

USE OF HYDRATES TO STORE NATURAL GAS

Ben Aseme

Adebusola Odunuga

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Abstract

Storage of Natural gas is needed and important in the oil and gas industry. There are existing methods of storing natural gas but the use of hydrates is one of increasing interest. Natural gas hydrates can be useful since some naturally occur in polar and deep oceanic regions. In this project, focus is placed on storing natural gas using hydrates formed using pressurized tanks. Natural gas hydrates were found to have lower capital cost than other methods used for storing natural gas currently in the industry as a result of absence in need for cushion gas. Cushion gas accounts for a sizeable amount of the fixed capital investment especially in other forms of natural gas storage systems. Salt caverns were shown to be profitable for short term storage but also showed relatively high activation costs.

Storing natural gas using hydrates is definitely an option that should be investigated given the resource value of natural gas.

Executive Summary

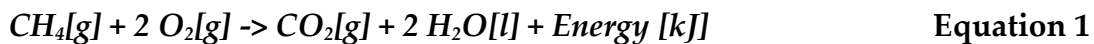
Gas Hydrates are practically clathrates of natural gas in which water solidify to form a crystal system. In this project, other methods used in storing natural gas were analyzed and compared to storing natural gas using hydrates. Hydrates can be naturally found in deep polar region where there is high pressure and low temperatures. The storage method using hydrates is observed through a pressurized tank. Total cost of natural storage using hydrates for capacity of 10^7 mmbtu is \$2.46/mmbtu. For the same capacity, the total capital investment is \$15.00/mmbtu and the return on investment is 0.65 which increases as the capacity of the storage tank increases. Natural gas hydrates have lower total capital investment than the other three methods of storage studied (Depleted Reservoir, Aquifer, and salt caverns). Hydrates of natural gas can be very useful for peak shaving. Suppliers can make tank readily accessible to consumers when needed, which will reduce the strain on resources when natural gas in high demand.

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Introduction

The fossil fuel natural gas is a mixture of the hydrocarbon gases methane (70-90%), ethane, propane, butane (0-20%), carbon dioxide (0-8%), oxygen (0-0.2%), nitrogen (0-5%), hydrogen sulfide (0-5%) and rare gases (trace). Natural gas is a resource primarily because it releases substantial energy when combusted or burned (approx. 1000 Btu/cubic ft). Natural gas is composed primarily of methane and its combustion equation is given below as:



Compared to all other fossil fuels, natural gas combustion produces less environmentally-harmful materials per volume of energy released making it the cleanest burning fossil fuel. The released energy is used residentially, commercially and industrially for heating or power generation purposes. Natural gas currently satisfies 24% of total energy consumption in the United States with a projected annual growth of 1% over the next 20 years. These important characteristics of natural gas make it a valuable energy resource now and for the future.

Natural Gas Storage

Traditionally, the demand for natural gas has been highly seasonal. In colder climates, the winter months demand more natural gas supplies for heating purposes while warmer climates might demand more natural gas supplies during the hot summer months for air cooling requirements. These periods of seasonal high demand are referred to as *base* periods. Periods of daily or weekly high demand are referred to as *peak* periods and can vary as much +/- 20% from the average consumption rates. The resource value, unsteady pattern of natural gas demand and the fact that most primary gas producers and primary gas consumers are not in proximity warrant storage system(s) that will guarantee consumers natural gas supply by reserving excess natural gas during the low demand periods for supply during the high demand periods.

Business Plan

An analysis is conducted to compare 3 existing methods of storing natural gas. They are listed below together with our proposed method.

- ❖ *Depleted gas reservoirs*
- ❖ *Salt caverns*
- ❖ *Aquifers*
- ❖ *Natural gas hydrates (Proposed)*

In each of the main storage methods, natural gas is stored in large reservoirs underground. Natural gas is injected into the underground reservoir or formation at pressures exceeding the natural pressure of the gas. Gas is extracted for delivery using the reservoir-to-wellhead gas pressure differential through standard gas wells. To attain and maintain this pressure differential, the reservoir pressure must be above the gas wellhead pressure. Hence a certain amount of gas (*base* or *cushion* gas) must remain in the reservoir to provide the needed pressure differential. The gas withdrawn during delivery cycles is called the *working* gas. It can then be deduced that withdrawal rates are highest when the withdrawal cycle begins and decrease as the working gas amount reduces.

A comprehensive study of the cost factors associated with each storage method is needed so as to make appropriate comparisons between our proposed method and the known methods of natural gas storage. Listed below are cost factor components of typical gas storage facilities:

- ❖ Injection wells/Withdrawal wells

- ❖ Compressors

- ❖ Gathering system

- ❖ Valves

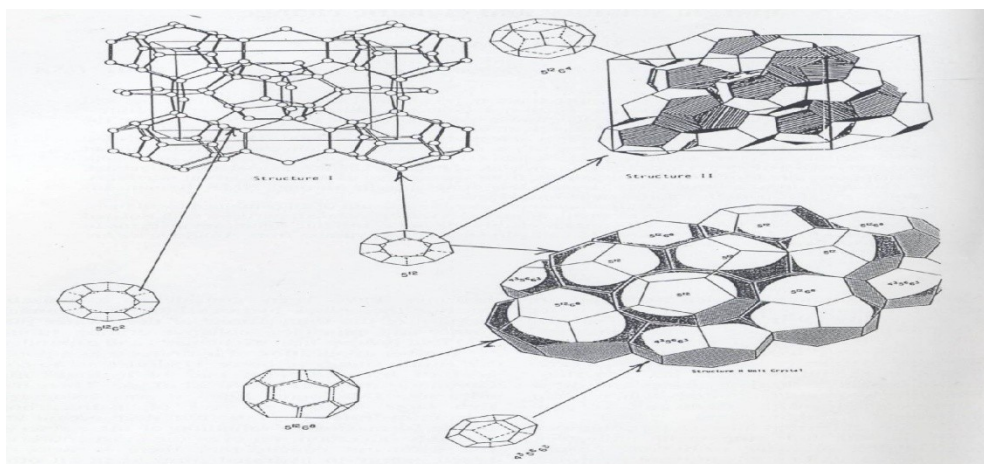
- ❖ Pumps
- ❖ Gas flow meters
- ❖ Dehydrators
- ❖ Separators
- ❖ Cushion gas
- ❖ Power (Electricity)
- ❖ Land
- ❖ Labor
- ❖ Equipment Installation/Setup
- ❖ Property Taxes/Insurance

Most of these cost factors apply to all storage methods although minimal changes might apply depending on the storage method. These factors will be developed and explained for the depleted gas reservoir gas storage method and applied to the other storage methods. Necessary cost factor changes will be made wherever they may apply.

Natural Gas Hydrates

Gas hydrates are naturally occurring solids composed of water molecules forming a rigid lattice of cage with most of the cages each containing a molecule of natural gas. Gas hydrates naturally occur both at very low temperatures and high pressure regimes in Deep Ocean.

Hydrates form in three repeating crystal structures; Structure I, Structure II, and Structure H. Structure I, is a body-centered cubic structure form with small natural gas molecules found in Deep Ocean. Structure II is a diamond lattice within a cubic framework, forms when natural gases or oils contain molecules which commonly occur in production and processing conditions. The newest form of hydrates just Structure H is an hexagonal structure that has cavities that have large enough to contain molecules size of common components of naphtha and gasoline.



FFig 1. Structure of Gas Hydrates (Henriet & Mienert 1998)

The geometry of structure is represented by the kind of cages they have. Crystal structures depend on the kind of lattice which contains natural gas. In this case, methane is the only natural gas to be considered. Table 1 shows the breakdown of each crystal structure according to their type.

Hydrate crystal structure	I		II		H		
	Small	Large	Small	Large	Small	Medium	Large
Cavity	5 ¹²	5 ¹² 6 ²	5 ¹²	5 ¹² 6 ⁴	5 ¹²	4 ³ 5 ⁶ 6 ³	5 ¹² 6 ⁸
Description	5 ¹²	5 ¹² 6 ²	5 ¹²	5 ¹² 6 ⁴	5 ¹²	4 ³ 5 ⁶ 6 ³	5 ¹² 6 ⁸
Number of cavities/unit cell	2	6	16	8	3	2	1
Average cavity radius (Å)	3.95	4.33	3.91	4.73	3.91	4.06	5.71
Variation in radius* (%)	3.4	14.4	5.5	1.73	Not Available		
Coordination number	20	24	20	28	20	20	36
Number of waters molecules/ unit cell		46		136		34	

Table 1: Hydrate Crystal Structure (Henriet & Mienert, 1998)

5¹² represent a crystal structure that has 12 faces with five sides per face. Methane gas forms Structure I crystal structure in which calculations are based on. The temperature and pressure at which hydrates can exist must fall under certain limits. Fig 2 shows the boundaries at which they must occur. In this project, Pressure at 6MPa and temperature of 20 °C were chosen since it falls within boundary needed for stable hydrate.

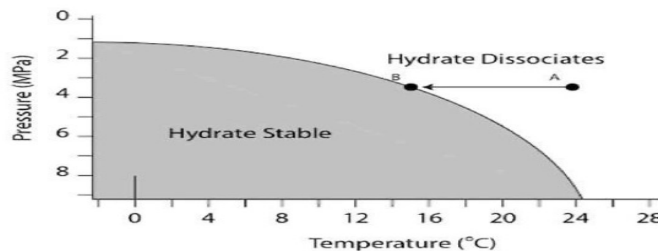


Fig 2: Boundaries of Temperature and Pressure

Storage Method of Hydrates

There are several advantages associated with storing natural gas using hydrates.

Hydrates can be used for economic storage of natural gas in cold countries and the cost associated can be relatively minimized. The use of natural gas hydrates for storage is also an alternative that maintains a high degree of safety. When a large volume of natural gas is ignited, explosions occur but with natural gas, the effect is drastically reduced due to water molecules present.

There are two ways of evaluating the cost of using hydrates. Fig 3 shows two options.

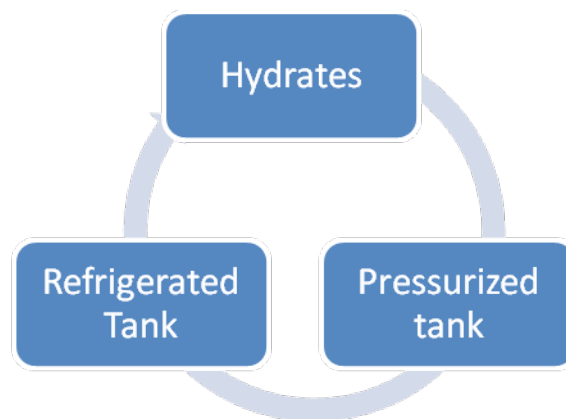


Fig 3: Possible options for evaluating gas hydrates

Drilling to conditions where the formation of hydrates is favorable can be expensive and time consuming. Also the geological formation of such topography must be monitored to ensure that natural gas can be stored with escape. Another method is to create a pressurized tank that would simulate the same conditions (Low temperature and High pressure). This method would enable engineers monitor the amount of gas stored and would create easy accessibility when needed. An Hydrate tank can also be created by using a refrigeration system, therefore keeping hydrate at temperature needed and also maintaining an average pressure. Below is the PFD for hydrates design

