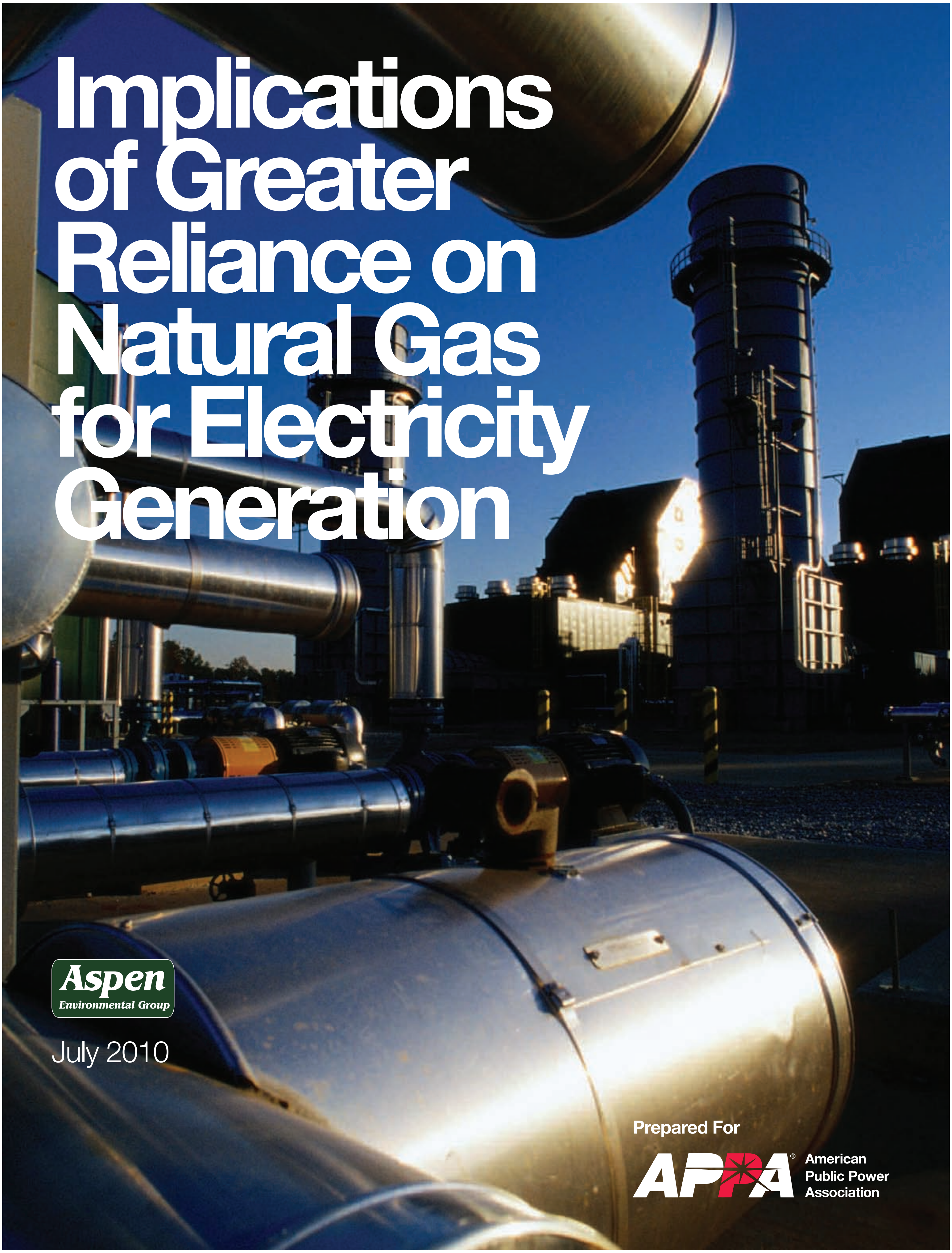
Implications of Greater Reliance on Natural Gas for Electricity Generation



Aspen Environmental Group

July 2010

Prepared For

APPA American Public Power Association

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The American Public Power Association

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Aspen provides independent, objective analysis of environmental and energy economics issues, including environmental compliance, impact assessment, and mitigation services for energy and infrastructure projects particularly for power plant siting, in addition to electricity resource planning. The firm has offices in San Francisco, Sacramento, Agoura Hills, 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 more than 40 natural gas-fired power projects around the country, forecast natural gas prices, negotiated contracts for natural gas supply and transportation, and evaluated proposed greenhouse gas policies for their effect on electric utilities and their customers.

Implications of Greater Reliance on Natural Gas for Electricity Generation

Executive Summary

This report—*Implications of Greater Reliance on Natural Gas for Electricity Generation*—examines the impacts on natural gas and deliveries to electric utilities should rules limiting utility emissions of carbon or other pollutants result in a shift away from coal towards using more natural gas to generate electricity. It 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 begins with a review of the natural gas industry for those who are less familiar with it. It then covers demand, supply, transmission and storage infrastructure, and operational changes that will need to be made by units switching from coal to gas. This report also examines the economics of switches from coal to gas. An understanding of these issues is needed if the electricity industry should need substantially more gas than several studies have suggested. If substantially more gas is needed, then a number of changes will need to be made by both the gas and electricity industries: changes such as massive infrastructure additions, changes to nominating and balancing services, changes to curtailment rules, and changes to subscription levels on interstate pipelines, for starters. The ultimate purpose of the study is to identify those implications so that policy makers can take them into account in deciding what regulations to adopt, and utilities can take them into account in making selections about what resources to use in providing electricity to their customers.

Demand

Demand for natural gas now is approximately 23 Trillion Cubic Feet (Tcf) per year in a market split roughly equally between serving the residential and small commercial, industrial, and electric generation sectors. Current demand is only slightly higher than the industry's prior peak of 22 Tcf in 1972. During that time industrial demand fell off, to be replaced by demand by electric generators. Several studies have looked at what future natural gas demand might be if carbon emissions were regulated. Their answers range considerably, depending on what the studies' authors assumed about the availability and cost of other generating resources. None of these studies appears to have looked at the full range of regulations that might affect electric generators and might lead to larger numbers of units to be converted from coal-burning to gas-burning. **If all existing coal fired generation were to switch to gas today, overall natural gas demand would total 36 Tcf per year, or half again as much as today. Two-thirds of the natural gas produced in the U.S. would serve electric power plants, compared to just under one-third today.**

Natural Gas Supply

This report largely takes as a given the expansion of natural gas production arising from shale-based supply and the idea that the industry could provide enough natural gas supply. Yet there remain issues and uncertainty that could affect this supply, as well as its price.

Expanding production of shale-deposited gas is attracting environmental concern and in some cases local opposition to gas drilling due to its use of a technique known as hydraulic fracturing. Fracturing injects large amounts of water and chemicals into a well to crack open rock formations and then hold the cracks open so that natural gas can flow up the well. EPA and others are studying the potential adverse impacts of hydraulic fracturing.

Even if fracturing continues, serving a much larger market will require even more drilling that is already at record levels. The implied supply curve reflecting the cost of new reserve additions developed herein suggests natural gas prices in the range of $10 per MMBtu to replace the reserves consumed last year. The Energy Information Administration's *AEO 2010* projects a gas price in 2036 of $8 per MMBtu with production not much higher than in 2000; a study for the Interstate Natural Gas Association of America includes a Base Case that projects $6.96 per MMBtu ($ 2008) with production in 2030 of roughly 27 Tcf. In other words, these studies show relatively high natural gas prices at demand levels generally more modest than reviewed herein. With these observations in mind, it seems unwise to expect to serve demand levels that are potentially very much higher than today without sending prices to much higher levels.

Transmission Infrastructure

To deliver the 60 or so Bcf we use each day from the supply basins where gas is produced to the end-users who will burn it, we use 300,000 miles of natural gas transmission pipelines and associated facilities that provide 130 Bcf per day interregional transfer capability. Nearly half the capacity we have today was built **AFTER** the industry achieved its previous peak demand of 22+ Tcf in 1972. The new capacity was needed in part to increase flexibility and to serve shifting regional markets, but primarily it was needed because old supply areas depleted and new ones were developed in other regions.

Estimates of new pipeline capacity required range from $106 Billion to $163 Billion in one industry study. This study escalates those estimates to $348 Billion should all coal-fired generation need to be replaced with natural gas-fired generation**. In looking at existing capacity, 21 states would find the interstate pipeline capacity coming into their state insufficient to serve existing demand plus the demand that would result from converting existing coal-fired generation to gas.** These kinds of infrastructure investments are typically financed and recovered in rates over an extended period of time and are expected to continue being used and producing revenue for the owners for years after that. The magnitude of the investment that would be needed (as described in this report) seems inconsistent with the oft-touted idea of natural gas as a temporary "bridge" fuel.

Storage Infrastructure

For the electricity industry to broadly switch its coal-fired units to natural gas, it will also need more gas storage capability. Geology limits opportunities to build storage where the market would prefer it. Because of that, the current 400 or so storage facilities are not distributed evenly across the country and many of those facilities are single season reservoirs—rather than higher deliverability salt cavern-based facilities.

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 West Virginia). 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. Scaling storage up to meet double the current electric generation (EG) gas burn implies a need to add 1.4 Tcf of storage. Adding this amount at the average $9 Billion per Tcf derived from a study done for the Interstate Natural Gas Association of America (INGAA) would thus cost close to $12.5 Billion.

Operational Considerations

The natural gas industry operates using a lot of conventions developed to serve primarily residential, commercial and industrial customers. For example, natural gas is scheduled, or "nominated," many hours before electric dispatch decisions are made. Tariff provisions that require transporters to match nominations to their usage (i.e., keep their deliveries into a pipeline in "balance" with the amount of gas they actually use) are not customized to provide the additional flexibility electric generators need. Canada's Province of Ontario helped electricity generators and the gas pipelines develop innovative ways of addressing these issues. Such innovations need to be considered in the U.S. if we are to burn much more gas for electricity generation.

Also to be considered is the issue of curtailment. Curtailment halts delivery of natural gas: large customers like electricity generators are typically looked to by local gas distributors' gas control operations as the first to curtail should supply or pipeline capacity run short. Those that are located along pipelines where capacity is tight often have back-up fuel capability, usually diesel fuel or residual fuel oil that they plan to be able to burn for only a few days. Most generators, however, do not have alternate fuel capability.

Hurricanes present another consideration. Even small storms cause crews to be evacuated from offshore drilling and production platforms. Traders bid up prices anticipating damage. Massive storms can cause significant damage to natural gas production infrastructure in the Gulf. For example, as a result of Hurricanes Katrina and Rita in 2005, 80% of U.S. offshore production (which is approximately 10% of U.S. total production) remained shut-in for a couple of weeks after Katrina, and again after Rita. Two key studies, including one by Sandia National Laboratories' National Infrastructure Simulation and Analysis Center, state that the disruption from the storms was not to consumer deliveries, but was absorbed by a reduction in deliveries to gas storage. Those studies, however, do not assess how that impact could be different if coal-fired generation switched to natural gas. It also turns out that winter 2005-2006 was extraordinarily mild; had a normal cold or colder-than-normal winter occurred, gas consumers in the Midwest, MidAtlantic and Northeast might have experienced winter month natural gas curtailments.

Finally, many electric utilities today burn little or no natural gas to generate electricity and don't have trained staff on hand to address these matters. They will need to obtain trained staff or purchase external expertise to manage natural gas procurement, plan their interstate pipeline capacity commitments, and much more closely follow natural gas market developments. They will need staff to "carry the pager" to manage daily nominations and imbalances. They will need to deal with price volatility and risk management on a scale that most have never done before.

What Retrofitting Coal Plants to Burn Natural Gas Means

The electricity industry can theoretically switch to natural gas either by retrofitting existing coal-fired units to burn natural gas or by closing the coal plants and building new gas-fired plants. Aspen's research uncovers no instances of coal plant retrofits to natural gas and, in fact, virtually all of the public references to conversion of coal to natural gas or repowering turn out instead to be replacements. The reason is economics. Even the U.S. Government Accountability Office (GAO), when it looked at this issue switching the Capitol Building power plant to natural gas, noted that not only was switching all U.S. coal-fired generation infeasible due the gas supply and infrastructure required, but that it would be more cost-effective to construct new gas-fired units than to retrofit existing coal-fired units to burn natural gas. Combined-cycle gas-fired generation costs roughly $1 million per MW, installed. Replacing 335,000 MW of coal-fired generation thus should cost in the range of $335 billion.

Additionally, even if gas-fired units are built to replace existing coal-fired units, many utilities likely still have outstanding debt service on the coal plants that must be covered. Most plants are financed over a 20- or even 30-year period and roughly 30% of the existing fleet is 30 years old or less. The need to complete paying off this debt and the impact on utility cash flow needs to be recognized as part of the cost of replacement.

Implications of Greater Reliance on Natural Gas for Electricity Generation

Introduction

This report—*Implications of Greater Reliance on Natural Gas for Electricity Generation*—was commissioned by the American Public Power Association (APPA), with financial support from the Utility Air Regulatory Group (UARG) and other electric utilities.[1]

The report provides a review of the natural gas industry for those who are less familiar with it. It will outline the range of and characteristics of current natural gas demand and how demand might change under different regulatory scenarios, particularly those under which it will be increasingly difficult for electric generators to operate their coal-fired generation. This report will largely take as a given the expansion of natural gas production arising from shale deposits; however, it will highlight uncertainty and environmental issues associated with this supply. It will review gas transmission and distribution infrastructure with an eye towards changes required to utilize that infrastructure to serve more demand and demand with characteristics different than it was built to serve. In that vein, it will describe some of the obstacles that electric generators face in managing the services they need in order to burn natural gas in power plants. These issues vary regionally, depending on the infrastructure available regionally and the flexibility or non-flexibility of that infrastructure to serve electric generation load. The gas system was not designed or built to serve electric generators. As will be seen later herein, many jurisdictions have not yet confronted the fact that electric generation remains the first off the system should a constraint or curtailment arise, which as we rely more heavily on natural gas to generate electricity could affect electricity reliability. The study provides information for policy makers and potential new users of natural gas about what kind of equipment would be needed to switch current coal-fired generation to natural gas: what would it cost to make the switch; what is the feasibility of such a switch; and how much natural gas would be required.

[1] APPA represents public power utilities across the country. UARG is a voluntary, nonprofit, unincorporated ad hoc group of individual electric utilities and trade associations; UARG's general purpose is to participate on behalf of its members collectively in the rulemakings of the Environmental Protection Agency and related litigation.

Definitions and Scale

A number of terms that may be unfamiliar or that are hard to mentally picture as to scale will be used herein. Natural gas demand when expressed annually will typically be in trillion cubic feet (Tcf). Daily demand is annual demand divided by 365 and will be expressed in billions of cubic feet (Bcf) per day or million British Thermal Units (MMBtu) per day. Cubic feet are a unit of volume, whereas Btus are a unit of heat. The heat content (or, Btus per cubic foot) varies by the source of the gas such that different pipelines will carry gas with a slightly different heat content. For the sake of simplicity, all calculations in this study will use 1.05 Btu per thousand cubic feet (Mcf).

Useful Conversions:

10 therms = 1 Decatherm (Dth)

1 Dth = 1 MMBtu

10,000 MMBtu = 10 MMcf/1.05

Ex: 80 MMcf … add three zeros and multiply by 5% = 84,000

The only real difference between an MMBtu and an Mcf is the heat content of the gas (1.05) and the number of zero's (scale).

Prices for natural gas are expressed in the wholesale market and in most gas purchase agreements as $ per MMBtu. **Most** consumers will see on the bill from their local gas company a price expressed in cents per therm.[2] Some consumers will see the wholesale cost of gas broken out separately on their bill from distribution and margin and some will not.

Another industry convention is to express pipeline capacity in terms of MMcf per day delivery capability. The bottom line is that the industry prices and buys gas in $ per MMBtu but usually measures capacity to deliver it in MMcf. Quantities more than 1,000,000 MMBtu will typically be expressed as Billion Cubic Feet (Bcf) and then Trillion Cubic Feet (Tcf). Bcfd means Billion Cubic Feet per day. MWs is MegaWatts of capacity available to generate electricity; MWh is energy, or the number of MWs times the number of hours those MWs were delivered. Last, but not least, in the gas business M means 1,000 but in the electricity business it means Mega, or one million.

