Estimating Natural Gas Salt Cavern Storage Costs

Nathalie Hinchey
Graduate Student
Center for Energy Studies
James A. Baker III Institute for Public Policy
Rice University
6100 Main Street
Houston, Texas
77005
USA
nh17@rice.edu

Abstract

This paper will examine the costs of injecting natural gas into salt cavern storage facilities. Salt caverns are primarily used for serving peak load gas demand as they offer high deliverability, in both injection and withdrawal processes related to natural gas. Many short term traders use salt cavern storage to maximize profits by arbitraging differences in price from unpredictable and occasionally unanticipated demand surges. It is generally acknowledged that injection costs increase in storage facilities as storage levels are high and withdrawal costs increase as storage levels diminish. Recently, demand for natural gas storage has declined due to decreased seasonal price spreads in response to a growth in supply from US shale sources and demand which recently has lagged supply. This has led to a dearth of investment in new gas storage capacity. Forecasts, however, predict that demand for storage capacity will increase in the next few years, mainly in response to US LNG exports and the use of natural gas in power generation. This demand will put pressure on existing storage capacity. Comprehension as to how storage, injection and withdrawal costs respond to increased demand for storage is essential to understanding natural gas pricing.

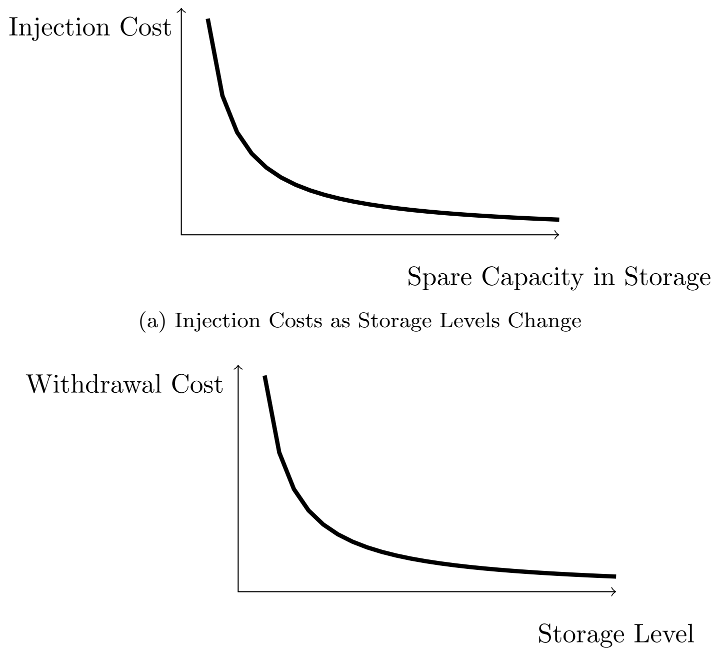
1 Introduction

Natural gas is an important fuel source used for residential heating, industrial manufacturing, and power generation in the U.S. and many other countries. It is the cleanest fossil fuel and provides significant advantages for power generation in the U.S. compared to most renewable energy sources due to its abundance, dispatchability and affordability. A significant challenge for the natural gas sector, however, is the seasonal and volatile nature of demand encountered paired with the steady and constant nature of its supply. In months with extreme temperatures, demand for natural gas skyrockets and in temperate months demand decreases significantly. This leads to unattractive price volatility for purchasers of natural gas and potential profits for suppliers of the fuel, who take advantage of spatial arbitraging opportunities. The use of storage for natural gas presents a unique and obvious solution to this problem, by decreasing price variation for consumers and still allowing profitable outcomes for suppliers of natural gas by introducing intertemporal arbitrage opportunities whereby, suppliers store gas during times of low demand and increase supply by drawing down inventories during times of high demand. Storage of natural gas is also important for transmission companies for load management and the balance of system supply.

Prior to 1992, gas storage facilities were almost exclusively owned and controlled by interstate and intrastate pipeline companies who sold natural gas as a bundled service including, production, transmission and storage services to consumers. In April 1992, the Federal Energy Regulatory Commission (FERC) issued Order 636 which essentially unbundled these services to help foster the structural changes necessary to create a competitive market for the American natural gas industry (American Gas Association, 2017). Order 636 instructed owners of storage facilities to open access to storage to third parties and only allowed the former to reserve space for their own use to balance system supply. The newly deregulated market presented arbitrage opportunities so that storage could be used not just as a physical hedge to market conditions, but as a financial tool to profit from price differentials for short term gas traders (Schoppe, 2010). Order 636, along with high price volatility, led to an impressive expansion of high deliverability storage facilities during the late nineteen nineties (Fang et al., 2016). High deliverability facilities allow for rapid injection and withdrawal of gas from storage and generally tend to have lower storage capacity; they are especially important for supplying unexpected demand surges in the electricity generation sector.

