Gas Storage Needed to Support Electricity Generation

Prepared For

The Utility Air Regulatory Group

and the

American Public Power Association

An Update to

Implications of Greater Reliance on Natural Gas for Electricity Generation (2010)

June 2012

Aspen Environmental Group

Update on Natural Gas Storage Needed to Support Electricity Generation

Table of Contents

List of Figures

This report was prepared by Aspen Environmental Group (Aspen) at the request of the Utility Air Regulatory Group (UARG) and the American Public Power Association (APPA). UARG is a voluntary, nonprofit association of electric generating companies and industry trade associations whose purpose is to participate on behalf of its members collectively in EPA's rulemakings and other Clean Air Act proceedings that affect the interests of electric generators. APPA represents the interests of more than 2,000 publicly owned electric utility systems across the country, serving approximately 43 million citizens. The study was prepared independently, by Aspen, using its best professional judgment and analysis of publicly-available data. Such data is not within the control of Aspen and we are not responsible for its accuracy. Any use of this report constitutes agreement that Aspen accepts no liability for consequences arising from said use.

Aspen's Integrated Energy Analysis Division provides independent, objective analysis of energy economics issues, for use in decision support and energy policy making related to selection and siting of electricity generating resources, transmission planning, renewables integration, socio-economic impacts and a wide range of natural gas issues. The firm has offices in Los Angeles, San Francisco, Sacramento, and Las Vegas.

The principal investigator for this report is Senior Associate Catherine M. Elder. Ms. Elder has more than 25 years of experience in the natural gas and electricity industries. She has reviewed fuel plans and prepared natural gas market assessments for use in financing more than 40 natural gas-fired power projects around the country. Additionally, she has prepared natural gas price outlooks, negotiated contracts for natural gas supply and transportation, and evaluated proposed greenhouse gas policies for their effect on electric utilities and their customers.

Update on Natural Gas Storage Needed to Support Electricity Generation

Executive Summary

In June 2010, Aspen delivered a report—*Implications of Greater Reliance on Natural Gas for Electricity Generation*—that was commissioned by the American Public Power Association (APPA), with financial support from the Utility Air Regulatory Group (UARG) and other electric utilities. The report presented a broad assessment of issues that would arise as utilities replaced their base load coal-fired electricity generating units with new units fired by natural gas. The study generally concluded that such a large switch would cost more and require more finesse and adjustments by both the electric utilities and natural gas industry than typically admitted or recognized. At UARG's request, Aspen has prepared an update on gas storage issues. Thus, this report explores changes to gas storage in the past two years and adds detail that goes beyond the general briefing on storage provided in the original report.

Key conclusions reached by this update include:

- FERC and state commissions have certificated close to 110 projects since 2000 resulting in a net increase in working gas capacity of 0.3 Trillion Cubic Feet (Tcf).
- There are only a handful of additional projects in the current approval queue.
- More than 85% of the new storage was certificated allowing it to charge market-based rates, which typically relate to the financial option value of storage based on changes in natural gas prices without regard to the reliability of electricity generation or delivery.
- End-use curtailment policies behind citygates could be updated to encourage use of storage by generators, where physically feasible.
- Where feasible, storage located closer to a generator provides a higher degree of reliability and may allow a more efficiently-sized pipeline.
- Storage is the key degree of freedom that allows pipelines to offer generators more flexible services
- Without new storage that is integrated into pipeline services and rates, pipelines will likely have to tighten their balancing requirements as capacity utilization limits are approached and greater variation in load by more gas-fired generation uses up line pack.
- Other uses compete for the same limited geology as underground gas storage and utilities may want to consider above-ground gas storage.

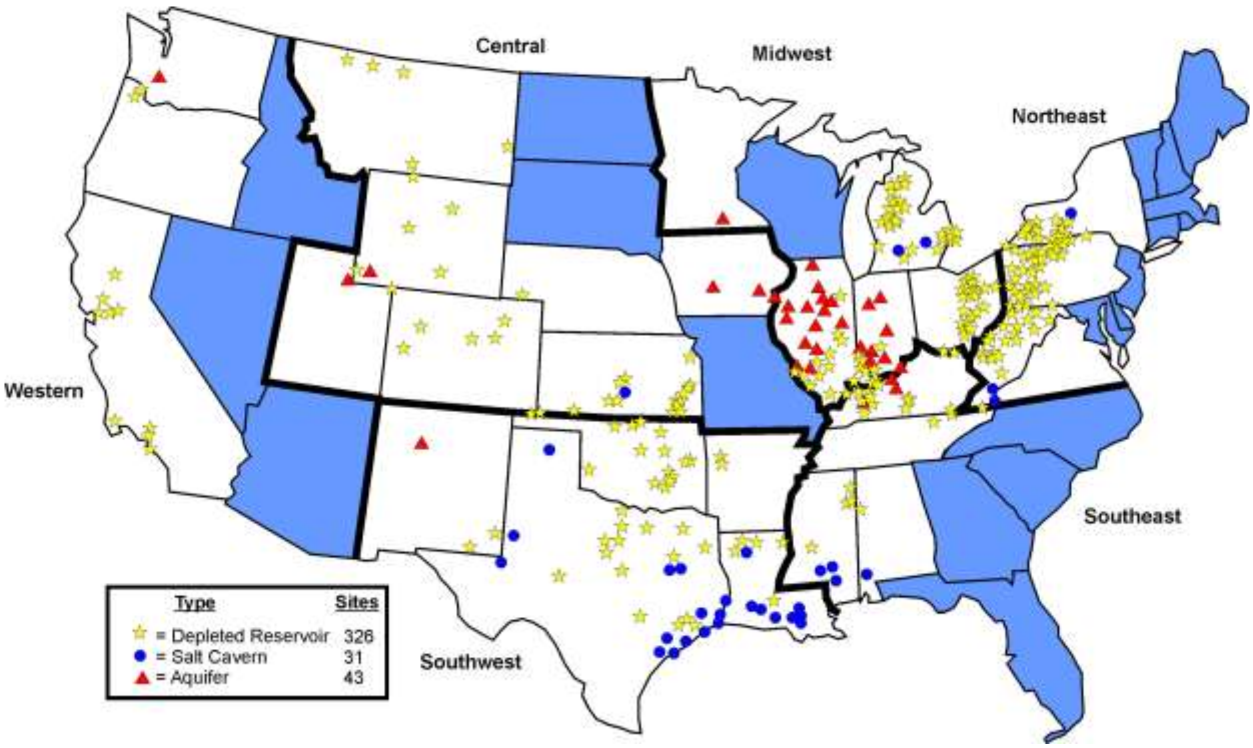
Key Points and Conclusions from the 2010 Report[1]

