600,000 per well ([\$600,000 + \$100,000 for P&A - \$100,000 for integrity tools] per well) or \$6,000,000. The danger of this approach is if large amounts of casing metal loss are observed, then the well will need to be P&A. The cost of drilling a new well will then increase from \$600,000 to \$800,000 per well. In order to estimate the total cost of these wells the following equation is used:

$$Cost_{Total} = Cost_{New\ Well} * \#_{New\ Wells} + Cost_{Integrity\ Tool} * \#_{Existing\ Wells} + Cost_{P\&A} * \#_{Failed\ Wells} \tag{10}$$

Based on the economics provided above, it is highly recommended that the operating company interested in this storage prospect run integrity tools to see if any of the existing wellbores can be reused. Each wellbore that can be reused will pay for six of the integrity tools required on the other wells. After running various scenarios, the potential cost savings calculated with (10) outweigh the risk of having to pay additional dollars to run the tools, P&A the wells, and drill new wells.

A robust strategy has been detailed above to assess if existing wells can be used for storage operations; alternative strategies can also be used to determine wellbore integrity. These alternative strategies should be employed if integrity tools are either not economically available for a given field, or if the downhole configuration is not capable of accommodating a tool; or if the storage prospect is in a Phase 2 (P2) or Phase 3 (P3) design. These criteria should be used with caution and if the storage field is commissioned, regular inventory tests should be conducted to verify no leaks are occurring. Alternative methods for evaluating wellbore integrity are:

1) Evaluating underground Cathodic Protection (CP) records (if applicable):

   a. If the prospective storage field had CP installed, check the historical rectifier reads, as a heuristic 1 amp of current is required to protect 1000 ft. of downhole casing. If the historical readings indicate less than 1 amp per 1000 ft., then corrosion can be assumed.

   b. If CP was never installed in the field it can be assumed the casing string could be corroding at a uniform rate. If CP has been installed in neighboring facilities or wells, it is likely the existing casing strong in the storage prospect have become the anode of an electrochemical reaction and have experienced aggressive corrosion. In this instance it would be recommended to consider P&A of all wells within the given field.

2) Evaluating DCA plots for a given well:

   a. DCA can be used by storage reservoir engineers to determine if there was an unexpected loss in production for a given well. A decrease in production can either indicate formation scale or a casing leak. Using DCA is difficult in determining leaks, however, a consistent curve will indicate minimum problems within the wellbore. With a consistent type curve it is possible to assume metal loss is minimal and the well can be reused with scheduled inventory tests.

3) Cement bond logs:

   a. Evaluation of cement bond logs can be used to determine if the wellbore was successfully electrochemically isolated from the surrounding formation. If the cement bond log appears to indicate a successful cement job, then the primary concern for wellbore integrity will be an internal corrosion mechanism. Internal corrosion will likely occur within the casing string if H_2O, H_2S, or liquids are present within the formation fluids being produced. If the well produced dry gas, then it can be assumed internal corrosion within the wellbore is minimal.

4) Age of the casing:

    a. Wells that were drilled historically have a greater probability of having integrity problems than wells drilled recently. This is because drilling practices have greatly improved over the years and the quality of the steel and coating manufacturing has improved. If casing used within a wellbore is over 30 years old, it is recommended an integrity tool be used to verify the condition of the steel or that the well should be P&A.

After considering all available information for the prospective storage reservoir, it was determined the field historically never had CP. Seven out of 10 of the wells within the reservoir were completed before 1950 and there were no cement bond logs taken during completion. After analyzing the type curves for each of the wells, no obvious deviations could be identified. However, there was not enough evidence to rule out the possibility of downhole integrity concerns. For this field it is recommended integrity tools be run to verify the wellbore integrity.

4.3. Determine storage facility deliverability rates

The most important thing in designing a new storage facility for a storage reservoir engineer is estimating the reservoir's deliverability rates throughout a heating season. This is considered to be one of the most difficult things to do as there are multiple assumptions that need to be made while interpreting historical operating data. Oftentimes these data sets do not have all of the necessary pieces of information such as line pressures, operating conditions, etc. In order for this to be complete, the storage reservoir engineer will use DCA for each of the known wells to determine individual well deliverability. After individual well deliverabilies are estimated, then the total field deliverability can be solved for by either summing all individual well deliverabilities or determining an average well deliverability for new prospective wells.

DCA is implemented by collected historical production data as a function of time. Generally, these historical data sets were captured by monthly production rates rather than daily production rates due to the lack of SCADA systems. The problem with monthly production rates is usually the number of days the well produced in a single month was not recorded. The only way to estimate the daily production rates is to assume the well produced every day in a given month. This can lead the storage reservoir to underestimate the deliverability in a storage reservoir, especially when the Initial Production (IP) rate is known. This is illustrated in Figure 4.2.

For a well that had a recorded IP of 18 MMCF/D, it is unlikely the trended IP rate using DCA analysis would be six times less. In order to compensate for the error, production data should only be considered when the reservoir has entered boundary dominated flow. For the actual transient response, the delivery can be estimated assuming exponential decline (b-factor = 0) using (5) for the time intervals that the well did not flow. The first data point that should be used is the IP recorded by the operating company. By using this methodology, the DCA plot is corrected to match expected deliverability decline curves, as shown in Figure 4.3. For this method to work it is imperative that initial production rates are available; if not, DCA should use the best data available. Please note that these results are functions of surface line pressure and surface facilities and these variables cannot be modified using this approach as they are unknown.

After completing all DCA for all available wells located in the reservoir, the data can be combined into a single plot. For the data set, the 10 DCA type curves are used, assuming exponential decline, and are plotted on a single graph for 30 – 50 years until all curves converge. Using the example data set, this occurs at 16000 days or 43.8 years. In order to get a represented decline curve for a new well completed in the reservoir at full inventory, all data points are averaged. For this data set, see the results in Figure 4.4. By using the results in Figure 4.4, the expected gas production rate for a new well drilled and completed into the storage reservoir is estimated to be 7,950 (MCFD).

The last step before decisions can be made on planning the location of storage facilities is deriving a correlation between the reservoir pseudo-pressures and the expected production rates. This can be estimated by plotting all available Pressure Divided by Gas Compressibility factor (P/Z) vs. production data available from the current field operator. Generally, these data sets will be scarce and interpolation will need to be used to better understand the data. From the provided data set there are seven wells that have some data points for both P/Z and rates. Some wells had multiple data points provided, others did not. For the purposes of this analysis, two outliers were neglected as they skewed the data set. The outliers have been marked as squares, all data points used in this analysis are rhombuses. The results of this analysis can be found in Figure 4.5. Using the results from Figure 4.5 the following correlation for pseudo-pressure vs rate was solved for and assuming a linear relationship. The equation is as follows:

$$\frac{P}{Z} = 0.065 * X(MCFD\ per\ well) + 252.46 \tag{11}$$

By using (11) in conjunction with the estimated initial production of a new well at full storage reservoir inventory, three different working gas cases can be evaluated for feasibility. This can be seen in Table 4.1.