The Shale Revolution significantly depressed seasonal price spreads and has consequently hindered new investments in natural gas storage facilities. In 2016, as in the three preceding years, no new underground facilities were developed in the U.S. and the only expansion of capacity is represented by brownfield investment in the South Central (Gulf) region, concentrated mostly in high deliverability salt cavern storage facilities (EIA, 2017a). A recent study by Fang et al. (2016) concludes that there will be increased demand for existing high deliverability storage space in the Gulf region in response to increased use of natural gas in power generation and growth in LNG exports. Further, changing weather patterns have reduced the reliability of historical demand curves in predicting gas demand which will most likely lead to more unexpected demand surges. All of these will encourage purchasers and suppliers of natural gas to seek access to flexible storage space which is best served by salt dome storage facilities. Understanding the costs of injecting and withdrawing natural gas from salt caverns, and responses and reactions to increased utilization of such facilities, will become increasingly important in comprehending the nature of supply of natural gas to end users and its pricing.

Anecdotal evidence acquired from industry experts suggest that the cost of



(a) Injection Costs as Storage Levels Change

(b) Withdrawal Costs as Storage Levels Change

Figure 1: Injection and Withdrawal Costs

injecting/withdrawing natural gas from storage depends on both the level of gas stored in the facility and the rate of injection/withdrawal. In particular, costs appear relatively stable and constant to inject gas when gas levels are below 85%-90% of total storage capacity, but they increase asymptotically when storage levels exceed this threshold. Similarly, withdrawal costs escalate when storage levels near the minimum (cushion gas) level. Figure 1 illustrates the effect storage levels have on both injection and withdrawal costs. Notice that as spare capacity decreases, injection costs explode whereas withdrawal costs decrease.

Due to projected increases in the utilization of salt cavern storage facilities in the Gulf Coast, the primary goal of this paper will be to develop and estimate a model that quantifies the degree to which injection costs ascend when storage levels near capacity. The benefits of estimating such a cost function are diverse: it will aid in valuation of gas storage methodologies, it will provide more clarity on the pricing of natural gas and will give some insight into the behavior of short term gas traders.

To facilitate the understanding of this problem, a brief introduction on the different types of demand for natural gas storage, the physical properties and types of underground storage as well as the nature of gas storage contracts will be presented. The paper will then provide a literature review of the relevant research in this area which will be followed by the theoretical model and model estimation, and finally an analysis of future expected storage costs.

2 Types of Demand for Natural Gas Storage

Due to its gaseous state, natural gas needs to be stored in an environment that maintains sufficient pressure to prevent leakage and resulting losses of the fuel. Pressure is also required in the storage facility to allow for the extraction of gas from storage. Naturally occurring underground formations, such as depleted oil and gas reservoirs, natural aquifers and salt caverns provide the most effective means to store gas in its natural form. Alternatively, natural gas can be stored in pipelines (when spare capacity is available) or as LNG[1] in LNG storage tanks; the latter requires liquefaction of the fuel prior to storage. Each type of storage facility has its own set of physical properties which in turn determine the cost of storing gas as well as the type of storage the facility is best suited for.

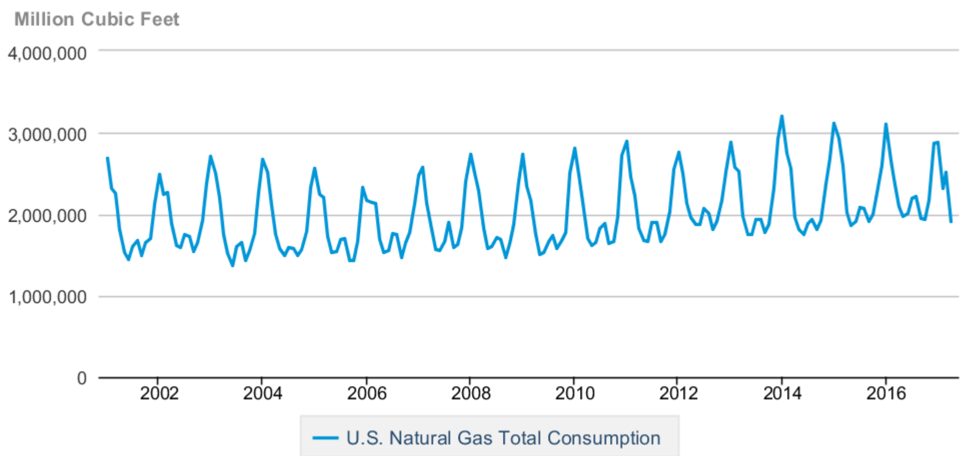
[1]The concept of Liquefied Natural Gas (LNG) was developed in the late nineteen seventies. The basic premise of LNG is to liquefy natural gas cryogenically, which reduces the fuel to approximately 1/600th of its gaseous volume at -260 degrees Fahrenheit, (-162.2 degrees Celsius), after the extraction of oxygen, water and carbon dioxide, as well as most sulfates (Office of Fossil Energy, 2016). This permits cost-effective transport of gas by way of specially constructed tanker ships. This process also requires a liquefaction plant and a regasification plant

