THE "SUPPLY-OF-STORAGE"

FOR NATURAL GAS IN CALIFORNIA

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Abstract: Do natural gas storage decisions in California respond to futures price spreads? Daily data about flows into and out of storage facilities in California over 2001-2005 and daily price spreads are used to investigate whether the net injection profile is consistent with the "supply-of-storage" curve deduced by Working for wheat. Storage decisions in California do seem to be influenced by intertemporal signals on NYMEX, but the magnitude of the effect is small. Strong seasonal and weekly cycles determine the net injection profile to a considerable extent. Regulatory requirements and operational constraints also limit the size of the response to intertemporal arbitrage opportunities. Results are surprisingly sensitive to the level of aggregation considered.

1. INTRODUCTION

Futures markets provide intertemporal price signals. As Working (1934) first showed for wheat and others have observed for many other commodities, at least some, if not most, market participants pay attention to those intertemporal price signals.[1] Those holding stocks of wheat look to the nearby spread, holding considerably more stocks when the nearby spread is in contango than when it is in backwardation. Those holding commercial stocks in Chicago are extremely sensitive to the spreads in wheat futures prices at the Chicago Board of Trade, commercial holders outside the delivery area less sensitive, and farmers retaining wheat on farm least sensitive. Working (1948 and 1949) called the aggregate relationship a "supply-of-storage" curve.

Those agents whose behavior is not closely tuned to the intertemporal signals in a futures market could simply be inattentive but they also could be experiencing another signal or facing constraints that make them unlikely to respond. Even while wheat is temporarily scarce in Chicago and the futures spread in sharp backwardation, wheat could be abundant in a relatively isolated location and hence the effective local spot-forward spread be one of contango and an inducement for both commercial firms and farmers in that location to store (Williams and Wright, 1989). Or farmers could have planned to use their relatively small quantities of wheat as feed later in the year regardless of the spread at the time of their decision, let alone the subsequent day-to-day fluctuations in that price signal.

Daily data from April 2001 to April 2005 for natural gas stocks and flows into and out of storage within California allow a determination of the reach of futures prices.

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[1] For eggs and butter (Brennan, 1958), for cotton and wheat (Telser, 1958), for coffee and cocoa (Thompson, 1986), for fuel oil (Lowry, 1988), for copper (Larson, 1994) and (Thurman, 1988).

Although not efficient in pricing in its first years (Herbert, 1992), the NYMEX natural gas futures market is now deep and active. Yet California is far from and only indirectly connected to the pipeline system centered on the Henry Hub in Louisiana, the delivery location on the NYMEX futures contract. Brinkmann and Rabinovitch (1995) earlier concluded that those in California would find limited hedging effectiveness to NYMEX futures. Two of the four storage facilities within California are operated by the two main distribution utilities, which are not organized as nimble trading firms and which are constrained by regulators to have a set quantity in store each November 1, the supposed start of the heating season. The other two facilities are operated primarily as a "public" grain elevator would be - charging a set price for storage for a set time - which has enticed a wide range of customers, some of whom are purely traders and who might be closely tuned to NYMEX futures spreads.

2. CHARACTERISTICS OF NATURAL GAS STORAGE

Apart from California's remote location relative to the delivery point for the NYMEX futures contract and of the public utility character of the two biggest storage facilities, a third reason exists for making this an interesting study of the relationship between futures spreads and stocks: logistic and operational differences in storing natural gas compared to bulk commodities such as wheat.

Unlike grain, for which discontinuous supply is the main source of seasonality in stocks, natural gas inventories display a strong seasonal pattern originating on the demand side. So strong is this seasonality that there are two official seasons in natural gas storage, one for injection that runs April through October and one for withdrawals going November through March, delimited by the assumed length of residential heating demand. When the relevant price spreads are in significant contango, a switch from drawdown to accumulation of inventories is possible for both grain and natural gas.

Natural gas flowing into and out of a storage facility competes for pipeline space with flows for other immediate uses or for injection in other facilities. Net injections display a weekly cycle that peaks during the weekend, when other demand requirements are lower. For grain, however, provided the elevators are open, no obvious reason exists for receipts and shipments differing across days of the week.

Although grain elevators can be placed virtually anywhere, natural gas can be stored only underground, in depleted reservoirs, aquifers, or salt caverns; the geological characteristics of the formation partly determine how flexibly the facility can be operated. An added complication is that the facility needs to be connected to the pipeline network, and local congestion can be much more of an issue than for grain storage. As for the costs of injecting storage into a facility, compressors use natural gas itself as fuel to push the flow into the reservoir. There is no analogue for such a physical cost when storing grain.[2] The amounts of gas that can be put in and out of a facility are limited by the corresponding injection and withdrawal maximum rates or by the capacity in the connecting pipeline, whichever is less.[3] Although such loading and unloading constraints do affect grain storage (Brennan, 1994), they seem less of an issue for a grain elevator,

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[2] Unlike grain bins, which can be emptied, natural gas storage facilities often need some minimum quantity present to keep the geological formation intact. This physical reality is recognized in the concept of "working gas", which is the relevant storage amount from a marketing perspective.

[3] Unlike for liquids like gasoline, pipeline or storage capacity for natural gas can be increased with additional compression. The concept of "capacity" acknowledges, however, the rapidly increasing costs beyond some levels of usage.

because the supply of transportation services can be considered nearly perfectly elastic for a single facility.[4]

Natural gas storage facilities cannot be viewed as self-contained operations but as nodes of the California, and in a broader sense of the North American, natural gas network. Injection and withdrawal decisions cannot be taken without accounting for the operational status of interconnecting pipelines which are, in turn, connected to the backbone pipelines owned by distribution utilities and ultimately to interstate pipelines. California receives its gas from Canada, the Rocky Mountains, and the Southwest producing basin.[5] Once the gas is inside the state, it is either delivered by the interstate pipelines or distribution utilities to their respective customers, or stored.

Figure 1 displays the location of the main intrastate pipeline and storage infrastructure in California (California Energy Commission, 2002). SoCalGas and PG&E more or less divide California south and north, and operate with minimal interconnection of their backbone networks, even though in several places their pipelines are merely a few miles apart.[6] These utilities' operations are subject to regulatory requirements, also with no coordination. Each utility must accumulate a given level of stocks by the beginning of the official withdrawal season to ensure they will be able to satisfy heating demand. PG&E and SoCalGas are entitled to recover their annual rate base according to rate-of-return style regulation. In contrast, Wild Goose and Lodi mainly store for others at market-based rates while also engaging in short-term trading on their own account.[7]

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[4] Systemwide, the constraints on transportation capacity may have profound affects on grain storage (Brennan, Williams, and Wright,1997).