4.4. <u>Recommendation of number of storage wells</u>

Table 4.1 summarizes the six different feasibility cases for the proposed storage field located in the Rocky Mountain region. For the purposes of this analysis, it was assumed that new wells would need to be drilled, three cases evaluated deliverability rates as a function of 1 to 1 infill drilling (16 wells) and the other three cases evaluate deliverability of 2 to 1 infill drilling (30 wells). As mentioned in section 4.2, the existing nine wells located at the facility could be reused depending on the integrity assessment of the wellbore. For the purposes of this analysis, it is assumed 1/3 of the existing wells can be reused.

Given the total size of the field and its geographical location, it is recommended that the storage facility should have 27 new wells drilled using 2-to-1 infill drilling for a total of 30 injection/withdrawal wells. In order to minimize surface impacts and required surface facilities, the wells will be drilled on six different pad locations using directional drilling technology. The wells should be completed as deviated wells, at a slight angle to maximize the reservoir cross sectional area. One additional observation well will be drilled at the known spill point located at the south end of the field. With 30 operating wells, it is estimated the maximum rate deliverability will be 284.3 MMCF/D at a pseudo-pressure of 868.5 psia. The minimum rate deliverability is estimated to be 83.8

MMCF/D at a pseudo-pressure of 434.1 psia. If field pressures fall below 434.1 psia, then it is projected that cushion gas will be produced from the reservoir. It is estimated it would take 119.1 days of continuous withdrawal to produce all available working gas. More details about the different design cases can be found in Appendix A.

4.5. Surface facilities for a new storage facility

Each prospective storage field will have different surface facility requirements depending on the scope of the project. For a typical storage facility, the following surface facilities are recommended upon converting a depleted hydrocarbon reservoir to storage:

1) Dehydration units, at minimum one per well pad;
2) Gathering pipeline system;
   a. Note that if existing gathering systems are converted to storage field service, they will need to meet all requirements as outlined in CFR 49 Part 192.
3) Metering facilities for storage injection and withdrawal;
4) Compressor(s).

Depending on incoming and storage gas quality, additional facilities may be deemed necessary in order to ensure pipeline quality gas can be delivered to storage customers at any given time of the year. These facilities are as follows:

1) Dew-point processing facility to lower CHDP of gas stream;
2) Nitrogen Rejection Unit (NRU) to lower nitrogen content;
3) Joule-Thomson (JT) Skids to lower CHDP of gas stream; can be used in conjunction with a dew-point processing facility;
4) H_2S processing facility to lower H_2S content.

4.5.1. Surface facility requirements for prospective storage facility

Before surface facilities specifications can be assessed, it is important for the storage reservoir engineer, along with a facilities engineer, to review the historical operating parameters of the depleted reservoir. Information such as gas composition/quality, historical flow rates, and historical pipeline gas specs can be used to determine what surface facilities will need to be present. Surface facility requirements can also be determined by looking at the different production fields around the storage prospect to determine if potential wet gas could be stored at the facility. If wet gas fields are present, gas processing plants located on transmission lines should be evaluated to see if these wet gas streams are processed upstream of the storage location.

For the prospective storage reservoir located in the Rocky Mountain region, historical data suggest the gas quality within the depleted reservoir was a dry gas with minimal water, low inert levels, and no H_2S present. Additionally, the historical records indicate a minimal amount of liquid hydrocarbons were produced, suggesting liquid loading problems were not present during its initial operation. From this information, it is deduced dehydration units and new metering facilities will be required. One dehydration unit will be located at each well pad, its design will allow it to process the maximum gas flow rate of the pad. There will be a total of six dehydration units required for this prospective storage facility. The metering facilities will be located at the beginning of the storage facility. There will be one injection metering facility and one withdrawal metering facility. They will be located at least five times the metering pipe diameter away from the connecting pipelines in order to ensure minimal metering errors.

In order to meet the market demand for injection and withdrawals in/out of the storage facility, compression will need to be installed. A small compressor was originally installed at the location to serve as a secondary recovery mechanism. However, due to a poor preventative scheduled maintenance the compressor was lost. It is proposed that a new 2-stage 10,000 Horse Power (hp) turbine be installed to serve for gas injection during the off-season and for a compressed withdrawal mode when more delta P is required late in the heating season.

The last consideration for the proposed storage facility is to determine if a dew-point plant, JT skid(s), nitrogen rejection unit, and/or an H_2S processing plant is needed. This is done by looking at the existing pipeline infrastructure in the area. The only transmission pipeline in the area has a large processing plant that removes possible hydrocarbon liquids (natural gas liquids) and dries out the gas stream. If all gas stored in the storage facility comes from upstream of this processing plant, then a dew-point plant or JT skid(s) will not be required. (Note: It is possible that a dew-point plant or JT skid(s) could be required if a new pipeline system is connected to the storage facility, bringing wet gas in from different locations.) Gas produced upstream of this process plant also has low inert levels and no traceable levels of H_2S. This indicates no nitrogen rejection unit and H_2S processing facility will be required.

4.6. <u>Assess transmission pipeline infrastructure</u>

Before a natural gas storage facility is constructed it is important for the proposed storage facility's operator to review the existing transmission pipeline infrastructure as well as future forecasts for hydrocarbon production. For the proposed natural gas facility located in the Rocky Mountain region, there is one 20" pipeline that has a MAOP of 788 psig. The only boost station for this pipeline is located more than 30 miles away. This pipeline has been fully subscribed by customers during the heating season. All gas transported on this pipeline is processed upstream of the prospective storage facility. No other pipelines exist in the area. During the off-season this pipeline capacity can be used to fill the storage field; however, there is currently no way to move ~300,000 Dth/D within this pipeline. For this storage facility to be successful, an additional transmission pipeline will need to be installed in order to bring the storage gas to market. It is estimated that 20 miles, 20” or greater pipeline with a MAOP of 1400 psig would need to be installed in order to connect the storage field to the market. This transmission line would be built, owned, and operated by the operator of the storage facility.