In principal, there are two different purposes for storing natural gas. The first is to meet base load gas demand. Essentially, when considering base load demand, storage operators purchase natural gas during times of low demand, or the "shoulder months"[2] and sell the gas during periods of high demand in order to arbitrage profitable seasonal price differences. Typically, natural gas demand is highest during the winter months, when the latter is typically used to heat houses, as well as commercial and industrial structures, and increasingly, during the summer months to provide air conditioning, as natural gas has contributed to a growing share of power generation in the United States. In 2016, natural gas accounted for approximately 33.8% of electric generation in utility scale facilities (EIA, 2017). It is the predictable, seasonal nature of demand for gas that has provided the need and incentive to develop storage facilities to satisfy base load demand. Figure 2 below provides an illustration of the seasonal demand for natural gas. Gas stored for base load demand tends to be held in storage for longer periods to account for changing seasons and weather patterns.

Natural gas storage can also be used to meet peak load demand. Facilities that serve peak load gas demand generally do so on short notice to fulfill unexpected surges in demand and profit from the resulting price spikes. Peak load storage facilities may hold gas for as little as a few days to as much as a few weeks before the withdrawal and sale on the market (Natural Gas Supply Association, 2014). They are generally used to satisfy unforeseen demand spikes from local distribution companies (LDC), power generators and theoretically from LNG exporters to store supply when liquefaction operations are interrupted (Fang et al., 2016). Most of the high deliverability capacity in the Gulf Region is leased by short term traders who profit from price differentials. Due to their high deliverability, salt cavern storage facilities, to be described below, are the best suited underground storage facilities to serve peak load de-

[2] These are generally the months of May-June and September-October.

Figure 2: Seasonality of U.S. Gas Demand



Source: U.S. Energy Information Administration

mand. When considering above ground facilities, LNG peak shaving plants can be used for the same purpose. Due to the existing infrastructure in salt cavern storage in the Gulf region, as well as the expected growth in demand for high deliverability storage in the Gulf region, this paper will focus on estimating the costs of injection of natural gas into salt caverns in the Gulf region.

3 Physical Properties and Types of Underground Storage

Depleted oil and gas reservoirs, aquifers, and salt caverns are the most common formations used for underground storage. The particular desirability of these three types of underground storage is based on their geological and geographical traits. Each differs in terms of its working gas capacity, base (cushion) gas, shrinkage factor, deliverability and geographical location. A storage facility's working gas capacity refers to the amount of gas that can be withdrawn from and injected into storage for use. Since storage reservoirs must maintain a certain amount of pressure for extraction purposes, there is a minimum amount of gas required, called the base or cushion gas level, below which no gas can be extracted from storage. Essentially, a storage operator must inject a certain amount of gas into the reservoir that is extremely difficult to recover. It is preferable, in terms of profitability, to have a lower base gas level. The working gas capacity and the base gas make up the total capacity of storage.

The shrinkage factor of a storage facility refers to the amount of leakage of gas that occurs in the reservoir; this is a natural phenomenon experienced in most underground facilities. Deliverability reflects the rate at which gas can be withdrawn and injected into storage. Higher deliverability indicates that natural gas can be cycled through the storage site more quickly. Finally, the proximity of the storage site to end users and market centers is another important factor in warranting interest in a particular storage site. Brief descriptions of the aforementioned types of storage facilities are presented below.

3.1 Depleted Oil and Gas Reservoirs

Depleted oil and gas reservoirs consist of empty formations underground that have been exhausted from prior oil and gas extraction. These formations provide natural cost advantages as the geological characteristics of the site are already known from previous activity. Further, depleted reservoirs normally have existing infrastructure to extract and transport natural gas, which lowers investment costs. Consequently, depleted reservoirs are generally the cheapest storage sites to develop and are the most abundant in the United States. They are primarily located in producing regions of the U.S. and require about 50% base gas (Natural Gas Supply Association, 2014). Depleted reservoirs are typically used to satisfy base load demand as they have lower deliverability.