Aspen's 2010 report for APPA and UARG provided a basic overview on natural gas storage.[2] It explained that the industry uses three kinds of underground gas storage: depleted oil or gas reservoirs, aquifers or

[1] A complete copy of the he original report released by APPA in July 2010 can be downloaded fromhttp://www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf.

salt caverns. Figure 1 displays their distribution, by type, across the country. Blue states have no storage in service at this time. Depleted oil or gas reservoirs and aquifer storage tend to cycle injections and withdrawals once per year and tend to be rate-based storage. Salt Cavern storage, on the other hand, tends to be capable of cycling several times per year and is offered at market-based rates. It is possible, however, to add enough injection and withdrawal capability to some reservoirs to make them capable of cycling more than once. We noted that several pipelines don't have much or any storage located along them and that storage service adds cost.

Figure 1: U.S. Underground Gas Storage Facilities by Type



Source: EIA and Aspen Environmental Group

The 2010 study's conclusions about gas storage are repeated below. Aspen finds all of them to remain valid.

1. Storage is used by different market segments for different purposes.
2. Different types of storage suit the intended use of different market segments.
3. Geology limits opportunities to build storage where the market would prefer it; accordingly, storage is not distributed evenly across the country and most of it is reservoir-based.
4. Areas without much storage include: Nevada, Idaho and Arizona, the Central Plains states, Missouri and virtually the entire East Coast (except far upstream in western New York, western Pennsylvania and western Virginia).

[2] See pp. 57 to 72 of the 2010 report. At page 6 one will also find a methodology to quickly convert from MMcf to MMBtu. In this update, Aspen generally tries not to repeat the discussion in the 2010 report.

5. Pipelines that have little access to storage include: Florida Gas Transmission, Kern River Gas Transmission, Southern Natural, Transco, Iroquois, Maritimes & Northeast, Alliance, Gas Transmission Northwest, Northern Border, Trailblazer, Transwestern, El Paso Natural Gas, and Williston Basin Pipeline.
6. Some high deliverability storage is reservoir-based but most is provided via salt caverns.
7. The capital costs to build new storage are field- and cavern-specific, varying with geology, field or cavern pressure and the configuration of injection compressors, withdrawal wells and other equipment selected to optimize project economics.
8. Greater reliance on natural gas to produce electricity means we need more storage and more flexible storage.
9. Scaling storage up to meet double the current Electric Generation (EG) demand implies a need to add 1.4 Tcf of storage.
10. A recent study for the Interstate Natural Gas Association (INGAA) found a need to add 0.45 to 0.6 Tcf of storage at a cost of approximately $8.9 Billion per Tcf. Adding 1.4 Tcf would thus cost close to $12.5 Billion.
11. The annual fixed costs for even a small amount of storage inventory can amount to several million dollars per year and represent a significant financial commitment on the part of the generator.
12. Electric utilities or generators managing a single or only a few gas-fired units are not typically well-positioned in terms of staff or institutional experience to closely manage multi-turn storage in a volatile price environment.

Recent and Expected Additions to Storage

The latest list of storage facilities from the U.S. Department of Energy's Energy Information Administration (EIA) shows 411 individual fields totaling 4.4 Tcf of working gas capacity, with a total withdrawal capability of 104 Bcf in a single day. This is slightly higher than the roughly 400 underground gas storage fields with 4 Tcf of working gas capacity and a total maximum daily withdrawal capability of approximately 88 Bcf per day noted in our 2010 report.[3] Since January 2010, the Federal Energy Regulatory Commission (FERC) has certificated 28 new storage projects. All but four of these were certificated with market-based rates. Nine of them are relatively large projects such as Magnum Gas Storage's 42 Bcf in Utah, the 22.4 BcfTricor Ten Section Storage Hub in California's southern San Joaquin Valley, the Ryckman Creek 35 Bcf project near Opal, Wyoming and two large projects in Louisiana. Other than Ryckman Creek, Aspen has been unable to confirm that any of the projects just mentioned have yet closed financing or proceeded to construction. These and the other smaller expansion projects certificated by FERC, if constructed, would increase working gas capability by another 0.237 Tcf.[4]FERC has another 40 Bcf of storage projects pending and lists three, worth maybe another 50 Bcf on the horizon.[5]

3 This excludes the roughly 100 small LNG needle peaking operations that exist for meeting peak day demands in specific locations where there is no underground gas storage and pipeline capacity into the region is lower than peak day demand.

4 See http://www.ferc.gov/industries/gas/indus-act/storage/certificated.pdf. The list is dated February 1, 2012 and was accessed May 2012. The list does not shown when the project initially filed its certificate application at FERC. Aspen expects most of those applications took most of a year to process, as would construction, once all permitting is obtained. For many of the large independent storage projects, development and environmental work likely took three to five years. Smaller, expansion projects with cost of service rates likely take half as much time from concept to operation as large new independent storage projects where the developer is struggling to convince users to subscribe. Part of the ironic yin and yang of storage is the need versus cost and complexity.

5 See http://www.ferc.gov/industries/gas/indus-act/storage/pending.pdf and http://www.ferc.gov/industries/gas/indus-act/storage/horizon.pdf. Both these lists are dated February 1, 2012 and were accessed May 2012.