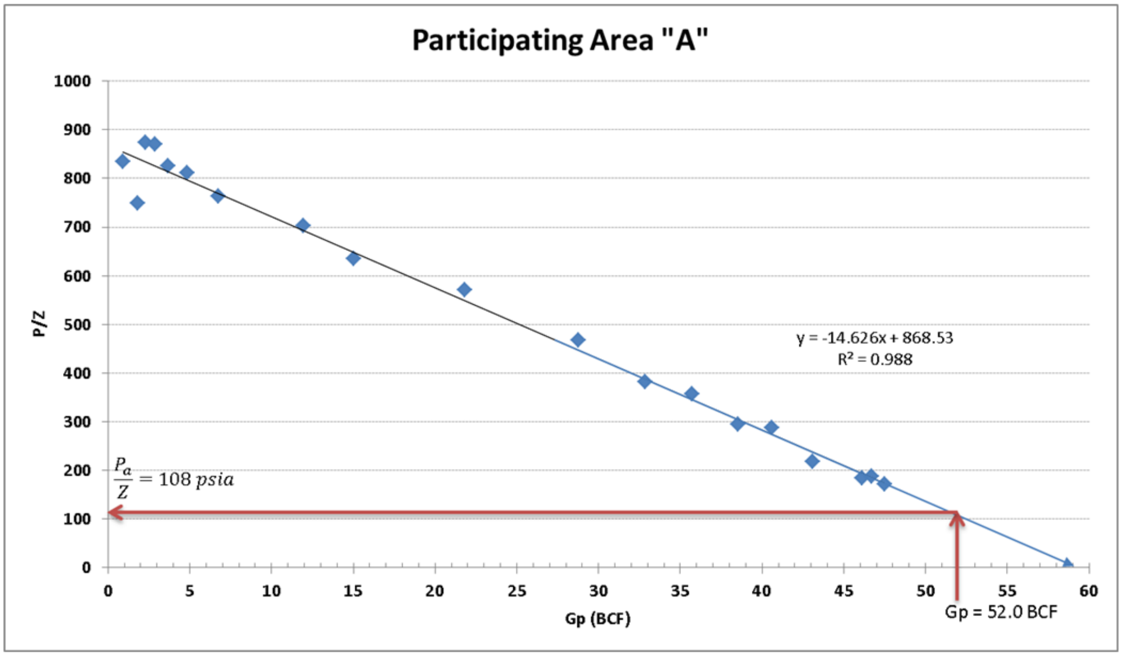

Figure 4.1: Participating area “A” P/Z vs. Gp hysteresis plot.

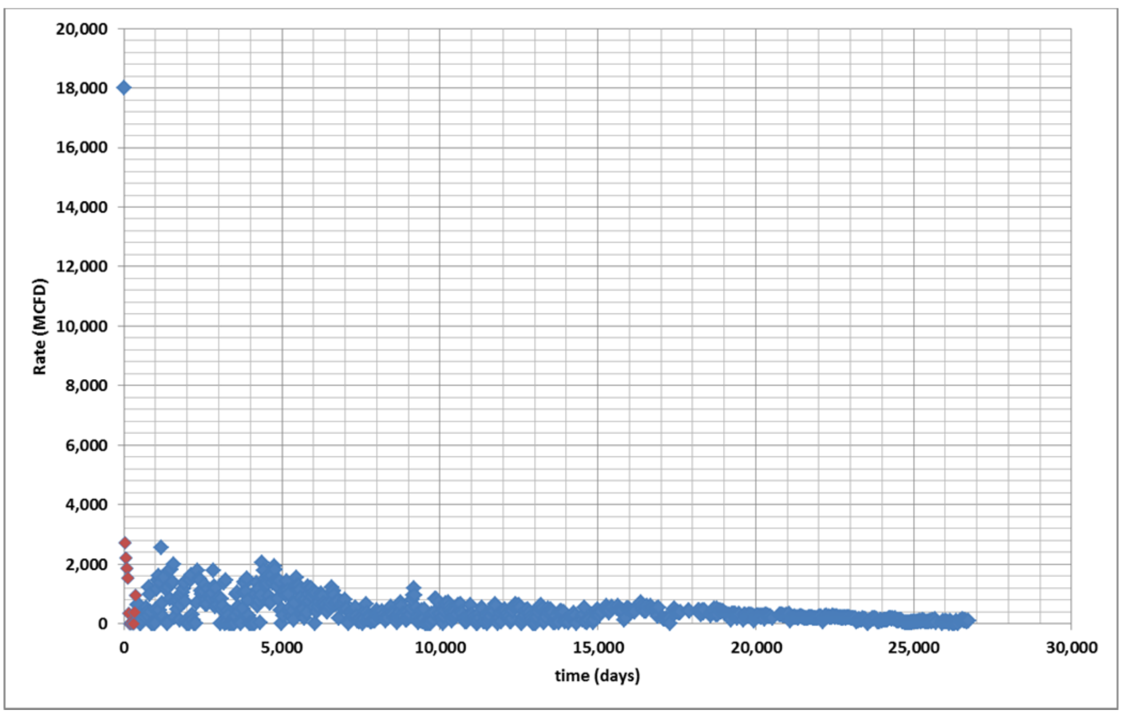

Figure 4.2: DCA with month data production error.

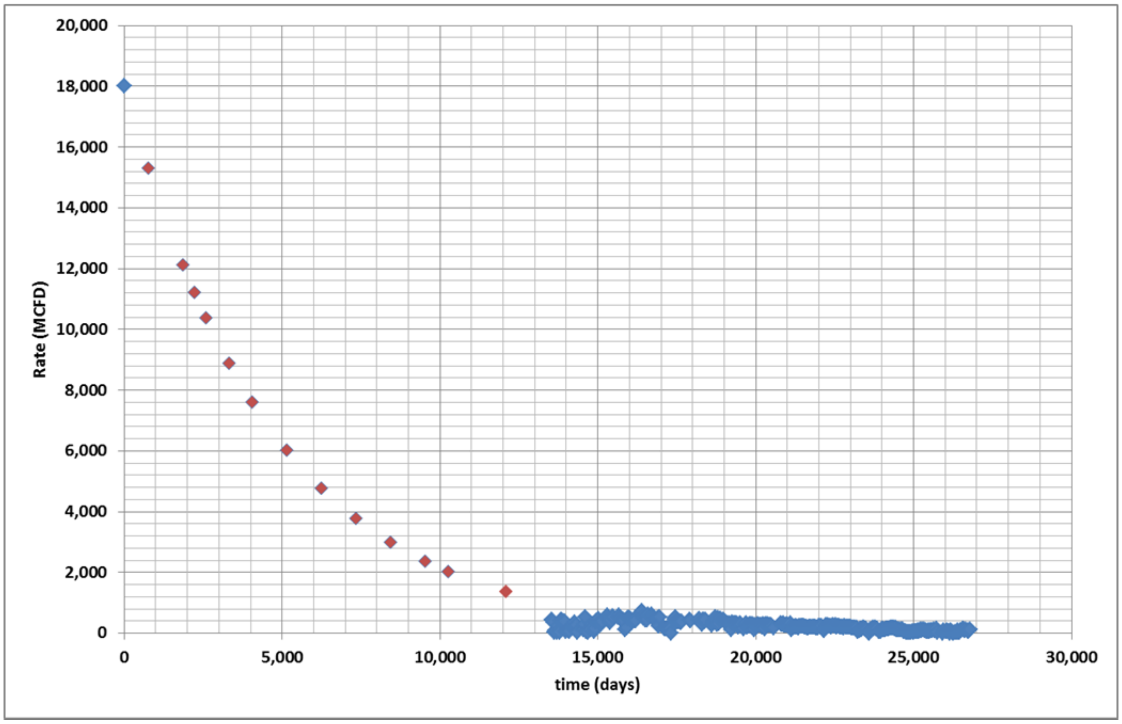

Figure 4.3: DCA assuming exponential decline (b-factor = 0). Red data points represent decline data using (5), whereas blue data points represent actual production data.