3.2 Aquifers

Natural aquifers can also be converted for use as a natural gas storage site. They have geological characteristics similar to depleted reservoirs (EIA, 2015) yet they are less well known. Aquifers are generally more expensive to develop than depleted reservoirs and require the highest base gas of all 3 storage facility types. They are generally used for base load demand, although they are occasionally employed to serve peak load demand as well (Natural Gas Supply Association, 2014). Aquifers are the least desirable form of storage and are generally commissioned when there are no depleted fields or salt caverns nearby.

3.3 Salt Caverns

Salt caverns are primarily located in the Gulf region and are created by a process called "salt mining" where water is injected into salt formations underground to dissolve the salt and create a cavern (Fairway Energy, 2017). While salt caverns require the highest initial investments for development, they provide the lowest per unit costs for gas storage. This is due to the high deliverability of salt caverns, which is higher than both depleted reservoirs and aquifers. Salt caverns only require about 33% of cushion gas (Fang et al., 2016) but have much lower storage capacity, making them less viable to serve base load demand. Salt caverns are primarily employed to serve peak load demand; they accounted for approximately 8% of all gas stored underground in the U.S for the year of 2017 as of April 2017 (EIA, 2017b).

4 Storage Technology and Contracts

When the owners of natural gas decide to inject or withdraw gas from storage, they are motivated primarily by their variable costs, in this case the injection and withdrawal rates charged by storage operators. Understanding the nature of storage contracts is then vital to modeling the decision process of gas owners to inject and withdraw gas from storage, which will help uncover their respective cost functions.

The majority of underground natural gas storage facilities are owned by interstate and intrastate companies, although a significant number are owned by LDCs and independent storage operators as well (Natural Gas Supply Association, 2014). Owners of storage facilities generally lease out storage space to third party clients according to detailed contracts, that specify a monthly, fixed payment based on the leased storage space, as well as variable payments. The monthly leasing rate depends on the type of service required by the customer. A renter can either choose to purchase uninterruptible service, which guarantees access to the allocated storage space, or interruptible service, where the rented space is accessible only when the storage provider is capable of providing the space. Predictably, uninterruptible space is more expensive than interruptible storage space.

The storage operator also charges for the injection of gas into and the extraction of gas from storage, subject to daily withdrawal and injection limits, as well as the associated fuel costs. The technology to extract gas from storage differs from the technology to inject gas into storage. Typically, the injection and extraction costs are not identical, although occasionally the storage operator charges the same rate for injection and extraction. In fact, the Spindletop storage facility in Beaumont, Texas, operated by Centana Intrastate, which will be examined in this paper, charges the same rate[3] to inject and extract gas, within daily maximum injection and withdrawal bounds.

To inject natural gas into storage, the incoming gas needs to be filtered and then compressed by a gas motor or turbine, which requires fuel (DEA,

[3]Based on the most recent rate postings by the Texas Railroad Commission.

2017). Most natural gas contracts, according to postings by the Texas Railroad Commission, charge approximately 2% of injected gas volume to cover fuel costs, in addition to the injection charge.

To extract natural gas from storage, the gas first needs to be sufficiently pressurized, and compressors may be required to compress the gas before being distributed to the network. While in storage, gas absorbs water which can be corrosive and damaging to pipelines. Storage operators must thus remove all hydrates from the gas, usually through a process called glycol dehydration (DEA, 2017).

5 Literature Review

There appears to be no, or a negligible amount, of research on estimating injection/withdrawals costs into storage, in particular salt cavern storage fields. This is most likely because costs are not readily available and only aggregate level data on storage levels are accessible to the public, which makes the exercise at hand very difficult to achieve. Most research in terms of analyzing underground natural gas storage has focused on valuing underground storage fields. The majority of the literature uses either intrinsic valuation methods, which essentially consider the seasonal price spreads to value storage facilities, or extrinsic valuation techniques, which focus more on financial hedging and trading. All of the papers described in this section use calibration techniques to provide a valuation of storage. This paper is one of the only papers that employs estimation strategies to examine the storage and investment problem with respect to natural gas storage.

In particular, Boogert and De Jong (2008) develop a Monte Carlo valuation method where they employ a Least Squares Monte Carlo methodology using an American options framework to model the investment decisions of storage and ultimately value storage. Cortes (2010) expands this methodology by introducing multi-factor processes into the Least Squares Monte Carlo algorithm. Chen and Forsyth (2007), on the other hand, develop a valuation method using a semi-Lagrangian technique to solve the storage problem that is modeled as a Hamilton-Jacobi-Bellman equation. Thompson et al. (2009) derive a valuation method using nonlinear partial-integro-differential equations. Finally, Henaff et al. (2013) and Li (2007) both present valuation methods that effectively combine extrinsic and intrinsic valuation principals to represent a more realistic setting.