Since 2000, FERC has certificated 104 projects.[6] These projects would, if constructed, increase working gas capacity by nearly 1.2 Tcf. (Several additional projects have been certificated by state commissions, bringing the total number close to 110). 75 of the FERC-certificated projects, representing 85% of the associated working gas capacity, were certificated with market-based rates rather than traditional cost of service rates. Projects certificated in California also are allowed to charge market-based rates (as are those in western Ontario). Recall that market-based rates are often preferred by storage projects developed and operated independently of a pipeline or local distribution company. Market-based rates support a business model aimed at capturing the option value of storage based on changes in natural gas prices: *intrinsic* value is the difference between current spot prices and forward prices; *extrinsic* value is the potential value due to future movement of these prices. [7]

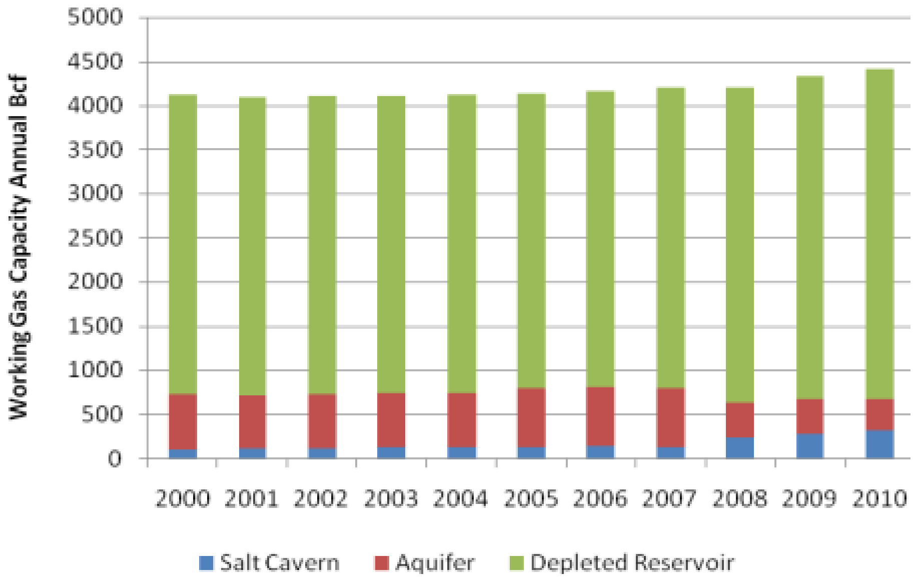
Despite approval for 1.2 Tcf, review of the underground gas storage capacity update released by EIA in April 2012 shows that from 2000 to 2010, working gas capacity increased by a net of only 0.3 Tcf. (See Figure 2) Closer inspection of Figure 2 shows that part of the discrepancy between certificated projects and actual additions is a function of a decrease in aquifer-based storage. Adjusting for the reduction in aquifer-based storage, however, does not explain all of the difference. Aspen estimates that 25% of the capacity certificated by FERC has not yet proceeded to construction. The more recent projects certificated likely would not have had enough time from receipt of FERC approval to complete conversion of their open season precedent agreements to service agreements, close financing and complete construction. Some of the certificated projects, however, likely found insufficient market commitments to move forward. One result from greater use of market-based rates may be that we see more projects certificated but not built.

Note also that roughly half of the new storage certificated and constructed is highly flexible salt cavern storage. Aspen expects that a check of individual applications would show that even the reservoir storage being constructed is equipped to offer highly flexible multi-turn storage (Ten Section and Ryckman Creek would be examples of multi-turn reservoir storage).

[6] Aspen did not look for the number of projects that might have been certificated by or that are pending in front of state Commissions. California, for example, has certificated several projects during this period. According to the list of jurisdictional projects available on FERC's website (at http://www.ferc.gov/industries/gas/indus-act/storage/fields.asp, accessed May 2012), about 3 Tcf of current working gas capacity is FERC-jurisdictional. The rest of US working gas capacity Is owned and operated by local distribution companies subject to state jurisdiction.

[7] A 2004 report by FERC staff entitled "Current State of and Issues Concerning Underground Gas Storage"(found in Docket AD -04-11-000) does a very good job of illustrating intrinsic versus extrinsic value and the host of issues that affect underground gas storage development. Staff also cites users' reluctance to enter into long-term contracts for storage as an impediment to storage development.

Figure 2: Gas Storage Capacity Additions by Year and Type: 2000 to 2010



Source: Aspen Analysis of EIA Data[8]

Generator Use of Storage

There are several reasons that generators might want to subscribe to storage service. These include: i) as part of a diversified portfolio of opportunities to manage changes in natural gas prices; ii) to assure reliable access to supply in high demand scenarios when flowing supply might not be available or iii) to help manage imbalances by injecting or withdrawing day to day differences between supply nominations and actual gas burns.[9] Whether storage will benefit a given generator depends on its individual circumstances: where it is located, demand conditions and price behavior in that local market or upstream markets, how often it operates, the degree to which it operates on a more baseload basis as opposed to variable basis (and is there a fuel besides natural gas that provides the utility with its baseload power); whether it is behind a local distribution company citygate, its ability to recover the cost of storage in the market price of its electricity or rates it charges its customers, whether pipeline capacity into the region is constrained or fully subscribed, how many natural gas marketers are active in the region and what kinds of flexibility they offer their clients and whether the generator is a utility versus an independent generator.[10] Below, we focus on how a generator might use storage to provide reliability and how one might use storage to manage imbalances.

---

8 Found at http://www.eia.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm. Accessed May 2012.

9 By way of review, imbalances are daily differences between the quantity a shipper nominates and tenders for delivery (less any share of compressor fuel delivered on an "in-kind" basis) versus the quantity the end-user actually consumes. The 2010 report described imbalance management at length.

10 While this report will not discuss it in the detail it deserves, one problem for both pipelines and generators is cost recovery of ancillary services. Pipelines that don't have the robust facilities needed to support the desire for greater flexibility can add facilities but they are costly and electric generators cannot necessarily, particularly in

Use of Storage to Provide Reliability

One of the ways that utilities help assure reliable provision of electricity is via access to reliable fuel supply, and they typically store many months' worth of coal, on–site, in a pile plainly visible inside the utility plant fence line in a pile that stores supply. The pile, often representing 60 to 90 days' worth of coal supply, is large enough to absorb interruptions in coal deliveries. Natural gas, in contrast, is delivered and burned in a constant, real-time stream. The delivery is underground and not visible other than perhaps a valve and meter set. In most states access to natural gas has not been required in order for a utility to generate baseload power – they used coal.