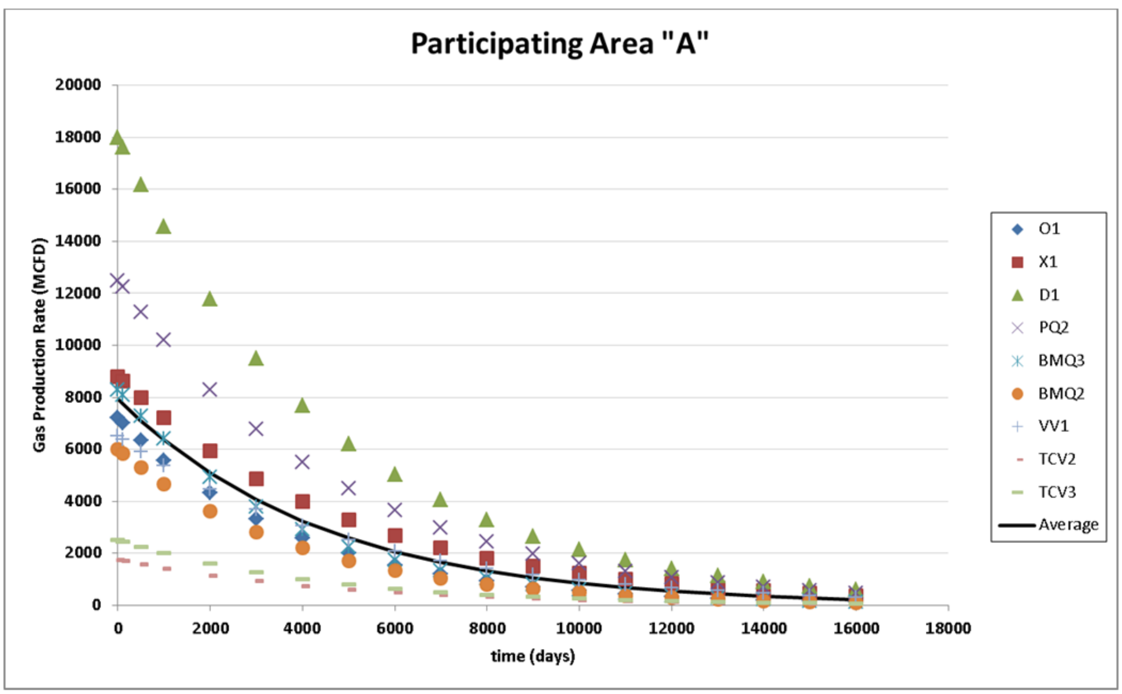

Figure 4.4: Combined DCA curves for participating area “A.”

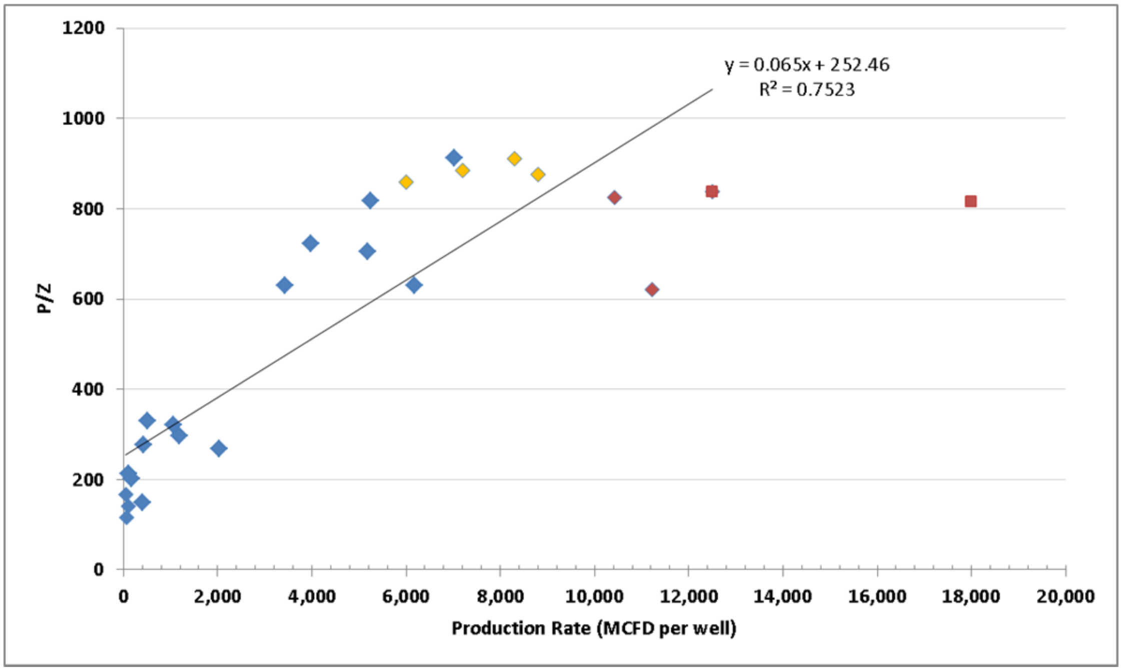

Figure 4.5: P/Z vs production rate to generate deliverability correlation.

Table 4.1: Participating area "A" field deliverability scenarios

OGIP		59,400,000	
EUR		53,400,000	
CUM (March-2011)		51,983,912	
2011 Remaining Reserves (MCF)		1,397,874	
Shut-in P/Z (estimate)	psi	109	
Injection Cushion Gas Volume[1]	MCF	22,283,912	
Native Cushion Gas Volume	MCF	7,416,088	
Total Cushion Gas	**MCF**	**29,700,000**	
P/Z with 20 Bcf Working Gas Added	P10	726.7	
P/Z with 25 Bcf Working Gas Added	P50	799.8	
P/Z with 29.7 Bcf Working Gas Added	P90	868.5	
Total Gas Required: CG + WG	**(MCF)**		
at 20 Bcf Working Gas	P10	49,700,000	
at 25 Bcf Working Gas	P50	54,700,000	
at 29.7 Bcf Working Gas	P90	59,400,000	
Estimated Well Rate (in Mcfd)			
Avg rate at P/Z of 400.0 psi	(min)	2,270	
Avg rate at P/Z of 726.7 psi	(P10)	7,295	
Avg rate at P/Z of 799.8 psi	(P50)	8,420	
Avg rate at P/Z of 868.5 psi	(P90)	9,478	
		1 to 1 infill[2]	**2 to 1 infill[3]**
Number of wells		16	30
Estimated Total Delivery Rate (Mcfd)			
Minimum deliverability (400 psi)		36,318	68,095
Max deliverability (726.7 psi/20 Bcf WG)	P10	116,726	218,861
Max deliverability (799.8 psi/25 Bcf WG)	P50	134,727	252,613
Max deliverability (868.5 psi/31 Bcf WG)	P90	151,648	284,340
Number of Withdrawal Days			
at 726.7 psi/20 Bcf Working Gas	P10	216.5	102
at 799.8 psi/25 Bcf Working Gas	P50	240.3	110.7
at 868.5 psi/29.7 Bcf Working Gas	P90	258.3	119.1

decline rate (D)[4] 0.00225322 MCFD/D

[1] Volume of gas required to increase P/Z from 115 to 400 psi

[2] 1 to 1 infill (16 wells)