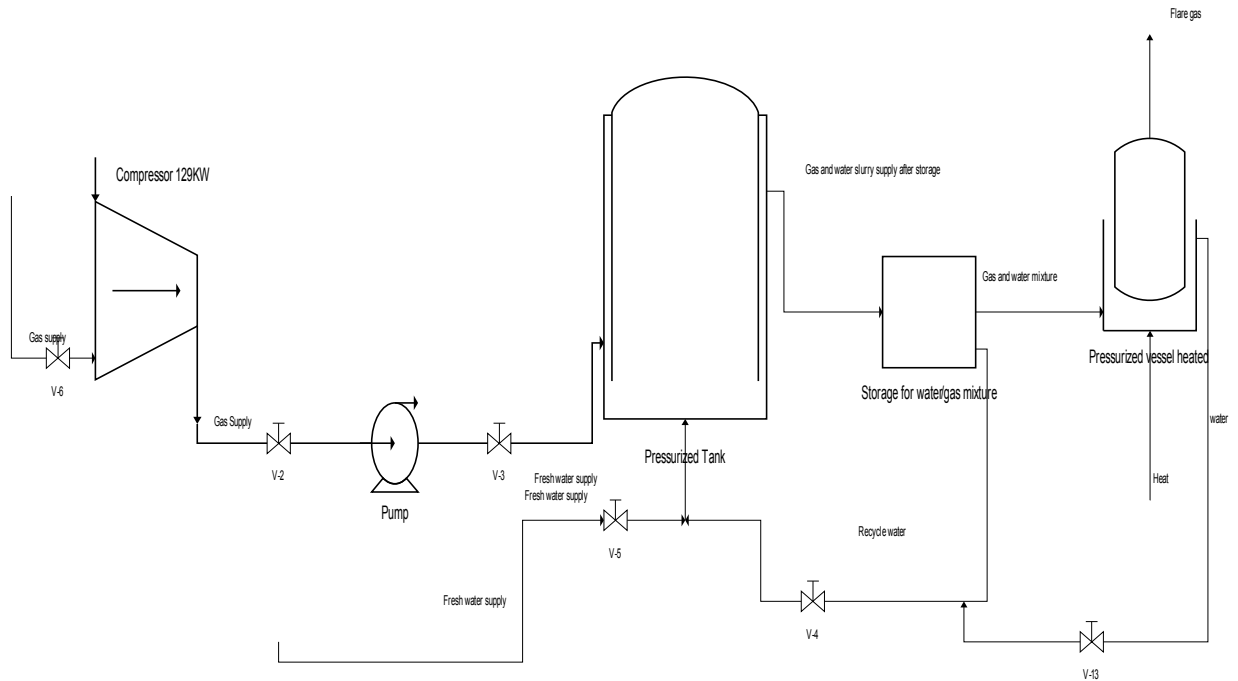


Fig 4: PFD of storage systems using Hydrates

The cost of this storage method was based on the amount of natural gas to be stored and the size of each hydrate. The rate of hydrate formation must be evaluated. This was done using the equation below (Mannel, 2008)

$$R = 4\pi K^* \mu_2 (f - f_{eq})$$

Where R is the rate of hydrate formation, μ_2 is the second moment of distribution around particle size for hydrate; f is the fugacity of gas, f_{eq} is the fugacity of gas at equilibrium, and K^* is the kinetic parameter. The chosen parameter for pressure and temperature is 6MPa and 273k. Using this parameters and the CNGA equation of state, compressibility is calculated

$$Z = \frac{1}{1 + \frac{344400P^{1.7855}G}{T^{3.825}}}$$

Where z is the compressibility, SG is specific gravity of gas, P is pressure in psig, and T is temperature in °R. In estimating the volume of the reactor, the equation below is used,

$$V = \frac{Q}{R}$$

Where V is the volume of the reactor, Q is the gas flow rate in the reactor, R is the rate of hydrate formation. When the capacity of the reactor tank is achieved, the cost can be estimated using (Timmerhaus, 5th Edition). This estimation is based on the cost of tank

with insulation and a stirrer. Other cost associated with using hydrates for natural gas includes equipment cost, cost of installation, and fees associated with storage.

For re-gasification, the tank is depressurized and heat is applied to the tank. Below is a PFD diagram illustrating the design.

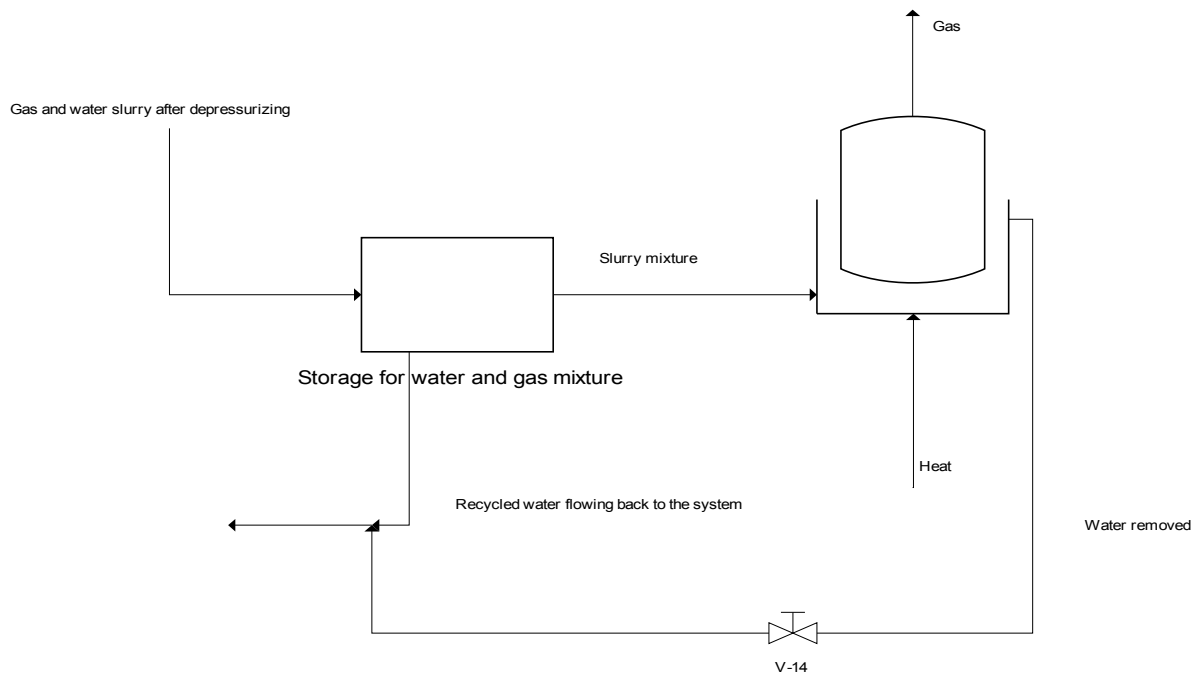


Fig 5: PFD showing gas recovery method

Depleted gas reservoirs

Depleted gas reservoirs are natural gas reservoirs that have been sapped of all recoverable natural gas. This results in an underground geological formation that is capable of holding or reserving natural gas. Storing natural gas using depleted

reservoirs is the most common gas storage method. This partly due to the fact that most of the infrastructure already exist thereby minimizing activation costs and time.

Injection/Withdrawal wells

Gas wells are used to transfer gas into and out of a gas storage reservoir. Combination injection/withdrawal wells are most common because of their reduced cost but this depends on the reservoir characteristics (H₂O influx, gas bubble shape, etc). These wells are usually much larger in diameter than normal gas producing wells to allow increased gas deliverability. For this study, we assumed worst case scenario and chose to use separate gas injection and withdrawal wells. We opted to use schedule 40 medium grade steel with nominal diameter of 0.5 inches as our well casing and tubing material. The well casing had an inner diameter of 12.625 inches and outer diameter of 15 inches while the well tubing had an inner diameter of 12 inches and an outer diameter of 0.624 inches. The well casing material weighed approximately 9.3 lbs per foot length and the well tubing material weighed approximately 2.4 lbs per foot length. The average depth of natural gas reservoirs is 5500 feet which gives a total of 51,150 lbs and 13,200 lbs of medium grade steel for the well casing and tubing respectively. Current prices for medium grade steel are about 1,000 dollars per lb. The resulting total

cost for well casing material is 153 million dollars and 39 million dollars for well tubing material.

Depleted gas reservoirs have the largest holding capacity of all gas storage methods therefore requiring a slightly higher number of injection and/or withdrawal wells. A minimum of 2 injection wells and 1 withdrawal well would suffice bringing the total well material cost to 193 million dollars. The calculated cost is for replacing the well materials after years of disuse for a reservoir with this maximum capacity.

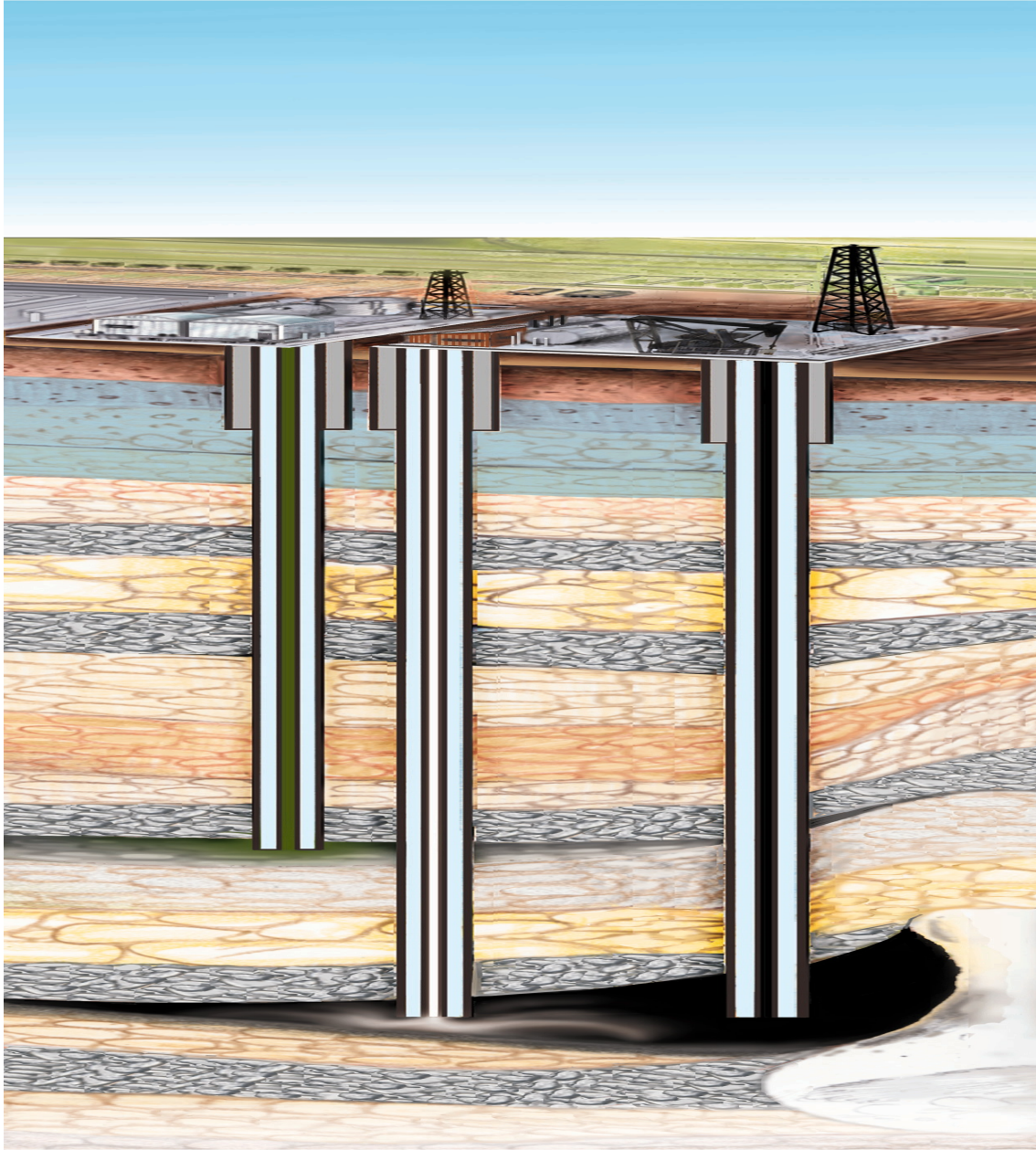


Fig 6: Diagram showing an observation, withdrawal and injection well (<http://www.princeton.edu/~hotinski/Resources>, 2006)

Compressors

Compressors increase the flow rate of a fluid by decreasing its volume.

Compressors are needed to provide the needed injection horsepower to fill the gas reservoir. Compressor discharge pressures vary greatly between the beginning and end of the injection process. Centrifugal compressors are not designed to sustain such varying ranges thus reciprocating – type compressors were used in this case.