Some hints and comparisons of scale:

- Average household consumption of natural gas is 69 MMBtu (Dth) per year, or 5.75 MMBtu per month.
- A new combined-cycle natural gas-fired power plant (NGCC), in contrast, typically uses between 7 and 7.5 MMBtu to generate a MWh of electricity. In other words, the NGCC generates a single MWh using about 1.3 times what a household uses in a month.
- Annual U.S. natural gas consumption is in the range of 22 to 23 Tcf per year, depending on weather. 30% of that natural gas is used to generate electricity.
- A standard 36-inch large-diameter natural gas pipeline typically delivers 1 Bcf per day.

[2] Some gas utilities bill in hundreds of cubic feet, or ccf, instead of therms.

- That same pipeline can serve roughly six 1000 MW gas-fired plants if the plants operate all at full output all 24 hours in a day.
- Current coal-fired electric generating capacity in the U.S. totals approximately 335,000 MW. That capacity operated in 2008 at an average 72% load factor to produce 1,985,801 GWh of electricity.[3]
- A new 1000 MW gas-fired combined-cycle power plant that operates all 24 hours in a day (i.e., at a 100% load factor) will consume approximately 168,000 MMBtu per day. That's enough gas to serve 890,000 households for a day.
- Using new combined-cycle gas-fired units to replace the 1,985,801 GWh generated with coal in 2008 would have required 13.2 Tcf more natural gas – more than half again what we consume now.[4]

A new 1000 MW combined-cycle gas-fired unit that operates all 24 hours in a day will burn 168,000 MMBtu per day.

Converting to annual Tcf ...

120,960 MMBtu per day x 365 days

=

44,150,400 MMBtu per year

=

42,048 MMcf per year

=

0.042048 Tcf per year

3 Sourcewatch showed 335,840 MW for 2005 (its latest available); EIA shows 337,300 nameplate capacity versus 313,200 net summer capacity in 2008. We rounded to 335,000 MW.

4 The 2008 net generation from coal is taken from EIA's Electric Power Monthly, Table 1.1., Net Generation by Energy Source.

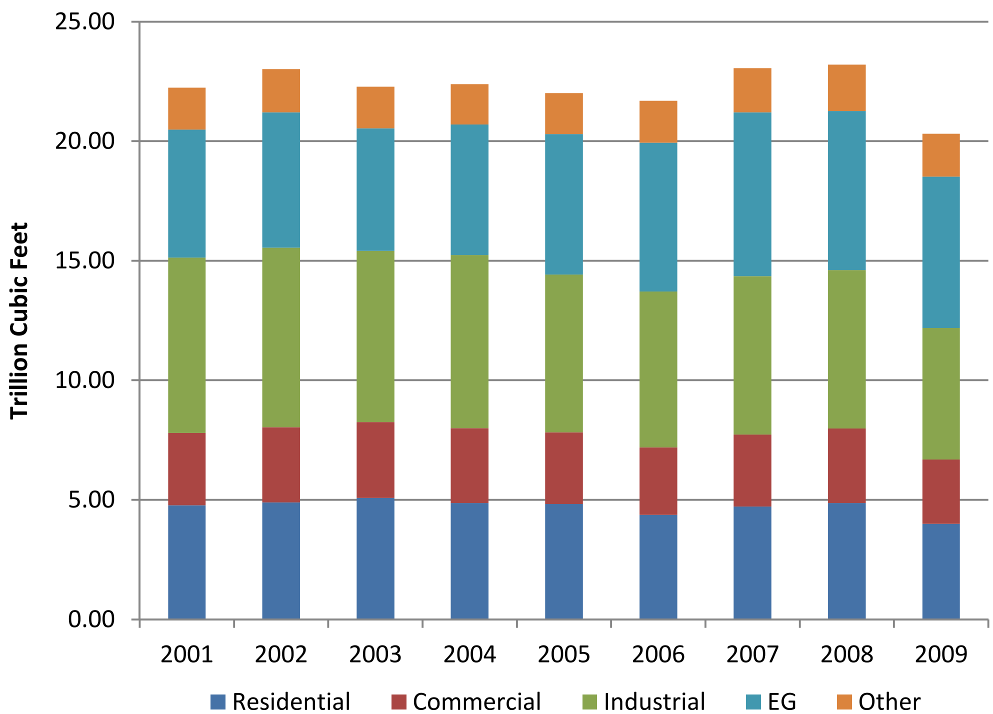
Natural Gas Demand

The U.S. used approximately 23 trillion cubic feet (Tcf) of natural gas in 2009. Sectorally, the 23 Tcf breaks down roughly to 30 percent each consumed by i) residential and commercial consumers, ii) industrial consumers and iii) electric generators. The remaining 10 percent is consumed by miscellaneous uses such as fuel to operate processing facilities, pipeline and distribution system compressors, and as natural gas vehicle fuel. Annual natural gas demand by sector back to 2001 is shown in Figure 1.

A box large enough for a basketball or kickball can hold close to 1 cubic foot of natural gas. The average home uses 66,000 of those boxes worth of natural gas in a year.

Residential demand is highly seasonal. It is often projected largely on the basis of number of households and projected heating degree days. Residential demand per household has been trending slightly downward over time owing to more energy efficient new home construction standards and weatherization retrofits to existing homes.[5] Without growth in the number of households, total residential natural gas demand would be falling.

Figure 1: Natural Gas Demand by Sector Since 2001



Source: EIA *Natural Gas Annual*

[5] According to EIA's Residential Energy Consumption Survey, of the 111 million U.S. households in 2005, 69.4 million used some amount of natural gas.

Residential natural gas demand is not particularly sensitive to price, as confirmed by numerous studies; it may be as low as -0.12, meaning that a 1% increase in price produces a 0.12% decrease in demand, although the elasticity varies some regionally.[6] In the West and South, annual total gas bills are a very small portion of consumer household budgets. Customers rarely get real-time price signals owing to the timing of billing periods relative to when the local distributor purchased the gas. In many jurisdictions, the local distributor may not be able to change the cost of gas seen on the customer bill without regulatory approval; surprisingly, not all utilities even have pass through mechanisms on their gas costs. Even during periods of relatively high spot prices, residential demand appears to be more weather responsive than price responsive. The key driver for residential demand is weather-related demand associated with space heating. [7]

Commercial demand is similar to the residential sector. It is weather-sensitive since it is largely a function of floorspace and due to efficiency increases doesn't show large changes over the long-term.

Demand by industrial and electric generation (EG) customers has changed more than that of residential and commercial sectors. Industrial demand tends to not vary by season but was sufficiently price sensitive that it has declined significantly over time. Higher natural gas prices beginning around 2000 eliminated considerable industrial demand. At roughly the same time, the use of natural gas to generate electricity began to grow with the move to deregulated markets and the rise of merchant generators who could relatively quickly site, finance and build combined-cycle natural gas generating stations. Industrial demand declined by nearly 20% from 2000 to 2009 (from 7.3 Tcf down to 6 Tcf). During the same period EG demand rose, picking up the most of difference, rising from 5.3 Tcf in 2000 to 6.8 Tcf in 2009. EG demand typically causes a slight secondary peak each July and August (on the Pacific Coast it is more August and September). The increase in air conditioning load during summer heat waves can also be enough to move natural gas prices, either regionally or at Henry Hub.[8] Hot weather combined with other events such as a nuclear outage, pipeline outage, or dry hydro-electric conditions (usually either the Pacific Northwest or California) can cause larger price spikes.

Residential and commercial demands make natural gas a winter-peaking market. Transportation and distribution capacity (covered in Section 4) is adequate to serve current winter peak demand. Figure 2 shows how the highly seasonal residential and commercial sector demands drive the peak in total

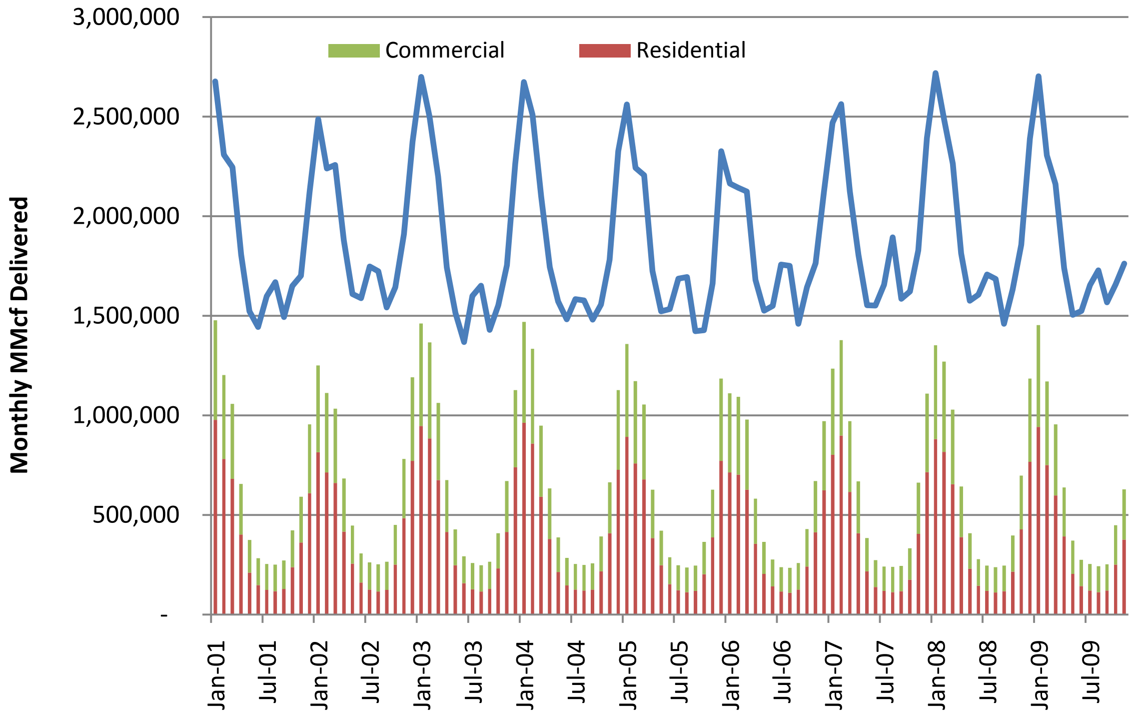
[6] See, for example, M. Bernstein and J. Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy," Prepared for the National Renewable Energy Laboratory, Subcontract Report NREL/SR-620-39512, February 2006. Bernstein and Griffin estimated short-run residential sector elasticities of -0.03 for the West South Central census region and -0.18 for the Pacific Coast census region. The American Gas Association (AGA) recently published updated short- and long-term price elasticity estimates based on data from its members but it is only available to non-members for a fee.

[7] AGA, INGAA and others sponsored a highly-publicized study arguing that increased direct use of natural gas will reduce primary energy consumption, consumer energy costs, and national CO2 emissions. The study can be found at: http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=GTISolutions/ClimateChange/reducingcarbonemissions.xml .

[8] Henry Hub is a location in Louisiana where the Sabine Pipeline interconnects with as many as twelve other pipelines and gathering systems. It is used by the New York Mercantile Exchange as the physical delivery point to settle gas futures contracts. The Henry Hub price is recognized as a national benchmark price.

demand across the months. The Figure's blue line is total demand, including the industrial and EG sectors (which are not otherwise shown, for emphasis). EG's slight summer uptick is also readily visible in the "total" line.

Figure 2: Illustrating Peak Nature of Monthly Natural Gas Demand



Source: EIA *Natural Gas Monthly*

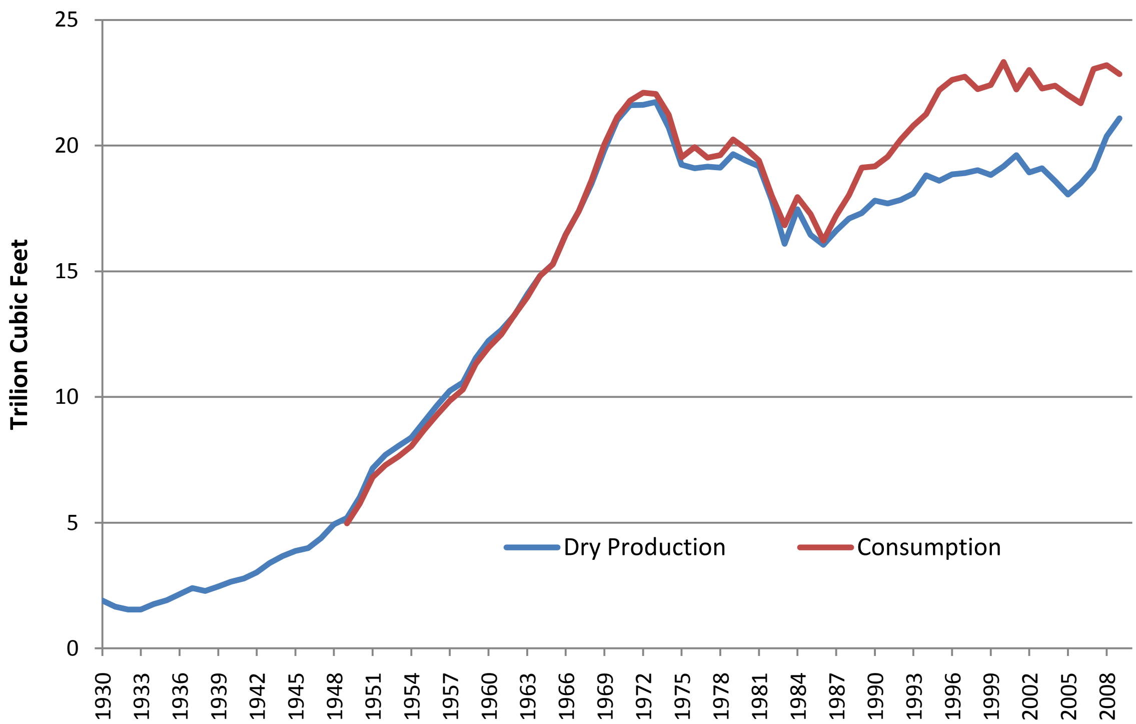
Today's annual total demand is only slightly higher (1 Tcf, or 4.5%) than the previous peak set in 1971 of 22 Tcf. Natural gas demand declined substantially after the 1970's Energy Crisis; schools and factories in Indiana, Ohio and Illinois spent days closed in the winter of 1976-1977 because gas was unavailable due the winter season in general or because the back-up fuel they had selected was unable to reach them due to bad weather. People were told that there wasn't enough natural gas; in 1978 Congress enacted new laws to encourage efficiency, preclude the use of natural gas as a boiler fuel in new facilities, and deregulate wellhead prices.[9] Recession and higher prices for natural gas also influenced fuel choices. By 1981, natural gas demand was less than 75% of what it had been in 1971. From the peak in 1971 it took nearly 25 years for the industry to get back to its prior annual peak.

A key purpose of this study is to raise awareness about how demand for natural gas could change with the possible promulgation and implementation of new regulations. The most prominent and most often studied is carbon regulation, but carbon is only one of the regulations electric utilities expect to have to address between now and 2017. Other pending regulations pertaining to "conventional pollutants" such as sulfur dioxide, nitrogen oxides, particulate matter, mercury, coal ash, etc., will also impose

[9] These included the Fuel Use Act, the Public Utilities Regulatory Policy Act, and the Natural Gas Policy Act.

compliance costs. Compliance with these regulations could require control equipment ranging from scrubbers, activated carbon injection, baghouses, and electrostatic precipitators, depending on the unit. The range of potential regulations is summarized in Figure 4, a graphic (not produced by Aspen) that has been extensively circulated amongst the electric utility industry and regulators.