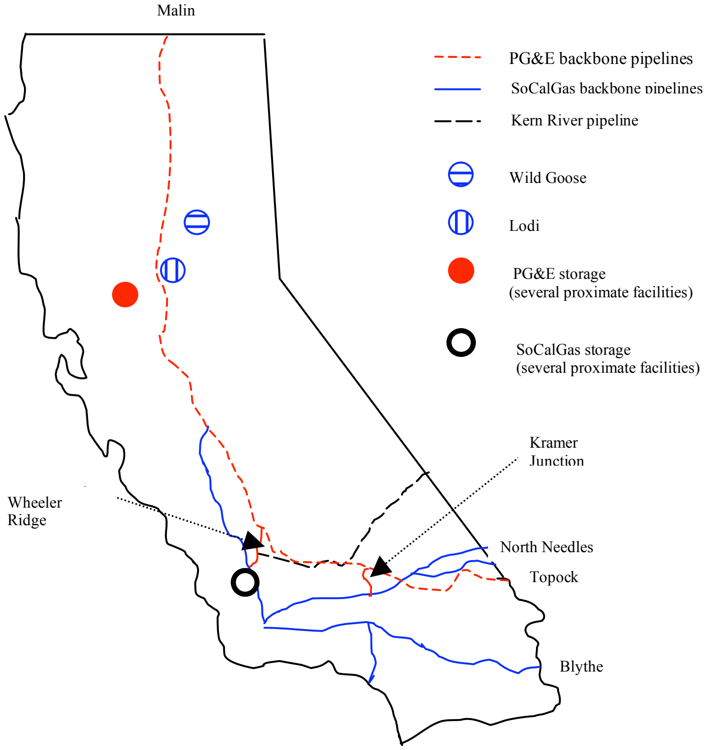
[5] In-state production contributes about 15% of total consumption.

[6] That is, various routes into California do not compete directly, unlike the situation De Vany and Walls (1996) have found for parts of the network in the Eastern U.S.

[7] Wild Goose gets its name from the prestigious hunting club below which a depleted gas field existed. Locating a storage facility there involved extra cost and inconvenience (the compressors had to be muffled

Figure 1

Physical configuration of the California natural gas network



Storage facilities in Figure 1 and for the rest of the analysis are aggregated into four points, even though the two utilities each have several facilities in their two general areas marked in Figure 1. As the utilities provide aggregate data, that is the unit of analysis used here. Most of the capacity in utility-owned facilities is dedicated to "core" customers, although industrial users and electricity generators can also acquire storage space in them.[8]

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for the sake of the ducks), but was anyway the best option because of the scarcity of locations with similar geological features and close to the PG&E backbone pipeline system.

[8] Core customers are residential and small firms who require utility gas service. Noncore customers are industrial, cogeneration, wholesale and utility electric generation customers who have alternative fuel capability

Table 1

Aggregate natural gas storage capacity in California[9]

Working gas capacity (Bcf)[10]	Maximum injection rate (MMcfd)	Maximum withdrawal rate (MMcfd)
256	2,025	5,714

Given the amount of storage capacity available statewide, it would take 127 days, approximately four months, at the maximum injection rate to fill all of it. In practice, the injection season has to be longer (seven months officially) because there is not enough pipeline capacity available to bring all that gas into the storage facilities in a 4-month frame while satisfying the other daily demand requirements.

One of the basic trade-offs in designing energy distribution networks is that between pipeline and storage capacity. In the producing areas, nature herself provides storage facilities. In the extreme, no storage capacity in consuming regions would be needed if pipelines were built big enough to satisfy peak demand requirements. Because such a configuration is clearly cost inefficient (huge pipelines would be half empty most of the year), storage in demand areas comes into play. The flexibility with which storage facilities can be operated largely depends on the balance between working gas capacity and rates of injection and withdrawal. A low injection rate or a tiny pipeline interconnection diminishes the usefulness of a storage reservoir as it would not be

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[9] The capacity figures in Table 1 include the recent expansion undertaken at Wild Goose, which came online in April 2004 and added 10 Bcf of working gas storage capacity, 370 MMcfd of injection capacity and 280 MMcfd of withdrawal capacity. Nationwide storage capacity is some 9,000 Bcf.

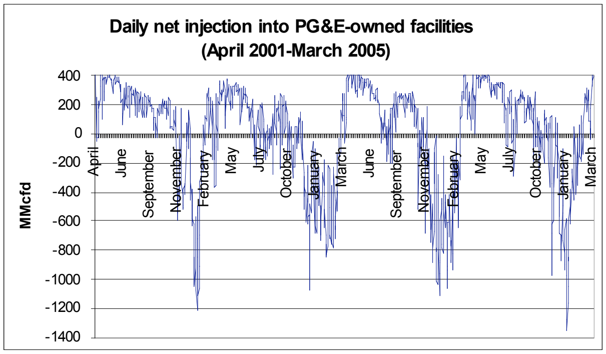
[10] 1 Bcf = 1,000 Mmcf. Natural gas flows are normally expressed in million cubic feet per day (Mmcf/d). On the other hand, the convention for prices is to use dollars per million British termal units ($/ MMBtu). 1 MMBtu is approximately equal to 1 MMcfd. MMcfd is a measure of volume while MMBtu refers to the heating power (the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit).

feasible to cycle its contents in one year, the relevant storage cycle imposed by natural gas demand.

Over the last twenty years, deregulation and the introduction of a futures market for natural gas have changed the character of natural gas storage operations (Doane and Spulber, 1994). Previously, storage services were bundled with transportation, as they were strictly tools for balancing pipeline flows and for smoothing seasonal price fluctuations derived from the demand cycle.[11] Independent storage facilities, one of the byproducts of the deregulation process in the natural gas industry, have largely contributed to the rise of more market-oriented uses of storage capacity. One of the hypotheses to be tested in the econometric analysis here is whether these facilities appear as significantly more price-responsive than those owned by the utilities.

The following set of figures illustrates the difference in injection profiles between utility-owned and independent storage facilities in California, especially the facility at Lodi. Figures 2-5 have been scaled according to the injection and withdrawal capacities of each facility so that they convey information about degree of utilization.

Figure 2



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[11] Indeed, transportation expenses themselves were often bundled into a pan-seasonal, pan-territorial price of natural gas (Hubbard and Weiner, 1991).

Figure 3

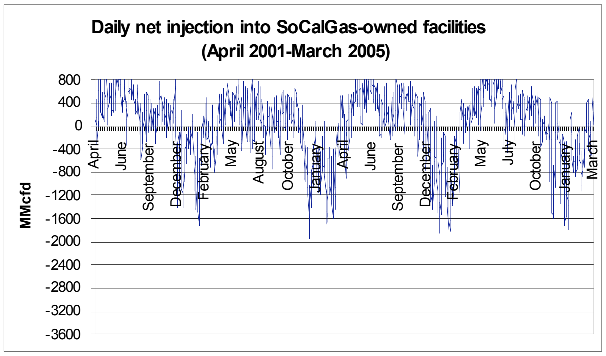
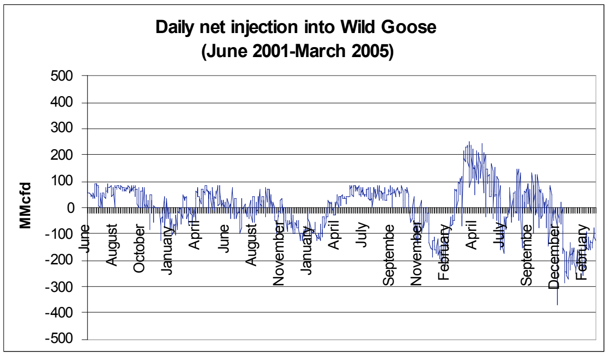
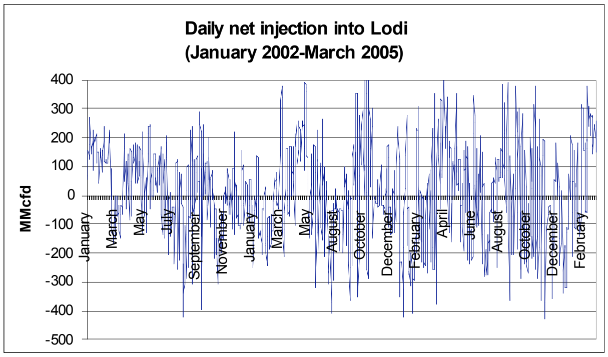