[3] 2 to 1 infill (30 wells)

[4] based on average early decline rates of wells in Participating Area "A"

CHAPTER 5

STORAGE FACILITY ECONOMICS

The last step to a perspective underground baseload storage facility is running the economic parameters of the project to see if there is a market for the new facility. Economic factors to be considered are the cost of construction, capital administration costs, right-of-way easements, taxes (federal and state), operating and maintenance costs, price of cushion gas, cost of downhole integrity tools, cost of plug and abandonment, and the cost of drilling new wells. These costs will be functions of project location, materials logistics, and the required internal rate of return for the operating company. Due to confidentiality agreements the costs presented in Table 5.1 and Table 5.2 are representative of general estimates for the Rocky Mountain region and are not specific to this proposed project. The complete capital cost estimate can be found in Appendix B.

Three different feasibility cases were evaluated for the prospective storage facility using the capital and O&M cost estimates above. In order to determine if the project is feasible, the Internal Rate of Return (IRR) must be greater than 10% and the storage rate must be less than \$1.00/Dth. For the first scenario an IRR of 13% was used as a basis to calculate the storage rate, assuming a 15 year contract. For this scenario it is assumed the operator will inject all of the required cushion gas into the reservoir. The results of this scenario are provided in Table 5.3. After analysis the first scenario yields an annual rate greater than \$1.00 per Dth. Thus, at this time this project is deemed not economical with a required IRR of 13% for this scenario.

For the second scenario an IRR of 10% was used as a basis to calculate the storage rate, assuming a 15 year contract. For this scenario it is assumed the operator will inject all of the required cushion gas into the reservoir. The results of this scenario are provided in Table 5.4. The results of the second economic scenario are closer to the $1.00 per Dth threshold; however, the results indicate this project would result in costs too high for the market to bear. At this time this project is not deemed economical with the required IRR of 10% for this scenario.

For the third and final scenario an IRR of 13% was used as a basis to calculate the storage rate, assuming a 15 year contract. For this scenario it is assumed the storage customers will provide their own cushion gas, proportional to their working gas capacity. The operator will have 15 years to either purchase the cushion gas in place at market value or at the end of the storage contract the storage customer will have the right to withdrawal that cushion gas. The results of this scenario are provided in Table 5.5.

After analysis of all of the three different economic scenarios for the prospective storage facility it is recommended this project not be pursued further until the forward gas curves change. The storage facility is too expense to bear the consistent price of natural gas around $4 - $5 a Dth year round. This project should be economically revisited if the price of natural gas increases by over $1 a Dth and if the price of natural gas in the off-season becomes greater than the effective annual storage rates calculated in the above scenarios.

Table 5.1: Capital cost estimate for perspective storage facility.

Item	Description	Amount ($M)
1	New Pipeline Construction	$9,775.55
2	Pipeline Construction	$19,976.35
3	Right-of-Way	$154.00
4	Environmental (reports, approvals, permits, inspection)	$3,500.00
5	Metering and Regulation	$4,000.00
6	Compressor Station	$25,000.00
7	Well Costs	$18,105.00
8	Administrative Costs	$8,875.00
9	25% Contingency	$20,533.00
10	Dehydration Units	$1,620.00
11	Cushion Gas	$118,104.73
12	Total	$229,643.64

Table 5.2: Annual operation and maintenance cost estimate for the storage facility.

Item	Description	Amount ($M)
1	Pipeline O&M (20 miles of transmission pipeline)	$141.89
2	Compression (1x 10,000 hp unit)	$327.12
3	Metering and Regulation (2x facilities)	$40.00
4	Wells + Dehydration Units	$100.00
5	Total	$609.01

Table 5.3: Economic scenario #1, 13% IRR with operator owned cushion gas.

Line #		
1	**Scenario #1 ----Solve for Required Rate**	
2	Investment ($MM)	$111,538,902.40
3	Initial Cushion Gas Investment ($MM)	$118,104,733.60
4	Total Investment ($MM)	$229,643,636.00
5	Storage Capacity (Bcf)	29.7
6	Contract Term (Years)	15
7	**Economic Results**	
8		**Required Annual Rate**
9		$1.61 per Dth
10		
11	**Assumptions:**	
	UIRR: 13%	
	NPV: $0	
	Cushion Gas: 22.3 Bcf @ $5/Dth	
	Miles of Pipe: 20	
12	Compression HP: 10,000	
13	Interconnect O&M: $40,000/annually	
14	Additional Employees O&M: 4 @ $300,000	
15	Book Life: 27 yr.	
16	Tax Life: 15 yr.	
17	Combined Federal & State Tax 37.44%	
18	Other Taxes 1.0 %	
19	Working Capital 0.5%	
20	Cap Structure: 47%/53% Debt/Equity. Cost of debt 7.15%	

Table 5.4: Economic scenario #2, 10% IRR with operator owned cushion gas.

Line #		
1	**Scenario #2 ----Solve for Required Rate**	
2	Investment ($MM)	$111,538,902.40
3	Initial Cushion Gas Investment ($MM)	$118,104,733.60
4	Total Investment ($MM)	$229,643,636.00
5	Storage Capacity (Bcf)	29.7
6	Contract Term (Years)	15
7	**Economic Results**	
8		**Required Annual Rate**
9		$1.31 per Dth
10		
11	**Assumptions:**	
	UIRR: 10%	
	NPV: $0	
	Cushion Gas: 22.3 Bcf @ $5/Dth	
	Miles of Pipe: 20	
12	Compression HP: 10,000	
13	Interconnect O&M: $40,000/annually	
14	Additional Employees O&M: 4 @ $300,000	
15	Book Life: 27 yr.	
16	Tax Life: 15 yr.	
17	Combined Federal & State Tax 37.44%	
18	Other Taxes 1.0 %	
19	Working Capital 0.5%	
20	Cap Structure: 47%/53% Debt/Equity. Cost of debt 7.15%	

Table 5.5: Economic scenario #3, 13% IRR with customer owned cushion gas.