Figure 3: Annual Natural Gas Demand and Supply since 1930

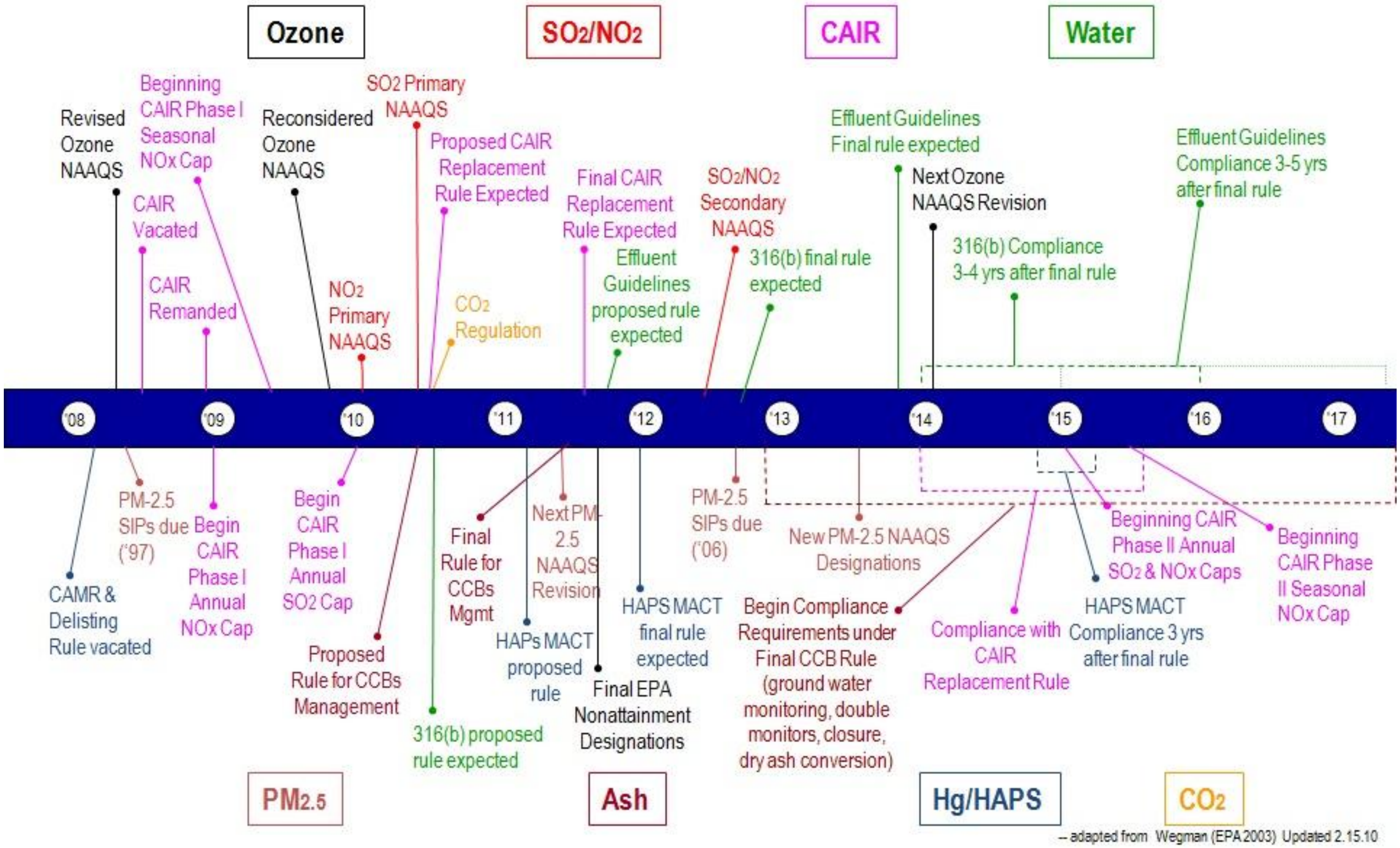


Source: EIA *Natural Gas Annual*

While this study will not further evaluate those regulations or the associated potential compliance costs, utilities are already talking about how the costs to retrofit existing coal-fired units (with the scrubbers, baghouses and electrostatic precipitators mentioned above) in order to comply with these regulations will cause utilities to consider whether to make the retrofit or instead switch to an alternative source of generation. In particular, the utilities are typically comparing the cost of retrofitting coal-fired generation to meet any one of these regulations with switching to natural gas.[10] Compliance with these rules, cumulatively, even before considering carbon regulation, is more likely to change the relative economics of electric generation; as coal-fired generation becomes more costly relative to others, utilities will modify the mix of resources they use to meet customer load.

[10] For examples of comparative economics among control technologies see, J. Cichanowicz, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies," Prepared for the Utility Air Regulatory Group, January 2010; or Woods, et. al., "Cost and Performance Baseline for Fossil Energy Plants," National Energy Technology Laboratory, August 2007.

Figure 4: Timeline for Potential EPA Rules Affecting Electric Power Plants



Source: Provided by APPA

Exactly what changes will be made by utilities—and how they will drive demand for natural gas—will depend on what assumptions electric generators make concerning the level of electricity load growth they think they will see, the amount of energy efficiency they think they will achieve, how much success they think they will have in adding generation from renewable sources, and how much new nuclear capacity will be built. It also depends on whether one believes that geologic carbon capture and sequestration (CCS) will be commercially deployable and available to utilities in locations with diverse geology, the price at which CCS will be available, whether one allows the models to retrofit old units to accommodate CCS technology, and the level of any carbon emissions caps. If a cap and trade program is adopted via legislation, gas demand will be affected by the number of allowances granted, by the number of offsets available, and by any restrictions that are placed on the use of offsets and allowances in achieving compliance with carbon limits.

Table 1 summarizes the results of five different studies done over the last two years that contain projections of the electricity industry's generation resource mix, including natural gas demand. The studies reach different conclusions about natural gas demand because they make very different assumptions about likely future load growth, how much can be achieved by increases in energy efficiency, how much generation will be produced by renewable energy sources (Renewables), and how much new nuclear generation will be built.[11] All of these things have an impact on how much natural gas the industry will burn to generate electricity.

The first and second studies—done in 2008 and 2009—are EPA analyses of S. 2191, Senators Lieberman and Warner's cap and trade bill, and of H.R. 2454, passed by the House of Representatives and sponsored by Representatives Waxman and Markey. EPA's analyses looked at the impacts of cap and trade for carbon emissions. It is unclear whether EPA also assumed implementation of the proposed Clean Air Interstate Rule (CAIR) but it does not appear to have assessed the possible effects of other regulations identified in Figure 4 that might affect electric generators in the foreseeable future. EPA's S. 2191 analysis (denoted EPA L-W in Table 1) contains load growth of 0.8%.[12] This is roughly half the actual load growth experienced on average over the last twenty years. EPA allowed new nuclear generation and increased renewable generation. Coal-fired generation is displaced and by the end of the study period about two-fifths of what remains is retrofit with CCS.[13] Natural gas-fired generation increases, both in relative and absolute terms, to represent 25% of the resource mix as compared to its

[11] Renewable energy sources generally means generation using wind, solar thermal, solar photovoltaic, geothermal or biomass resources. As discussed in more detail later herein, each of the studies turns out to use different assumptions as to which Renewables make up the bulk of the renewable generation they assume to be available.

[12] "EPA Analysis of the Lieberman-Warner Climate Security Act of 2008," March 2008 found at http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf. The published analysis went only to 2025; in extending it to 2030 Aspen recognized that nuclear and Coal CCS had met their resource limits, thus requiring new generation added to meet load be gas-fired. While Aspen tends to refer herein to load growth as an "assumption," we well understand that the models typically iterate back and forth between prices and load to reach an equilibrium result. They may employ an assumption about energy efficiency but some of the change in demand is also price response. EPA's later analysis of Waxman-Markey attempted to better tease out of the analysis the difference between conservation and price response.

[13] CCS is first deployed by 2015 and reaches its maximum availability limit by 2025.

current 21%, using an additional nearly 4 Tcf of natural gas per year. This represents an increase in the use of natural gas to generate electricity of approximately 60%. (If the projected use of the "tools" used to reduce emissions, including allowances and offsets, nuclear generation, Renewables, CCS or control of load growth turns out to be unachievable, then natural gas use would theoretically be higher.)

Table 1: Comparison of Various Studies' EG Resource Mix and Resulting EG Gas Burn

	2008	EPA L-W	EPA W-M	AEO 2010	Duke CCPP	INGAA (Base)
Annual Load Growth	1.5%	0.8%	0.41%	1.00%	0.2%	1.4%
Share of 2030 Load Served By:						
Nuclear	20%	24%	23%	17%	20%	21%
Renewables	3%	13%	11%	11%	20%	8%
Coal	48%	18%	37%	44%	13%	40%
Coal CCS	0%	12%	3%	0%	20%	2%
Natural Gas	21%	25%	19%	21%	21%	23%
Petroleum	1%	2%	2%	1%	1%	1%
Hydroelectric	6%	5%	6%	6%	6%	5%
Total Resources[14]	100%	100%	100%	100%	100%	100%
Gas Burn for EG in 2030 (Tcf)	6.9[15]	9.3	6.8	8.3	6.0	9.8
Gas Burn for EG in 2036 (Tcf)	6.9	10.75[16]	7.7	8.8	7.4	n/a
Total U.S. Gas Demand	22.9	26.7	23.7	24.8	23.4	28

Source: Aspen Analysis

EPA's analysis of H.R. 2454 (denoted EPA W-M in Table 1) shows even smaller load growth, only 0.41%.[17] Such lower load growth combined with the number of domestic and international offsets allowed under Waxman-Markey, combined with the purchase of allowances at relatively low prices, led EPA to conclude that the industry would be able to meet its emissions targets with far less drastic changes to the resource mix. Nuclear generation increased to 23% of the portfolio and Renewables to 11%. Much less coal was retrofit with CCS, only 3% of the coal-fired fleet, but up to its assumed capacity limitation. Coal was not displaced as much as under the S. 2191 analysis, with the overall result that natural gas' market share did not increase and in fact was reduced to 19% of the portfolio. While a reduction in relative terms, this 19% still represents an increase in natural gas demand by electric generators of approximately 0.8 Tcf per year by 2036. Should the low load growth, access to offsets and low allowance prices not occur, the gas burn would presumably be higher unless other more economic

[14] Totals may not add to exactly 100% due to rounding.
[15] 6.9 Tcf is the 2008 natural gas burn for electricity generation.
[16] EPA's study of Lieberman-Warner contained projections out to 2025; the 10.75 Tcf is taken from a simple projection extending that analysis.
[17] "EPA Preliminary Analysis of the Waxman-Markey Discussion Draft," April 2009 found at http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf

options were available to reduce emissions. The H.R. 2454 analysis does not appear to have included other EPA regulations affecting electric utilities that were identified in Figure 4.

The third study—EIA's latest Annual Energy Outlook (AEO 2010)—projects increased natural gas use in electric generation of about 2 Tcf by 2035 and total U.S. natural gas demand of approximately 24 Tcf. Notably, EIA's analysis did not assume regulation of carbon emissions or the adoption by EPA of other regulations limiting emissions from fossil-fired generation such as those shown in Figure 4. Nonetheless, the Outlook's increase in gas use is attributable "to growing concerns about GHG emissions [that] make [gas] more attractive than coal and because new natural gas-fired plants are much cheaper to build than new renewable or nuclear plants."[18] In other words, anticipation and discussion of potential regulation leads utilities to switch some of their resource decisions away from coal-fired generation.

The fourth study—done by Duke University's Climate Change Policy Partnership at the Nicholas School of the Environment (Duke CCPP)—used the same National Economic Modeling System (NEMS) used by EIA but updated some assumptions about natural gas supply to see what impact that might have on the natural gas market, including demand for electric generation.[19] The key update was perhaps not the oft-cited update to the assumptions about shale-deposited natural gas: the shale gas update turns out to be relatively minor in that Duke CCPP merely updated the reserves available from the Haynesville Shale to assume they would ultimately match those known to exist in the Barnett Shale.[20] Assumptions regarding other shale-deposited reserves and production were not updated. The Duke CCPP study also constrained LNG imports and updated generation construction costs relative to EIA. The biggest change from EIA's modeling was to obtain from NETL an add-on to NEMS that allows NEMS to evaluate the economics of carbon capture and sequestration retrofits to existing coal-fired generation.[21] In addition, Duke CCPP shows very little load growth: only 0.2% per year. The Duke CCPP study modeled ten scenarios, including a business-as-usual case with no carbon regulation, carbon regulation with the updates described above, and then various combinations of higher and lower gas extraction technology and electric generation technology development.

The general result—which did not consider what the impact on electric generators would be if EPA were to adopt the other new regulations depicted in Figure 4 from coal generating units—was only a small increase in demand for gas-fired generation. Nuclear generation remained relatively constant, owing to its high cost relative to alternatives. Coal-fired generation decreased and was replaced by Renewables, most of which are biomass. Approximately 60% of the coal-fired generation that remained in place was

[18] EIA, AEO 2010 *Early Release*, Report #: DOE/EIA-0383(2009), p. 10. EIA says it assumes only existing laws in preparing the AEO but Administrator Newell explained in a March 1 presentation to the OECD in Paris that a premium was added to the capital cost of CO_2-intensive technologies to reflect market behavior in advance of possible CO_2 regulation.

[19] Hoppock, Dave, Patrick Bean and Eric Williams (Duke University, Climate Change Policy Partnership), *The Influence of Technology and a Carbon Cap on Natural Gas Markets,* 2009.

[20] The Haynesville shale is located largely in Louisiana; the Barnett shale in Texas. Figure 7 shows all of the U.S. shale-deposited gas supply production areas.

[21] Op. cit., p. 13

assumed to be retrofit with CCS technology.[22] The net result is little change in the amount of natural gas burned to generate electricity: 0.5 Tcf. Duke CCPP did prepare a scenario in which it assessed the possibility that CCS, either new CCS or retrofit to existing coal- and gas-fired units, might not be available or deployable until after 2030. That scenario shows change increase in the gas burn relative to the main S. 2191 case but it also assumed low natural gas technology development. Duke CCPP's "High natural gas technology development/low electric technology development" case shows a 2030 gas burn nearly 30% higher than in its main S. 2191 case, or just over 9.5 Tcf.

The fifth study—which the Interstate Natural Gas Association of America (INGAA) released in October 2009—was performed on INGAA's behalf by ICF International.[23] ICF, via Energy and Environmental Analysis (acquired by ICF in 2007), has long provided demand, supply and infrastructure projections to INGAA, the American Gas Foundation and the former Gas Research Institute (now Gas Technology Institute). It also performed a good portion of the modeling reported in National Petroleum Council studies dating back to 1992. ICF uses its own Gas Market Model (GMM).

The INGAA study assumed electricity load growth more consistent with the recent past than the EPA, EIA or Duke CCPP studies: 1.4%. The base case adds 25,000 MW of nuclear generation yet its share of the generation portfolio on a percentage increases only slightly, owing to load growth. Renewable capacity triples, but only contributes 8% of the portfolio. Coal adds 40 GW and the new coal is fitted with CCS; on a percentage basis, however, its share of the resource portfolio shrinks from 48% today to 42% by 2030. Natural gas adds 260 GW of capacity and operates in more hours of the day to increase its load factor; its share of the electric resource portfolio grows to 23% from 21% today. Because the overall electricity market is larger due to the assumed level of load growth, this seemingly small 2% increase in natural gas' market share represents an increase in annual natural gas demand of nearly 4 Tcf over current levels: 6.9 Tcf in 2008 versus 9.8 Tcf in 2030, which represents nearly a 40% increase in the EG gas burn. Total U.S. gas demand winds up at approximately 28 Tcf, or 20% higher than today.

Some interesting observations can be drawn by comparing these studies. For example:

- EPA's analysis of Waxman-Markey sets load growth at about half what the agency assumed a year earlier when they analyzed Lieberman-Warner. In fact, the much lower gas burn projected

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[22] Duke CCPP added CCS to about 160,000 MW of the 262,000 MW of coal-fired capacity projected to exist in 2030, but did not break out in the results the MWh generated by CCS capacity versus non-CCS coal-fired capacity. (Compare Duke CCPP Figure 12 to Figure 13A.) In addition, Duke CCPP shows a total of 220,000 MW of capacity implementing CCS. Given that the study projects only 160,000 MW of that to be on coal-fired generation, the rest must be presumed to be applied to natural gas-fired generation.