Even the gas-fired power plants built in the last ten to fifteen years were not built with alternate fuel capability. Those built by independent power developers were typically financed on the basis of whether they could get enough gas to operate on days with positive "spark spreads," i.e. days on which electricity prices are high enough relative to natural gas prices that the unit can operate profitably. Plants with a business model based on operating in enough hours to make debt service and some return didn't necessarily incur the additional costs needed to be able to operate to provide baseload power or reliability in all hours or in extreme conditions. Thus, those new plants have not grappled with reliability in the same way as utilities with coal-fired generation.

Moreover, there is no "N-1" contingency planning that addresses redundancy in natural gas delivery capacity. Some of the newer gas-fired generation is located to take advantage of multiple pipeline delivery options in an effort to obtain a level of redundancy or in hopes of inducing competition among pipelines to provide more attractively-priced or flexible services or to induce competition among gas suppliers. But the coal plants that get replaced as new regulations make them uneconomic to operate are not necessarily located near existing pipelines. They may not have obvious opportunities to induce pipeline to pipeline competition in the provision of more attractive rates or flexible services. And, as shown in the 2010 study, most of those coal-fired plants are not located near gas storage.[11]

Locating a plant closer to gas storage can help address the reliability issue – under certain conditions. The key is how close it is. Greater distance to the storage facility means it takes longer for the gas to reach the generating plant (remember, gas moves only about 20-30 miles per hour), which matters more or less depending on line pack conditions (i.e., the degree to which there may be some slack gas supply temporarily stored in the pipe itself). Locating a plant closer to gas storage also helps optimize pipeline capacity, as storage can reduce the need for upstream pipeline capacity.

This is illustrated in Figure 3. Imagine a load center with a peak day demand of 1500 MMcf that occurs perhaps twice per year and an average day load of 900 MMcf. With no storage, the delivery pipeline would need to be sized to deliver the 1500 MMcf each and every day. Under current pipeline rate

---

organized markets that clear at a marginal cost (set as a gas price times heat rate of last unit dispatched), recover those costs. Unresolved cost recovery issues are a key impediment to using more gas for electricity generation.

[11] See Figure 17, p. 64 of the 2010 study. It makes sense to think about the locations of those existing coal-fired plants being replaced with new gas plants at the same site in order to take advantage of the infrastructure existing at the site, such as water, access roads, rail (which may turn out to be useful if a plant needed back-up access to LNG or CNG delivered via rail) and, most especially, the substation and transmission line.

design, the generator would pay to reserve that capacity each and every day so that it would be available on the peak day.

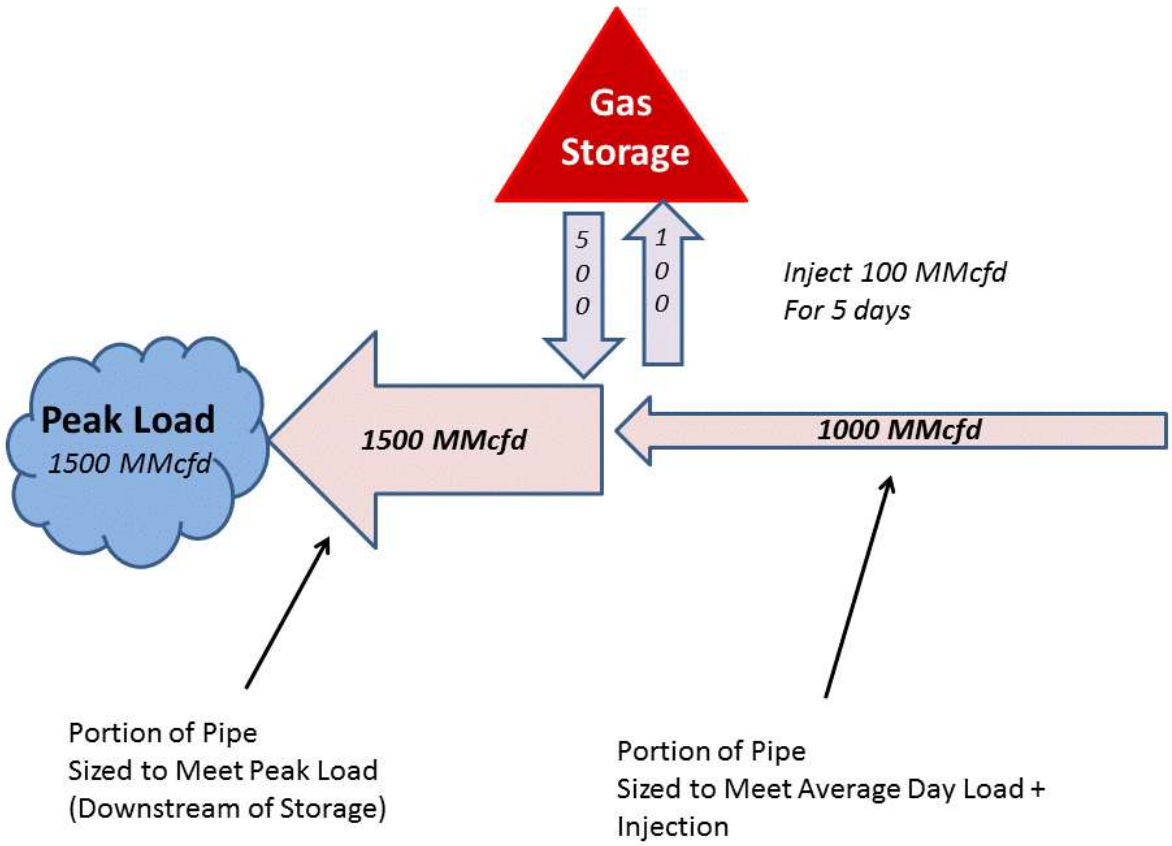
Now add storage. Figure 3 shows withdrawal capability of 500 MMcfd. The size of the injection capability matters less but the larger it is the more quickly we can fill our storage space. In this example, it is set to 100 MMcfd. That means that four days of injection will fill our storage space. With a peak requirement of 1500 MMcfd, and knowing we can supply 500 of that from storage, the portion of pipeline downstream of storage still needs to be sized at 1500 MMcfd. But upstream of storage we can size the pipeline to match our average day load size plus the 100 MMcfd of injection, for a total of 1000 MMcfd. That lets us flow gas to serve average day load and our 100 MMcfd into storage.