Line #		
1	**Scenario #3 ----Solve for Required Rate**	
2	Investment ($MM)	$111,538,902.40
3	Initial Cushion Gas Investment ($MM)	$0.00
4	Total Investment ($MM)	$111,538,902.40
5	Storage Capacity (Bcf)	29.7
6	Contract Term (Years)	15
7	**Economic Results**	
8		**Required Annual Rate**
9		$0.76 per Dth
10		
11	**Assumptions:**	
	UIRR: 13%	
	NPV: $0	
	Customer(s) provides Cushion Gas	
	Miles of Pipe: 20	
12	Compression HP: 10,000	
13	Interconnect O&M: $40,000/annually	
14	Additional Employees O&M: 4 @ $300,000	
15	Book Life: 27 yr.	
16	Tax Life: 15 yr.	
17	Combined Federal & State Tax 37.44%	
18	Other Taxes 1.0 %	
19	Working Capital 0.5%	
20	Cap Structure: 47%/53% Debt/Equity. Cost of debt 7.15%	

CHAPTER 6

CONCLUSIONS AND FUTURE RECOMMENDATIONS

Underground natural gas baseload storage facilities are a vital part of infrastructure for natural gas systems worldwide. These facilities are used to ensure adequate gas supplies for residential, commercial, educational, and industrial users and serve as a way for E&P and pipeline transmission companies to maximize assets year round. As populations grow and as market demands fluctuate, potential storage facilities will need to continue to be evaluated by professional geologists and storage reservoir engineers in the form of feasibility studies. If a storage prospect is deemed technically viable it is important that the operating company thoroughly explore the economics of the prospect before committing capital dollars.

6.1. Conclusion for prospective storage facility

For the prospective storage facility located in the Rocky Mountain region it is concluded the facility is technically viable. The location of the depleted dry natural gas reservoir is strategically situated by large interstate pipeline systems ensuring a wide selection of potential storage clients. For this underground reservoir it is estimated the OGIP was 59.4 BCF using hysteresis analysis. The cushion gas requirement was solved to be 50% of the OGIP or 29.7 BCF. There is currently 7.4 BCF of native gas present in the reservoir. The required injection cushion gas requirement is estimated at 22.3 BCF.

The maximum field deliverability was estimated to be 284.3 MCF/D at a reservoir pressure of 868.5 psia. The minimum field deliverability was estimated to be 83.8 MCF/D at a cushion gas pressure of 434.1 psia. Maximum and minimum deliverabilities assume 30 injection/withdrawal wells are present at six different well pads throughout Participating Area "A."

After analyzing three different economic scenarios for the prospective storage field, it was determined this project is not economically feasible under current market conditions. If the storage field operator chose to build this facility, supplying the cushion gas, the annual storage rate exceeds what the market can bear at $1.00 a Dth. If the operator chose to build this facility under the context that the storage customers would have to provide their own cushion gas, the annual storage rate is calculated to be below the $1.00 threshold. However, the barrier to market entrance is estimated to be too high for an average storage customer to want to bear. After reviewing all economic information available at this time, it is highly recommended this project should be economically revisited if 1) the price of natural gas increases by over $1 a Dth and 2) if the price of natural gas in the off-season becomes greater than the effective annual storage rates calculated in at this time.

6.2. Future recommendations for storage prospect

It is recommended the perspective operating company of the new storage facility in the Rocky Mountain region consider contracting a petroleum engineering/geology consultant to shoot 3D seismic over the field and create a 3D simulation of the underground reservoir. This simulation can be used by its storage reservoir engineers to further identify opportunities within this field and perhaps reduce the capital costs of this storage project by evaluating the possibilities of 1) using horizontal drilling to minimize the number of wells, 2) simulate storage well performance if vertical wells are hydraulically fractured, and/or 3) simulate if the prospective storage facility can be pressurized over the original discovery pressure. 3D simulation will also provide a greater window in helping storage reservoir engineers select new locations to drill new wells and location of observation wells while avoiding areas where faults may exist.

6.3. Thesis contributions to the scientific community

The content outlined in this thesis provides a quantitative approach in conducting a feasibility study for a proposed underground baseload storage facility in a depleted natural gas reservoir. By combining the results of decline curve analysis (assuming exponential decline) in conjunction with a depleted reservoir's hysteresis plot, yields a repeatable method to estimate critical storage reservoir parameters such as:

- Native cushion gas;
- Required injection cushion gas;
- Working gas;
- Original gas in place;
- Original native reservoir pressure;
- Individual decline curves for existing wells;
- Average decline curve for proposed wells drilled at maximum inventory.

After solving for critical storage reservoir parameters, this thesis provides a repeatable process for storage facilities design including a method of solving for the number of required wells, requirements for surface facilities, and a detailed cost estimate for the Rocky Mountain region. Due to this publication individuals will be able to analyze storage prospects worldwide to determine a project's technical and economic feasibility.

APPENDIX A

DELIVERABILITY SCENARIOS

Table A.1: Participating area "A" deliverability scenario 1.

MCF Working Gas				20,000,000
Scenario 1: 20 BCF working gas/726.7 psi, 16 wells				
Q (MCFD)	Days	P/Z	Cum (MCF)	Working Gas Remaining
116,726	**0**	**726.7**	**0**	**20,000,000**
114,125	10	716.1	1,154,253	18,845,747
111,582	20	705.8	2,282,788	17,717,212
109,096	30	695.7	3,386,180	16,613,820
106,665	40	685.8	4,464,988	15,535,012
104,289	50	676.1	5,519,760	14,480,240
101,965	60	666.7	6,551,031	13,448,969
99,694	70	657.5	7,559,325	12,440,675
97,472	80	648.4	8,545,154	11,454,846
95,301	90	639.6	9,509,019	10,490,981
93,177	100	631.0	10,451,408	9,548,592
91,101	110	622.6	11,372,801	8,627,199
89,072	120	614.3	12,273,665	7,726,335
87,087	130	606.3	13,154,457	6,845,543
85,147	140	598.4	14,015,626	5,984,374
83,250	150	590.7	14,857,607	5,142,393
81,395	160	583.1	15,680,828	4,319,172
79,581	170	575.8	16,485,708	3,514,292
77,808	180	568.6	17,272,656	2,727,344
76,075	190	561.5	18,042,069	1,957,931
74,380	200	554.6	18,794,340	1,205,660
72,722	210	547.9	19,529,850	470,150
71,663	216.5	543.6	20,000,000	(0)
71,102	220	541.3	20,248,953	(248,953)
	deltaP	185.3	psia	

Table A.2: Participating area "A" deliverability scenario 2.