[23] ICF International, "Natural Gas Pipeline and Storage Infrastructure Projections Through 2030," INGAA Foundation, October 2009. Found at http://www.ingaa.org/cms/31/7306/7828.aspx. We will come back to the INGAA study when we discuss infrastructure additions; the study represents analysis performed on behalf of the interstate gas pipelines as to capacity additions required to serve expected gas load. Its demand scenarios are conservative relative to some that we will evaluate in contemplation of switching coal-fired generation to natural gas and thus is only a starting point for the required gas transmission and storage capacity additions.

under Waxman-Markey appears due primarily to the difference in the load growth assumption.[24]

- Duke CCPP's analysis assumes virtually no load growth (0.2%): that and increased Renewables leads to little change in the gas burn but a big change in the contribution by coal. No reader should doubt the significant impact that the load growth assumption makes on the need for portfolio additions and how much gas must be burned. Note that none of the studies, largely due to its assumed cost, add very much nuclear power with the exception of EPA's original analysis of S. 2191, which added virtually a plant per year.

- INGAA has load growth most consistent with historical reality, which also means it didn't allow much in the way of energy efficiency. Its higher load growth combined with a much more conservative addition of Renewables to the portfolio results in a gas burn that is almost as high as under EPA's analysis of Lieberman-Warner. Of course, that analysis would show a still higher gas burn than either it does or INGAA does if it increased load growth from the assumed 0.8% to the more historically consistent 1.4% INGAA uses while holding all other resource assumptions constant.

Without the combination of low load growth, high Renewables, the availability of geologic CCS and use of allowances and offsets, it looks impossible to meet carbon targets without burning much more natural gas. If those assumptions do not hold, the resulting EG gas burn is much higher.

The point of comparing these studies is that one needs to not look only at the conclusions the studies reach about the gas burn, but look at how the studies reached that conclusion. Many, if not most, of the resource mix assumptions embedded in the studies are highly uncertain; some may not be achievable in terms of the availability of certain resources or access to carbon offsets and allowances. In fact, it is unlikely that any one of these cases will turn out to match reality. Even the natural gas industry's own analysis of its future (as embodied in the work of the National Petroleum Council) has varied considerably as reality turned out to be different from the industry's assumptions as to its resource base and other factors.[25] Again, these analyses by and large do not consider the effects of the other regulations depicted in Figure 4 that electric utilities may face.

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[24] The other reason Waxman-Markey shows less of an increase in the natural gas burn is because it allows regulated entities to use domestic and international offsets to help achieve carbon compliance. This study will define the role of offsets in more detail later herein. If those offsets are not available or if electric utilities cannot obtain them, in the quantities assumed, then the gas burn may well be higher.

[25] Note, for example, the marked change in tone from the 1999 National Petroleum Council Study touting the natural gas industry's ability to serve a 31 Tcf market albeit needing to face some "challenges" in order to do so (not the least of which was its complaints about federal land off limits to drilling), to the 2003 study "Balancing Natural Gas Policy," and then to the 2007 study "Facing the Hard Truths About Energy" that natural gas supply is declining with little hope of increasing production. Of course, then came shale production and a new radically different view of production possibilities.

Table 2 provides five additional scenarios developed by Aspen that are designed to further highlight the point that different assumptions about the electricity resource mix drive the projected natural gas burn. The additional scenarios evaluate different combinations of some of the resource mix results shown in the Table 1 studies. Accordingly, the five additional scenarios do not necessarily represent economic dispatch of electricity generating plants or economic resource additions. Rather, they are merely "what if" scenarios represented in an annual energy balance built initially from the mix EPA projected in its analysis of Waxman-Markey as shown in Table 1.[26] Nuclear and renewable resources are typically changed first, then coal-fired resources. Natural gas is "on the margin" and picks up whatever remaining difference might exist between supply and demand so that all demand is met. To reiterate, the analysis says nothing about cost; the point was to recognize that the resource assumptions reflected in the studies summarized in Table 1 may not hold and to see what kind of changes to the mix—without worrying about what could cause those changes or how probable they might be—would create much higher natural gas burns.

Table 2: Range in Projected EG Natural Gas Burn and Total Demand

	Alternative Resource Mix Comparisons				
	1	2	3	4	5
Annual Load Growth	1.00%	0.41%	0.41%	0.41%	0.41%
Share of 2030 Load Served By:					
Nuclear	19%	23%	23%	23%	23%
Renewables	9%	20%	20%	20%	20%
Coal	31%	35%	28%	13%	5%
Coal CCS	2%	3%	3%	3%	3%
Natural Gas	33%	12%	19%	35%	43%
Petroleum	2%	2%	2%	2%	2%
Hydroelectric	5%	6%	6%	6%	6%
Total Resources	100%	100%	100%	100%	100%
CO_2 Emissions in 2030 (million tons)	2,669	2,082	1,912	1,574	1,344
Gas Burn for EG in 2030 (Tcf)	11.9	4.1	6.8	11.0	13.8
Gas Burn for EG in 2036 (Tcf)	13.8	5.1	7.7	12.5	15.1
Total U.S. Gas Demand	29.8	21.1	23.7	28.5	31.1

Source: Aspen Analysis

Scenario 1 is built starting with the load-resource mix projected by EPA in analyzing Waxman-Markey. In that analysis EPA assumed load growth of 0.41%. We tested what the mix looks like if load growth is instead assumed to be higher: 1%. 1% is higher than what EPA assumed but still lower than the historical average of 1.5%. We left all other resources at the levels projected in EPA's analysis but increased gas, as our assumed marginal resource, to pick up the increased load. The percentages

[26] An energy balance merely stacks up hours generated by available sources and compares the total resource hours available to energy demanded. It shows whether resources are sufficient to meet all demand and summarizes how that demand will be met.

contributed by each resource are slightly lower than shown in Table 1 for the EPA W-M scenario because these are the percentages that result in 2030, which reflect that 1% load growth. The resulting EG gas burn is 13.8 Tcf (compared to 6.9 Tcf in 2008).[27]

Scenarios 2 through 5 revert to the 0.41% load growth used by EPA. In Scenario 2 we pushed Renewables to 20%.[28] No other non-gas resources were changed; their relative percentages shift slightly because of the lower load growth assumption. With the lower load growth and the increase in Renewables, resulting gas burn is 5.1 Tcf. In short, lower load growth and serving 20% of that load with Renewables cut the EG gas burn from 13.8 Tcf to 5.1 Tcf, a vast difference. Emissions are lower than either what EPA projected or in Scenario 1, but still use offsets (that may not ultimately exist) to achieve carbon compliance.

Scenario 3 tries to get emissions lower. It does that by keeping the load growth, nuclear generation and Renewables the same, but switches some coal for natural gas. In fact, the reduction in coal-fired generation it tests is 5% per year. This brought natural gas use back up to 7.7 Tcf to match what EPA showed in its Waxman-Markey analysis, but carbon emissions from the electricity industry are too high, meaning that generators would have to buy lots of allowances in order to achieve compliance under this resource mix. Scenario 4 cuts out more coal-fired generation and replaces it with gas. Other resources hold their respective resource portfolio market shares. The gas burn increases to 12.5 Tcf but the emissions are finally low enough (1,600 million tons) that generators would not have to buy so many allowances to achieve carbon compliance.[29] Scenario 5 goes further still, cutting out most but not all coal. With all other assumptions the same, the natural gas burn goes to 15.1 Tcf. (CO_2 emissions would fall to 1,344 million tons.)

Gas Burn if All Coal-Fired Generation Switched to Gas:

335,000 MW * 7 MMBtu/MWh * 24 hours * 365 days …
* .72 Capacity Factor

Now convert to TCF by dividing by 1.05 MMBtu/cf and 1,000,000,000
= 14.1 Tcf

We need to ask another question. What would the gas burn be if all existing coal-fired units were required to switch to natural gas? Scenario 5 did not address quite that question because it still left 5% of the existing coal-fired capacity in place (and allowed load growth). The electric industry has approximately 335,000 MW of existing coal-fired capacity. These plants are located as shown in Figure 5. Switching all 335,000 MW to gas (at an assumed heat rate equal to that of a new NGCC and running the NGCCs at the 72% load factor of the existing coal-fired fleet – slightly more than 16 hours per day)

[27] This scenario actually produces carbon emissions in 2030 that are higher than EPA projected as compliant with the caps so either the industry has to obtain a lot of offsets or some further change would need to occur to reduce the carbon emissions, likely some sort of further substitution of Renewables or nuclear to back out some coal.

[28] Aspen selected 20% for illustrative purposes; it is somewhat consistent with a potential national Renewable Portfolio Standard and is the same figure used by Duke CCPP.

[29] The point is not that buying allowances is a "bad" way to achieve compliance but to highlight the tradeoff between gas burns and allowance prices.

results in a natural gas requirement of 14.1 Tcf.[30] Add to that the gas being burned in the gas-fired units that exist today—another 6.9 Tcf—and total natural gas demand for electric generation ends up at 21.0 Tcf. Adding in other sectors' gas demand yields a total natural gas demand of 37.1 Tcf per year, half again (or more precisely, 61%) more than current annual natural gas demand of 23 Tcf. This result is captured in Table 3.

Table 3: Natural Gas Demand if All Coal-Fired Generation Replaced with Gas at Current Electricity Market Size/No Growth

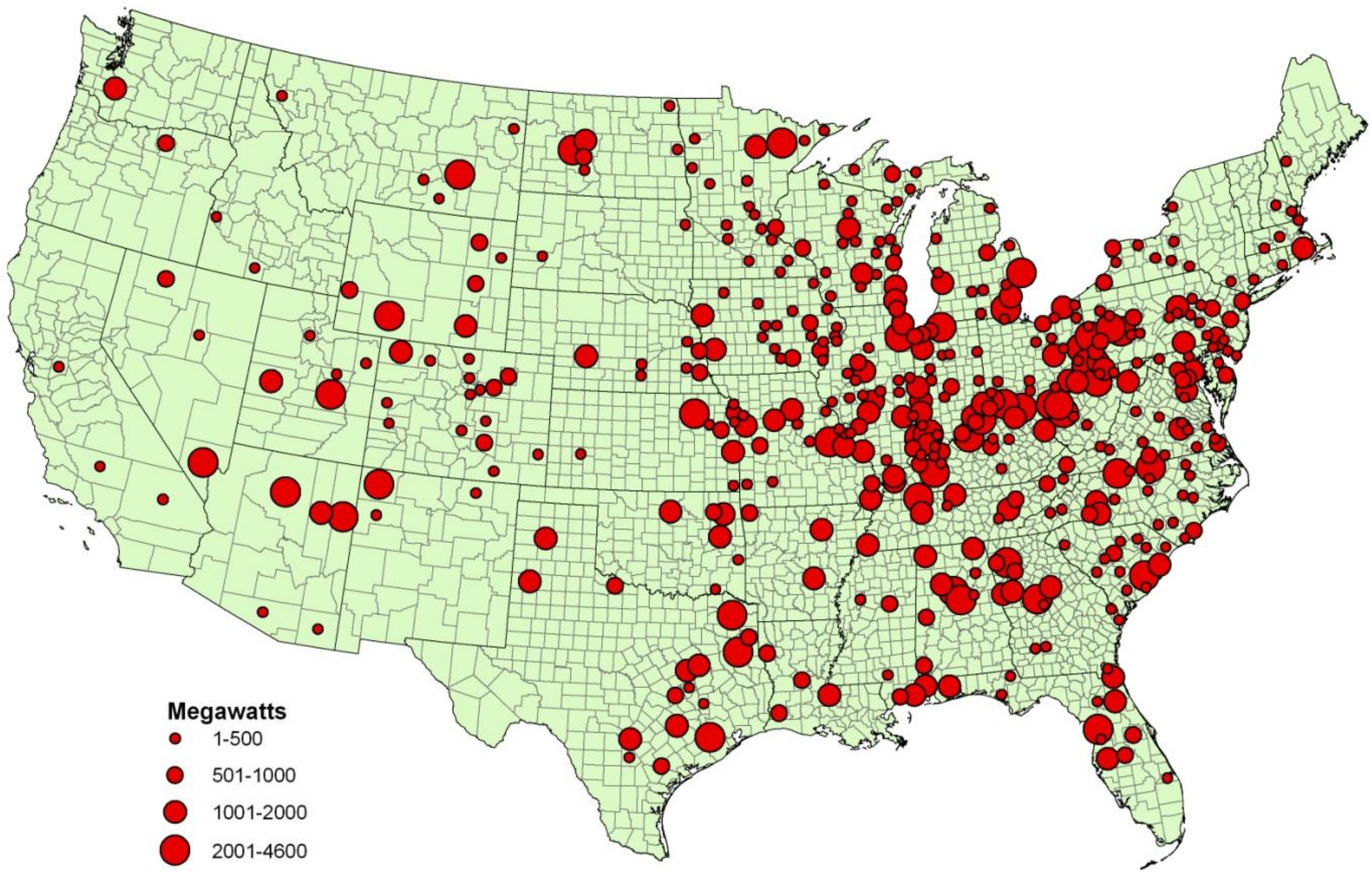
	Tcf
2008 EG Gas Burn	6.9
EG Gas Burn if All Existing Coal-Fired Generation Replaced[31]	14.1
Subtotal EG Gas Burn	21.0
All Other Sectors	16.1
Total Annual Natural Gas Demand if All Existing Coal-Fired Generation Replaced	37.1

Source: Aspen Analysis

[30] This is lower than the 15.1 Tcf gas burn estimated in Scenario 5 because Scenario 5 allows load growth. Scenario 5 would be even higher if it removed all coal.

[31] Assumes load factor of 72%, equal to what EIA reported for coal-fired generation's 2008 load factor. Using generated GWh instead of MW of capacity and simply multiplying by a gas-fired unit's heat rate also yields a required gas burn of roughly 14 Tcf.

Figure 5: Location of Existing U.S. Coal-Fired Generation (By County)



Source: EIA (http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html)

There is another factor in addition to the resource mix changes that is at play in the analyses that consider carbon regulation but project little increase in the natural gas burn. Note that not all of the scenarios in Tables 1 or 2 necessarily get the electric industry down to its so-called pro rata "share" of carbon reductions.[32] The gas burn estimated in the analysis of Waxman-Markey, in particular, relied heavily on the purchase of additional allowances and offsets, as Waxman-Markey allowed as many as 2 billion tons worth of domestic and international emissions offsets to count towards carbon compliance. (By way of background, in a cap and trade-type program one can think of allowances as essentially "tickets," given out by a government implementing cap and trade, allowing one to emit. A utility can emit as much CO_2 as it has allowances to cover. If it doesn't have enough allowances it can choose to either reduce its emissions or purchase allowances third-parties.[33]) Offsets provide additional "tickets" from outside the cap and trade program and are an important tool in trying to make sure that emissions reductions are achieved from the most cost-effective sources. They can be created when one takes an action NOT required by regulation that has the effect of reducing CO_2 emissions. Planting trees to take up CO_2, for example, could create an offset. The offset is verified by a third-party and documented on a piece of paper and, of course, must meet the conditions of being permanent and incremental to other actions; it is given value because some governments will count it towards carbon compliance like an allowance. Thus, activities outside the CO_2 regulatory program can reduce emissions, thereby defining offsets that emitters can theoretically either create or buy, and then "turn in" along with their allowances to cover their carbon responsibility. The more offsets available, the lower the price of allowances (since an offset is a substitute method for achieving carbon compliance). The lower the price of allowances, the less economic it is and the less need for a utility to switch away from burning coal and the lower the cost of implementing carbon regulation.

Many of the analyses looking at carbon regulation had lots of offsets, which pushed the price of allowances down, and the electric utilities achieved compliance by buying these lower-prices allowances and offsets. If those assumptions do not hold, the industry will likely achieve compliance by burning more gas.

The purpose of highlighting the role of allowances and offsets is to emphasize that if a final cap and trade program does not allow offsets or if the electricity industry cannot get the offsets because other industries obtain them first, then more drastic resource mix changes would be needed in order for the electricity industry to achieve carbon compliance. These more drastic resource mix changes, such as those shown in Mix 4 and 5 of Table 2, entail much higher natural gas burns than assumed in other analyses of the impacts on the industry of carbon regulation. To repeat: if the offsets do not materialize or utilities cannot get them, then allowance prices will be higher and the gas burn will be higher.