Figure 4



Note: Injection capacity was upgraded from 80 to 450 MMcfd in March 2004

Figure 5



The series in Figures 2 and 3 for PG&E and SoCalGas follow a very similar seasonal profile in terms of flows into and out of storage. Such a strictly seasonal pattern is also discernible for Wild Goose in Figure 4, but not for Lodi, which switches continuously between injection and withdrawal. Although less frequently, the other three facilities also switch modes of operation all through the year, so that the distinction between injection and withdrawal season is not clear cut. Figures 2 through 5 display enough variability to make the case for an econometric specification of injection decisions containing variables other than a seasonal dummy. Observations where gas is withdrawn during the official injection season and vice versa have the highest information content as to the relation between net injection and price spreads since chances are that switches to a countercyclical behavior respond to a price signal.[12] The percentage of countercyclical observations ranges from 14% for Wild Goose to 37% for Lodi.

Storage decisions are mainly being taken by three types of agents: utilities to satisfy core inventory requirements, industrial customers and electricity generators (these can choose between the storage services of the utilities or those offered by one of the two independent storage facilities), and independent facilities operating as proprietary traders. How much of their observed behavior can be explained with data on intertemporal and spatial arbitrage opportunities? How sensitive are the conclusions to level of aggregation? How can we account for the special features of natural gas storage, namely, nonlinear fuel costs and potential bottlenecks in the pipeline system? The data set in this study allows for insights on all three questions.

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[12] Conversations with the storage operators revealed that those switches are sometimes done for operational reasons like testing of the compressors.

3. THE RELATION BETWEEN INTERTEMPORAL SPREADS AND STORAGE DECISIONS IN CALIFORNIA

According to the theory of the "supply of storage", stocks should be held when their value, as reflected in futures prices, is expected to increase enough over time as to cover storage costs. The bigger the contango, more of the commodity should be placed into storage. These propositions emphasize the allocative role of future prices, according to which spreads guide inventory levels. However, in the "supply-of-storage" literature, price spreads have been considered the dependent variable and explained by the stock level. This direction of causality is merely a convention established in Working's seminal studies; at the aggregate level, both stocks and spreads are simultaneously determined. Granger (1969) argued that bi-directional causality may appear as a byproduct of data aggregation. When data sets with finer sampling whether over space or time are used, *a priori* information about the ordering of the variables often results in models where only one direction of causality makes sense.

Figure 6 can be interpreted as California's "supply-of-storage" curve for the April 2001- January 2005 period and emulates Working's original plots for wheat. Stocks as of the first day of April, July, October, and January are plotted against the two-month spreads observed on those dates.[13] The highest inventory buildups in California coincide with the deepest contangoes but approximately the same spread results in very different stock levels (part of the stock variability results from seasonality in the inventory profile). That is to say, the shape of the fitted curve suggested by the scatter plot does not follow closely the supply-of-storage theory.

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[13] The spot price level at Malin on the Oregon border during this period has averaged at 4.11 $/MMBtu but went as low as 1.22 $/MMBtu and as high as 11.46 $/MMBtu. Nearby futures prices were nearly as variable, around a slightly lower mean.

The expected positive relationship between stocks and spread (defined as the further-to-expiration minus the closer-to-expiration contract so that positive values are contangoes and negative ones backwardations) shows up clearly in Figure 7.[14] The difference is that in Figure 7 stocks are plotted against the two-month spread observed two months before rather than the two month spreads observed on those dates.

Comparison of Figures 6 and 7 suggests that, at this level of spatial aggregation, it is spreads that determine stocks rather than the other way around. The deepest backwardation (-0.743 $/MMBtu in April 2001 with respect to the June contract) resulted in the lowest stock level two months later, although the biggest contango ($1.809 in November 2004 with respect to the January 2005 contract) did not provide enough of an incentive to fill the storage capacity because it happened at a time of year in which demand for heating dictates the need for stock withdrawals.[15] All in all, California stocks in the aggregate seem to be somewhat sensitive to the NYMEX intertemporal price signal.

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[14] Over those three years, interest rates were stable and unusually low, so the spreads are not adjusted for financing costs.

[15] In percentage terms, contangoes for natural gas are sometimes much larger than for most other commodities.

Figure 6

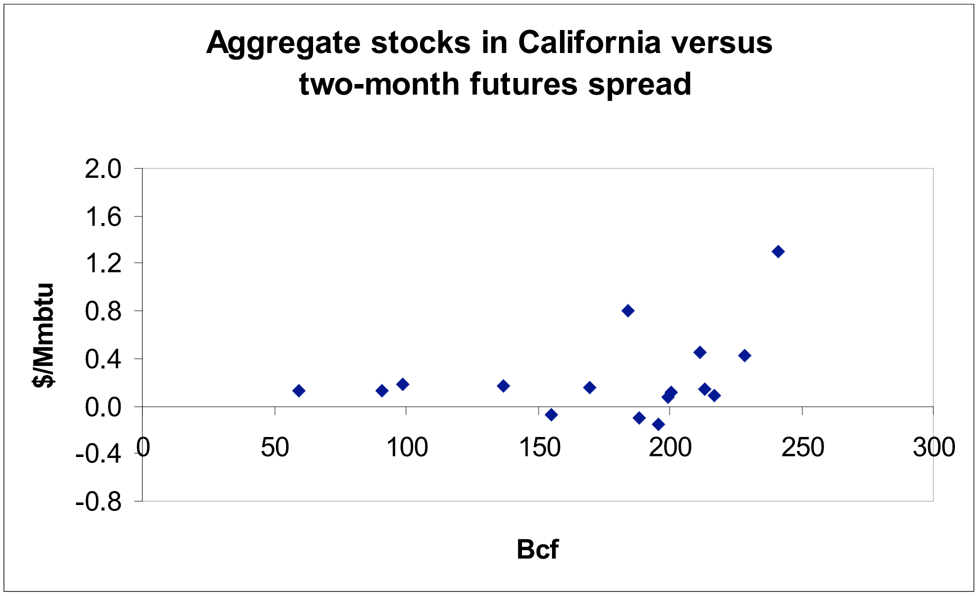
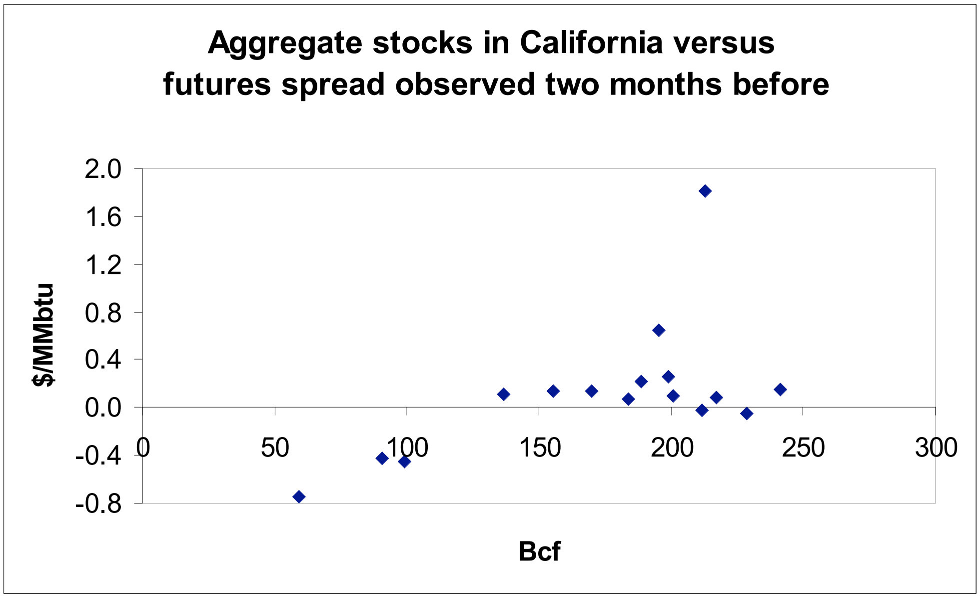