MCF Working Gas				25,000,000
Scenario 2: 25 BCF working gas/799.8 psi, 16 wells				
Q	Days	P/Z	Cum	Working Gas Remaining
134,727	**0**	**799.8**	**0**	**25,000,000**
131,725	10	787.6	1,332,260	23,667,740
128,790	20	775.7	2,634,836	22,365,164
125,921	30	764.0	3,908,391	21,091,609
123,115	40	752.6	5,153,571	19,846,429
120,372	50	741.5	6,371,008	18,628,992
117,690	60	730.6	7,561,320	17,438,680
115,068	70	719.9	8,725,112	16,274,888
112,504	80	709.5	9,862,974	15,137,026
109,998	90	699.3	10,975,484	14,024,516
107,547	100	689.4	12,063,207	12,936,793
105,151	110	679.6	13,126,696	11,873,304
102,808	120	670.1	14,166,489	10,833,511
100,517	130	660.8	15,183,116	9,816,884
98,278	140	651.7	16,177,092	8,822,908
96,088	150	642.8	17,148,922	7,851,078
93,947	160	634.1	18,099,100	6,900,900
91,854	170	625.6	19,028,107	5,971,893
89,808	180	617.3	19,936,416	5,063,584
87,807	190	609.2	20,824,487	4,175,513
85,850	200	601.2	21,692,772	3,307,228
83,938	210	593.5	22,541,712	2,458,288
82,067	220	585.9	23,371,737	1,628,263
80,239	230	578.4	24,183,268	816,732
78,451	240	571.2	24,976,719	23,281
78,399	240.3	571.0	25,000,000	-
76,703	250	564.1	25,752,488	(752,488)
	deltaP	235.7	psia	

Table A.3: Participating area "A" deliverability scenario 3.

MCF Working Gas				29,700,000
Scenario 3: 29.7 BCF working gas/868.5 psi, 16 wells				
Q	Days	P/Z	Cum	Working Gas Remaining
151,648	**0**	**868.5**	**0**	**29,700,000**
148,269	10	854.8	1,499,586	28,200,414
144,966	20	841.4	2,965,761	26,734,239
141,736	30	828.3	4,399,270	25,300,730
138,578	40	815.4	5,800,839	23,899,161
135,490	50	802.9	7,171,181	22,528,819
132,472	60	790.6	8,510,992	21,189,008
129,520	70	778.6	9,820,951	19,879,049
126,634	80	766.9	11,101,724	18,598,276
123,813	90	755.5	12,353,961	17,346,039
121,054	100	744.2	13,578,298	16,121,702
118,357	110	733.3	14,775,356	14,924,644
115,720	120	722.6	15,945,744	13,754,256
113,142	130	712.1	17,090,055	12,609,945
110,621	140	701.9	18,208,871	11,491,129
108,156	150	691.8	19,302,759	10,397,241
105,747	160	682.1	20,372,275	9,327,725
103,391	170	672.5	21,417,962	8,282,038
101,087	180	663.1	22,440,351	7,259,649
98,835	190	654.0	23,439,960	6,260,040
96,633	200	645.0	24,417,298	5,282,702
94,480	210	636.3	25,372,861	4,327,139
92,375	220	627.7	26,307,134	3,392,866
90,317	230	619.4	27,220,591	2,479,409
88,304	240	611.2	28,113,695	1,586,305
86,337	250	603.2	28,986,902	713,098
84,730	258.3	596.7	29,700,000	-
84,413	260	595.4	29,840,638	(140,638)
	deltaP	273.1	psia	

Table A.4: Participating area “A” deliverability scenario 4.

MCF Working Gas				20,000,000
Scenario 4: 20 BCF working gas/726.7 psi, 30 wells				
Q	Days	P/Z	Cum	Working Gas Remaining
218,861	0	**726.7**	0	20,000,000
213,984	10	716.1	2,164,224	17,835,776
209,217	20	705.8	4,280,228	15,719,772
204,555	30	695.7	6,349,088	13,650,912
199,998	40	685.8	8,371,852	11,628,148
195,542	50	676.1	10,349,549	9,650,451
191,185	60	666.7	12,283,183	7,716,817
186,925	70	657.5	14,173,734	5,826,266
182,761	80	648.4	16,022,164	3,977,836
178,689	90	639.6	17,829,410	2,170,590
174,707	100	631.0	19,596,390	403,610
173,798	102	629.0	20,000,000	-
170,815	110	622.6	21,323,963	(1,323,963)
	deltaP	104.10		

Table A.5: Participating area “A” deliverability scenario 5.

MCF Working Gas				**25,000,000**
Scenario 5: 25 BCF working gas/799.8 psi, 30 wells				
Q	**Days**	**P/Z**	**Cum**	**Working Gas Remaining**
252,613	**0**	**799.8**	**0**	**25,000,000**
246,985	10	787.6	2,497,987	22,502,013
241,482	20	775.7	4,967,832	20,032,168
236,101	30	764.0	7,382,649	17,617,351
230,841	40	752.6	9,743,663	15,256,337
225,698	50	741.5	12,052,073	12,947,927
220,669	60	730.6	14,309,052	10,690,948
215,753	70	719.9	16,515,744	8,484,256
210,946	80	709.5	18,673,270	6,326,730
206,246	90	699.3	20,782,726	4,217,274
201,651	100	689.4	22,845,183	2,154,817
197,158	110	679.6	24,861,688	138,312
196,846	110.7	679.0	25,000,000	-
192,765	120	670.1	26,830,370	(1,830,370)
	deltaP	129.67		

Table A.6: Participating area “A” deliverability scenario 6.

MCF Working Gas				59,400,000
Scenario 6: 29.7 BCF working gas/686.5 psi, 30 wells				
Q	Days	P/Z	Cum	Working Gas Remaining
284,340	**0**	**868.5**	**0**	**59,400,000**
278,005	10	854.8	2,811,724	56,588,276
271,811	20	841.4	5,560,802	53,839,198
265,755	30	828.3	8,248,631	51,151,369
259,834	40	815.4	10,876,573	48,523,427
254,045	50	802.9	13,445,965	45,954,035
248,384	60	790.6	15,958,109	43,441,891
242,850	70	778.6	18,414,283	40,985,717
237,440	80	766.9	20,815,732	38,584,268
232,149	90	755.5	23,163,677	36,236,323
226,977	100	744.2	25,459,309	33,940,691
221,920	110	733.3	27,703,793	31,696,207
217,422	119.1	723.5	29,700,000	29,700,000
216,975	120	722.6	29,898,247	29,501,753
	deltaP	145.96		

APPENDIX B

CAPITAL COST ESTIMATE OF STORAGE FACILITY

Table B.1: Complete capital cost estimate of prospective storage facility.