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[32] EPA's analysis of Waxman-Markey showed a reduction in carbon emissions from the electricity industry of only 10%, to 2,180 tons, by 2025 and relatively low allowance prices. See, Executive Summary, page 6, found at http://www.epa.gov/climatechange/economics/pdfs/WaxmanMarkeyExecutiveSummary.pdf

[33] A utility should buy allowances and continue to emit CO_2 when the cost of allowances is less than its cost to reduce emissions. From an economists' perspective, the purpose of cap and trade is to create a market so that utilities and parties can compare the cost of emitting versus reducing emissions and transact to achieve the least-cost mix of emissions and reductions.

Some of the gas-fired merchant generators have argued that carbon emissions could be reduced immediately if we simply directed the utilities to turn down coal-fired generation in favor of gas-fired merchant capacity that has been built but that is not currently being dispatched.[34] These are largely combined cycle plants not operating at full capacity. The Congressional Research Service (CRS) performed a study of this question and released its results in January 2010.[35] CRS found that the underutilized existing natural gas combined cycle (NGCC) plants operated at an average capacity factor of 42% in 2007. Doubling that capacity factor to operate at 85% could theoretically displace 32% of 2007's coal-fired generation. But then CRS asked about the locations of the plants: are the gas-fired plants located near the coal-fired plants they would be replacing? This pertains to whether the gas-fired plants could deliver their output to the same markets as the coal-fired plants they are replacing without adding new transmission capacity.[36] CRS found that 60 of the 298 plants coal-fired that met its study criteria were located with 10 miles of one of the underutilized gas-fired plants. (Those 298 plants represented 98% of 2007's coal-fired output and the 60 plants located within 10 miles of an underutilized gas-fired plant represented 5% of 2007's coal-fired output.) 9% of the coal-fired units were located within 25 miles of one of the underutilized coal-fired plants.[37] The emissions that would be eliminated by backing down those coal-fired units and operating the gas-fired units at a higher capacity factor total 3% to 5% of CO_2 emissions from coal-fired generation.

Overall, Aspen concludes that it is important to understand how the various studies, largely focused solely on carbon cap and trade, arrived at their conclusions about the amount of natural gas likely to be burned by electric generators. Whether it be expectations about constructing nuclear capacity, the amount of Renewables added, how much energy efficiency is achievable and how consumers will change their load patterns in response to higher prices, or whether geologic or other CCS will be available and how much it will cost, and whether the electric industry can purchase enough allowances or offsets, each constitutes a critical assumption subject to uncertainty. Aspen's analysis shows that even in a scenario with low load growth and 20% Renewables, the combination of no new nuclear power and lack of CCS, means that for the electricity industry to reach emissions of around 1,500 million tons by 2030 it will have to burn a lot more natural gas than any of the major studies has projected.

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[34] Merchant generators are plants, usually NGCCs, built by an independent generator rather than a utility for the purpose of selling electricity via bilateral contracts or into competitive market exchanges.

[35] Kaplan, S. "Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants," Congressional Research Service, January 2010.

[36] The author's experience working on financing of merchant power plants is that while many may not have firm supply or transportation contracts to support operations at an 85% capacity factor, most likely have delivery interconnections that are physically sized large enough to deliver that much gas and at least looked at being able to meet load equal full output for 24 hours on an interruptible basis. Accordingly, additional gas transmission capacity to support these plants may not be necessary. Electric transmission, however, would only have been assessed or required to deliver power into the control area which is not the same as getting it to the load center of the utility phasing out its coal plant.

[37] Op. cit., p. 17

Summary Observations Related to Natural Gas Demand

1. Current natural gas market size is 23 Tcf.
2. 30% is consumed by the residential and commercial, industrial, and electric generation sectors, respectively.
3. Residential demand is highly seasonal; demand per household is declining but the growing number of households keeps annual use for the sector fairly constant.
4. Space heating use during winter months by the residential and commercial sectors is responsible for the seasonal shape of natural gas demand.
5. Virtually all expected growth in natural gas demand will occur in the EG sector.
6. EG causes a small upward blip in summer natural gas demand; summer heat waves change demand by enough to move prices.
7. The EG sector burned 6.9 Tcf of natural gas in 2008.
8. EIA's AEO 2010 projects EG natural gas demand to increase by approximately 2 Tcf by 2030 even if carbon regulation is not adopted.
9. Other projections of natural gas demand in 2030 for the electricity sector range from 6.8 Tcf to 10.7 Tcf.
10. These electricity sector demand projections—which generally did not consider the additional regulations under consideration by EPA that will also encourage fuel-switching—are highly dependent on assumptions about electricity load growth, whether new nuclear power is built, the amount of renewable generation, whether CCS is commercially demonstrated and deployable for new plants or retrofits, and the number of offsets allowed to count towards carbon responsibility.
11. Changing these assumptions results in estimates ranging from 4.1 Tcf to 13.8 Tcf in 2030.
12. Switching all 335,000 MW of existing coal to natural gas today would create additional natural gas demand of 14.1 Tcf; EG demand, including existing gas-fired generation, would total 21.0 Tcf.
13. Adding in other sectors creates a 2030 natural gas requirement of 37.1 Tcf, some 61% larger than with the current electric resource portfolio.
14. The potential for additional EPA regulation of other hazardous pollutants and construction costs are encouraging some utilities to switch to gas now.

Natural Gas Supply

Natural gas supply consists of reserves in the ground and the ability to produce flowing supply from those reserves. EIA reports estimates of proved reserves each year based on the results of producer surveys. "Proved" reserves are determined based on drilling into a formation and represent an estimate of what could be produced with reasonable certainty at current prices and regulation.[38] Those estimates are usually, but not always, conservative relative to what the formation ultimately produces. Proved reserves grow when drilling information allows additions to reserves in excess of that year's production. As shown in Figure 6, annual proved reserves fell from 1973 until the mid-1990s but have grown every year since. At the end of 2009 EIA reported proved reserves of dry natural gas of 245 Tcf.

Proved reserves are those that have been drilled enough to allow reasonable certainty in the eyes of accountants and engineers that they can be produced at current prices. U.S. proved reserves are enough to last ten years if we continue to use what we used last year.

Probable reserves require more drilling to confirm the size of the deposits and production rates.

Probable, possible and speculative resources are tracked by the Potential Gas Agency at the Colorado School of Mines and the U.S. Geological Survey. The Potential Gas Agency announced in June 2009 year-end 2008 probable, possible and speculative resources of 1,836 Tcf.[39] Probable, possible and speculative reserves are categories of increasing uncertainty found in existing fields, new fields, and frontier areas with little prior drilling, respectively. They are additive to the proved reserves reported by EIA, but unlike proved reserves the market prices needed to drill these reserves is unknown. One should understand that changes in market prices affect the estimate of proved reserves: higher prices allow probable reserves to move into the proved category. The corollary of this point is that the resource base is vast: producing enough gas is only a matter of being willing to pay the price needed to drill and process it ready to flow into a pipeline.

Turning reserves into flowing supply rests with individual producer decisions to drill production wells. Individual producers tend to specialize their investments into geologies and technologies to produce from a certain geology. Devon Energy, for example, was a pioneer in producing the Barnett Shale. Encana specializes in tight gas formations in the Rockies. Other companies tend to specialize in the deep water Gulf, for example.

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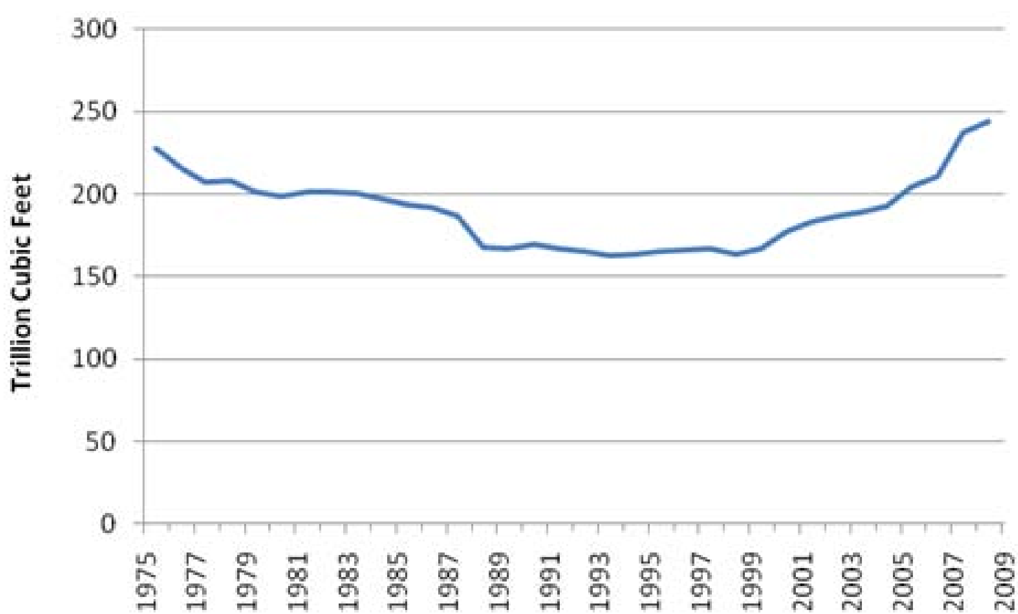
[38] Proved reserves are defined by the Securities and Exchange Commission (SEC) in Rule 4-10 of Regulation S-X. The definition was revised slightly January 1, 2010. For a detailed discussion of the changes, see SEC Release No. 33-8995.

[39] The press release can be found at http://www.mines.edu/Potential-Gas-Committee-reports-unprecedented-increase-in-magnitude-of-U.S.-natural-gas-resource-base. Approximately one-third of the total is shale-deposited gas.

Drilling decisions are generally cyclical. That is, when prices are high, producers have higher profits and spend more on drilling. When prices are low, profits are lower and producers cut back on drilling. Exxon-Mobil's retired chairman Lee Raymond said that the oil and gas business is all about technology. Technology drives the ability to understand formation characteristics and the drilling techniques applied by producers. Technology improvements allow production to increase at lower cost. Technology improvements also allow reserves that were only probable to be "proved up" and brought into production. This is what has happened with the shale formation gas now being produced. New technologies were tested and developed successfully in the Barnett shale in Texas and are now being applied to shale formations across the continent. Among these technologies is the application of horizontal drilling (diagonally across pay zones instead of straight down) combined with new ways of fracturing the shale rock and then propping it open to allow gas to collect and flow through the crack and up the well bore.

Figure 6: U.S. Annual Proved Reserves of Dry Natural Gas[40]



Source: EIA, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Annual Report 2008

Producers face anti-trust penalties for sharing too much information among themselves, not to mention their technologies, and lease acreage positions are at the core of what they see as a proprietary "leg-up" on competitors. As a result, producers do not share strategies or drilling plans. Being optimistic risk-takers by nature, producers tend to believe that they possess the next great formation that will be a great winner for their company. They ALL believe that. And they believe they can beat the producer down the road at the next leasehold or in the next basin and get their production to market first. The result is that when prices are high, producers collectively over drill; eventually the industry ends up with

[40] Dry reserves are the most common reference; they are reserves with the small amount of associated water and petroleum liquids removed.

more gas than is demanded. This is what transpired in 2008 and 2009. Combine that in 2009 with the onslaught from the recession, and you have lower demand at the same time you have higher production. The result is that prices then fall. This effect is seen looking at monthly natural gas spot prices: from the peak price in July 2008 of $13.98 per MMBtu prices fell to $1.98 per MMBtu in late September 2009.

The Role of LNG

The story about large quantities of proved and probable reserves that exist and the logic about drilling them into production is as true world-wide as it is in the U.S. It is also true that producers drill where they possess technological and geological expertise, looking for the least-cost opportunities worldwide. The rush to build terminals so that liquefied natural gas (LNG) could come to the U.S. was driven by the fact that world-wide, producers had gas in excess of what they could market, some of it from geographic locations in which there was no indigenous market or insufficient indigenous market to use all of the gas. At the same time, shipping costs and liquefaction costs declined such that it became possible to chill into LNG, transport it in a ship (generally known as "transship"), regasify it (i.e., heat it back to ambient air temperature so it returns to its gaseous state) and inject into a U.S. pipeline where there was a market with transparent, liquid and reasonably well-understood prices.

While on the subject of LNG, note that this study's sponsors have members located in places where there is no or very limited natural gas. These include Puerto Rico, American Samoa, the Virgin Islands, Guam and Hawaii. (Alaska's Cook Inlet region has local natural gas production but declining production is making it difficult for electric utilities to get natural gas.) For coal-fired plants in these locations to switch to gas they would need that gas to arrive as LNG.

While developers worked to build terminals in the U.S. and terminals in Canada and Mexico that could reach the U.S. or local markets (several were built) three things happened. The first is economic growth in Asia such that markets there contracted for large portions of the LNG. The second is that various events (e.g., an accident to a supply train in Algeria, the postponement of liquefaction construction in Indonesia, delays in investment in Australia due to cost increases) reduced the quantity of LNG expected to be available. The third is the current "excess" of supply relative to demand in the U.S., driven by the recession combined with the increase in production, that has pushed prices lower. U.S. natural gas prices have sunk lower than prices at the U.K. National Balancing Point (which drives Atlantic LNG) and have opened up a significant gap on a Btu basis relative to crude oil (which drives Pacific LNG).[41] The apt observation is that LNG could become relevant in the U.S. again if the relationship between U.S.

[41] The U.K. National Balancing Point is akin to Henry Hub in the U.S. in that it is the most liquid gas trading point in Europe and creates a benchmark price. It is used as the pricing and delivery point of the Intercontinental Exchange gas futures contract but is a virtual, rather than actual physical interconnection location.

natural gas prices, crude oil, and the U.K. National Balancing Point narrowed. Should U.S. production falter, those price gaps should indeed narrow and LNG would become more relevant to the U.S. market.

Uncertainty about Shale Production

While it is clear that there are plenty of natural gas reserves in the U.S. that can be produced, we don't know for the probable reserves what price it will take or what technology will be required to bring them into production. Even for the shale-deposited gas that has the industry abuzz there are issues that could make its production less, rather than more, certain.

Extraction Technology

As indicated above, shale production depends on use of a technique known as hydraulic fracturing, or simply "fracing." Shale is a sedimentary rock that is porous enough to hold gas but not permeable enough for the gas to move through the rock very well. Drilling horizontally across the formation exposes maximum gas-containing rock to the well bore. Then water and chemicals (known as fracing liquid) are pumped down the well bore at high pressure to fracture open cracks through the shale. In the next stage sand and compounds with latex-like properties are injected to hold the cracks open for a long period of time.[42] The cracks then allow the gas to flow towards the well bore and ultimately up the well.[43] Figure 7 shows the location of major geologic basins containing shale gas deposits.

[42] The liquid used to hold or "prop" the fractures open for the gas to flow are known as "proppants."

[43] The actual fracturing is done by what is known as a well services company. Halliburton, Schlumberger, and Baker-Hughes are examples of well-known well services companies. Different companies that do fracturing use different chemicals and additives to the injection fluid. These different chemicals and their properties are considered proprietary, much like a given producer's geo-technical expertise about a given geology is considered proprietary. Press reports sometimes compare the proprietary nature of the recipe to the concept of protecting the secret recipe for Coca-Cola.

Figure 7: Shale-Deposited Gas Supply Basins

Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Environmental Concerns

The Final Impact Assessment Report produced for the New York City Department of Environmental Protection (NYCDEP) cited the fracturing process involving "pumping three to eight million gallons of water and 80 to 300 tons of chemicals into [a] well at high pressure over the course of several days." [44] Half or so of the injected solution returns back up the well. The water that flows back up the well also tends to contain hydrocarbons and dissolved solids such that it must be disposed of via underground injection or industrial treatment (i.e., conventional wastewater treatment is not feasible). The injection water is usually trucked in. The NYCDEP study estimated 1,000 or more truck trips per well to haul in water and equipment and then haul out wastewater. In addition, as production from a given well falls off, the fracturing process is repeated. Some shale gas production wells require refracturing every 5 years, and the useful life of a well may be 20 to 40 years such that fracturing will be an ongoing process rather than something that occurs only when the wells are originally drilled. [45]

What worries residents and others about hydraulic fracturing is that it uses a fair amount of water, causes lots of truck trip activity over the life of the well to bring in water and take some of it back out, and that it injects chemicals underground at high pressure. The chemicals that are added contain some amount of materials that may be toxic and residents are fearful that these chemicals might migrate and potentially contaminate drinking water supplies.[46] Some of the production areas are closer to urban areas (such as Dallas/Fort Worth's location in the heart of the Barnett Shale) or to their water supplies (such as New York City's long-standing preservation and use of the Marcellus Basin watershed for drinking water). There are also stories like the one of a couple in Colorado whose water well exploded, emitting flames out of the top of the well, after fracturing was done on several area wells.[47] Increasingly, residents seem to be opposing local drilling.