Figure 7



Additional support for the direction of causality suggested by these two figures comes from market size and informational flow arguments. As of 2003, storage capacity in California represented barely 3% of the U.S. total, which makes the assumption that

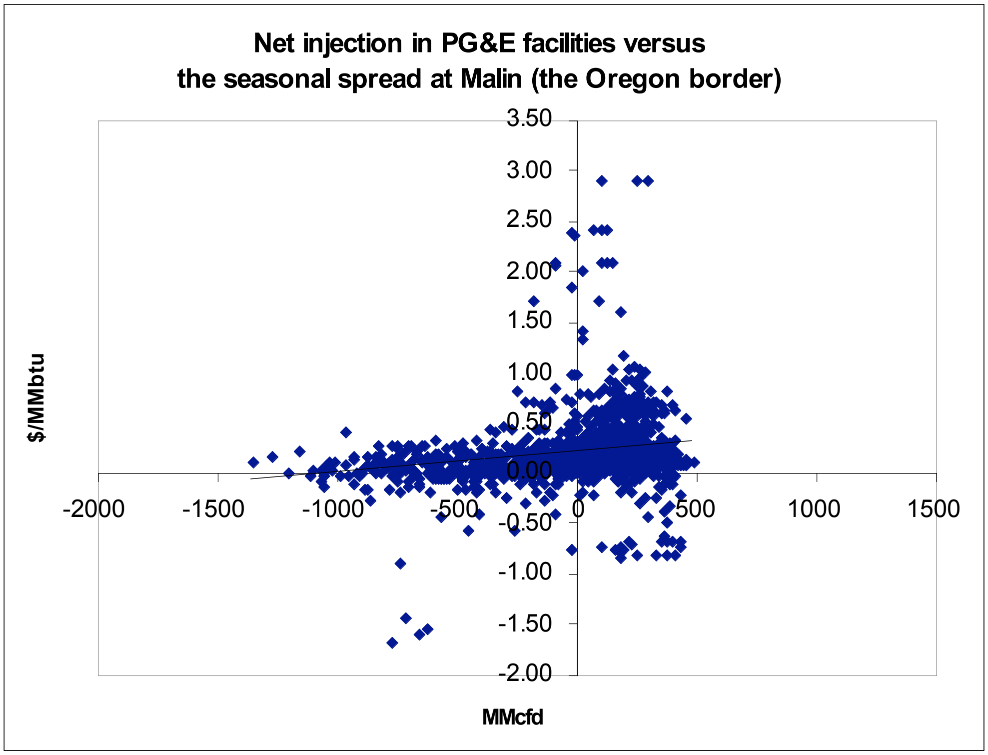
California takes the NYMEX price as given a reasonable one. Information about the continuously posted NYMEX futures may inform day-to-day decisions on how much gas to put into storage. The Energy Information Administration (EIA) releases U.S. inventory reports on a weekly basis, which Linn and Zhu (2004) have shown have an effect on NYMEX futures prices. On a daily basis, inventory changes are likely to play only a small role in determining futures price spreads just because the information is not easily available at that frequency.

Apart from direction of causality and level of data aggregation, the "supply of storage" relationship posed in the following analysis differs from past literature on the use of flows (net injections) rather than stocks as the dependent variable. This choice has important implications for the relevant intertemporal price spread to consider. For instance, April 1 stocks reflect to some degree the whole history of spreads relative to the futures contract for delivery on that month. However, flows - injection or withdrawal - in April 1 are forward-looking decisions that respond to the constellation of futures prices relative to all future dates observed that day. The past literature has focused on highly aggregated stock data and has not paid much attention to the determinants of flow decisions.

What would be the information gains from using daily injection data over the traditional analysis of monthly stocks versus spreads? The percentage of countercyclical observations in the weekly or monthly series is much smaller than in the daily ones, with those observations being the most helpful in teasing out the degree of responsiveness to intertemporal spreads. Thus, the level of temporal disaggregation matters when it comes to capturing these relationships.

Figures 8 through 11 plot daily net injection versus the spread per month observed each day (result of gas transactions that took place the day before) with respect to the futures contract for the beginning of the next season (either April or November).[16] The strong seasonal cycle in natural gas demand makes price at the beginning and ending of the heating season a relevant benchmark for those taking storage decisions.

Figure 8



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[16] Daily data for stocks and net injection were provided by the California Energy Commission. Daily spot price data come from Natural Gas Intelligence, a reporting service that conducts daily surveys of transactions at trading hubs across North America. Finally, the futures price data come from Norman Consulting by way of NYMEX.