These papers do not seem to focus on the cost of injecting and withdrawing natural gas into and from storage respectively, nor how these costs change with storage levels. These costs will ultimately affect profitability and should be expected to influence the final calibrated valuations of underground natural gas storage. The results from this paper should be helpful in increasing the reliability of the valuation methodologies described above.

There have been many papers, however, that have examined the decision to invest in inventories. The storage decision problem can be viewed as an inventory problem. This paper uses an empirical approach very similar to the Euler-equation estimation technique, first introduced by Hansen and Singleton (1982). In the context of this paper, the most important research on the inventory problem was performed by Cooper et al. (2010). While looking at the decision to invest in capital, Cooper et al. (2010) use Euler equations to recover capital investment costs in a discrete choice setting. The methodology employed in Cooper et al. (2010) is very similar to the estimation technique proposed in this paper to estimate natural gas injection costs.

6 Data

This section will present and describe the data used in estimation. Proprietary data on the injection and withdrawal rates of gas into the Spindletop Storage Facility, operated by Centana Intrastate, was generously provided by Genscape, Incorporated. The Spindletop Storage Facility is a salt cavern storage field located in Jefferson County, Texas with a storage capacity of 21,100 million cubic meters (Mmcf) and cushion gas of 6929.8 Mmcf. Genscape, Inc. monitors gas flows into and out of storage using infrared technology and electro-magnetic field monitors. The dataset provided by Genscape, Inc. provides a rare glimpse into storage decisions at the firm level. This analysis would not be possible with industry level data, which is the only publicly available data. Daily storage levels and rates are measured in Mmcf and are observed from June 1, 2015 to January 31, 2017.

The gas trading hub located nearest the Spindletop storage cavern is the TexOk Hub. Daily TexOk spot prices were obtained from Bloomberg and the TexOk prompt month futures prices were created by adding the Henry Hub prompt month futures with the TexOk futures differentials, all acquired from Bloomberg. Finally, the operating characteristics of the Spindletop Facility, such as working gas capacity and base gas, were obtained from the Texas Railroad Commission.

7 Model and Results

7.1 Theoretical Model

To recover the cost functions of injecting/withdrawing gas into/from storage, we build a model where a representative agent makes a series of static (daily) investment decisions based on storage volumes, spot prices and futures prices in a competitive gas market to maximize the expected daily profits. Assuming the observed storage decisions are profit maximizing and given observed prices, we can use first order conditions derived from the model to back out the cost parameters. The methodology used in this paper is inspired by and similar to the work of Hansen and Singleton (1982).

The storage decision model was designed as a repeated, static problem, as opposed to a dynamic problem, to capture the idea that most gas traders make short term decisions and change their positions quickly. This has been confirmed through conversations with industry experts. This behavior is expected when considering salt caverns that typically serve peak load demand. Had the dataset been given for a storage field that served base load demand, a dynamic setting would have been the appropriate selection.

Let $P^F_{t,t+n}$ represent future contract prices for gas at time t for delivery at time $t+n$ and P^S_t be the spot price of gas at time t at the nearest trading hub. Define i_t as the injection of gas into storage at time t and w_t as the withdrawal of gas from storage at time t. Allow G_{Max} to be the maximum storage capacity of the storage facility and G_{Min} to be the base gas (cushion gas) of the storage field. Let g_t represent the level of gas in storage at time t. $C_I(g_t, i_t, G_{Max})$ is the cost of injecting i_t gas into storage, which is a function of the current storage level, g_t, and the maximum storage capacity, G_{Max}, as well as the injection rate, i_t. Similarly, $C_W(g_t, w_t, G_{Min})$ is the cost of withdrawing w_t gas given the current storage level, g_t, the base gas, G_{Min} and the withdrawal rate, w_t. Let $C_{Fuel}(i_t)$ represent the variable fuel cost incurred during injection and $C_T(i_t)$ represent the cost of transporting the gas to and from storage. We will define $C_V(i_t)$ to represent the sum of $C_{Fuel}(i_t)$ and $C_T(i_t)$. Finally, define the agent's information set at time t as I_t, β as the discount factor and η to be a number between 0 and 1.