The closer the storage, the shorter the piece of pipe that has to be sized to meet peak demand. With the coal pile, generators have wanted it located within the plant fence. That clearly isn't possible with underground gas storage if we locate the replacement gas units at the existing coal-fired generating sites: the geology to allow underground gas storage simply does not exist adjacent to all existing coal-fired plants.

The next issue to think about is the probability of interruption. Aspen is aware of and has not conducted a study comparing the probability of gas pipeline interruptions to coal delivery interruptions. The 2010 study pointed out that service on an interstate pipeline should be firm if the shipper holds firm capacity. However, outage events such as those caused by Hurricanes Katrina and Rita or the huge February 1 to 3, 2011 snow storm that affected most of the U.S. and intense enough cold in Texas to cause rolling electricity outages plus interruptions in access to natural gas in Texas, New Mexico, Arizona and California. The 2010 study also pointed out that generation located behind local distribution company citygates are subject to that state's end-use curtailment rules. Those rules typically made gas-fired generation first off the gas system, to preserve access to gas for "higher priority" customers. These rules were reasonable in an electricity resource mix in which natural gas was not relied on to provide baseload service or to assure reliability.

In some jurisdictions, such as California, customers who have gas in storage are allowed to use it even if gas service to their class must be curtailed. This is because the distribution system is sized bigger than the transmission system and much of the storage is located so gas can be delivered close to the distribution level. Most storage, however, is not so configured. Overall, while storage promises to enhance the reliability of access by electric generators, the location of most storage makes it ability to make good on the promise less than clear.

Figure 3: Example of How Storage Provides Reliability and Reduces Size of Upstream Pipeline Capacity



Source: Aspen Environmental Group Graphic

Generator Use of Storage for Imbalance Management

The 2010 study discussed imbalance management at length and the fact that pipelines generally require gas to be delivered in even hourly increments over the gas day. By way of review, pipeline shippers are required to match the gas they schedule to the gas delivered into the system on their behalf by a supplier, which must also equal that amount of gas they burn. Most pipelines have a small amount of excess capacity they can use to absorb some small percentage of differences before system integrity is threatened.[12] Most local distribution companies that offer open access transportation service (i.e, allow end-users to buy gas from any supplier they choose and only buy transportation from the local distribution company) also impose balancing rules because they are essential to preserving system integrity.

[12] But beyond that small percentage, more gas going into a pipeline than is going out the other end means pressure inside the pipeline will increase. Before the pressure reaches unsafe levels, the operator must remedy. This is accomplished by taking gas out of the pipe, either via controlled release into the atmosphere, flaring it, or putting the gas somewhere else such as storage.

The gas industry schedules gas in four windows that start at 11:30 A. M. Central Clock Time, roughly twenty-four hours before gas is delivered. (See Figure 4.) The first window is the primary opportunity for a shipper to nominate a quantity of gas that will be delivered into the system by him or on her behalf. The gas pipeline confirms the nomination and schedules it some five hours later. Both of the nomination and its acceptance and scheduling occur before electricity dispatch for the same energy day. The subsequent windows were intended to allow for small corrections or fixes that might be necessitated if a nomination were rejected or if an unexpected event occurred. The spacing of the windows does not allow a generator to nominate gas and fire-up on short notice as might occur in a utility when a baseload unit has an unscheduled outage. Because the windows are too broad and too few, a generator that needs to fire-up on short notice is likely to do so anyway, without having nominated the gas. When they do this they are taking someone else's gas and creating a system imbalance. One should expect the penalties for doing this to rise as the system gets tighter with more generators replacing coal-fired generation with natural gas.

Figure 4: Gas Nomination and Scheduling Confirmation

Cycle	Nomination Time *	Confirmation Time	Effective Time
Timely	11:30amDay Prior	4:30pm Day Prior	Start of Gas Day
Evening	6:00pm Day Prior	10:00pm Day Prior	Start of Gas Day
Intraday 1	10:00am Day Of	2:00 pm Day Of	5pm Day Of
Intraday 2	5:00pm Day Of	9:00 pm Day Of	9pm Day Of

* All Hours are expressed as Central Clock Time.

Source: Aspen Environmental Group

If a generator knows it will have excess gas on a given day, it can nominate that gas to be delivered to storage instead of to the plant. Conversely, if it knows it will burn more than its supplier will deliver it can nominate to burn gas from the storage instead. Sometimes, the imbalance tolerance is wide enough that the imbalance can be nominated into or out of storage the day after the deviation occurred, but this depends pipeline to pipeline and situation.

Use of Storage to Provide Flexible Pipeline Services

In addition to the imbalance management issue described above, generators are going to need increasingly more flexible services from pipelines. These include services such as Park and Loan or No-Notice or Hourly Service, which are all forms of short-term storage. Thus, providing hourly flexibility requires storage so that the pipeline can manage the implicit imbalances on an hourly basis. In other words, not nearly all of the new storage that is needed will be subscribed to by generators. In fact, many generators are undoubtedly unaware the degree to which storage is important even though they don't have direct access to it. Storage (and to some degree, line pack) are what allows pipelines and local gas distribution companies (LDCs) to provide the more flexible services that generators need.