Calculating the compressor cost required an estimate of the theoretical injection horsepower which was calculated using the equation:

$$HP = Q \times T_1 \times Z_1 \times \left[\frac{k}{k-1} \right] \times \left[\left(\frac{P_2}{P_1} \right)^{\frac{k-1}{k}} - 1 \right] \quad \text{Equation 2}$$

HP = Theoretical Horsepower

Q =flow rate in Million Standard ft³ per day

P_1 =Suction-side pressure in psia

P_2 =Discharge-side pressure in psia

T_1 =Suction-side temperature in degrees Kelvin

Z_1 =compressibility factor

k =ratio of natural gas specific heats

It will take about 180 days to inject a depleted gas reservoir to half its maximum volume which in this case is 10 BCF (billion cubic feet). Since depleted reservoirs require about half the

maximum storage volume to be used as cushion gas, the gas injection flow rate (Q) is approximately 28 million standard cubic feet per day. The compressor is operating under standard conditions therefore the suction-side gas temperature (T_1) and pressure (P_1) are 288 Kelvin (15 °C) and 14.7 psia (1 atm) respectively. The discharge-side pressure (P_2) is equivalent to the maximum reservoir pressure which is approximately 550 psia (37.4 atm) for a total gas volume of 10 BCF. The compressibility factor (Z_1) for natural gas is given by the equation:

$$Z_1 = \frac{P_1 V_m}{R T_1} \quad \text{Equation 3}$$

V_m = molar volume

R = gas constant

The molar volume used in this calculation was 22.5 (liters/mole) and the gas constant was 0.082 (liters*atm/Kelvin*mol). Substituting values into equation 3 gives a compressibility factor of 0.95. The ratio of specific heats (k) is given by the equation:

$$k = \frac{C_p}{C_v} \quad \text{Equation 4}$$

C_p = Gas specific heat capacity at constant pressure

C_v = Gas specific heat capacity at constant volume

The specific heat capacity of natural gas at constant pressure is 0.56 Btu/lb_m°F and 0.44 Btu/lb_m°F at constant volume. The ratio of specific heats (k) has a calculated value of

1.27. From equation 2, the compressor requires about 41,500 horsepower theoretically. It has been noticed that compressors lose ideal functionality after weeks of operation because gas properties may vary from the compressor design basis. It is therefore advisable to multiply the theoretical horsepower by a de-rating factor when sizing the compressor. A de-rating value of 0.95 is reasonable in obtaining the actual compressor horsepower. Our compressor thus requires about 39,400 horsepower actually. The calculated compressor cost is about 39,000,000 dollars. This depleted gas reservoir needs two compressors for the two injection wells which gives a total compressor cost of 79 million dollars for maximum capacity.

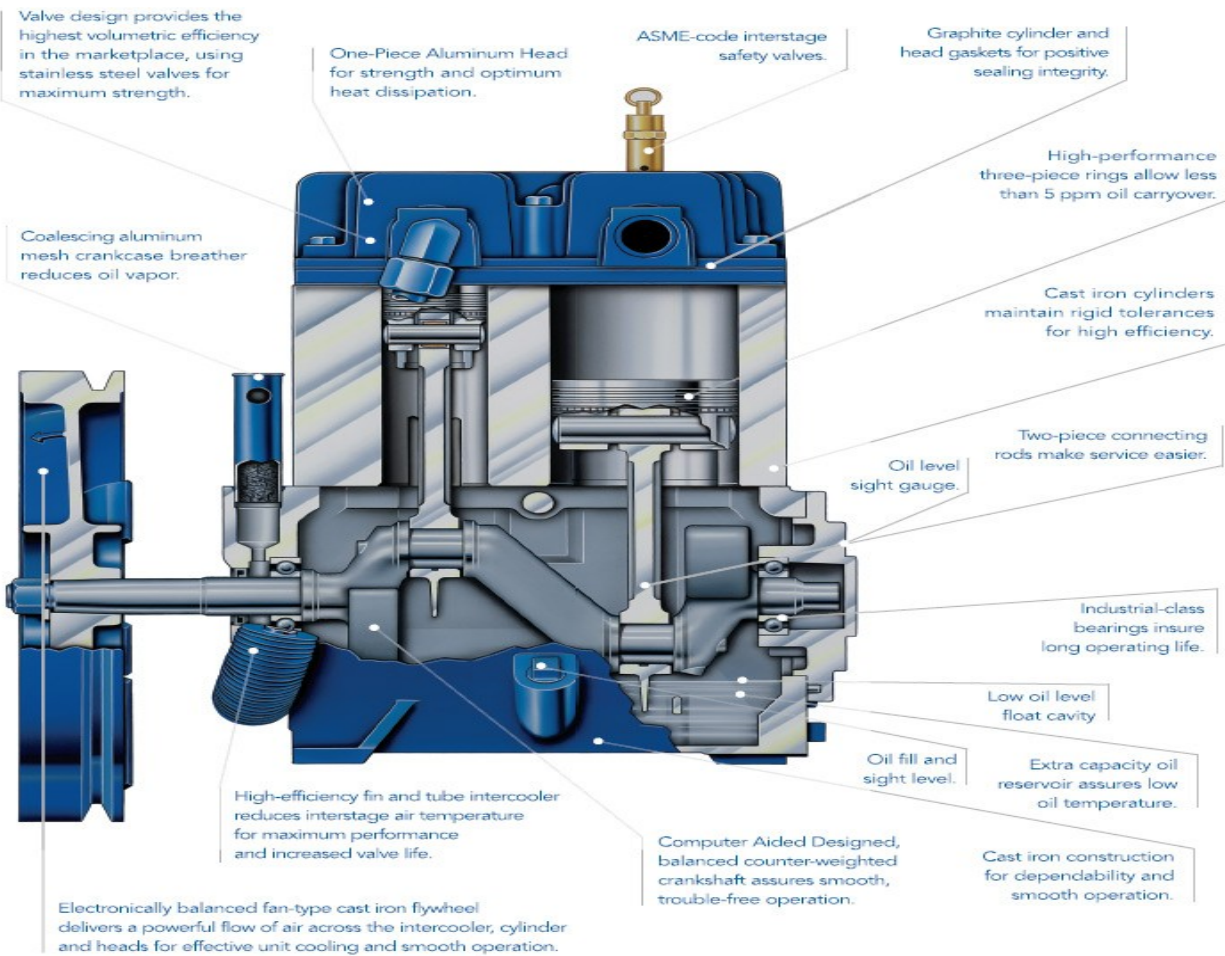


Fig 7: Reciprocating compressor (<http://images.google.com>, 2008)

Gathering system

The gathering system is a network of pipes that connect the gas reservoir wells to central gas collection points. These ½ inch nominal diameter, schedule 40, medium grade carbon steel pipes have larger diameters than those of producing gas field wells to accommodate the increased volumes from the large-bore gas reservoir wells. The thickness and internal diameter of this gathering system's pipe were 1 and 15 inches respectively. Pipe lengths of approximately 400 meters (1312 feet) are reasonable and

were used in this case. The calculated weight for this pipe material is 10 lbs/ft which gives a total pipe weight of 13,000 lbs. At an average cost of 1,000 dollars per lb, it would cost approximately 13 million dollars maximum to setup our gas gathering system.



Fig 8: Gas gathering system (www.ogf.com/Articles/Article_Display.cfm?Art, 2005)

Valves

Valves control fluid flow by fully or partially closing or opening. Valves are important in controlling the flow pattern of gas into and out of the gas storage reservoir. Stainless steel self-contained control valves ($\frac{1}{2}$ inch nominal diameter) that can withstand the maximum reservoir pressure of 550 psia were used in this case. The calculated cost for purchasing our valves came up to 13 million dollars. This cost varied

with the capacity of the reservoir and the corresponding nominal diameter (which depended on the gathering system pipe size) using java programming techniques.



Fig 9: Sample self-controlled gas valve (<http://www.globalspec.com>, 2000)

Pumps

Pumps are used to transfer fluids between locations. Associated pump costs were calculated using the gas withdrawal capacities of the pumps. The working gas withdrawal rate for the average depleted reservoir is 120 days. Dividing half the total gas volume (5 BCF) by the withdrawal period gives a gas flow rate of 41.7 million standard cubic feet per day. This is equivalent to 13.7 cubic meters (3615 gallons) per second. The calculated cost of a withdrawal well pump with this capacity is approximately 420, 000 dollars.

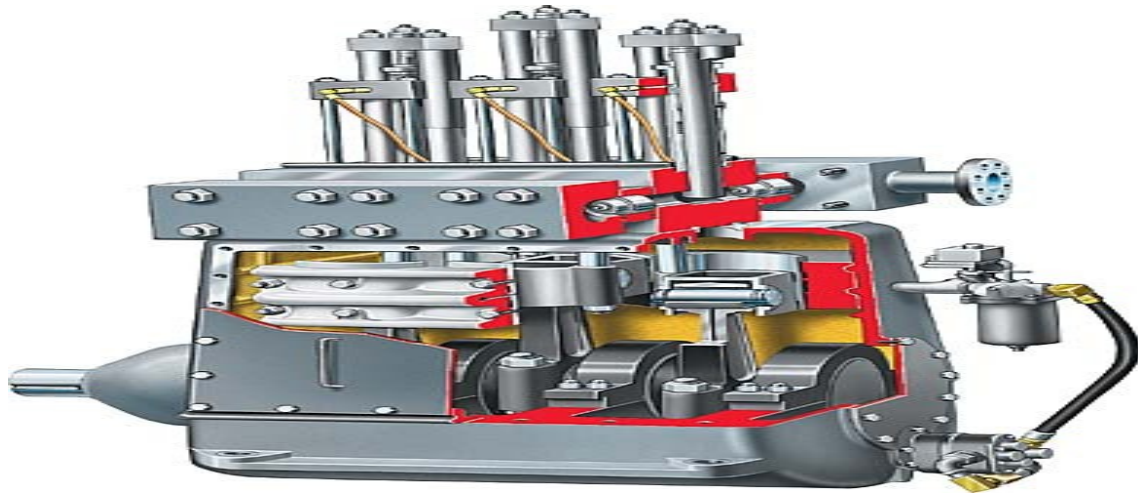


Fig 10: Vertical reciprocating pump (<http://images.google.com>, 2008)

Gas flow meters

These are devices used to maintain accurate gas injection and withdrawal inventory control by measuring the flow or quantity of the moving gas. Gas flow meters are an important component in a natural gas storage facility because inaccurate gas flow measuring techniques could imply significant financial losses. After extensive research, we opted to use the *GE panametric ultrasonic GM868* ultrasonic gas flow meter for our storage facilities. The versatility, accuracy and space saving design of this gas flow meter make practical sense. This flow meter costs about 5,000 dollars. This price does not vary with the capacity of the reservoir because it comes in a one-size-fits-all model.



Fig 11: GE panametric ultrasonic GM868 ultrasonic gas flow meter (<http://cgi.ebay.com>, 2009)

Dehydrators

Most storage facilities possess a certain amount of water within their geological formations. This residual liquid evaporates into the injected gas and upon withdrawal, can decrease the pipeline quality of the gas and cause pipeline freezing if the gas is not dehydrated. These dehydrators are located at the central collection point and basic glycol units. Glycol units are used because of their cost-cutting potential and satisfactory performance. A glycol unit works by pulling the 'wet' natural gas through the bottom of an absorber containing glycol. As the 'wet' gas penetrates upward, it

releases its water into the glycol solution and dry gas is obtained at the top of the absorber. When saturated with water, the glycol solution is pumped through a reboiler or regenerator which boils the glycol-water mixture and separates the glycol from the water. After separation, the glycol can be returned to the absorber to contact and dehydrate additional wet gas. The associated cost was about 12,500 dollars and it was also constant for varying reservoir capacities.