The profit maximizing agent then chooses i_t at each period t to maximize:

$$E_t(\beta^{t+n}(\eta p^F_{t,t+n}+(1-\eta)p^S_{t+n})i_t-p^S_t i_t-C_I(g_t,i_t,G_{Max})-\beta^{t+n}C_W(g_{t+n},w_{t+n},G_{Min})-C_V(i_t)|I_t) \tag{1}$$

such that:

$$i_t = w_{t+n} \tag{2}$$

$$g_t = g_{t-1} + i_t - w_t \tag{3}$$

where:

$$\frac{\partial C_I(g_t,i_t,G_{Max})}{\partial i_t} > 0 \tag{4}$$

$$\frac{\partial^2 C_I(g_t,i_t,G_{Max})}{\partial i_t^2} > 0 \tag{5}$$

$$\frac{\partial C_W(g_t,w_t,G_{Min})}{\partial w_t} > 0 \tag{6}$$

$$\frac{\partial^2 C_W(g_t,w_t,G_{Min})}{\partial w_t^2} > 0 \tag{7}$$

Thus, the agent goes to the gas spot market at day t and purchases gas to maximize expected profits given its information set at time t. The agent secures futures contracts for time $t+n$ for η shares of the gas purchased and decides to sell $1-\eta$ shares in the spot market at time $t+n$ at the prevailing spot market price. Securing futures contracts is essentially a mechanism for the agent to purchase an insurance policy that locks in profits. The share of futures contracts the agent obtains, denoted by η, while not explicitly modeled in this problem, will be a function of an agent's risk aversion and expectations of future prices. The agent then stores this gas until time $t+n$, when all gas purchased at time t is delivered.

Equation (2) is a simplifying assumption that restricts all gas purchased at time t to be sold at time $t+n$; it is essentially the agent's budget constraint. Equation (3) describes the transition of gas inventories in storage. Equations (4)-(7) suppose the cost functions for injection and withdrawal of natural gas are strictly convex functions in injections and withdrawals, respectively. That is, injection costs increase at an increasing rate as injections increase and storage levels augment and withdrawal costs behave similarly as withdrawals increase and inventory levels are subsequently depleted.

Plugging (2) and (3) into (1), the agent then solves the following problem:

$$\max_{i_t \in \mathbb{R}} E_t(\beta^{t+n}(\eta p^F_{t,t+n}+(1-\eta)p^S_{t+n})i_t - p^S_t i_t - C_I(g_t, i_t, G_{Max}) - \beta^{t+n} C_W(g_{t+n}, i_t, G_{Min}) - C_V(i_t)|I_t) \tag{8}$$

The following first order condition then follows from (8):

$$E_t(\beta^{t+n}(\eta p^F_{t,t+n}+(1-\eta)p^S_{t+n}) - p^S_t - \frac{\partial C_I(g_t, i_t, G_{Max})}{\partial i_t} - \beta^{t+n}\frac{\partial C_W(g_t, i_t, G_{Min}}{\partial i_t} - \frac{\partial C_V}{\partial i_t})|I_t) = 0 \tag{9}$$

Equation (9) provides a moment condition that can be used to estimate the parameters of the model, once cost functions have been specified. Since the expectation in equation (9) is conditioned on the agent's information set at time t, any object in the information set, known at time $t-s$ for $s \geq 0$, will be orthogonal to the moment equation and can thus be used as an instrument to create enough moment conditions to identify the parameters.

7.2 Cost function specifications

As previously mentioned, the cost of injecting/withdrawing gas into/from storage depends on the level of gas in storage at the time of injection/withdrawal as well as the rate of injection/withdrawal. As the level of gas in storage increases, it becomes increasingly more expensive to inject gas. As the storage level nears the maximum capacity of the storage facility, the cost of injection explodes to infinity. Anecdotal evidence suggests this phenomenon normally occurs once the storage level nears 85% of the maximum capacity of the facility. Conversely, as storage levels are depleted, it becomes increasingly more expensive to withdraw gas from storage since there is less pressure in the reserve to expel the gas from storage. In fact, there is a level of gas in the storage facility from which no gas can be extracted from the facility once storage levels are beneath this floor (Natural Gas Supply Association, 2014).

In terms of the empirical model, this means we must design an injection cost function that increases with injection rates and for which the cost of injecting gas increases asymptotically when storage levels near the maximum storage capacity of the facility. Similarly, we must design a withdrawal cost function where the cost of withdrawing gas increases with the rate of withdrawal and increases asymptotically when storage levels near the base level.To identify and estimate the asymptotic nature of these cost functions, sufficient observations are needed where storage levels are above 85% of the maximum storage capacity level and are within 15% of the base gas level. There are sufficient observations in the dataset to identify an injection cost function that increases asymptotically with storage levels. However, there are no observations of storage levels even remotely near the cushion level of the storage facility; thus, a withdrawal cost function that increases asymptotically when storage levels are depleted is not identified given the dataset. The cost of withdrawal will thus be lumped in with the cost of transporting the gas to and from storage. This cost, denoted by C_{W+T}, will simply be modeled to increase with the rate of gas withdrawn and transported and will not be of much interest to this study - it will essentially be provided to facilitate the estimation of the injection costs. The cost of injection is modeled as:

$$C_I(g_t, i_t, G_{Max}) = \frac{\alpha i_t}{(G_{Max} - g_t)^\delta} \tag{10}$$

The cost of withdrawal and transportation is modeled as:

$$C_{W+T}(w_t) = \gamma w_t^2 \tag{11}$$

The total variable cost function will then consist of the injection, withdrawal and transportation costs, as well as some additional costs faced by the agent. In particular, the agent will pay a fuel charge of 2% of injected gas volumes at the time of injection, a common clause in storage contracts and present in the Spindletop contracts.

Total variable costs will then be modeled as:

$$\begin{aligned} C_{TotalVariable} &= C_I(g_t, i_t, G_{Max}) + C_{W+T}(w_{t+n}) + FuelCharges \\ C_{TotalVariable} &= \frac{\alpha i_t}{(G_{Max} - g_t)^\delta} + \gamma w_{t+n}^2 + 0.02 i_t p_t^S \end{aligned} \tag{12}$$

We can then plug (12) into (9), multiplied by a vector of instruments known at time t, to obtain the following:

$$z_t' E_t(\beta^{t+n}(\eta p_{t,t+n}^F + (1-\eta) p_{t+n}^S) - p_t^S - \frac{\alpha}{(G_{Max} - g_t)^\delta} - \frac{\alpha \delta i_t}{(G_{Max} - g_t)^{\delta - 1}} - \beta^{t+n} \frac{\gamma}{2} i_t - 0.02 p_t^S | I_t) = 0 \tag{12}$$

where $z_t' \in I_t$ is a $1 \times q$ vector, such that $q \geq 3$, of orthogonal instruments. The law of iterated expectations and the orthogonality of the instruments from I_t imply:

$$E_t(z_t'(\beta^{t+n}(\eta p^F_{t,t+n}+(1-\eta)p^S_{t+n})-p^S_t\frac{\alpha}{(G_{Max}-g_t)^\delta}-\frac{\alpha\delta i_t}{(G_{Max}-g_t)^{\delta-1}}-\beta^{t+n}\frac{\gamma}{2}i_t)-0.02p^S_t)=0 \tag{13}$$

which provide q moment conditions to recover α, δ, and γ using a generalized method of moments (GMM) methodology.

7.3 GMM Estimation

To estimate the model using GMM, z_t was constructed to contain the first 80 lags of past injection and withdrawal rates and the first 35 lags of spot prices. We allow 45% of the gas purchased at time t to be sold in futures contracts and the remaining 55% to be sold at time t for price p^S_{t+n}. This allows the agent to lock in some profits and also benefit from unexpected surges in demand. Prices are sourced from the TexOk gas trading hub; prompt month futures prices are used to reflect the short duration gas is held in storage in salt caverns and n is set to 30 to match the sale of the futures contracts. Prices have been converted from \$/Mmbtu to \$/Mmcf by multiplying the former by 1037 (EIA, 2017c) and quantities are measured in Mmcf. The discount factor, β, has been set to 1 since the agent only waits a month to collect total profits. Using generalized method of moments with Newey-West errors, and using the observed injection decisions, the estimates of the injection, and withdrawal and transportation costs are presented in Table 1.

A post estimation Hansen test was performed to confirm the validity of the instruments. Having obtained a p-value of 1, we can safely assume the instruments are exogenous to the error terms.

Figure 3 plots the surface of injection costs for varying injection rates and storage levels. We see that costs remain relatively stable until they near about 90% of capacity, where they increase asymptotically. These dramatic cost in-

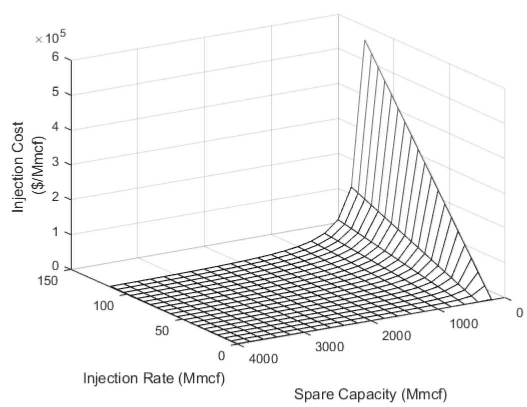
Table 1: Results

	Cost Parameters
α	7.07e+07**
	(1.98)
δ	1.828826****
	(28.99)
γ	0.4808489****
	(8.21)
N	522

t statistics in parentheses

* $p < 0.1$ ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

Figure 3: Estimated Injection Cost Surface



creases are likely to affect natural gas pricing.