Figure 9

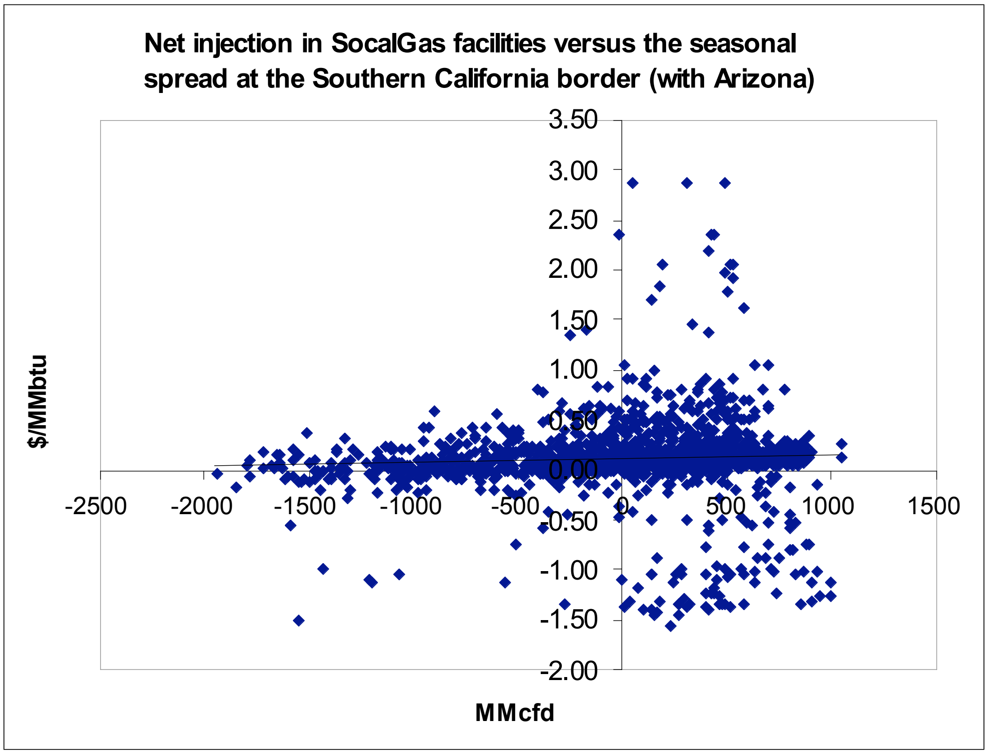


Figure 10

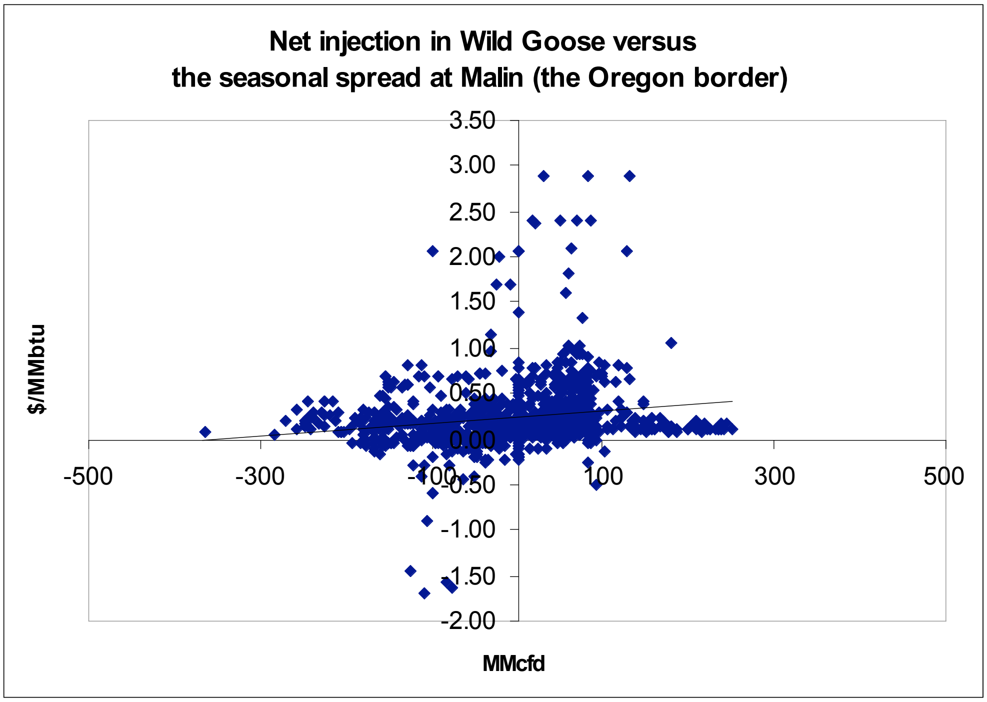
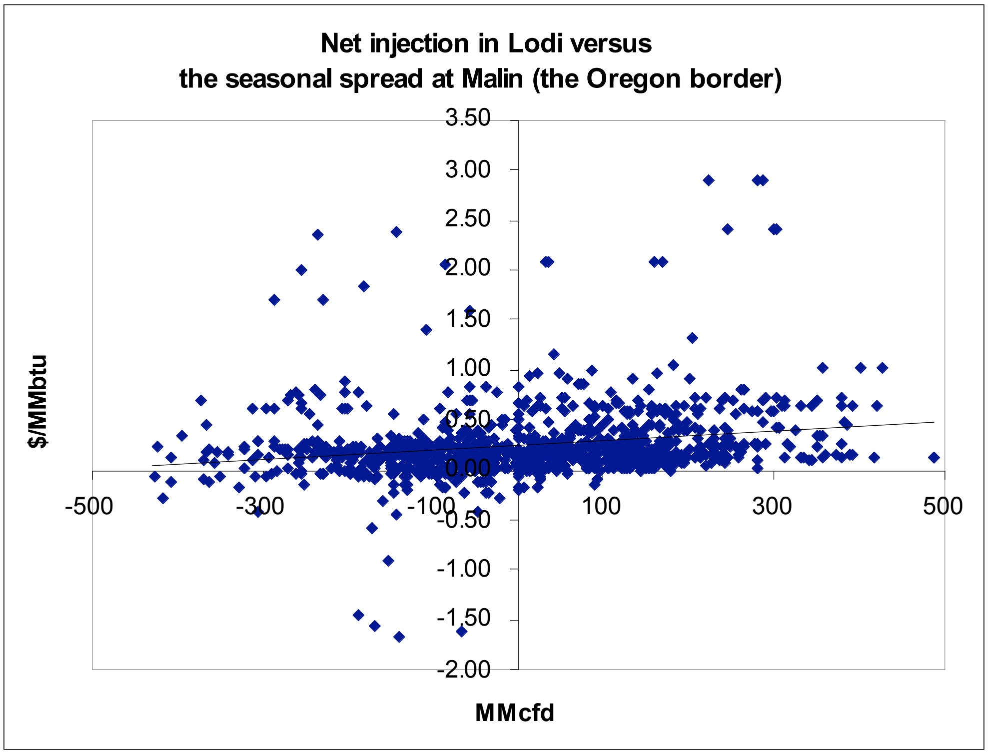


Figure 11



None of the plots reveal a strong positive relationship between the futures-spot differential and net injection. The intercept for each trendline provides, if the "supply-of-storage" theory is right, a rough estimate of the monthly carrying charge at that facility. All intercepts, except the one corresponding to SoCalGas, are in the range of 20-25 cents/ MMBtu. Only for a contango of at least that level would it be sensible to inject gas and hold it for a month. Figures 8 and 9 for PG&E and SoCalGas contain data that span the longer period starting in April 2001 (data for Wild Goose start on May 22 of that year and Lodi only started operation in January 2002). Points in the Southeast quadrant violate the "supply of storage" theory.[17] Those points mainly correspond to the first two months of the data set, during which the local spot prices in California were at historical

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[17] Clusters of points at the far right end of the quantity axis suggest that injection capacity is, at times, a binding constraint in PG&E, SoCalGas, and Wild Goose (for Wild Goose the constraint was relieved after its recent expansion). Withdrawal capacity does not seem to be binding.

maxima for a host of reasons resulting in the California "energy crisis". Because the stocks owned by PG&E and SoCalGas at that point were well below the historical average and it was the start of the official injection season, these facilities were switched into injection mode even though the local spreads were in deep backwardation.