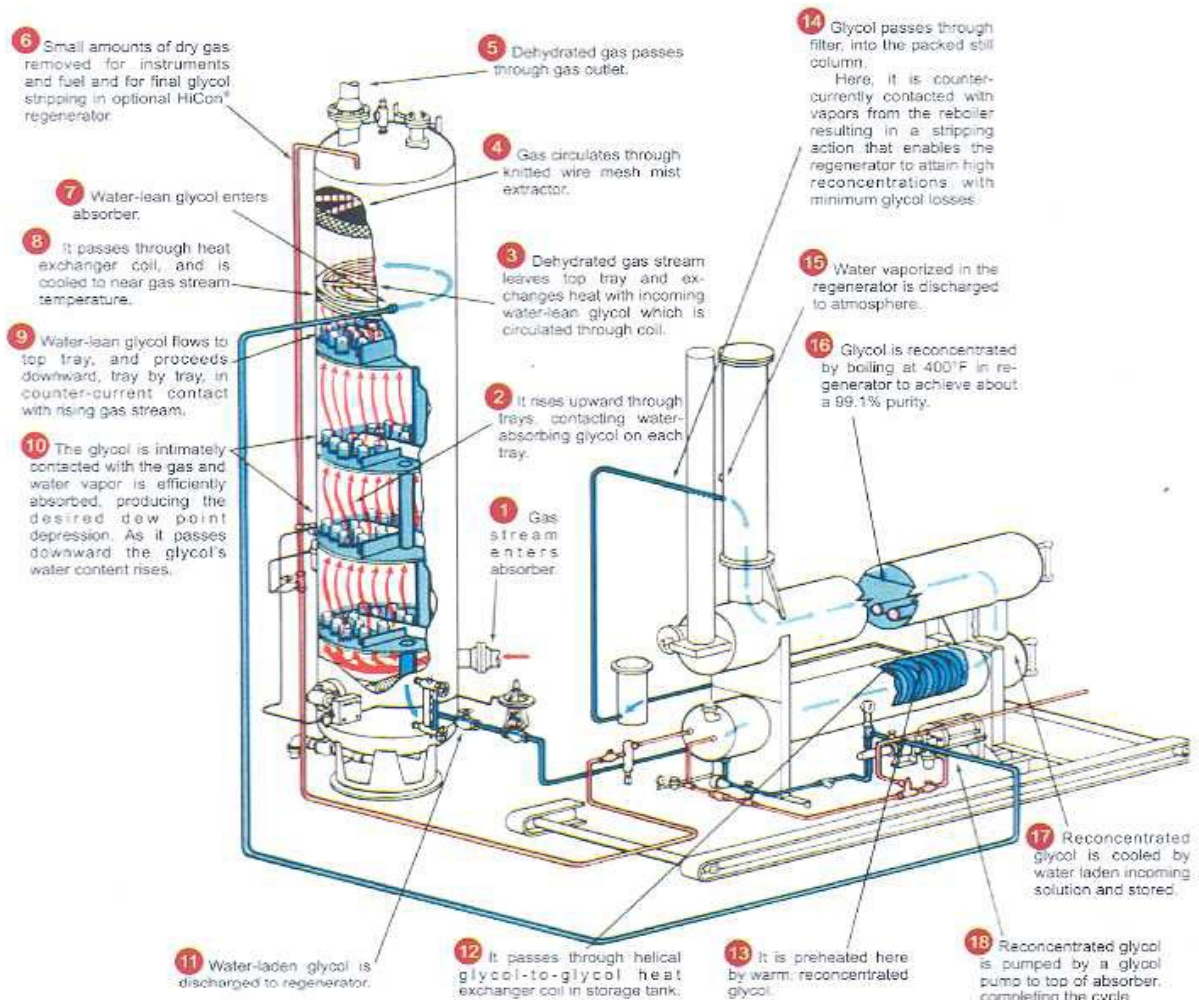


Figure12: Glycol dehydration process (www.images.google.com, 2009)

Central point separators

Central point separators are used for both the injection and withdrawal gas streams in a gas storage facility. Injection gas separators prevent injection pipeline dirt and debris from contaminating and clogging compressors and the well bore. The withdrawal separators prevent reservoir sand and water particles from entering the pumps and delivery pipeline. These separators should be designed to handle gases and liquids because of the high probability withdrawn gas is going to contain water molecules. Our separator cost about 1,700 dollars and varied with capacity due to glycol replacement costs.

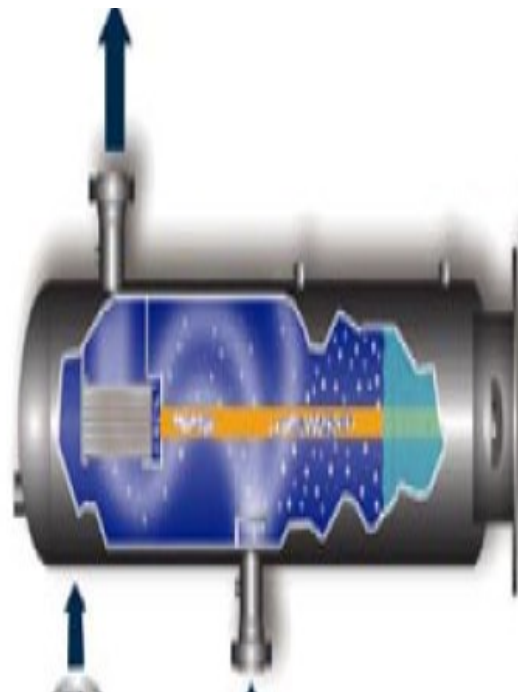


Figure 13: Gas/liquid separators (<http://www.peerlessmfg.com/pdf>, 2008)

Cushion gas

The cushion gas requirement for depleted gas reservoir storage systems is half the total storage capacity. We have a maximum storage volume of 10 BCF for this depleted gas reservoir. Current well-head prices for natural gas average \$4.00/mmbtu. We are using this as our standard price for purchasing the stored gas but will vary this cost to see how our storage cost plots respond. The calculated cushion gas would total 5 million mmbtu at a purchase cost of 20 million dollars. This is just the cost of purchasing the gas to be stored. It costs \$0.40/mmbtu to store the gas for depleted reservoirs. It would therefore cost 2 million dollars to store the gas in this reservoir. Gas injection and withdrawal fees also apply costing about \$0.02/mmbtu for both cycles. It would therefore cost \$100,000 to inject the working gas into the reservoir. The same cost would apply during the withdrawal cycle. Cushion gas costs total 22.1 million dollars for a storage reservoir of this maximum capacity at \$4.42/mmbtu. This cost varied slightly with increased and decreased gas purchase costs of \$2.42/mmbtu, \$6.42/mmbtu, and \$8.42/mmbtu.

Power (Electricity)

Electricity costs for the operation of this gas reservoir are based on the compressor and pump power requirements. Calculating the power rating of the pump

requires that we calculate the hydraulic and shaft power of the pump. The hydraulic power of the pump is calculated using the equation:

$$P_h = \frac{Q \times H \times \rho \times g}{1000} \quad \text{Equation 5}$$

P_h =Hydraulic power (Kilowatts)

H =Total head (Suction pressure – Discharge pressure)

Q =Fluid flow rate (m³/s)

ρ = density of the fluid (kg/m³)

g =acceleration due to gravity (m/s²)

We have a total head of 5485.3 psia, density of 0.8 kg/m³, fluid flow rate of 13.7m³/s and g to be equal to 9.8 m/s². From equation 5, the total hydraulic power requirements for the pump equal 589 kilowatts. The shaft power is derived from the equation:

$$P_s = \frac{P_h}{\eta} \quad \text{Equation 6}$$

The term η is the efficiency of the pump which for reciprocating pumps is approximately 70%. The calculated shaft power is thus approximately 841 kilowatts. The electrical power input is calculated by dividing the shaft power by an efficiency factor of 0.5. This results in a total electrical power requirement of 1682 kilowatts per hour for the pump. At current costs of \$0.05/kilowatt-hr for electricity, the pump would incur electricity costs of 84 dollars per hour. Withdrawal cycles are typically in the range of 120 days. The pump would be operating for a total 2880 hours bringing the total electricity costs to 23,000 dollars for the pump. The compressors operate at 39,705 horsepower which is equivalent to 3221.4 horsepower-hours (4,320 kilowatt-hours). At the cost of \$0.05/kilowatt-hr, the total cost of operating the compressors for the 180-day injection period totals 6 million dollars. The total electricity costs for a depleted reservoir with our maximum capacity is approximately 6.4 million dollars for the combined injection and withdrawal periods.

Land

There are restrictions when dealing with land used for natural gas storage. Wells or tanks containing large volumes of natural gas must be wells spaced at least 320-640 acres apart to allow efficient reservoir damage and to maximize the recovery of natural gas. No storage method must be located within 100 feet from private homes, 150 feet from public buildings and 50 feet from any stream. These criteria were used in

evaluating the cost of leasing or purchasing land that could be used for natural gas storage. For depleted reservoir calculations we used an approximate value of 10,000 acres at a yearly leasing cost of \$25 per acre. This gave a yearly leasing cost of \$250,000 dollars for maximum capacity operation.

Labor

Labor costs are important cost factor of gas storage facilities. Labor costs for gas storage facilities are incurred during the activation or design implementation period and possibly the gas withdrawal period also. For depleted gas reservoirs, this activation period is approximately 4 weeks because most of the needed infrastructure is already in place. Labor costs for activation projects are in the range of 30 dollars/hr per worker. This would result in a total labor cost of approximately 20, 000 dollars per worker over a four-week period. This cost also includes relocation, housing, feeding and transportation for each worker. Assuming it takes a ten-man team to activate a depleted reservoir, labor costs would total 200, 000 dollars for the four-week activation period. The withdrawal cycle would also require manpower to run the pump and other machinery so we assume it would cost 22 dollars/hr for each worker. Three workers would provide enough manpower for the entire 120 day withdrawal period. This gives combined labor costs averaging 190,000 dollars. This cost did indeed vary with storage capacity as less man-hours are needed as storage capacity reduces.



Fig 14: Fieldman hard at work (<http://images.google.com>, 2008)

Equipment Installation/Setup

The equipment installation costs as a percentage of the equipment cost are as follows:

- ❖ Separators: 40%
- ❖ Compressors: 45%
- ❖ Dehydrators: 42.5%
- ❖ Flow meters: 30%
- ❖ Pumps: 43%
- ❖ Valves: 40%
- ❖ Piping: 38%

This gave us a total installation cost of about 40 million dollars for a 10BCF maximum capacity storage reservoir.

Property Taxes/Insurance

Property taxes are in the range of 2 to 4 percent for highly populated areas and in the range of 1 to 2 percent for less populated areas. Gas reservoirs are primarily situated in remote, less populated areas. Property taxes for our depleted gas reservoir are about 1.5 percent of the total fixed capital investment. Property insurance is about 1 percent the total fixed capital investment per year. Totaled costs came to 3.5 million dollars and decreased for lesser storage volumes. Details of our results are contained in the attached excel sheets.

Salt Caverns

Salt caverns for the storage of natural gas are large underground tanks created from salt deposits (salt domes or beds) by solution mining (leaching) procedures. The salt is dissolved by injecting water through the well tubing. The dissolved salt is pumped out through the well casing. The resulting brine is sold to salt companies or injected into porous rock formations far beneath any surrounding water reservoirs. The cavern dimensions can then be determined directly by the water injection flow rate and the bottom-end position of the well tubing. Sound technology is used to determine if the proper cavern dimensions have been reached through leaching and the resulting

cavern space is dried using gas injection. Although salt caverns are generally much smaller in capacity than any other storage method, their walls can possess structural integrity as high as that of steel preventing little or no gas seepage. This makes salt caverns very ideal for gas peak shaving. We are assuming this salt cavern has a maximum gas holding capacity that is half that of that of the depleted reservoir. Our calculated costs for a salt cavern included all the cost parameters previously explained. The costs comparisons between depleted reservoirs and salt caverns are shown are shown in the plots below and explained in detail in our attached excel sheets.