Florida helps illustrate this. Florida has no storage today. An above-ground LNG storage facility, Floridian Natural Gas, was certificated by FERC in 2008. Expected to cost $600 million and provide send out capability of 800 MMcfd, it has not yet proceeded to construction, owing to what it says in a recent FERC filing is the "Great Recession" having temporarily reduced market interest. Floridian explains that it is now seeing revived interest as the economy recovers and pipeline capacity is getting closer to full utilization.[13]

The pipelines that serve Florida, however, do have either connected to their systems or located within reasonably easy access of their systems, gas storage capability. They also pass nearby Henry Hub and robust production areas of the Gulf Coast and are interconnected with a number of other pipelines. Thus, even with Florida's current heavy reliance on natural gas for electricity generation and lack of in-state gas storage, the pipeline services offered may be sufficiently flexible that generators have not to date felt constrained. The question is (and that Floridian is betting on) at what point more gas-fired generation will cause that current level of flexibility to become insufficient and lead Florida's gas-fired generators to seek local gas storage service. This question is going to be played out again and again as enough coal-fired generation is replaced with gas to "use up" the current degrees of freedom in the gas system. Without additional storage that the pipelines and local distribution utilities can use to maintain line pack and provide flexible services, generators will become unable to respond to electricity dispatch requirements

The Northeast provides another example that underscores how storage supports flexibility (and the consequences of the lack thereof). The pipelines that serve the Northeast are full during winter months. Storage accessible from the Northeast is located in western New York and Pennsylvania (plus the large LNG terminal at Everett, Massachusetts, that can backfeed the pipelines that terminate at the Boston citygate). At gas' 20 to 30 mile per hour speed, gas needed from those underground storage fields in order to serve the urban load centers is nearly a full day away. The geology closer to those load centers is unable to support underground gas storage. (In fact, the entire eastern seaboard is devoid of depleted oil or gas reservoirs that can be used for storage.)

On March 2, the New England Independent System Operator (NEISO) declared abnormal system conditions owing to capacity deficiency in Rhode Island and southeastern Massachusetts.[14] Algonquin, an interstate pipeline that delivers natural gas into Connecticut, Rhode Island and Massachusetts, subsequently issued a system notice to its shippers, warning them of the requirement to balance their deliveries of gas into the system with their takes of gas out of the system. The notice specifically warned electric generators not to take extra gas out of the system even if they were in a net positive imbalance

[13] See March 30, 2012 application to amend certificate of convenience and necessity in docket CP08-13, p. 4.

[14] See http://www.iso-ne.com/calendar/detail.action?eventId=114306&link=yes&filter=off and http://www.iso-ne.com/calendar/detail.action?eventId=114307&link=yes&filter=off

position (meaning they had left extra gas on the system on a prior day that they needed to work off). The implication of this is that if NE-ISO dispatched a generator who had not already nominated gas to operate, that generator would be taking someone else's gas and would be in direction violation of a pipeline operating notice. In a case with extreme system limitations, that generator might not have been able to operate. Storage, other than LNG isn't feasible in the Northeast, which will become an increasing problem, but if it were feasible it would provide an obvious solution.

Note that each pipeline is different relative to distance covered, number of size of gas receipt points, number and size of gas delivery points, operating pressures at each of those points and between them, etc. This means that 20 Bcf of storage on a complex system like Texas Eastern with multiple interconnections with other pipelines and storage located along its length isn't going to support the same range of flexibility as it would on a simpler system like Kern River that doesn't have as much load diversity, supply interconnections, or storage, for example.[15] And that means it is not possible to be specific about how much storage a given pipeline will need to support more flexible services

In the 2010 study, Aspen described a need to add 1.4 Tcf in additional working gas capacity. 1.4 Tcf is only a 30% increase in working gas capacity and was arrived at by scaling up from the current relationship between total U.S. natural gas demand and working gas capacity. It did not take into account the need to increase the flexibility in pipeline service. Thus, given that the proportion of the natural gas market that needs highly flexible services (i.e., electric generators) could double, the 1.4 Tcf might well be too low. 1.4 Tcf plus existing working gas capacity of 4.4 Tcf would mean

To be sure, the operator achieves some flexibility by oversizing pipe relative to load so that he can compress more gas into it. This difference between the load and gas in pipe is called "line pack." Operators routinely pack transmission and distribution pipelines at night, while demand is otherwise low (but gas is still flowing in) in advance of higher demand in morning hours. Operators also typically pack lines in advance of a cold front.

The combination of line pack and storage support a range of services that pipelines or local gas distribution companies can offer and that gas-fired generator needs. Panhandle Eastern pipeline, for example, serves 27 gas-fired generation facilities representing over 12,000 MW of capacity. Note the range of short-term storage and flexible, no-notice services provided by Panhandle:

- Hourly Firm Transportation -- Customized flow patterns to meet the needs of electric generators.
- Quick Notice Transportation -- Flexible nomination/scheduling procedures for shippers who need to react quickly to flow rate changes.
- Enhanced Firm Transportation -- Provides non-ratable flow in the gas day.
- Gas Parking Service -- Parking and lending to minimize imbalances and penalities.
- Flexible Storage Service -- Allows for customized firm injection and withdrawal rights subject to Panhandle Energy's approval.

[15] Texas Eastern moves gas supply produced along the Gulf of Mexico coast in Texas and Louisiana to serve load in Mississippi, Arkansas, Tennessee, Missouri, Kentucky, Illinois, Indiana, Ohio, Pennsylvania, and into the New York City area. It interconnects with multiple other pipelines and storage along its route. Kern River moves supply produced in the Rocky Mountains (primarily western Wyoming and Colorado and northeastern Utah) and moves it southwestward to Las Vegas and into southern California.

- No Notice Service -- Combines transportation and storage services to simplify nominations and imbalance management.
- Intraday Gas Parking Service -- Provides intraday swing for shippers using standard IT or FT services.
- Delivery Variance Service -- Provides incremental tolerance for daily scheduling variances.

A pipeline without excess line pack capability or storage cannot easily provide these kinds of services. Thus, the target market for the addition of new storage may not be generators *per se* but pipelines and distribution systems.

Competition for the Geology By Other Uses

The 2010 report described the limitations imposed by geology that prevent one from necessarily putting storage exactly where one might want it. There are also other uses competing for that same geology that could reduce the opportunity to add underground gas storage.