4. CONSIDERATIONS FOR THE CHOICE OF PRICE SPREAD VARIABLES

Because the natural gas futures market comprises 72 delivery months at any one time, there are as many simultaneous intertemporal signals. Which signal, if any, seems to be most relevant for flows and stock decisions in California?

The local spreads shown in Figures 8-11 combine an intertemporal and a spatial element. For the econometric analysis both elements are considered separately. The intertemporal element (NYMEX futures – spot price at the Henry Hub) reflects the pure carrying charge; the spatial spread (e.g., difference between spot price at the California border and at the Henry Hub) contains information about the cost of transporting natural gas to some point in California. This locational basis depends on how congested the pipelines are and on the contemporaneous relative value of gas in California versus Louisiana. Such separation is not just an artificial construct. The basis swap futures contracts offered by NYMEX at Malin and SoCal provide protection from basis risk and allow taking advantage of spatial arbitrage opportunities.

Malin at the California-Oregon border, the SoCal border average, and the Henry Hub are the chosen locations for spot prices in this model.[18] Another choice in constructing the price spreads is what futures maturities to consider. Given that there is

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[18] The daily spot price at a given location is the average price from a survey of transactions involving gas to flow the next day. Most natural gas, however, is traded during the last five business days of each month (bidweek) to flow the following month. The average price from those monthly trades is the bidweek price.

an official storage season for each operation mode (i.e., injection and withdrawal), it makes sense to look at the futures contracts associated with their start (April and November). The "seasonal" spread defined here is, for any day, the difference between the closer to expiration of the April and November NYMEX futures contracts and the spot price at Henry Hub. The "seasonal" spread is then adjusted by dividing it by the number of months until expiration so that it refers to the storage return per month. Results will also be reported for the adjusted two-month spread. Intuitively, at any one date, the spread per month associated with different futures contracts should be approximately the same; otherwise there would be arbitrage opportunities not being exploited.

Table 2

Descriptive statistics of intertemporal price spreads

Spread (per month) $/MMBtu	mean	standard deviation	minimum	maximum
2 month NYMEX futures- Henry Hub spot	0.06	0.34	-6.13	1.84
Season-long NYMEX futures-Henry Hub spot	0.15	0.28	-6.13	1.55

Table 3

Descriptive statistics of locational basis

	mean	standard deviation	minimum	maximum
Malin spot - Henry Hub spot	-0.32	0.83	-8.94	5.99
SoCal border average spot – Henry Hub spot	0.14	1.78	-9.31	10.30

The difference in the mean spreads per month for the two-month and season-long spreads is striking but can be explained by the expectation of the demand jump in November as residential customers switch on their heaters. The expected jump in demand translates into a higher-than-otherwise price for that futures contract as well.

As extreme as are some contangoes observed during these four years, even more extreme are the backwardations. The asymmetry in the distribution of prices has its flip side in an observation that can be made for Figures 2 through 5 (Bresnahan and Spiller, 1986): Injection capacity is used sometimes at its maximum (stopping the contango from deepening too much) but withdrawal capacity is not used similarly to limit the extent of backwardation with respect to the local spot price. Why is withdrawal capacity not used more heavily in response to backwardations (or in response to contangoes that do not cover the full carrying charge)? Bottlenecks in pipelines and regulatory inventory requirements are plausible explanations. Data about daily flows in and out of storage allow for deeper investigation of these issues.

As for the locational basis, the positive mean for the SoCalborder average results from the extreme price peaks experienced in that location during the California energy crisis. The mean locational basis starting as of June rather than April of 2001 is -0.20.

5. SENSITIVITY TO SPREADS

The econometric analysis presented in this section, as explained in Section 3, asks whether natural gas injection decisions are tuned to futures price signals. Natural gas flows in and out of storage continuously; whereas prices are only generated during business days. According to industry convention, the price that applies to storage flows during weekends and holidays is that from the previous business day. Such an assumption allows equalizing the length of the stock and price series but also alters the structure of the latter. Both daily injection and daily spreads are highly autocorrelated. For the spread series, the hypothesis of a unit root can be rejected at the 1% level in all cases (such result is robust to the assumption made about non-business days). The stock level series present strong evidence of the existence of unit roots. The correlograms of the net injection series show strong first-order autocorrelation but the null hypothesis of a unit root can be rejected at the 5% significance level. The inclusion of the lagged dependent variable as a regressor corrects for autocorrelated errors and weakens the significance of the spread variables.

Table 4

List of variables for the econometric analysis

Dependent variable: ***Net injection*** (MMcfd)

Regressors:

lag**ged *injection***: first lag of net injection series (MMcfd).

stock: beginning-of-the-day stock level (Bcf).

day-of-week dummies: the results from the six dummy variables must be interpreted with respect to Wednesday.

Heating degree days (hdd): average temperature in the PG&E or SoCalGas system minus 65 degrees Farehnheit.

Cooling degree days (cdd)**:** 65 degrees Fahrenheit minus average temperature in the PG&E or SoCalGas systems.

Operational flow order (ofo)**:** 1 if the pipeline system is subject to an operational flow order, 0 otherwise.

Henry Hub spread**:** NYMEX futures closing price for the seasonal or second to nearest contracts ($/MMBtu)- Henry Hub spot price[19]

basis: Malin (SoCalborder) daily spot price – Henry Hub spot price

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[19] Regressions were run for the spread relative to the January futures contract and for the nearby and three-month spread but the results are not reported here.

Table 5

Estimated coefficients from OLS regressions of daily net injection by facility on lagged intertemporal spread and lagged locational basis