While New York City's environmental concerns seem most related to the quality of its Marcellus basin-sourced drinking water, other regional water resource agencies indicate concern about the quantity of water used to support shale-deposited gas production. The industry points out that the water used to bring up well drilling mud ("mud," comprised of sand, water and chemicals, that lubricates the drill bit and carries rock cuttings and debris up the well bore as drilling continues) is less than for other sources

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[44] New York City Department of Environmental Protection, "Final Impact Assessment Report," December 2009, p. ES-1.

[45] One difference between shale-deposited gas wells and conventional wells is their production profile. Both shale, tight gas and coalbed methane formations produce more of their gas in the first few years, then taper off to very low levels for a long period of time. Conventional wells exhibit a similar but much less pronounced decline pattern.

[46] Similar concerns are often raised about carbon dioxide injection. The drilling techniques are largely the same technology, whether used for shale-deposited gas, CO_2, or geothermal but applied to different geology. Different companies tend to be expert at understanding different geologies and formations, which leads to protection as to what exact techniques are being used. With respect to fracing, the composition of chemicals used and their proportions relative to each other are considered trade secrets.

[47] "Drilling Process Causes Supply Alarm" *The Denver Post*, November 17, 2008 found at http://www.denverpost.com/breakingnews/ci_11001835 or see Amos' complete story at http://www.earthworksaction.org/cvLauraAmos.cfm .

of energy, per MMBtu produced, and that it is less than other regional uses.[48] A Fact Sheet put out by natural gas producer Chesapeake Energy (Chesapeake) refers to using an average shale gas well requiring as much as 600,000 gallons of water and an average of 4.5 million gallons over the life of the well. 5 million gallons is the amount of water New York City uses in seven minutes. Chesapeake notes that the water used for developing shale-deposited gas represents a 1.5% increase in water use in each shale area. Use of the water is said to not represent a long-term commitment of the resource in contrast to the case with most other uses of water. Chesapeake points out that the water used is purchased and where required, permitted, which ensures that it does not interfere with the supply of water available to other users.

Wells to produce shale-deposited gas are fractured upon initial production and then may be re-fractured five or six times over the life of the well to keep production going. These wells often produce 50% or more of their gas early in their first year of production.

The National Energy Technology Laboratory (NETL) produced in 2009 what it called "a primer" on shale gas development. It cited 3 million gallons of water as most commonly needed for drilling and hydraulic fracturing of horizontal shale gas well, noting that the volume can vary substantially between wells.[49] Wells in the Barnett shale take the least amount of total water to drill and fracture (2.7 million gallons per well) while wells in the Marcellus take an estimated 3.9 million gallons. NETL also noted that the volume of water per foot of wellbore may be decreasing with development over time of new technologies to produce shale-deposited gas.

Even Texans, who are known for being tolerant of inconveniences and impacts created by oil and gas drilling, have some complaints about drilling in the Barnett Shale. The Texas Commission on Environmental Quality (TCEQ) conducted tests in December 2009 in response to resident complaints of toxic emissions and odors from wells drilled into shale deposits. Some of the emissions were allegedly benzene and tests paid for by the Town of Dish in Denton County found benzene emissions five times the long-term exposure limit.[50] TCEQ's own tests reportedly found no emissions over limit but the testing and discussion continue.

The 2005 Energy Policy Act exempts fracing from regulation under the Safe Drinking Water Act (SDWA). Fracing isn't just used to produce shale-deposited gas but is also used in the "tight" gas formations common to producing areas in the Rockies supply area (generally Colorado, Wyoming, and eastern Utah) and in producing coal-bed methane. In 2004 EPA reviewed studies about the impacts of fracing and concluded it was safe.[51] EPA also entered into a Memorandum of Understanding with Halliburton,

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48 Chesapeake Energy, "Water Use in Deep Shale Gas Exploration," Fact Sheet March 2010. Found at http://www.chk.com/Media/CorpMediaKits/Water_Use_Fact_Sheet.pdf

49 "Modern Shale Gas Development in the United States: A Primer," U.S. Department of Energy National Energy Technology Laboratory, April 2009, p. 64. Another useful briefing paper is available from the California Energy Commission: "Shale-Deposited Natural Gas: A Review of Potential," CEC 200-2009-005-SF, February 2010.

50 Fort Worth Star-Telegram, "Tests Find Emissions of Fort Worth Drilling Sites Don't Exceed Standards," January 12, 2010.

51 The study is available at http://www.epa.gov/ogwdw000/uic/wells_coalbedmethanestudy.html. Aspen has not reviewed it in detail but notes that it applies to coal bed methane wells and that carbon dioxide is sometimes used as part of the proppant.

Schlumberger and other well services companies (who are the ones that actually provide the fracturing services) providing that the companies would stop using diesel fuel as part of the fracturing liquid in coal-bed methane wells. Concerns about fracing and its exemption from the SDWA have led to the introduction in Congress of legislation to repeal that exemption in what is known as the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act.[52] In addition, EPA announced in early 2010 that it will conduct a $1.9 million peer-reviewed study with significant stakeholder input into the potential adverse impacts of hydraulic fracturing. Without a comprehensive study it is difficult to assess whether the concerns are valid and what impact they might have on access to natural gas.

Seismic Events

Hydraulic fracturing has been associated with some amount of increased seismic activity. Complaints about earthquakes believed to be caused by hydraulic fracturing have arisen in California, Texas and Switzerland. The California drilling occurred in an earthquake prone area 100 miles north of San Francisco. A Swiss project was found to have caused a magnitude 3.4 quake near Basel in 2006, also the site of previous significant seismic activity (a 6.7 magnitude quake in 1356 is said to have severely damaged Basel). The drilling in both these cases was related to geothermal energy projects in which the fractures would be used to pump water down to hot rock which would return to the surface as steam.[53] The information reviewed in preparing this report did not indicate what kind of proppants would be used to hold open the cracks created by the fracturing.

Similar relatively small quakes have been reported in the Barnett Shale near Dallas-Fort Worth, an area unknown for seismicity. Seismologists at Dallas' Southern Methodist University and the University of Texas, Austin issued a report in March 2010 finding those quakes to have been caused plausibly by the reinjection of water into a disposal well that activated a fault thought to be inactive.[54] The quakes are said to have stopped once injection into the disposal well stopped. The scientists say they do not understand why other disposal wells did not cause similar quakes nor do they have a good understanding of the region's underlying seismicity, presumably because of the infrequency of such events in north Texas. They also cited a lack of complete information about the subsurface structure in the area, including the porosity and permeability of the rock and the potential fluid path. A second study looking at quakes in and around Cleburn, Texas (located in the Barnett Shale, near Dallas/Fort Worth) remains underway.

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[52] Exxon-Mobil's agreement to purchase independent producer XTO Corp contains a clause allowing Exxon-Mobil to walk away if the FRAC Act passes. XTO's production and expertise is largely in shale-deposited gas. The FRAC Act, among other things, requires disclosure of the chemicals used to fracture rock formations for producing gas. On April 13, 2010 Exxon-Mobil came out in support of public disclosure of fracing liquid compounds in a further effort to avoid legislation that would limit fracing.

[53] See, for example, "Geothermal Project Review Underway," *Lake County News*, July 26, 2009. Found at: http://lakeconews.com/content/view/9681/764/ or "Deep in Bedrock, Clean Energy and Quake Fears," *New York Times*, June 24, 2009. Found at: http://www.nytimes.com/2009/06/24/business/energy-environment/24geotherm.html .

[54] Frolich, C., et. al., "Dallas-Fort Worth Earthquakes Coincident With Activity Associated With Natural Gas Production," The Leading Edge, Volume 29, p. 270. Found at http://smu.edu/newsinfo/pdf-files/earthquake-study-10march2010.pdf

Some suggest that production of shale-deposited gas will increase carbon dioxide emissions. It isn't that the methane (CH_4) produced from shale deposits is not chemically different from other methane. Rather, the stream of compounds produced from a natural gas well actually contains a number of hydrocarbons besides pure methane. Those other hydrocarbons can be butane (C_4H_{10}), propane (C_3H_8), ethane (C_2H_6), pentane (C_5H_{12}), and others. The more of those heavier hydrocarbon molecules are contained in the gas stream, the higher the carbon content, which would create higher emissions. The relative mix of the different hydrocarbons varies by formation. Often, the heavier hydrocarbons (which are produced from the well as either a liquid or are easily condensed out of the gas stream, hence, they are known as "natural gas liquids" or condensates) are processed out of the gas stream and sold separately. Higher prices for natural gas liquids, all else equal, encourage producers to drill where the liquids content of the gas is higher.[55] If markets for those products are not favorable or if little processing capacity is available, producers may leave some or all of the higher Btu-content substances in the gas stream. Combusting that gas would then emit more CO_2 than average for natural gas.

Natural gas production from shale formations is suggested by some to cause more CO_2 emissions than production from conventional natural gas because of the water and hydraulic fracturing liquids being trucked into, and then away from, the drilling site. Cornell University's Dr. Robert Howarth, for example, has encouraged further study of this, pointing out that if we added to the standard estimates of CO_2 emitted by combustion of natural gas the emissions associated with "development, processing and transportation of natural gas (due to the use of fossil fuels to build pipeline, truck water, drill wells, make the compound used in drilling and fracturing, and treat wastes and the loss of carbon-trapping forests) …" as well as gas leaked "during production, transport processing and use," then natural gas may not be "significantly better than coal in terms of the consequences for global warming."[56] An economy-wide program would seem to capture those emissions and one would expect the fugitive emissions should be calculated in the "Inventory of U.S. Greenhouse Gas Emissions and Sinks" compiled by EPA; Aspen has not found evidence that shale-deposited gas produces higher fugitive emissions than other natural gas production. This study highlights the point only to highlight that if such concerns turn out to be valid, they could become an impediment to production at high levels or acceptance of the use of shale-deposited natural gas.

If the Deepwater Horizon blowout and leak does not scuttle plans to drill in the OCS, production from any new wells that result from expanded OCS leasing is unlikely before 2017.

Other issues around drilling contribute to uncertainty about our willingness to produce potentially much higher quantities of natural gas. 1999's National Petroleum Council report indicated the natural gas

55 Casually, one does hear anecdotes that some of the current shale-deposited drilling is occurring in order to obtain the value of the higher liquids-content gas.

56 Howarth, Robert. "Preliminary Assessment of the Greenhouse Gas Emissions from Natural Gas obtained by Hydraulic Fracturing." Found at http://www.technologyreview.com/blog/energy/files/39646/GHG.emissions.from.Marcellus.Shale.April12010%20draft.pdf. To be fair, cap and trade programs proposed to date certainly do not ignore all of those emissions but have tended to deal with them outside the electricity sector.

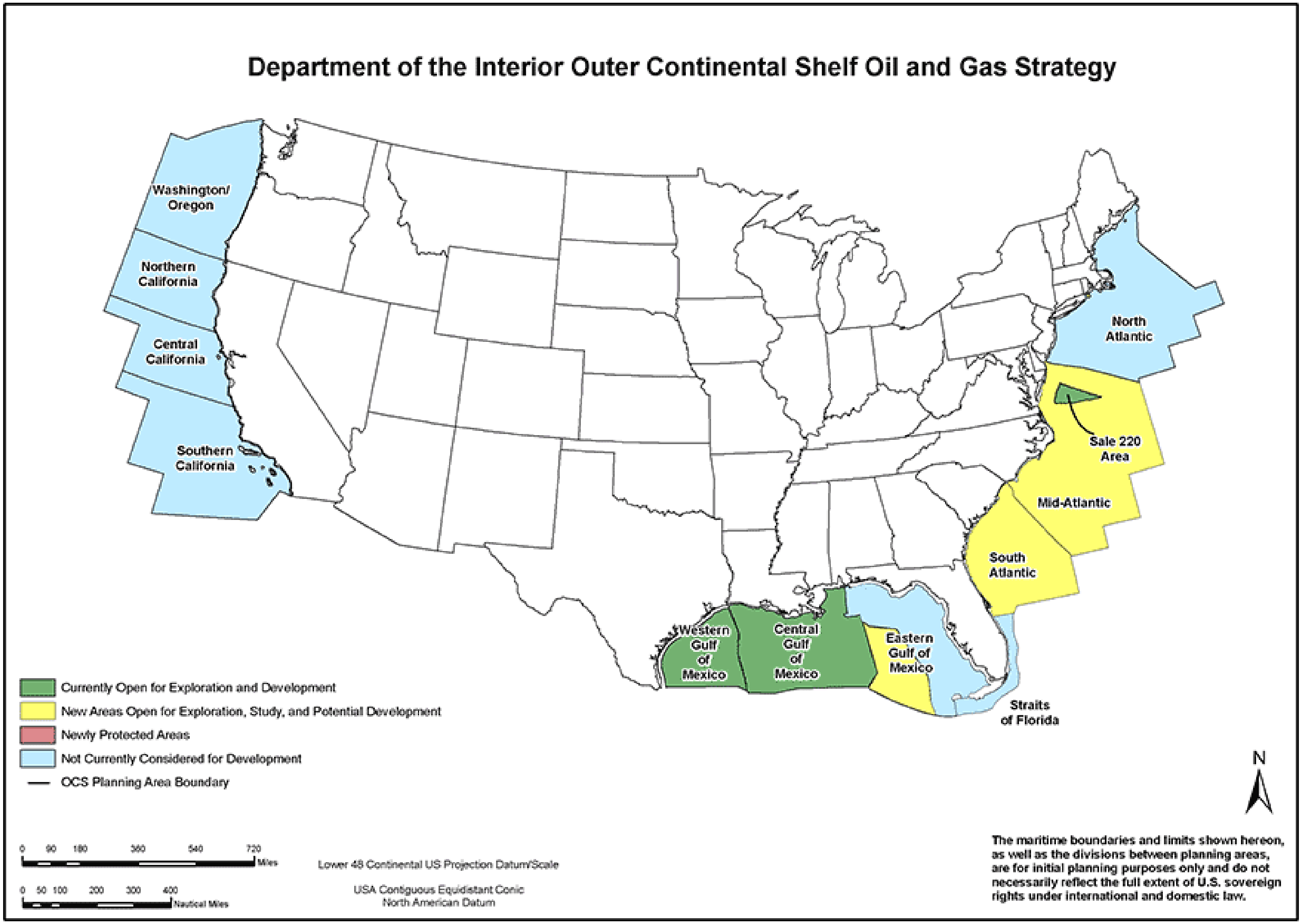
industry could serve a 30 Tcf market but that it needed federal lands off limits to drilling (including the Outer-Continental Shelf, or OCS) made available and the industry continues to deliver that message. While there are signs drilling may be expanded, other signs suggest otherwise. On January 6, 2010 Interior Secretary Ken Salazar announced the Bureau of Land Management (BLM) would more carefully scrutinize applications for oil and gas drilling on federal lands and he reversed the approval of more than 30 leases in Utah that many groups felt the Bush administration had rushed through approval without sufficient regard for the proximity to Arches National Park or other sensitive lands.