The delta coefficient, which measures the degree to which injection costs become asymptotic when storage levels increase, is the most informative and interesting when considering the questions this paper seeks to answer. This coefficient is statistically significant and surprisingly large; it empirically confirms that injection costs explode as storage levels near capacity. Fang et al. (2016) note that in the past few years, salt cavern storage capacity has been underutilized in the Gulf region. This has been in response to low price differentials. With predicted increases in price spreads, as a result of increasing LNG exports from the Gulf area and the growing use of natural gas in the power generation sector, price differentials are expected to increase in the coming years. Inevitably, then, more pressure will be exerted on the existing underground storage and this is likely to increase the cost of storing gas. Understanding how these costs will change should aid investors, planners and policy makers in understanding and predicting natural gas pricing. Stored natural gas accounted for 20% of consumed natural gas during the 2016 winter season (ALL Consulting, 2016); understanding the pricing of storage is then pivotal in understanding the natural gas industry in itself.

Interestingly, the parametric assumptions of this cost function allow the cost function to be relatively constant when storage levels do not fluctuate greatly and to increase asymptotically when storage nears capacity. Tariffs charged by the Spindletop Facility, operated by Centana Intrastate, are posted by the Texas Railroad Commission, its state regulator. These rates are subject to maximum injection and withdrawal rates and do not cover the rates charged when storage levels are above the posted levels. The estimated injection cost function then provides some insight into rates that would be charged if storage levels increased.These estimates can be safely assumed to be representative of other salt caverns in the region with similar working capacity, and daily maximum withdrawal and injection rates. In terms of the validity of the model, it does a rather good job at predicting current prices given observed storage levels. The most recently posted injection tariffs for the Spindletop Storage Facility hover between 0.01$/Mmbtu and 0.02$/Mmbtu. Converting the estimates back to Mmbtu from Mmcf, the model predicts the cost to inject one Mmbtu of gas, at the median level of storage observed in the dataset, to be 0.027$. We can then more confidently examine some implications of these estimates in the next section.

8 Examining the Impact of Increased Utilization

Having obtained an injection cost function, we can now explore how prices would change for different utilization rates of storage in salt caverns. First consider how costs would vary if storage levels remained within the bounds that have been observed in the years 2015-2016. Note that the two years in question have been considered years of low utilization in the industry. If the median of storage levels shifted to the 75th percentile of storage levels observed during 2015-2016, the cost to inject would increase to 0.04$/ for one Mmbtu. If this shift landed on the 99th percentile of observations, the cost would increase to 0.06$ for one Mmbtu. These increase in storage levels present significant cost increases and would surely affect the profitability of storing gas.

Now consider the outcome if storage levels were increased to levels beyond what was observed in the dataset for 2015-2016. Without a quantification of costs, these predictions would be extremely difficult to make. The storage capacity of Spindletop is 21,880,700 Mmbtu. If storage levels were to reach 95% of this level, to 20,786,665 Mmbtu, the cost to inject one Mmbtu of gas would skyrocket to 0.21$. When the price of gas tends to be 2-4/Mmbtu, this increase in injection costs will seriously reduce profits. Injection costs are only one of many costs gas traders have to pay to bring their product to market. Increased use of salt cavern storage will clearly affect pricing and storage decisions by traders which will ultimately affect the natural gas market. This topic has received relatively little attention but could have enormous consequences for the market in a few years time.

9 Conclusions and Policy Implications

There will most likely be a greater need for salt cavern storage in the Gulf region. Increased LNG exports from the area as well as the electric sector's growing reliance on natural gas will put increasing pressure on the existing underground storage capacity. Moreover, changing weather patterns are making seasonal predictions more difficult which will put more value on storage facilities that can respond to quick changes in demand. Since injection and withdrawal costs are sensitive to the amount of pressure in the storage field, these costs are likely to change in the coming years with increased use of the facilities. This paper has provided estimates on how injection costs will change as storage is used more extensively, using a GMM estimation technique that recovers the unknown parameters from profit maximization assumptions and observed injection/withdrawal rates. The estimated results stipulate that as storage levels near capacity, injection costs increase asymptotically. The quantification of an injection cost function into salt cavern storage is an important finding for determining natural gas pricing and understanding the behavior of short term natural gas traders, who have a considerable influence on the market. At the theoretical level, it should also aid in building models that seek to determine the value of natural gas storage fields. The landscape of the U.S. natural gas market has greatly changed in the past few years and continues to do so, mainly in response to the Shale Revolution and the beginning of U.S. LNG exports; the natural gas storage industry is due to change with it.

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