	PG&E		SoCalGas		Wild Goose[20]		Lodi	
	seasonal	2month	seasonal	2month	seasonal	2month	seasonal	2month
R^2	0.888	0.885	0.880	0.88	0.856	0.855	0.567	0.568
D-W statistic[21]	2.00	2.05	1.80	1.80	2.11	2.11	2.06	2.06
lagged injection	**0.761** (52.03)[22]	**0.760** (46.91)	**0.732** (49.27)	**0.732** (49.35)	**0.803** (46.57)	**0.804** (46.42)	**0.624** (28.41)	**0.623** (28.44)
stock	**-0.907** (-4.59)	**-1.139** (-4.59)	-0.264 (-1.11)	**-0.447** (-1.75)	-0.325 (-1.39)	**-0.370** (-1.56)	**-5.513** (-4.88)	**-6.739** (-5.20)
Monday	**-63.837** (-5.64)	**-69.460** (-5.25)	**-275.30** (-13.67)	**-276.28** (-13.72)	1.617 (0.54)	1.715 (0.58)	**45.554** (3.79)	**44.921** (3.74)
Tuesday	-10.699 (-0.95)	-12.792 (-0.97)	23.966 (1.22)	23.705 (1.210)	**-12.534** (-4.26)	**-12.843** (-4.24)	**-44.562** (-3.73)	**-44.865** (-3.76)
Thursday	-13.242 (-1.18)	-18.571 (-1.42)	**31.815** (1.63)	**31.512** (1.612)	2.050 (0.70)	2.123 (0.725)	16.705 (1.43)	16.302 (1.40)
Friday	13.703 (1.22)	10.228 (0.78)	**121.73** (6.22)	**122.26** (6.24)	0.587 (0.20)	0.721 (0.24)	**40.072** (3.42)	**39.926** (3.41)
Saturday	**33.133** (2.93)	**28.829** (2.19)	**232.44** (11.65)	**234.31** (11.74)	**7.659** (2.58)	**7.939** (2.68)	**104.27** (8.89)	**104.16** (8.89)
Sunday	**-21.870** (-1.93)	**-26.940** (-2.04)	**84.454** (4.18)	**85.431** (4.23)	0.587 (0.19)	0.838 (0.28)	**57.523** (4.81)	**57.359** (4.80)
Hdd	**-12.214** (-14.09)	**-13.360** (-13.30)	**-34.453** (-17.63)	**-35.138** (-17.95)	**-1.454** (-7.38)	**-1.535** (-7.95)	**-2.345** (-3.49)	**-2.728** (-4.26)
Cdd	**-5.199** (-6.51)	**-5.759** (-5.93)	**-12.527** (-9.13)	**-11.839** (-8.61)	-0.306 (-1.58)	**-0.290** (-1.47)	**-2.299** (-2.71)	**-1.999** (-2.32)
Ofo	-1.306 (-0.14)	-4.545 (-0.39)	**-149.89** (-7.03)	**-158.51** (-7.31)	**9.748** (3.72)	**9.659** (3.68)	**89.590** (8.85)	**86.344** (8.43)
Lagged seasonal spread	**30.275** (2.51)		**76.178** (3.69)		**9.555** (2.45)		**33.927** (2.55)	
Lagged 2month spread		**25.472** (2.11)		**66.707** (3.64)		**6.759** (1.90)		**35.930** (2.97)
Lagged locational basis	**10.711** (2.67)	**24.715** (2.56)	**10.685** (3.20)	**10.195** (3.03)	-0.152 (-0.07)	0.920 (0.44)	**-26.259** (-2.81)	**-29.385** (-3.09)
Constant	**183.40** (9.82)	**223.15** (9.43)	**180.90** (7.28)	**193.30** (7.53)	**12.994** (3.43)	**14.086** (3.75)	20.086 (1.43)	**29.136** (2.06)

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[20] For Wild Goose, a Chow test indicates that the hypothesis of equal coefficients in the pre-expansion and post-expansion periods must be rejected. The results in Table 5 correspond to the pre-expansion period. Figure 4 showed that injection capacity was often binding at Wild Goose before the upgrade that came online in April 2004.

[21] The relevant upper and lower bounds of the Durbin-Watson statistic are 1.35 and 2.03. Thus, the null hypothesis of no autocorrelation will not be rejected for Wild Goose and Lodi. Meanwhile, results for the utility-owned facilities lie on the inconclusive region of the test.

[22] t-statistic is in parenthesis. Estimated coefficients whose t-statistic is above 1.66 are significant at the 5% level and bolded.

Most of the variability in net injection is explained by the chosen set of regressors, except for Lodi. The negative and significant relationship between the current stock level and the day's net injection captures the nonlinearity in injection costs; When the storage reservoir is nearly full, additional injections become increasingly costly in terms of needed compression power.

All facilities reveal a similar weekly cycle with injection peaking on Saturday and reaching a low Monday in the utility-owned facilities and on Tuesday in the independent facilities.[23] Competition for pipeline space between gas for storage and gas for consumption is a likely explanation for this result as industrial and electricity generation demand is higher on business days.

In a structural model of flow and storage decisions taken on the natural gas transportation and distribution network, degree days would appear on the right-hand-side of the demand equation. The regressions whose results are reported in Table 4 are better interpreted as a reduced-form model where degree days are used as a proxy for the seasonal cycle in demand.[24] Scatter plots of net injection versus heating and cooling degree days show a strong relationship that is close in shape to an inverted parabole. However, temperature does not cause flows into or out of storage directly but indirectly through demand. Extreme cold or warm temperatures increase natural gas demand, which is partly satisfied by bringing additional flows from out of state into the system and partly through withdrawals from within-state storage. For the utility-owned facilities, inventory withdrawals are heavier in response to heating than cooling demand.

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[23] Often, customers of the independent facilities make deals on Friday for gas flows in Saturday, Sunday and Monday. That may explain why Tuesday behaves as the beginning of the business week for Wild Goose and Lodi.

[24] An injection season dummy that takes the value 1 from April to October was eliminated from the model as it becomes insignificant when degree day variables are included.

For Lodi because of its serving electricity generators, the magnitudes on both degree days variables are similar.

Operational flow orders (OFOs) were in place 12% of the time in the PG&E system and 7% in the SoCalGas system during the period under consideration. OFOs are called by the pipeline system operators when the prevailing pressure is close to upper or lower bounds where it would jeopardize the operation of the system. When an OFO is in place, customers must keep a closer balance between the amount of gas they request to be put in the pipeline and the amount they actually consume day by day; otherwise they pay a penalty. Most OFOs correspond to situations of high pipeline load so it can be viewed as a proxy for congestion in the intrastate pipelines. According to the estimates in Table 5, OFOs trigger different responses across the four storage facilities in California. Customers holding capacity in independent storage facilities inject gas to help balance their accounts with the pipelines. PG&E-owned facilities do not respond to OFOs and SoCalGas customers withdraw rather than inject gas under those circumstances. In the PG&E system customers can "park" gas in the pipeline. The opposite sign for SoCalGas versus the independent facilities in Northern California implies that in the former system flows from out of state are reduced in response to an OFO event and storage withdrawals compensate for that pipeline inflow reduction. On the other hand, customers of independent facilities in Northern California seem to be moving the gas that was "parked" in the PG&E pipelines into storage to reduce the pipeline load factor. OFOs are an example of an operational constraint that could be muffling responses to intertemporal price signals in the futures market.

The price regressors are lagged one period since information available at the time injection decisions are taken corresponds to the previous day. Then, the contemporaneous local spot price (and thus the locational basis) is simultaneously determined with the storage and flow decisions but the lagged basis is a predetermined variable for which endogeneity does not constitute an issue. Net injection decisions in all four facilities are in accordance with the "supply-of-storage" theory in that they respond positively to increases in the intertemporal spread per month. As for the locational basis, the magnitude of the effect is smaller but still significant for all facilities except Wild Goose. For the utility-owned facilities, the estimated coefficient on the basis is positive, which would be consistent with the idea of gas flowing towards the network hubs in which it is most valuable at the time. For Lodi, the estimated coefficient on the locational basis is negative. A plausible explanation for the negative sign can be given when taking into account that customers in this facility are primarily electricity generators. Those customers withdraw most of their inventories during the summer because that is when natural gas demand for electricity generation peaks; Summer happens to be the season in which the relative value of natural gas in California versus the Henry Hub is highest as well.

Additional insight on the magnitude of these coefficients comes from paying attention to the units in which they are measured. The estimated coefficients on the intertemporal spread are such that a 1.00 $/MMBtu increase in the spread (a huge change considering the average spreads reported in Table 2) would result in increase in injection approximately equal to 10% of injection capacity in any of the facilities, either utility-owned or privately operated.

In sum, according to the evidence in Table 5, storage decisions in California are made with an eye on profitable arbitrage opportunities although preset seasonal and weekly cycles determine the injection profile to a considerable extent and there are additional regulatory requirements and operational constraints that limit the size of the response.