One of those is geologic carbon sequestration. Depleted reservoirs and aquifers are the target formations for storing carbon dioxide (CO_2). The U.S. Department of Energy's National Energy Technology Laboratory, for example, assumes that all depleted oil and gas reservoirs and water aquifers are available for use in its estimate of CO_2geologic sequestration capacity.[16] These are denoted in Figure 5. The deep saline aquifers contemplated for use by CO_2may also a target for gas storage in areas where there are no depleted oil or gas reservoirs or salt caverns, but perhaps less so as they are often not capable of providing quick-turn storage, and the fact that they require more compression and cushion gas means they are more costly to develop.[17]

Another energy asset competing for the same geology is underground compressed air energy storage (CAES).Targets for CAES development are again the same underground depleted gas or oil reservoirs or salt domes that could be developed into underground gas storage.[18] Aspen expects that CAES will be increasingly important as a tool to back up intermittent renewables in real time and in ways that natural gas-fired units cannot.

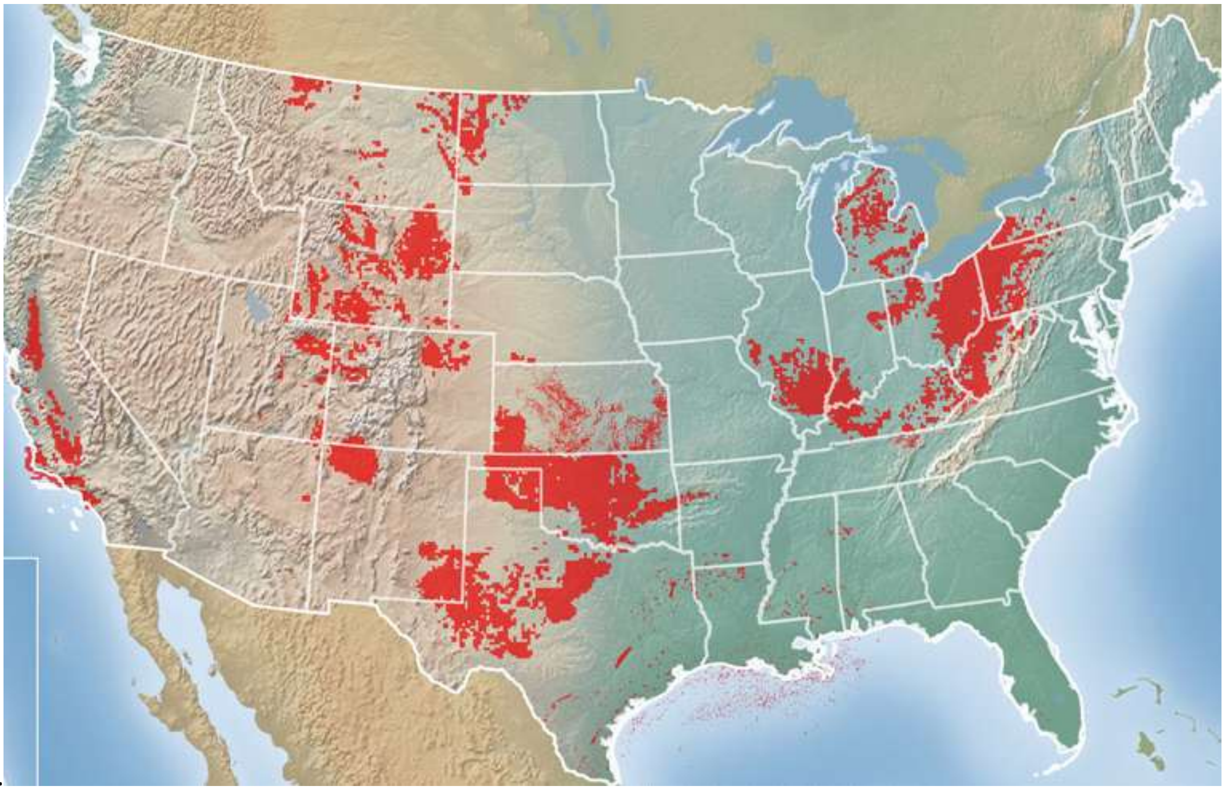
In certain cases, drinking water or water produced from oil and gas operations is stored underground. There is at least some concern that produced and "flowback" water from greater use of hydraulic fracturing, in areas where that water cannot be treated to be acceptable for other uses, is and will be injected underground. Some of these injections may be into formations that could be used for underground gas storage.

[16] They also talk about shale formations providing the ideal cap rock to assure the CO_2 cannot escape. The National Energy Technology Laboratory materials provide no indication it is thinking about how widespread hydraulic fracturing of shale formations could reduce or restrict CO_2 storage capability.

[17] At p. 65 of the original study, we cited an estimated cost of $4.5 Billion per Tcf (excluding the cost of cushion gas) to develop new, multi-turn high-deliverability storage.

[18] See presentation of Dr. Li Kou, especially p. 10, at http://www.aertc.org/conference2010/speakers/AEC%202010%20Session%207/7F%20ESO%20Mech.%20&%20Phase%20Change/Li%20Kou/Kou%20Presentation%20at%20Advanced%20Energy%20Conference%202010SECURED.pdf (accessed June 21, 2012).

Figure 5: Location of Depleted Oil and Gas Reservoirs


.
Source: DOE NETL

Last but not least, certain federal or other lands are protected and not accessible for oil and gas production. A typical gas storage development involves an on-site or near on-site control room, several well pads, dehydrators, injection compressors, construction of roads to reach the facility and construction of a pipeline header to tie the withdrawal wells to gas transmission. The natural gas industry has noted going back to the National Petroleum Council's study in 1999 that access restrictions precluded development of oil and gas resources on federal lands, including 40% of the resource estimated to exist in the Rockies. In its 2008 inventory of oil and gas resources on federal lands, the Bureau of Land Management (with contributions from a number of other federal agencies including the Department of Energy, the US Geological Survey, and the Department of Agriculture, estimated that only 10% of the resource in the Rockies may be accessible.[19] Some of these restrictions may affect access to the depleted reservoirs needed for underground gas storage. f

For clarity, not every depleted oil or gas reservoir is suitable for underground gas storage, for CO_2 storage, for water storage or for CAES. Suitability for gas storage, for example, is defined by a