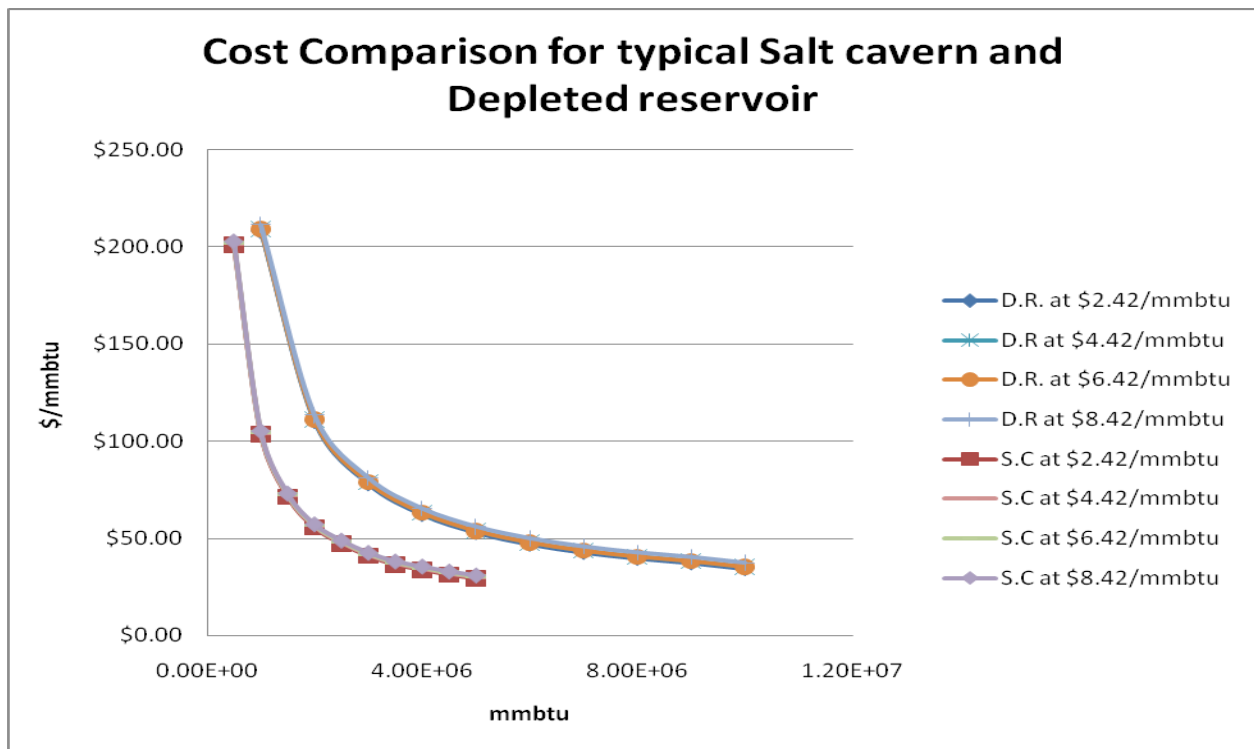


Fig 15: Cost comparison for depleted reservoir and salt cavern.

Our results show negligible changes on the overall curve for both depleted reservoirs and salt caverns when the purchase cost of gas was varied. A plot of the return on investment is shown below with the average gas purchase cost of \$4.42/mmbtu.

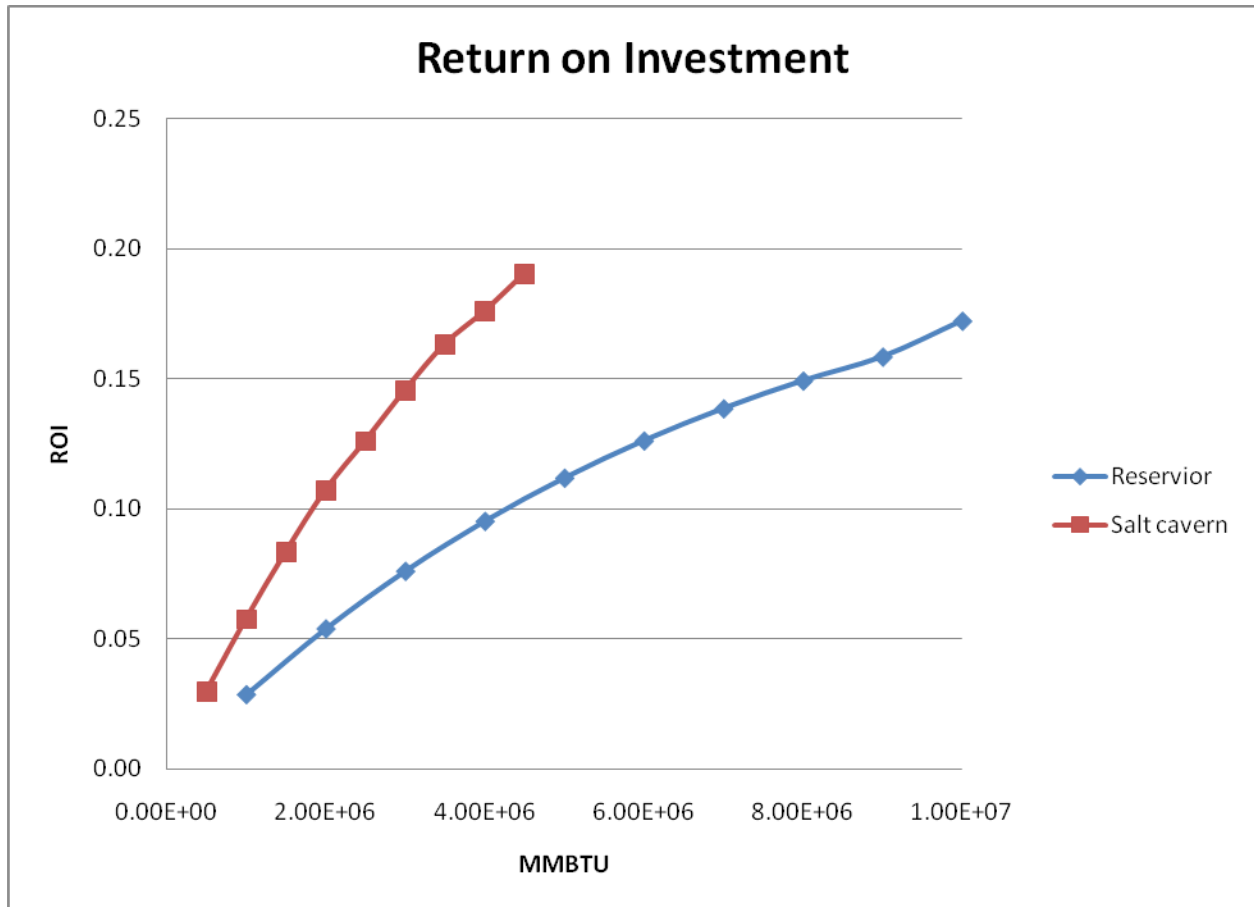


Fig 16: Return on investment plot for a depleted reservoir and salt cavern

Our plots show error bars which were calculated with 30 percent error. This was derived by calculating the error values for each cost component and finding the error average.

Overall our plots show that salt caverns are more profitable at smaller storage volumes but depleted reservoirs are more profitable long term.

Aquifer

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. However, in certain situations, these water containing formations may be reconditioned and used as natural gas storage facilities¹. In order to consider aquifer for natural gas storage, several factors have to be considered. The Geological characteristics of an aquifer are important.

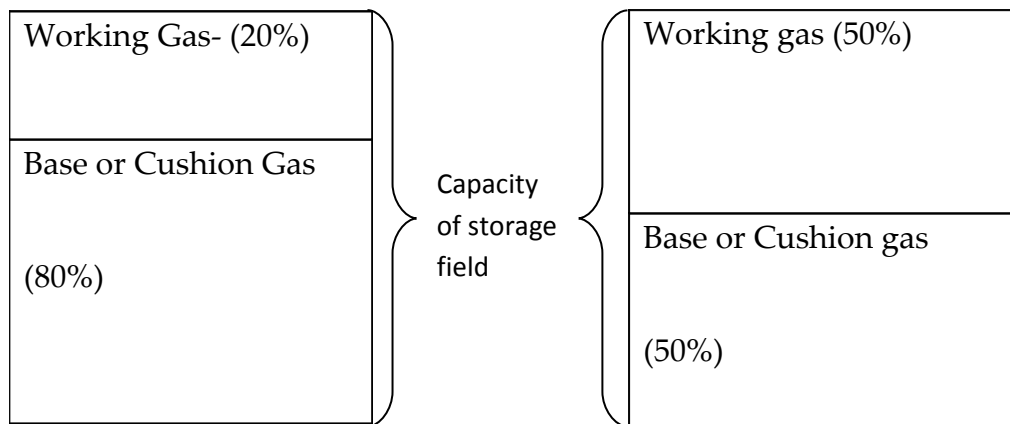


Fig 17: Aquifer cushion gas needs vs. Depleted reservoir gas needs

If an aquifer is found appropriate for storage, other supporting infrastructure has to be built to support its use. Aquifers require cushion gas of up to 80% of total volume which make its utilization very high. Aquifers are mostly built when the price of natural

gas is low. This is done to minimize the cost of natural gas spent as cushion gas. To determine the cost of developing an aquifer, similar criteria used for depleted reservoir was used. Since aquifers are natural water reservoirs, water must be evacuated before it can be used as natural gas storage. One of the major environmental concerns is the case of leaky aquifer. Enough amount of cushion gas must be in place to prevent any leakage. Pressure is an important parameter. Aquifers must operate at a high pressure to reduce the possibility of leakages. Cost analysis include labor, compressor, pump, utilities, land, cushion gas other miscellaneous cost. Below shows the PFD diagram for Aquifer design

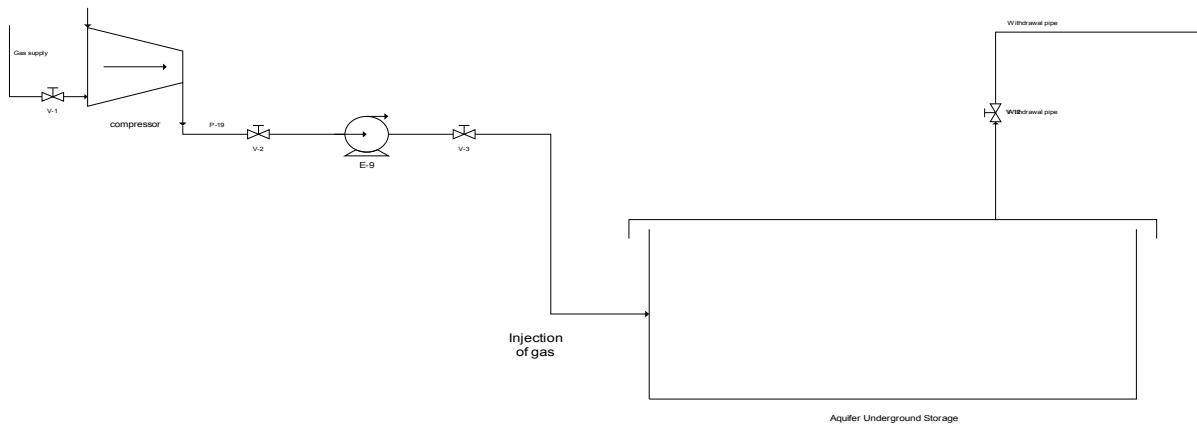


Fig 18: Aquifer system Design

Economics and Risk Analysis

The graph below shows the cost of storage per mmbtu. According to our results, Aquifer cost higher than hydrate after designed. This is due to the volume of cushion

gas needed before natural gas can be stored. Using hydrates to store natural gas seems to be more stable and less expensive when a pressurized tank is used.

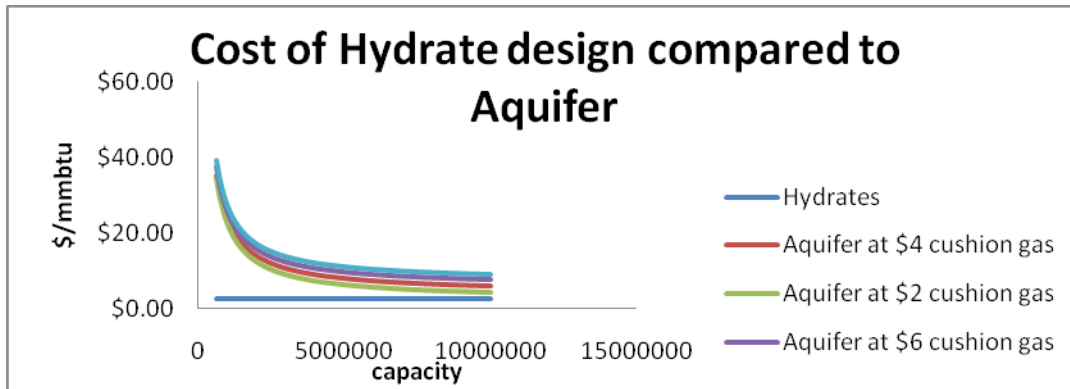


Fig. 19: Graph comparing storage method

The total cost of hydrates for 10^6 mmbtu is \$25 million while aquifer cost approximately \$60million. If the cost of natural gas reduces to about \$2/mmbtu, then it would cost approximately the same amount to build an aquifer storage or create a storage tank for hydrates. In todays market, it is unlikely that natural gas would become that cheap. Current market price for natural gas is about \$4/mmbtu. Using that price, then it would cost about \$40million more to get an Aquifer ready for natural gas storage.