President Obama and Secretary Salazar, on the other hand, announced on March 31, 2010 a Comprehensive Strategy for Oil and Gas Development and Exploration (Strategy). The Strategy would open some of the OCS to oil and gas drilling, including the southern portion of Minerals Management Service (MMS) Lease Area 181 off Florida's Destin Beach and areas off the Mid and South Atlantic as well as areas off Alaska's North Slope.[57] Despite the Board of Supervisors in Santa Barbara County (the location of an oil spill in 1968) having passed a resolution in 2009 in support of new oil and gas drilling off its own coast, California and the entire Pacific Coast remain protected as does Bristol Bay in southwestern Alaska. (See Figure 8.) The President's Strategy will allow lease sales for the opened areas only after geologic and environmental studies are completed, not before 2012. As a result of the April 20, 2010 Deepwater Horizon platform 50 miles off the Louisiana coast, current OCS drilling is on hold, safety reviews of existing rigs are underway, and the scoping meetings for the Virginia OCS lease sale were postponed (see Department of Interior May 6 press release). When the reformed MMS does get back to holding lease sales, it seems reasonable to expect greater scrutiny and analysis of environmental impacts and safety equipment as a result of the accident and the subsequent safety reviews. It remains to be seen if the spill will change public reaction and expectations about offshore drilling or drilling in general. One might also ask if any of the safety issues are pertinent to wells drilled for geologic CCS.

Notably, off-shore drilling is more technically complicated such that it is regarded as "unconventional" irrespective of whether the underlying rock formation is shale or tight sands or whatever it might be. In addition, the seismic data on these potential reserves is 30 years old, gathered before off-shore moratoria took effect, and until exploratory drilling is complete there is no way of knowing whether the reserves will produce profitably at current prices. Actual production is unlikely to occur before 2017. The intent is not to criticize off-shore drilling but simply to point out that the industry has made a point of saying it needed the OCS opened up in order to serve higher demand. Whether such drilling will occur is uncertain and it is unclear what new sorts of compliance mechanisms or their costs might be.

[57] MMS estimates put the technically recoverable undiscovered reserves made available if OCS exploration goes forward at 210 to 250 Tcf. Technically recoverable means that technology exists to produce the reserves but does not indicate at what price doing so would be economic. EIA prepared an "OCS Access" case in AEO 2007 and updated it for AEO 2009. Assuming virtually no change to regulations that affect the electricity resource mix, EIA projected access to off-shore resources would increase U.S. gas supply by a mere 3% compared to its Reference Case projections. Found at http://www.eia.doe.gov/oiaf/aeo/otheranalysis/ongr.html.

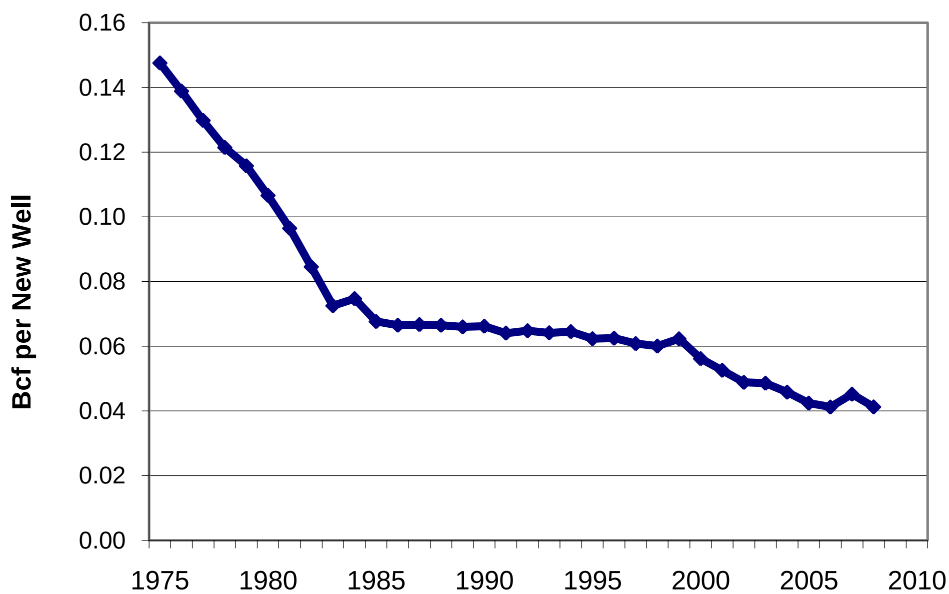
Figure 8: Three New OCS Lease Areas Opened for Offshore Drilling (pending Deepwater Horizon review)



Price Impacts

Natural gas prices are likely to rise as demand increases to work off the supply bubble created by the recession and recent over-drilling. Longer term, prices will depend on how much gas we need and the technology available to meet that demand. Over the past ten years prices generally rose (subject to temporary impacts from weather or economic conditions). In economists' parlance, this largely occurred because we moved "up" the supply curve with enough new technology to replace production but not quite enough to shift the supply curve "out." During that time, the data showed a pronounced decrease in production per new well (see Figure 9). The widespread application of techniques developed in the Barnett Shale to other shale formations, likely encouraged by 2007 – 2008's higher natural gas prices, has reversed that, thus seeming to have finally shifted the curve out. Put differently, stagnant technology seems to result in falling production per new well and prices increase as a result; major technology improvements, on the other hand, allow production per new well to increase and the industry can produce more gas at previous price levels.[58]

Figure 9: Gas Production per New Well



Source: Aspen Analysis of EIA data from *Natural Gas Annual*

Using data reported to EIA for natural gas cost per well drilled for 2000 through 2007, Figure 10 shows the implied aggregate supply curve that results from simply plotting the trend line of the data. The suggestion is that proving up an additional 25 Tcf of reserves should cost well over $10 per MMBtu. The pattern at which higher levels of proved reserve additions increases is striking. Assuming U.S. gas supply

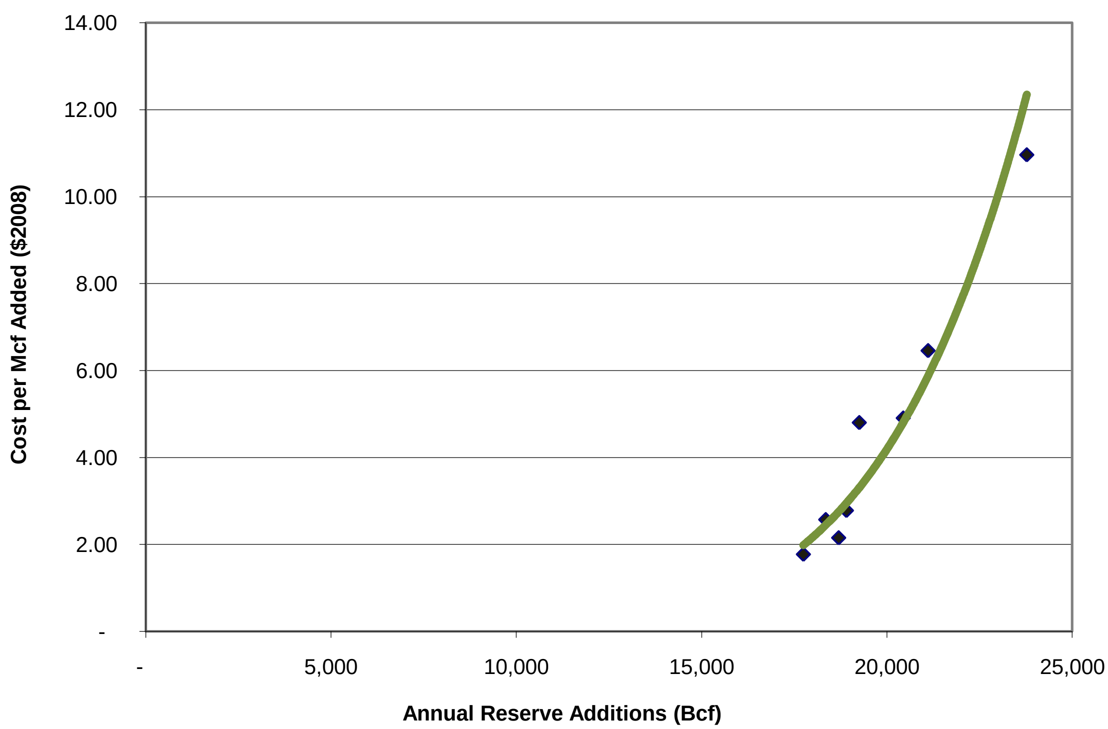
[58] It is possible to use information about current well depletion rates (production from existing wells falls every year) and production per new well to compute how many wells must be drilled to achieve a given level of production. Aspen has not performed that calculation here; however, all else equal, a need to drill more wells implies higher natural gas prices.

needs in the range of 30 Tcf, roughly consistent with scenarios 1 or 5 of the alternate resource mix scenarios presented in the Demand section of this study (or the 28 Tcf in the INGAA study's Base Case), it seems hard to not advise consumers they should expect prices to return to the $10 MMBtu range.[59]

By way of comparison, EIA's *AEO 2010* put prices at approximately $8 per MMBtu to produce 24 Tcf in 2035 (see Table 1 of the *Early Release*). Note that it projected only a 2 Tcf increase to be needed over current production levels. Most of that increased production will consist of shale-deposited gas, along with North Slope gas transported via a new pipeline from Alaska. Imports, composed of pipeline gas from Canada and LNG, will decline.

The INGAA study's Base Case put its U.S. benchmark price at $6.96 per MMBtu (in $ 2008) for U.S. production of approximately 27 Tcf. Its High Case put prices lower, at approximately $6 per MMBtu, but it did so assuming that the additional supply is produced with more Arctic gas, more LNG, OCS drilling, and that the decline in conventional supply levels out. One must surmise that the modelers assumed such sources would cost less than current conventional and unconventional supplies.

Figure 10: Implied Natural Gas Supply Curve Through 2007



Source: Derived by Aspen using EIA Reported Cost per Well Drilled

[59] $10 per MMBtu is more than double current prices, which are "low" due to the recession's impact on demand combined with higher drilling and production.

Even with the ability to produce potentially plentiful natural gas supplies from shale deposits, the large amounts of shale-deposited reserves were added in a high price environment. Should the U.S. need to add proved reserves every year in the 25 to 35 Tcf range—more than the industry has ever added before—it simply does not seem credible to expect that prices would not return to the $7 to $10 per MMBtu range absent further cost-lowering technology improvements or unusual events.

Summary Observations Related to Natural Gas Supply

1. U.S. proved reserves of natural gas currently total 245 Tcf, enough to meet 2009's annual demand of 23 Tcf for 10.6 years.
2. Proved reserves have increased by more than enough to cover annual production for each of the last 15 or so years.
3. Probable, Possible and Speculative reserves total 1,836 Tcf, enough should all of it become producible to meet 2009's annual demand for nearly 80 years
4. Drilling investment increases when oil and gas prices are higher.
5. Producers collectively tend to overdrill when prices are high, leading to price cycles.
6. LNG deliveries to the U.S. are driven by the relationship between U.S. natural gas prices versus the U.K. National Balancing Point (Atlantic LNG) and crude oil prices (Pacific LNG).
7. Should U.S. natural gas production falter, those price gaps should narrow and LNG would again become relevant to the U.S. market.
8. Production of shale-deposited gas relies on a technique called hydraulic fracturing that is attracting increasing environmental concern and, in at least a few cases, some local opposition to natural gas drilling.
9. EPA announced in March 2010 that it is commissioning a peer-reviewed comprehensive study of the potential adverse impacts of hydraulic fracturing.
10. It is unclear how limits on drilling on federal lands, greater scrutiny in the review of oil and gas drilling applications by BLM or some opening up of the OCS to drilling will be addressed and whether they will increase or decrease natural gas drilling.
11. Production per new well has fallen virtually every year since 1975. The number of wells drilled and production pattern from shale-deposited gas may have stemmed the decreases, at least temporarily.
12. Production per new well and the rate of depletion of existing wells versus demand and imports is what determines how much natural gas the U.S. must produce.
13. The implied aggregate supply curve for 2000 through 2008 suggests that adding proved reserves of more than 25 Tcf per year requires natural gas prices of $10 per MMBtu or higher.
14. *AEO 2010* projects a 2036 gas price of $8 per MMBtu (with production only 1 Tcf more than in 2009).
15. The INGAA study's Base Case projects $6.96 per MMBtu ($ 2008) with production in 2030 of roughly 27 Tcf. Even with access to shale deposited-gas, Aspen remains dubious of the ability to produce more gas prices lower than $6 per MMBtu without further cost-lowering technology improvements.

Natural Gas Delivery Infrastructure

Natural gas is transported from producing areas to end-users all over the country through pipelines. Large-diameter, high-pressure trunklines use compression to push natural gas through the pipelines to the "citygates" of local distribution companies and large, direct-connect customers. Except in cases where natural gas is produced and transported to customers entirely within the state in which the gas was produced, natural gas is transported through interstate pipelines regulated by the Federal Energy Regulatory Commission under the Natural Gas Act.[60] FERC does not regulate commodity natural gas prices but mandated beginning in the late 1980's (culminating in Order No. 636) that interstate pipelines completely separate the function of selling natural gas from the function of transporting natural gas.[61] Pipelines must also facilitate the liquidity and transparency of a market for firm pipeline capacity by posting on a public bulletin board their list of shippers and offers by those shippers to buy and sell firm capacity. FERC does regulate transportation rates, the terms and conditions of all aspects of transportation service, and grant certificates of public convenience and necessity to construct new or expanded transportation capacity. Nearly two-thirds of states produce less natural gas than they consume and are therefore dependent on the interstate pipeline system to bring gas to their local distribution systems and end-users.

The natural gas pipeline system began its existence when two oil pipelines were built in 1943, known as the "Big Inch" and "Little Big Inch;" these pipelines were built to move oil via land from Texas to the Midwest and eastward to serve areas around New York City and Philadelphia, avoiding German U-Boats along the East Coast. The two systems were sold as war surplus to became Texas Eastern Transmission Corporation (TETCO) and converted to natural gas service in 1947.[62] Today, the U.S. is served by more than 200 pipeline companies that own more than 300,000 miles of pipe delivering gas to all regions of the country, the configuration of which are shown in Figure 11. EIA reports that at least half of this capacity was built in the 1950s and 1960s. At that time most gas was produced in Texas, Oklahoma and the Gulf Coast; most pipelines originated there and delivered gas from there to the Midwest and Northeast.

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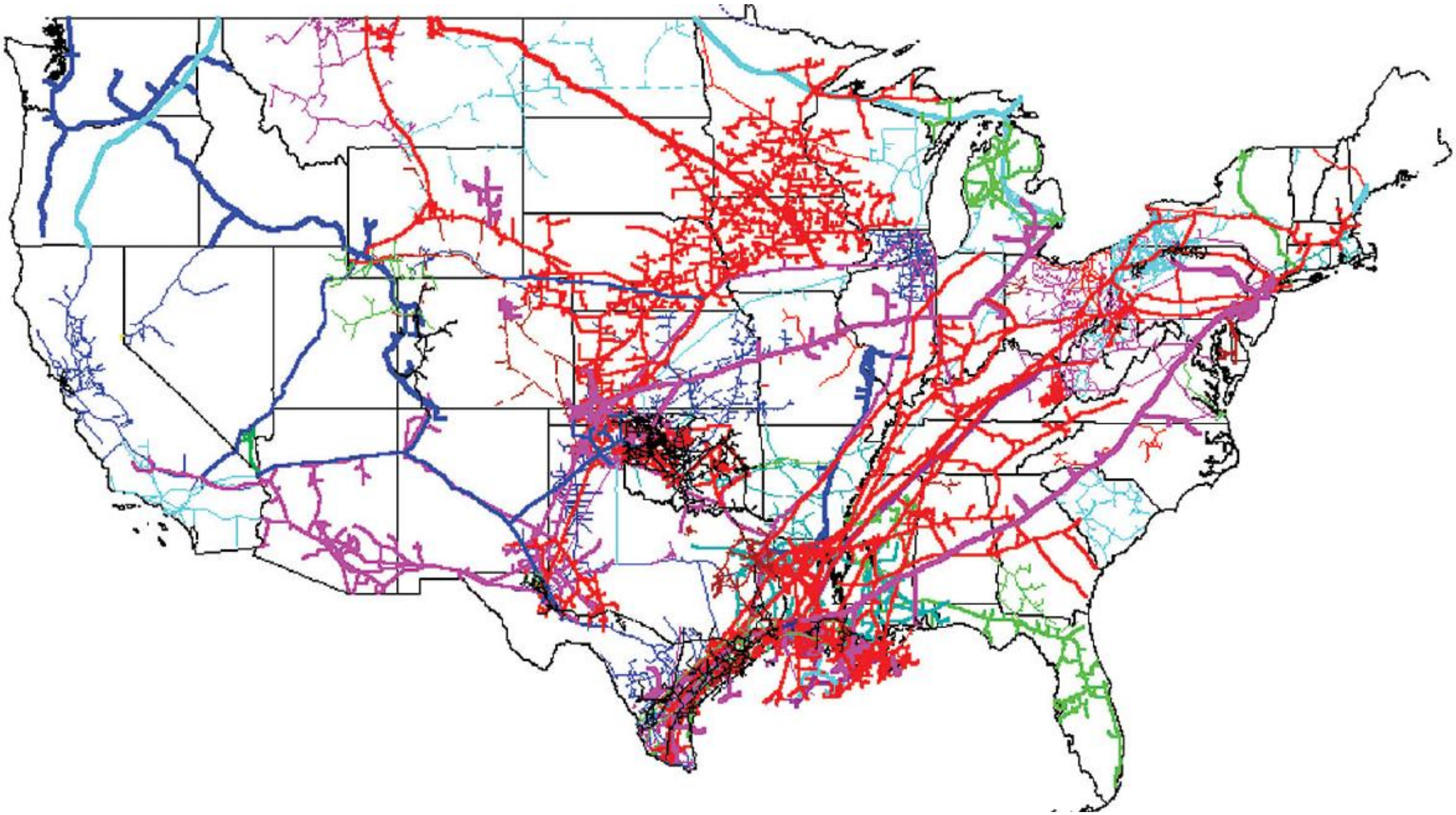
[60] Transmission pipelines that do not cross state lines and that are regulated by their respective states are known as "intrastate" pipelines. Most demand is served in Texas, for example, via intrastate pipelines. California's large local distribution companies take a portion their gas supplies directly from local producers and transport it to end-users. Michigan Consolidated (MichCon) is directly hooked to local gas production. Intrastate pipelines are almost always regulated in some manner by a state regulatory commission.