[19] The Executive Summary of BLM's inventory can be found at: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/energy/EPCA_Text_PDF.Par.18155.File.dat/Executive%20Summary%20text.pdf. Accessed June 2012.

combination of factors, including the potential for fluid migration, the need for gas to be left in place to maintain field pressure, and the ability to drill additional wells into the formation without damaging it.[20]

Other Types of Natural Gas Storage May Increase in Relevance

Some gas utilities have local facilities that they use to serve extreme, short-term spikes in demand known as "needle peaks" via liquefied natural gas (LNG). There are about 100 of these facilities in the US.[21] They are typically owned by local gas distributors and were built in places where it was more economically feasible to build on-site LNG capability than to expand interstate pipeline capacity to meet very high demand that might occur only three to four days per year. Of the 100 LNG peakers, about 60 take natural gas flowing from a pipeline, chill it into LNG, store the LNG, and later regasify the LNG into normal-temperature gas and add it to supplies flowing to them via pipeline for delivery to customers via their local distribution lines. The other 40 have no on-site liquefaction capability and instead receive the LNG via truck and sometimes by rail or barge.

The local LNG needle peakers together provide deliverability summing to 11 Bcf per day, or about 110 MMcf per day.[22] By way of comparison, a new 500 MW highly efficient combined cycle unit that needs to operate all 24 hours on a peak gas demand day would use approximately 85 MMcf, meaning that at least the average-sized LNG peaker is large enough to provide at least a day's worth of gas to a typically-sized new gas-fired power plant. The size of these facilities actually varies from those that store only 4 MMcf to those that store 2 Bcf.[23]

Injections of LNG into these storage facilities is typically slow, over a period of months, while the withdrawal is over just a few days. Some facilities might be economically equipable with more liquefaction capability to allow faster refill. For those that receive their LNG via truck, very small facilities would be fillable with only a few truckloads, each carrying 10,000 gallons.[24] Filling the larger of the satellite facilities, as those without liquefaction are often called, may require 4 to 6 truckloads per day.

From this one can calculate that to serve the entire gas requirement of a new, highly efficient, 500 MW power plant at full output for all 24 hours in a given day (i.e., 85 MMcf) with LNG delivered via truck, one would need 106 truckloads of LNG, or 4.43 per hour. Operating that plant for only 8 hours would need 29 MMcf, which at 10,000 gallons per truck would require 36 truckloads, still more than one per hour (each truck delivers 0.8 MMcf). Thus, serving a large power plant via trucked-in LNG seems infeasible. But let's look at the case of a 50 MW peaker for 8 hours. The peaker will have a less efficient heat rate then the new combined-cycle unit, say 11,000 MMBtu per hour, so the unit would burn 3.1 MMcf in 8

[20] See Dennion, et al., "Detailed Protocol for the Screening and Selection of Underground Gas Storage Reservoirs," Society of Petroleum Engineers, 2000. Found at http://www.humble-inc.com/media/37377/detailed_protocol_for_screening_and_selection_gas_storage.pdf. Accessed June 2012.

[21] See U.S. Department of Energy, "Liquefied Natural Gas: Understanding the Basic Facts," p. 7. Found at http://www.fe.doe.gov/programs/oilgas/publications/lng/LNG_primerupd.pdf. Accessed May 2012.

[22] EIA, "U.S. LNG Markets and Uses: June 2004 Update, p. 13. At http://www.eia.gov/FTPROOT/features/lng2004.pdf. Accessed May 2012.

[23] Id, p. 15

[24] 50,000 gallons of LNG is approximately 4 MMcf of natural gas, or 12,500 gallons would equate to 1 MMcf.

hours. That equates to about 4 truckloads, or one every two hours during the 8-hour operating period, which seems much more feasible given that some of the larger satellite LNG facilities require 4 to 6 truckloads per day to refill.

The 1.4 Tcf needed new storage discussed in the 2010 report was a scale-up based on the relationship between total demand for natural gas and storage available today. From the 1.4 Tcf, we derived a need to add 127 new gas storage fields. Note that the 1.4 Tcf and 127 new fields are somewhat higher than FERC has certificated in the past ten years and are roughly double what was actually constructed.

Final Thoughts

As more coal-fired generation is replaced with natural gas a greater proportion of the U.S. gas requirement will require a level of flexibility that today's gas system struggles to offer to existing gas-fired generation. Gas storage will become increasingly important in allowing pipelines to maintain and increase their offering of flexible services customized for generators, and locating it near generators can both enhance reliability and reduce pipeline expansion costs. Yet we cannot put nearly as much of that storage as we would like near existing coal-fired generation and other uses will compete for the same, limited geology. Some utilities may instead prefer to look at above-ground, rate-based storage, located near their generation sites. This 2012 update offers eight additional findings, shown below.

2012 Conclusions Related to Gas Storage

1. FERC and state commissions have certificated close to 110 projects since 2000 resulting in a net increase in working gas capacity of 0.3 Trillion Cubic Feet (Tcf).
2. There are only a handful of additional projects in the current approval queue.
3. More than 85% of the new storage was certificated allowing it to charge market-based rates, which typically relate to the financial option value of storage based on changes in natural gas prices without regard to the reliability of electricity generation or delivery.
4. End-use curtailment policies behind citygates could be updated to encourage use of storage by generators, where physically feasible.
5. Where feasible, storage located closer to a generator provides a higher degree of reliability and may allow a more efficiently-sized pipeline.
6. Storage is the key degree of freedom that allows pipelines to offer generators more flexible services
7. Without new storage that is integrated into pipeline services and rates, pipelines will likely have to tighten their balancing requirements as capacity utilization limits are approached and greater variation in load by more gas-fired generation uses up line pack.
8. Other uses compete for the same limited geology as underground gas storage and utilities may want to consider above-ground gas storage.

Glossary

Line Pack – gas compressed more tightly into a pipeline, effectively creating a modicum of storage capability

Working Gas – the gas in a storage facility that can be consistently withdrawn and refilled.

Tcf -- Trillion cubic feet

Bcf – Billion cubic feet

MMcf – Million cubic feet

Citygate – the interconnection location where an interstate or intrastate gas transmission pipeline drops gas off to a local area for distribution