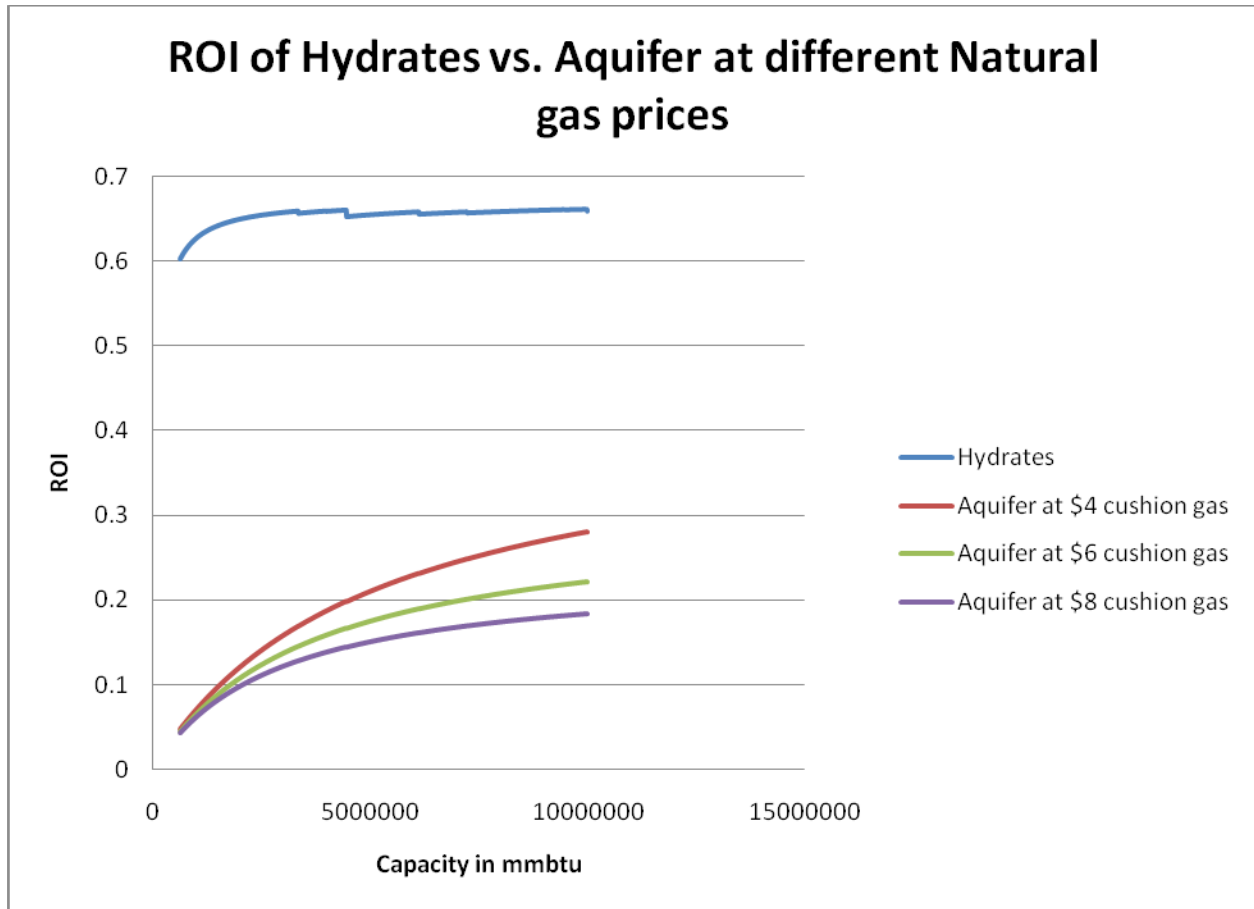


Fig 20: ROI comparison for Hydrates and aquifers at different gas prices

The return of investment on hydrates would determine whether this proposed method is profitable. Hydrates has a higher rate of investment even when the cost of natural gas is cheap. At 10^7 mmbtu, the return on investment is about 0.65%. It then progressively increasing until it levels off. This is about 40% greater than Aquifer.

Since the price of natural gas fluctuates depending on the season, the cost of cushion gas is varied. This gives an increase in total cost for each storage method. The graph below shows the comparison for aquifers.

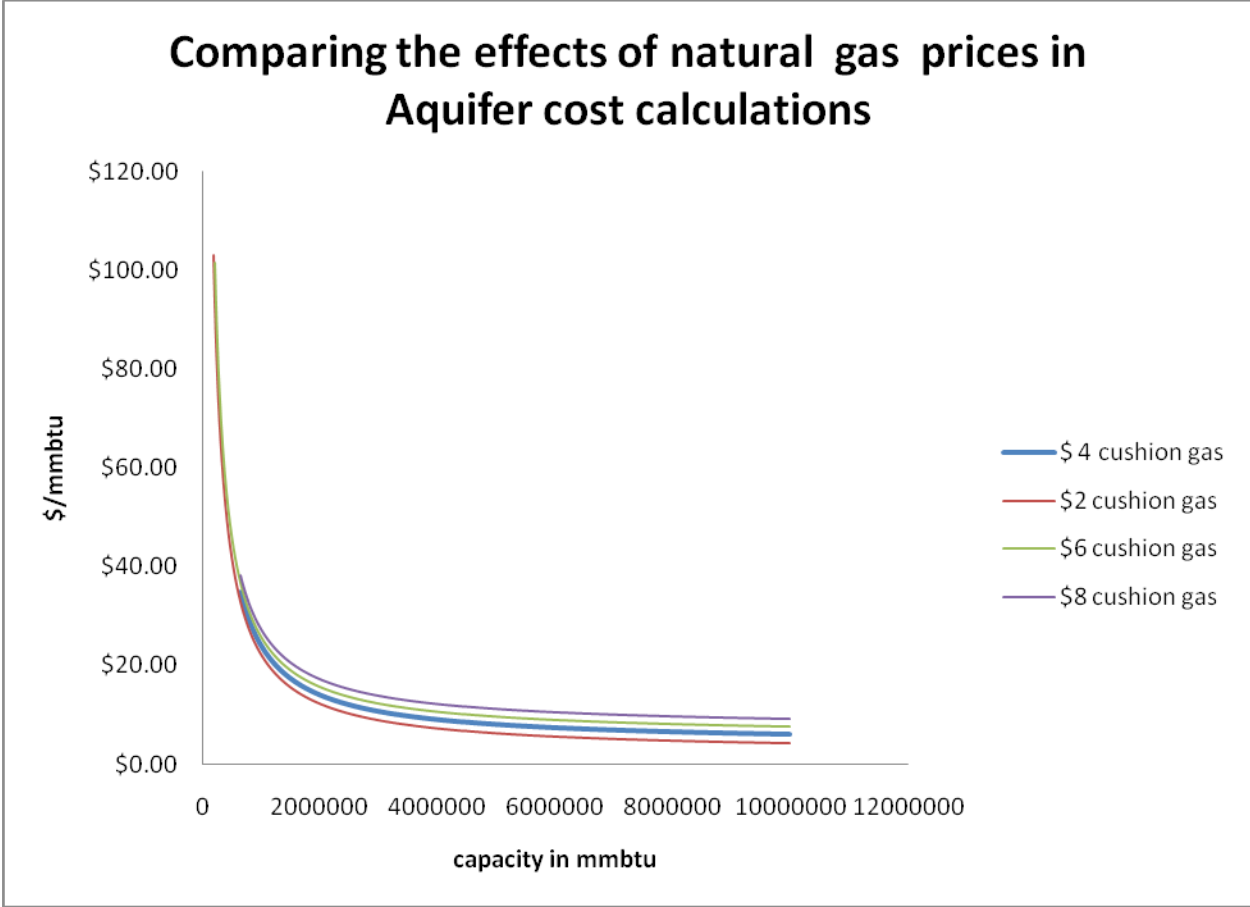


Fig 21: Effects of change in natural gas prices on aquifer costs

Summary Results for Aquifers and Hydrates		
	Hydrates	Aquifers
Compressor	\$291,466.80	
Pumps	\$83,333.34	
Cushion Gas	-	\$32,000,000.00
Extra Fees	\$1,800,000.00	
Land	\$45,000.00	\$25,000,000.00
Utilities	\$42,000.00	
Pressurised Tank	\$24,625,109.00	-
Valves	\$182,625.97	
Pipes	\$181,779.20	
TCl/mmbtu	\$15.18	\$35.65
ROI	\$0.66	\$0.28

Total Cost	\$25,591,314.31	\$60,113,205.31
------------	-----------------	-----------------

Table 2: Cost summary for hydrates and aquifers

Conclusion

Natural gas hydrates can be very useful for storing natural gas. Studies shows that it can be profitable when managed and designed to save money. Natural gas hydrates could provide easy access to storage when needed. Increased capacity makes the cost economically feasible and return on investment would increase over time. Operating cost of gas hydrates is low compared to the other methods; therefore more research should be carried out on the use of gas hydrates as natural gas. Exploring the possibility of storing gas using hydrates is definitely a worthwhile venture.