6. EFFECTS OF SPATIAL AND TEMPORAL AGGREGATION

Results from the daily analysis of individual storage facilities reveal sensitivity, although weak, to price spreads. Here, the same relationship is examined for longer sampling periods and aggregating over facilities in order to ascertain the gains provided by the more disaggregate analysis.

Spatial aggregation

Natural gas inventory figures are predominantly reported at the regional or state level. Net injections themselves are usually not reported but can be easily constructed from information on the stocks. In order to investigate the California net injection-spread relationship, summary measures of the prices and temperatures across the state must be constructed. Price spreads and total degree day measures for the aggregate California injection were constructed as weighted averages of the series for the PG&E and SoCalGas systems. The weights for the locational basis are based on the percentages of total flows for which Malin and the SoCalborder average are the reference price respectively. The weights on degree days were based on the percentage of total demand that each region represents. The OFO variable was not included because it is specific to each pipeline system.

Table 6

Estimated coefficients from OLS regressions of California-wide daily net injection on Henry Hub spreads and locational basis.

Dependent variable: California net injection	seasonal	2month
Lagged Henry Hub spread	**77.589** (2.69)	**66.227** (2.59)
Lagged locational basis	**18.104** (2.81)	**17.631** (2.72)

According to Table 6, one dollar increases in either the intertemporal or spatial spreads result in daily injection increases that represent 3.8% and 0.9% of the state's injection capacity respectively. Thus, the response in the aggregate appears to be smaller than that observed in the regressions for individual facilities. The estimated coefficients on stock, day-of-week dummies and degree days replicate the results seen for the utility-owned facilities in Table 5 because they make up for 85% of storage capacity in the state. Similarly, the results from considering jointly the three facilities sharing PG&E's pipeline infrastructure resemble closely those from PG&E-owned facilities. In general, the estimated coefficients for the California aggregate are not the sum of the individual coefficients. The behavioral differences between utility-owned and privately-owned facilities, which can be important to manage network operations efficiently and to design optimal regulatory rules are lost in models that look at aggregate California storage.

Temporal aggregation

The results in Tables 7 and 8 correspond to a set of regressions in which monthly and weekly net injection in California facilities respectively are a function of net injection last period, stock level at the beginning of the period, total heating and cooling degree days and monthly or weekly average price spreads. Price spread variables refer to the same period as injection because the ordering of variables cannot be discerned anymore. Day-of-week and OFO dummies are left out of the monthly and weekly level analysis.[25]

Table 7

Estimated coefficients from OLS regressions of California weekly net injections on intertemporal price spread and locational basis

Dependent variable: Weekly injection	PG&E		SoCalGas		Wild Goose		Lodi	
	seasonal	2month	seasonal	2month	seasonal	2month	seasonal	2month
Henry Hub spread	**86.566** (1.79)	**92.444** (3.112)	**259.98** (3.78)	**196.97** (3.89)	**17.789** (2.07)	**12.274** (1.88)	**72.113** (1.75)	**79.377** (3.03)
Locational basis	**22.776** (2.41)	**20.530** (2.21)	11.705 (1.02)	9.236 (0.80)	-1.411 (-0.24)	-1.031 (-0.18)	-29.266 (-1.26)	**-46.193** (-1.97)

The steeper in the contango is the weekly average intertemporal spread, the heavier the injection at any of the facilities. The magnitudes, even though adjusted to represent daily effects, are significantly bigger than those in Table 5 (and the bigger magnitude persists even when compared with daily regressions in which the day-of-week and operational flow order dummies (OFOs) were left out). However, only PG&E facilities seem to be paying attention to the differential between the local and Henry Hub spot prices. Such a result can be explained by the weekly cycle followed by the locational basis series. A dummy for Mondays has a positive and significant effect on the basis while Friday has a negative effect. The weekly pattern is hidden in the weekly average. The estimated coefficients on stock level and degree days continue being negative and significant for all four facilities.

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[25] The estimated coefficients from the weekly and monthly regressions were divided by 7 and 30 respectively so that they all represent a daily effect.

Table 8

Estimated coefficients from OLS regressions of California monthly net injections on intertemporal price spread and locational basis

Dependent variable: Monthly data	PG&E		SoCalGas		Wild Goose		Lodi	
	seasonal	2month	seasonal	2month	seasonal	2month	seasonal	2month
Henry Hub spread	76.026 (1.51)	22.87 (0.54)	61.466 (0.97)	-33.507 -(0.80)	11.366 (0.89)	12.583 (1.17)	61.467 (1.57)	**53.403** (1.665)
Locational basis	-4.766 (-0.39)	-1.516 (-0.12)	-11.020 (-1.50)	-9.855 (-1.26)	3.804 (0.20)	2.611 (0.138)	-4.267 (-0.12)	-13.903 (-0.35)

Heating and cooling degree days have much less explanatory power at the monthly level. An injection season dummy captures better the monthly injection profile. Responsiveness to price signals vanishes as short-term switches from injection to withdrawal and *vice versa* cancel out. The following example well illustrates the loss of information entailed when aggregating injection data. In November 2001, daily average injection in PG&E-owned facilities in November 2001 was minuscule (-4.81 MMcfd) and all the price spreads considered were in contango at that time. However, daily data shows that injections took place for the first three weeks of that month (as it would be expected in response to a contango) and were followed by heavy withdrawals in the last week of the month, withdrawals that offset almost entirely the initial injection. Similar issues would arise on an analysis of wheat shipments and receipts. The need for highly disaggregated data to carry out meaningful analysis of flows might explain why most of the literature on this topic restricts itself to data about stocks.

CONCLUSIONS

Multiple cycles of different frequencies can be discerned in series of stocks of natural gas. A seasonal cycle driven by demand and regulatory requirements, a weekly cycle that follows the dynamics of pipeline load, and daily adjustments to weather and operational conditions are all material to storage injection and withdrawal decisions. Such superposition of cycles is present for wheat as well, although in that case seasonality originates in the supply side and higher frequency patterns result from the logistics of transportation for the whole grain complex. The “supply of storage curve” proposed by Working may work so well for wheat because the seasonal cycle so dominates.

The question for natural gas is whether injection decisions (rather than the resulting stock level) respond to short-term arbitrage opportunities despite official seasons, regulatory requirements and operational rigidities. An exceptional data set allows an investigation of daily behavior in the four California storage facilities after controlling for the factors governing the lower frequency cycles. Highly disaggregate data mimic best the actual decision sequence and reveal that injection increases slightly as the intertemporal spread strengthens.

Even for wheat, but much more so for natural gas, a structural, simultaneous equations system would be necessary to fully comprehend the daily interactions of demand, flow and storage decisions, inevitably linked by the material balance equation that must hold in the network. A closer examination of the determinants of switches between injection and withdrawal decisions observed in daily data, maybe by means of a threshold regression model, could be a useful extension. Finally, it would be interesting to compare the California case with some other area closer to the Henry Hub to see how much does distance mute the price signals implied by the NYMEX futures price spreads.

Storage decisions in California do seem to be influenced by intertemporal price signals, but the magnitude of the effect is small and depends on the specifics of the various cycles and the nature of the storage facility. Time and space both matter but not in a simple way.

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