Pipeline Milage, 90% BLM-10% Private 20

Item	Description	Qty	Unit	Unit Rate	Amount	Totals
	General Project Expenses					
1	Right-of-way ($ 0.01/sq ft fee, with 50 ft right-of-way), BLM Land	95,040	Lin. Ft.	$0.50	$48,000	
	Right-of-way ($ 0.20/sq ft fee, with 50 ft right-of-way), Private Land	10,560	Lin. Ft.	$10.00	$106,000	
2	Environmental (reports, approvals, permits, inspection)	1	Lump Sum	$3,500,000	$3,500,000	
	Subtotal					$3,654,000
	New Pipeline Construction					
3	**Pipe Costs**					
	8" low cost	0	Lin. Ft.	$14.00	$0	
	8" high cost	0	Lin. Ft.	$20.00	$0	
	12"- 4.5 mile lateral	23,760	Lin. Ft.	$48.94	$1,162,814	
	12" high cost	0	Lin. Ft.	$26.00	$0	
	16" low cost	0	Lin. Ft.	$28.00	$0	
	16" high cost	0	Lin. Ft.	$41.00	$0	
	20" low cost	105,600	Lin. Ft.	$81.56	$8,612,736	
	20" high cost	0	Lin. Ft.	$52.00	$0	
	24" low cost	0	Lin. Ft.	$42.00	$0	
	24" high cost	0	Lin. Ft.	$61.00	$0	
	30" low cost	0	Lin. Ft.	$52.00	$0	
	30" high cost	0	Lin. Ft.	$76.00	$0	
	36" low cost	0	Lin. Ft.	$63.00	$0	
	36" high cost	0	Lin. Ft.	$92.00	$0	
	Subtotal, pipe					$9,775,550
	Pipe Construction Costs					
	8" std installation	0	Lin. Ft.	$ 16.00	$0	
	8" difficult installation	0	Lin. Ft.	$ 30.00	$0	
	12" std installation	23,760	Lin. Ft.	$ 100.00	$2,376,000	
	12" difficult installation	0	Lin. Ft.	$ 45.00	$0	
	16" std installation	0	Lin. Ft.	$ 32.00	$0	
	16" difficult installation	0	Lin. Ft.	$ 60.00	$0	
	20" std installation	105,600	Lin. Ft.	$ 166.67	$17,600,352	
	20" difficult installation	0	Lin. Ft.	$ 75.00	$0	
	24" std installation	0	Lin. Ft.	$ 60.00	$0	
	24" difficult installation	0	Lin. Ft.	$ 100.00	$0	
	30" std installation	0	Lin. Ft.	$ 75.00	$0	
	30" difficult installation	0	Lin. Ft.	$ 125.00	$0	
	36" std installation	0	Lin. Ft.	$ 90.00	$0	
	36" difficult installation	0	Lin. Ft.	$ 150.00	$0	
	Subtotal,construction					$19,976,352
	Receipt and Delivery Points, metering and regulation					
4	Reciept/Delivery Meter (50 MMCFD)	0	Lump Sum	$625,000	$0	
	Reciept/Delivery Meter (100 MMCFD)	0	Lump Sum	$1,000,000	$0	
	Reciept/Delivery Meter (200 MMCFD)	0	Lump Sum	$1,800,000	$0	
	Reciept/Delivery Meter (300 MMCFD)	2	Lump Sum	$2,000,000	$4,000,000	
	Reciept/Delivery Meter (500 MMCFD)	0	Lump Sum	$2,200,000	$0	
	Other Taps	0	Lump Sum	$2,000,000	$0	
	Deduction Without Chromatograph	0	Lump Sum	-$225,000	$0	
	Subtotal					$4,000,000
	Compressor Stations					
5			ISO Hp		$0	
	Total compression ,Solar or Cat		Lump Sum		$25,000,000	
	Compressor,> 10,000 Hp		ISO Hp		$0	
	Subtotal					$25,000,000
	Well Costs					
6	Drilling & Completions Costs	27	wells	$600,000	$16,200,000	
	Abandonment Costs	6	wells	$100,000	$600,000	
	Integrity Tools	9	wells	$100,000	$900,000	
	Logging Costs	27	wells	$15,000	$405,000	
	Subtotal					$18,105,000
	Miscellaneous					
7	River Crossings, Road Bores, Rail Crossings	0	per foot	$600	$0	
	Rock Trench	0	per foot	$20	$0	
	Dehy's	6		$270,000	$1,620,000	
	Subtotal					$1,620,000
	Total					
	Total					$82,130,902
	Administrative Costs					
8	Construction overhead (10% Total cost)	10%	Total Cost	$82,130,902	$8,214,000	
	AFUDC (Interest for total over 12 months at 10% annual interest)	1	Lump Sum	$250,000	$250,000	
	Other clearing costs (garage, shop, camp, building)	0.5%	Total Cost	$82,130,902	$411,000	
	Subtotal					$8,875,000
	Contingency					
9	Contingency (25% Scoping)	25%	Total Cost	$82,130,902	$20,533,000	$20,533,000
	Total					
						$111,538,902
	Cushion Gas (Required)					
10	Cushion Gas required for Injection	23,620,946.72	per Dth	$5.00	$118,104,734	$118,104,734
	Grand Total					
	Grand Total					$229,643,636

REFERENCES

[1] Ikoku, C.U. “Storage of Natural Gas,” in *Natural Gas Reservoir Engineering*, 2nd edition, Krieger Publishing Company, September 1992, pp. 317 – 353.

[2] “Underground Natural Gas Working Storage Capacity.” Internet: http://www.eia.gov/naturalgas/storagecapacity/, [10/17/2014].

[3] “Underground Natural Gas Working Storage Capacity.” Internet: http://www.intragaz.com/en/storage_types.html, [10/17/2014].

[4] Walton, I. CH EN 6167, Topic: “Pressure Transient Analysis.” WEB 1460, Faculty of Chemical Engineering, University of Utah, Salt Lake City, Utah, Spring 2014.

[5] Hummel, J.M., 1969, “Anatomy of a gas field – Clay Basin Daggett County, Utah,” in Lindsay, J.B., editor, *Geologic Guidebook of the Uinta Mountains - Utah’s Maverick Range*: Intermountain Association of Geologists Sixteenth Annual Field Conference, p. 117- 126.

[6] “Geo-modelling Services.” Internet: http://uogc.com/geo-modelling/, [10/21/2014].

[7] “Clay Basin Cross section Map.” Internet: http://www.questarpipeline.com/html/2FrameCrossSectMaps.html, [10/17/2014].

[8] Morgan, C.D., 2005, Clay Basin Gas Field, Daggett County, Utah, Utah Geology Survey, Utah Geological Association, p. 337-346.

[9] Sorkhabi, R., CH EN 6163, Topic: “Petroleum Reservoirs.” WEB 1460, Faculty of Chemical Engineering, University of Utah, Salt Lake City, Utah, Fall 2013.

[10] Roberts, Laura N.R., 2003, “Structure Contour Map of the Top of the Dakota sandstone, Uinta-Piceance Province, Utah and Colorado,” U.S. Geological Survey, http://pubs.usgs.gov/dds/dds-069/dds-069-b/REPORTS/Chapter_16.pdf, p. 7.

[11] Stewart, W.W., 1979, “Clay Basin”, in Cardinal, D.F., and Stewart, W.W., editors, *Wyoming Oil and Gas Fields Symposium Greater Green River Basin*: Wyoming Geological Association, p.101-102.