Works cited

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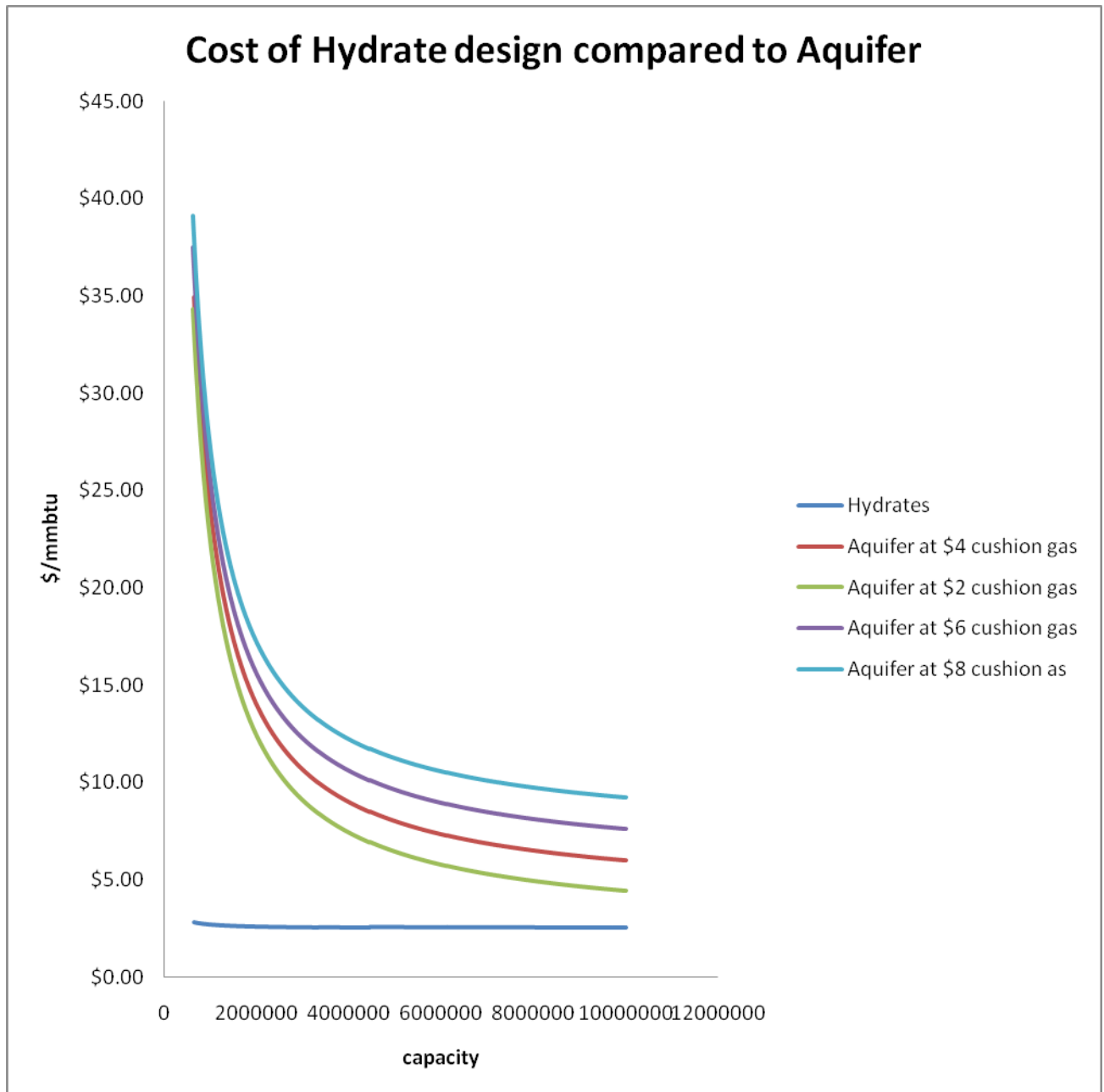
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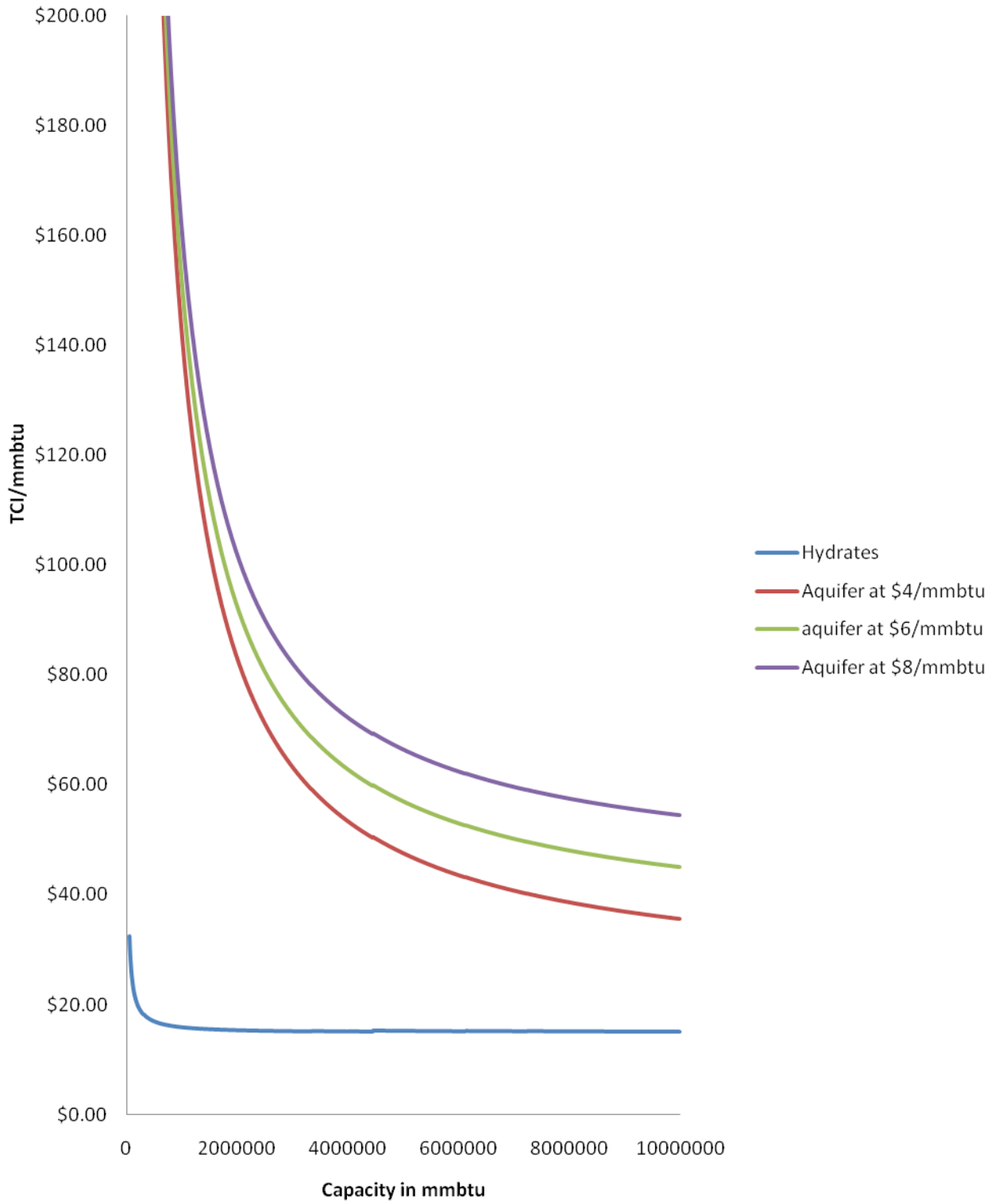
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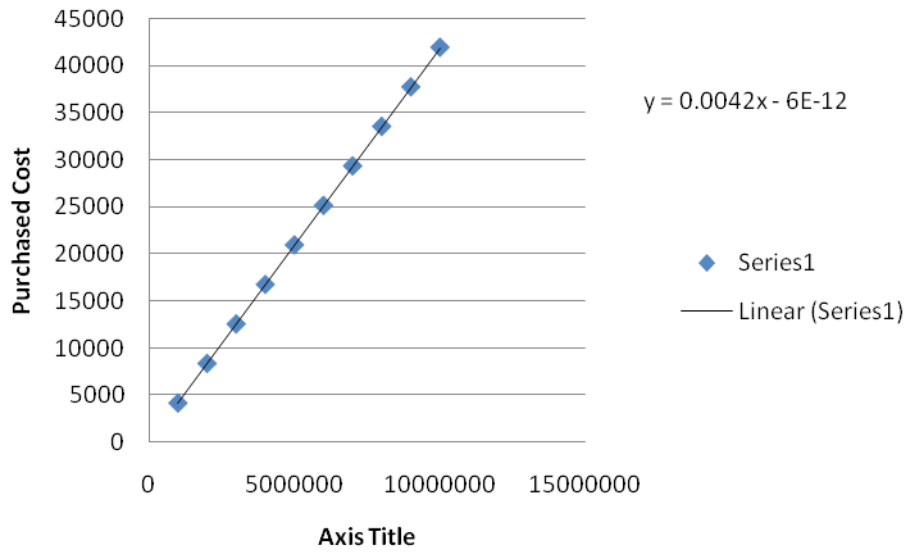
Cost comparison plots



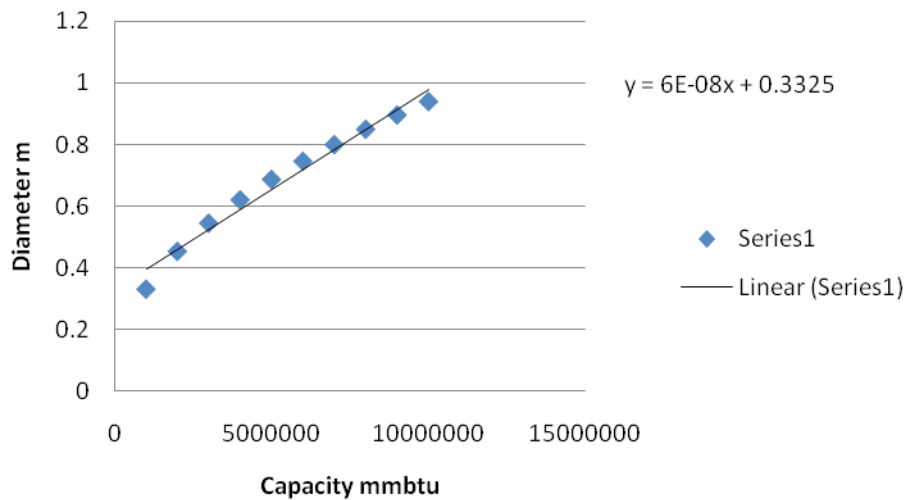
TCl of Acquirer compared to Hydrates



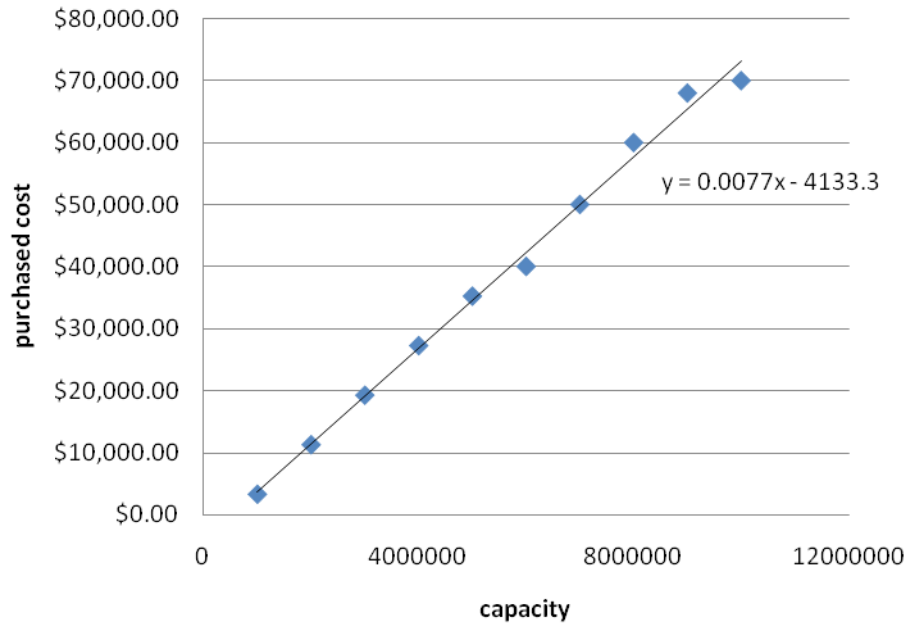
Extrapolation of Utilities Cost for Aquifer and Hydrates



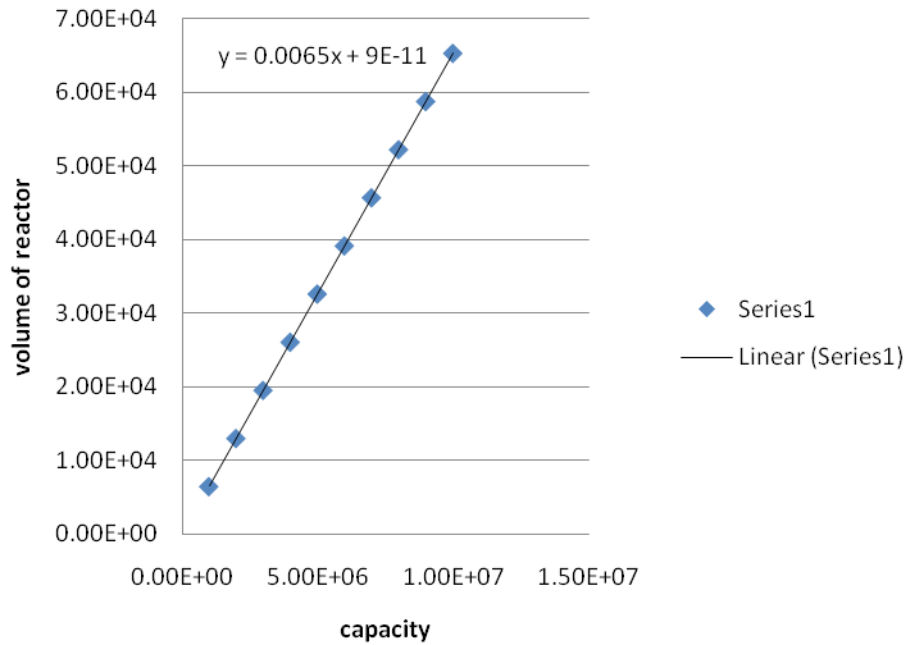
Extrapolation of Diameter Size for pipes and valves for Aquifer and Hydrates

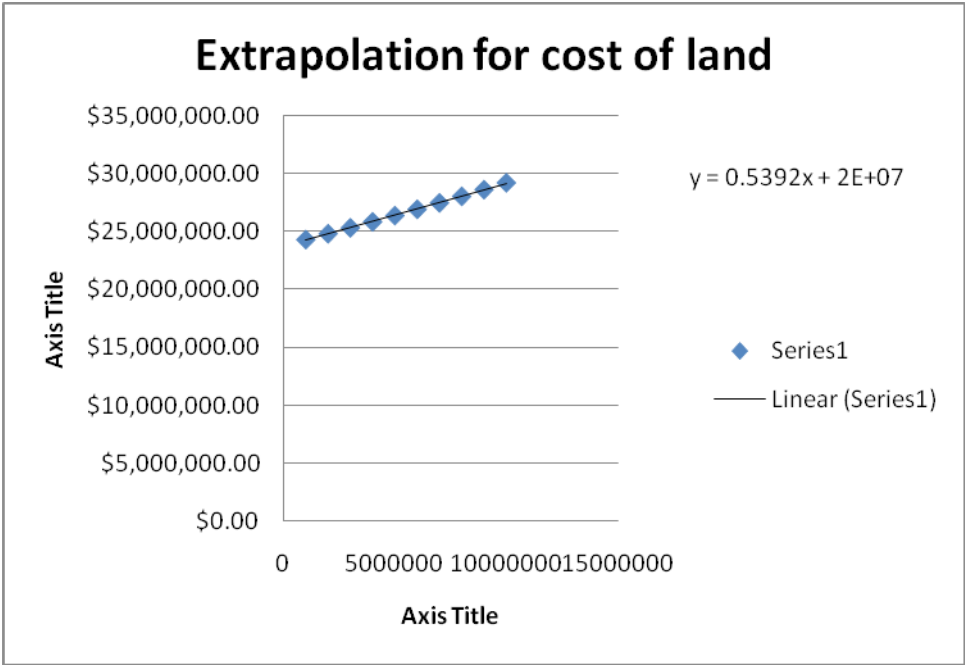
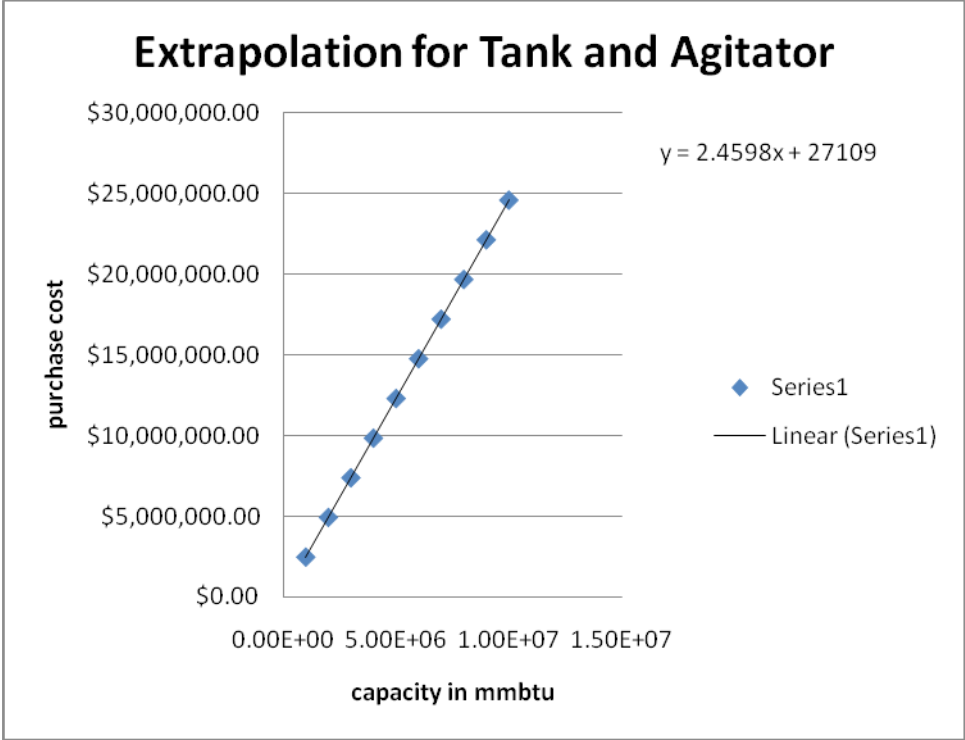


Extrapolation of Compressor Cost for Aquifer and Hydrates

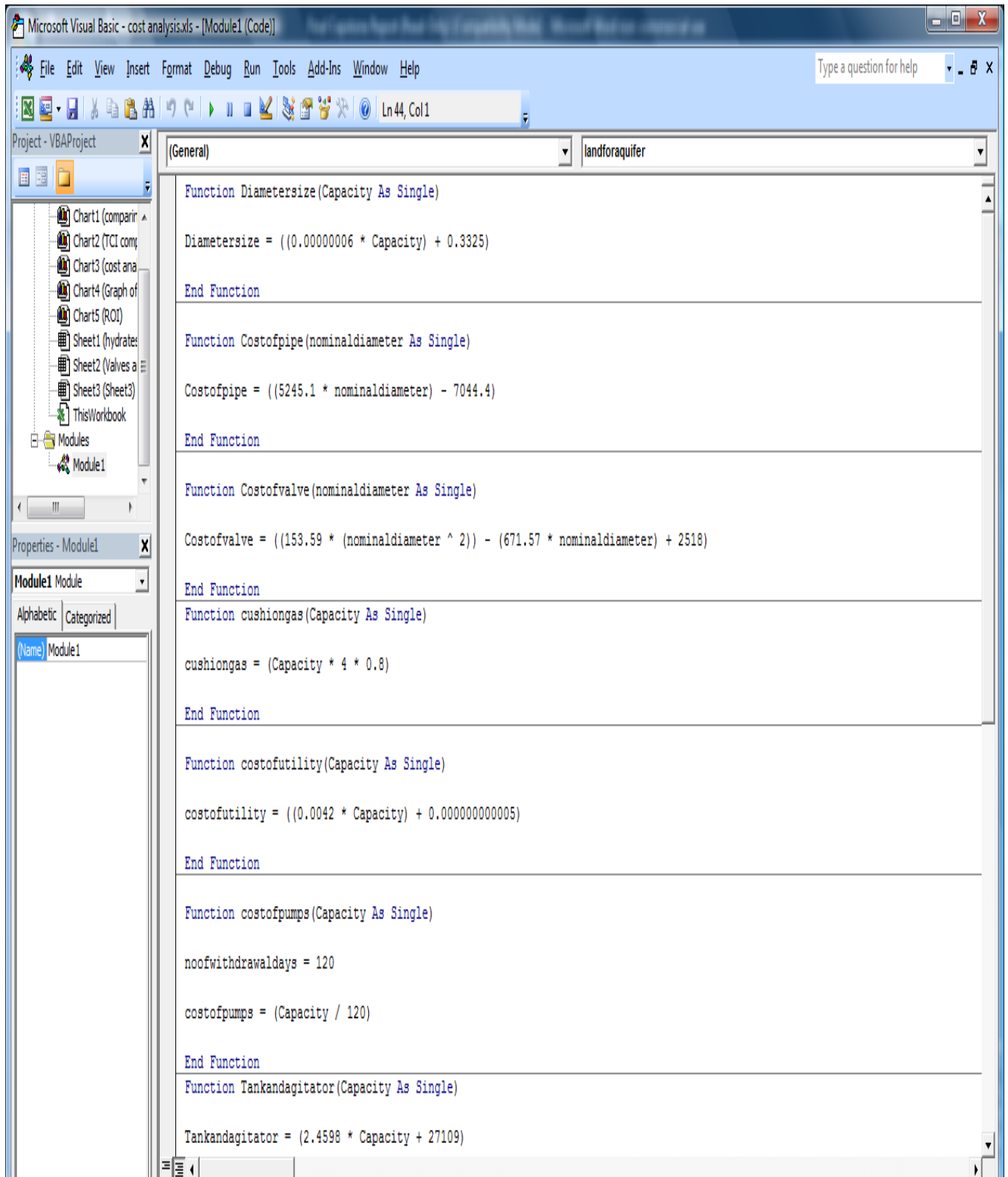


Volume of Reactor





VBA code for Aquifer and Hydrates



The screenshot shows the Microsoft Visual Basic editor window for a project named 'cost analysis.xls'. The main window displays the VBA code for Module1, which includes several functions for calculating diameters, costs, and other parameters related to aquifers and hydrates. The code is as follows:

```
Function Diametersize(Capacity As Single)
    Diametersize = ((0.00000006 * Capacity) + 0.3325)
End Function

Function Costofpipe(nominaldiameter As Single)
    Costofpipe = ((5245.1 * nominaldiameter) - 7044.4)
End Function

Function Costofvalve(nominaldiameter As Single)
    Costofvalve = ((153.59 * (nominaldiameter ^ 2)) - (671.57 * nominaldiameter) + 2518)
End Function

Function cushionogas(Capacity As Single)
    cushionogas = (Capacity * 4 * 0.8)
End Function

Function costofutility(Capacity As Single)
    costofutility = ((0.0042 * Capacity) + 0.0000000000005)
End Function

Function costofpumps(Capacity As Single)
    noofwithdrawaldays = 120
    costofpumps = (Capacity / 120)
End Function

Function Tankandagitator(Capacity As Single)
    Tankandagitator = (2.4598 * Capacity + 27109)
End Function
```


The screenshot displays the VBA editor interface. On the left, the Project Explorer shows a workbook with three sheets (Sheet1, Sheet2, Sheet3) and a module named Module1. The Properties window for Module1 is open, showing the name 'Module1'. The main editor area contains the following VBA code:

```
Function Tankandagitator(Capacity As Single)

Tankandagitator = (2.4598 * Capacity + 27109)

End Function

Function landforaquiifer(Capacity As Single)

landforaquiifer = ((0.5392 * Capacity) + 20000000)

End Function

Function extrafeesforaquiifers(Capacity As Single)

extrafeesforaquiifers = 2 * (0.04 * Capacity) + 2 * (0.05 * Capacity)

End Function

Function cushiongas2dollars(Capacity As Single)

cushiongas2dollars = (Capacity * 2 * 0.8)

End Function

Function cushiongas6dollars(Capacity As Single)

cushiongas6dollars = (Capacity * 6 * 0.8)

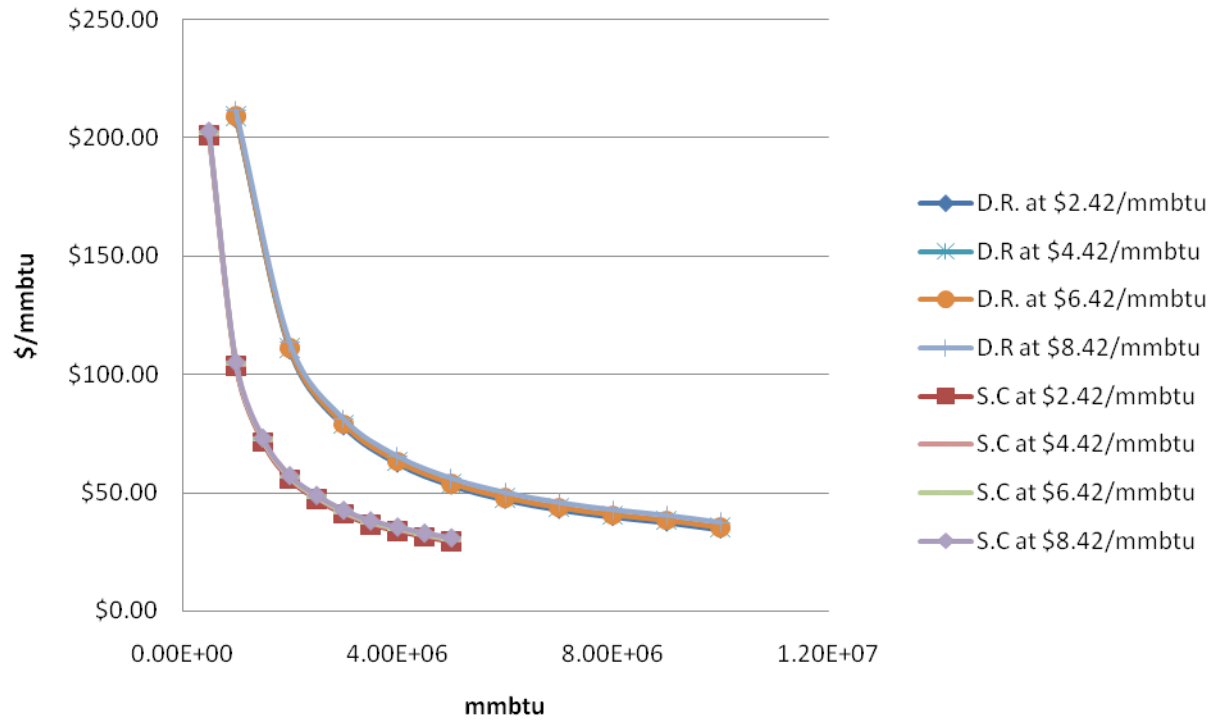
End Function

Function cushiongas8dollars(Capacity As Single)

cushiongas8dollars = (Capacity * 8 * 0.8)

End Function
```

Cost Comparison for typical Salt cavern and Depleted reservoir



Return on Investment