[61] This was known as elimination of the "merchant" function of U.S. pipelines. To the extent that a pipeline continues to sell natural gas it must do so from a separate affiliate and the FERC imposes strict rules about what information can be transferred between the two companies. The purpose was to make transportation of natural gas a competitive, non-discriminatory service and remove any ability by the pipeline to force shippers to purchase gas from the pipeline.

[62] *Handbook of Texas Online*, found at http://www.tshaonline.org/handbook/online/articles/BB/dob8.html (accessed March 12, 2010).

Figure 11: U.S. Natural Gas Transmission Pipelines



Source: U.S. Department of Energy

Most natural gas customers take service from a local distribution company (LDC). However, very large gas users, such as industrial facilities or electric power plants are often directly connected to a transmission pipeline. To some degree, whether a power plant is connected directly to a pipeline or instead to an LDC depends on which region of the country it is located. Plants in the West and newer merchant generator plants tend to be directly connected, while older plants and those in the East tend to be behind LDC citygates. In some cases, the LDC provides more flexibility in addressing imbalances or variation in gas use than available from the interstate pipeline. Importantly, while there are commonalities among the services offered by the various pipelines or LDCs, each is different. To understand what services and rules apply in a specific location, one must look at the tariffs of the specific pipeline or LDC in question.

As discussed earlier in this report, natural gas demand increased from 5 Tcf in 1947 to 22 Tcf by 1972. After that demand declined and did not match that 1972 peak again until the late 1990s. (See Figure 3.) During that time the natural gas industry was deregulated; natural gas commodity prices are now set by the market and the value of interstate pipeline capacity (not its cost, but its value) is also set by the market, measured in what the industry calls a "basis differential."[63] Efforts to encourage combined heat and power facilities led to the interest in electric industry deregulation and the rise of merchant generators. Natural gas demand has finally returned to its previous peaks largely due to the merchant generators' business model, which is based on ease of financing, lower capital cost of gas-fired plants, modular sizing, better ability to ramp operations up or down to follow load, and relative ease of obtaining permits to site and operate gas-fired generation.

Domestic production of natural gas also peaked in 1972. The gap that subsequently grew between supply and demand of domestic natural gas was met largely with gas from Canada's prolific Western Canadian Sedimentary Basin. In addition, as production waned in old fields some new U.S. gas fields were developed: the Rockies and San Juan basins are examples of producing areas that were developed or expanded after the peak. These expansions required the addition of new pipeline capacity to bring these new supplies to market. Note that virtually all of the capacity added since 1972 has been to deliver increased supply from new production areas or to serve demand that moved from one region to another, all while U.S. aggregate demand has not grown much past the 1972 peak. The key observation is that new pipeline capacity has to be built whether demand increases or not as the producing areas change. The corollary should be that the ability to have added this capacity says nothing, necessarily, about the ability of the industry to build capacity to serve potentially massive new demand.

Total existing pipeline capacity is large enough to meet peak day gas requirements. That means that on most days of the year, some pipeline capacity goes unused. Average pipeline utilization, for example, for the thirty largest U.S. pipelines in 2007 (latest year reported) was 59%.[64] Each pipeline has a

[63] FERC allows the secondary trading of interstate pipeline capacity on a transparent, non-discriminatory basis. Sometimes capacity trades for more than its tariffed cost and/or we see commodity price spreads between two locations open up that are more than the cost of transportation. When pipeline capacity carries an "economic rent," we see the pipeline or other new entrants hold Open Seasons to propose new capacity.
[64] Calculated from EIA data found at http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/MajorInterstatesTable.html

certificated capacity that represents the quantity of gas it can deliver under all conditions. In other words, there are certain conditions under which the pipeline can deliver more than its certificated capacity. Under cold temperature conditions, for example, gas molecules shrink and compress together, allowing the pipeline to deliver a little more gas. The pipeline, however, cannot do that under all conditions and pipeline operators will not promise to be able to do so. FERC allows a pipeline to sell as firm capacity only its certificated capacity. "Firm capacity" is capacity that shippers reserve for their use each and every day of the year.[65] Shippers pay for the right to have first call on that capacity. Should a pipeline sell capacity as firm and then curtail service, shippers have recourse to FERC.

When firm shippers leave capacity unused, then it becomes available to "interruptible" shippers; i.e., shippers who cannot count on it being available each and every day because someone else has first rights to it. On a pipeline that is seldom full, interruptible capacity might be available on many or most days. Some pipelines are full in winter and not in summer. Our analysis found that 8 of the 30 largest U.S. interstate pipelines had 2007 load factors of more than 80% and 12 had load factors over 70%. Florida Gas Transmission, Kern River Gas Transmission, Columbia Gulf, Natural Gas Pipeline of America, and Northern Border operated at close to 90% or higher load factors. Those pipelines represent about 10% of total U.S. pipeline capacity but could be much more than that into a specific state. Florida Gas Transmission, for example, represents about 60% of the pipeline capacity into Florida.

Most of the new pipeline capacity added in the last 30 years has been to deliver new supply to existing load or load that has shifted regionally. Both INGAA and EIA expect that trend to continue as existing production is replaced with supplies from new supply areas.

Pipelines may offer the summertime excess capacity under a service known as "seasonal firm." Seasonal firm is available each and every day with certainty during the season in which it is offered: usually summer plus some of the shoulder months. Seasonal firm service is commonly offered on some of the pipelines that serve the Midwest and Northeast. On some of those pipelines year-round firm service to new shippers is simply not available.

As demand grows new transmission capacity is needed. One question is how much new transmission is needed to deliver natural gas to meet the magnitude of demand that could occur if natural gas is relied on to reduce the electricity industry's carbon emissions. To answer that, Aspen went back to the INGAA study representing the industry's own projections of potential required capacity additions. We report those in Table 4 and compare the INGAA study's projection of new capacity to a selection of the EG demand cases developed in the demand section of this report.

Notably, the INGAA study projects a need to increase pipeline capacity by more than 16% over current capabilities even if demand shrinks. This occurs because of a projected shift in production to resources in locations that are not currently connected to the natural gas pipeline grid. Note the projected cost: a 16% expansion accumulates to a cost of $108 Billion, or, about $5 Billion per year.

65 Some pipelines offer an additional service that is firm only for a given season.

8 of the 30 largest U.S. interstate pipelines had 2007 load factors of more than 80%; 5 of those 8 had load factors of close to 90%

INGAA's Base Case calls for a 20% increase in gas transmission capacity. This would provide 25 Bcf per day of new pipeline capacity (compared to the 130 Bcf per day existing today). Consisting of 38,000 miles of pipe and associated compression horsepower, the cost projected to add this capacity is $129 Billion. In annual terms, that equates to $6.5 Billion per year. The High Case ramps the new pipeline capacity requirement up to 37 Bcf per day and a cost of $163 Billion. It would serve incremental EG sector gas demand equal to nearly what current EG demand is, allowing EG demand to just about double over current levels (around 13 Tcf). The annual investment is $8.1 Billion per year.

INGAA's modeling focuses on interregional flows, or, capacity needed to move gas from supply basins to market areas in general corridors that don't necessarily capture every individual pipeline and certainly do not capture LDC-level transmission.[66] Those projections of new regional capacity include the following corridors:

- Rockies to Northeast (not New England)
- Rockies to California
- Mid-Continent and East Texas to Northern Louisiana
- Western Canada to Chicago
- Gulf Coast to Florida

The High Case adds still more capacity from Western Canada, more from Rockies, more from Mid-Continent and East Texas, and considerable capacity to accept OCS gas. A comparison of Figure 4, showing the locations of current coal-fired generation, to Figure 9, showing natural gas transmission, suggests many more regional pipelines needing expansion were all coal need to be replaced with natural gas. Columbia, Transco, Sonat, Tennessee, Trunkline, Panhandle Eastern, ANR, Alliance, Guardian, EPNG, Colorado Interstate Gas, and Wyoming Interstate Gas are all examples. In addition, while Alaska's Cook Inlet (sometimes known as the "Railbelt") is struggling to get enough natural gas to meet current needs, other portions of Alaska, including Fairbanks, currently do not have access to local production or pipeline natural gas. Some routes for an Alaska pipeline might provide access for consumers in those markets, but completion of that pipeline remains at least ten years away.

AEO 2010, by comparison, had projected a much smaller increase in EG demand. It doesn't give specific projections on new pipeline capacity needed. It does, however, indicate that most new (Lower-48) natural gas supply will be shale-deposited gas and that a pipeline from Alaska would be in service by 2022.[67] Consistent with the INGAA study, EIA noted that new pipeline capacity is needed to deliver new

[66] This is easily seen by comparing Figure 9 showing natural gas transmission pipelines in this study to Figure 56 in the INGAA study.
[67] An on-going joke among gas industry analysts is that a pipeline from Alaska is always "ten years out." That is to say that in any given year we can look back at projections that assumed a pipeline from Alaska would be in service roughly ten years from the date of the forecast. If that pipeline is not built, then the associated gas supply would need to come from Canadian imports, lower-48 production or LNG.

supply to existing markets: "[s]hale and other unconventional resource development will drive pipeline expansions for the foreseeable future."[68]

Table 4: Comparison and Extension of Demand Cases to Determine New Gas Pipeline Requirements

Case	2030/ 2036 Incremental EG Gas Demand[69]	Equivalent Number of 1000 MW Coal-Fired Plants[70]	Pipeline Transmission Capacity Requirement	Miles of Pipe	% Increase Over Current Interregional Flow	Cumulative Cost
INGAA Low	- 0.5 Tcf		21 Bcf per day	28,900 Miles	16%	$108 Billion
INGAA Base	3.8 Tcf	88	25 Bcf per day	37,700 Miles	20%	$129 Billion
INGAA High	6.6 Tcf	153	37 Bcf per day	61,600 Miles	28%	$163 Billion
AEO 2010	1.9 Tcf	44				
Alt 1	6.9 Tcf	160	*Note that this is virtually identical to INGAA's High Case*			
Convert Existing Coal	14.1 Tcf	328	70 Bcf per day			$348 Billion

Source: Aspen Compilation

The INGAA estimates assume a 2010 cost per inch-mile of $60,000 and that costs escalate at slightly less than inflation, which the INGAA study assumed would be 2.5 percent per year.[71] INGAA allowed construction costs to vary by region and included both pipe and compression costs. In the base case, half the additions are said to be for laterals to connect supply or storage or power plants to a mainline, but we believe the consultants' model did not specifically model new downstream delivery capacity required because the model would not have generated or been fed the location of specific sites for new gas-fired generation needed to make such an estimate.

The INGAA estimates may be a little low: the base case and high case assume LNG imports of 5.0 Bcf per day and 4.4 Bcf per day, respectively. Those figures are roughly a quintupling over 2008 LNG imports,

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[68] Presentation by D. Gaul. Office of Oil and Gas to 2nd North American Pipelines Conference in Calgary, Alberta February 2009. Found at http://www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/2009/pipelinedynamics/pipelinedynamics_files/frame.html

[69] The INGAA cases go out to 2030; the other cases either went out to 2036 or the data was extended to 2036. The "Convert Existing Coal" case is simply the gas burn that would result today if existing coal-fired generation were replaced with new, efficient combined-cycled gas-fired generation.

[70] At 72% capacity factor U.S. coal-fired plants operated at in 2008.

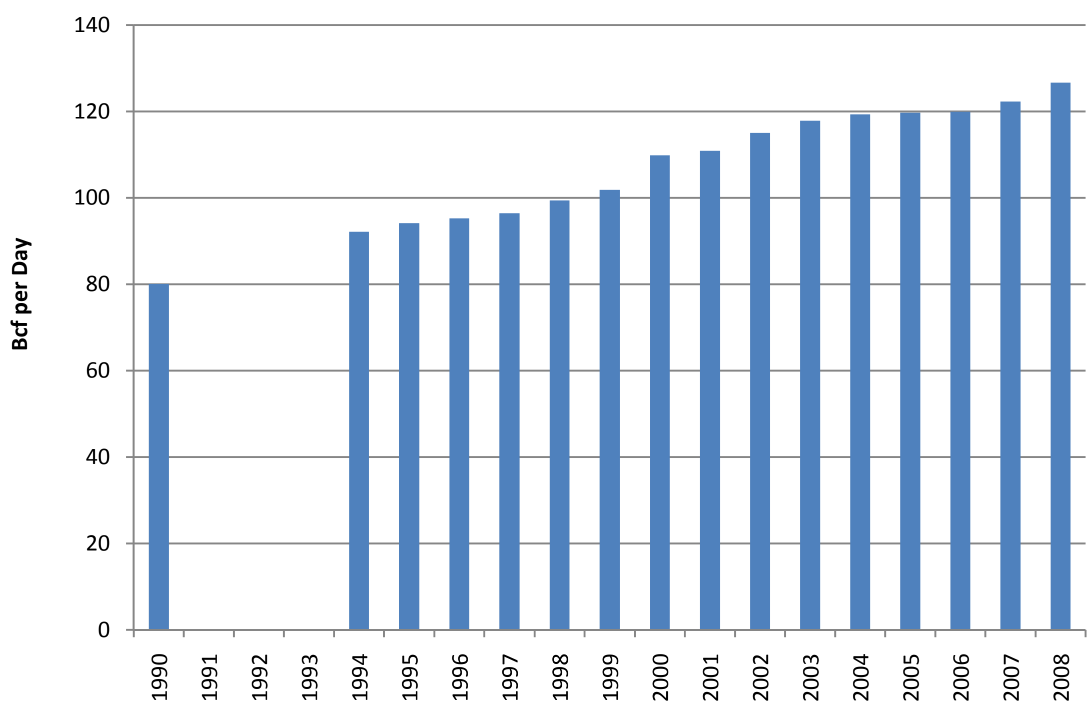
[71] An inch-mile is a standard expression that captures both pipeline diameter and length of the pipeline. A larger diameter pipeline uses more steel as does a longer pipeline.

Building new pipeline capacity is much easier than electric transmission capacity. From announcement date to commercial operation averages three years. Of course, pipelines routinely survey the market via nonbinding Open Seasons to assess market interest in new pipeline capacity.

which have been low due to U.S. natural gas prices being lower than world LNG prices. The pipeline capacity required to replace that LNG would be of longer mileage, owing to the fact that some of the LNG import terminals are located closer to market demand than would be the domestic production that would replace the LNG.

Adding new interstate natural gas pipeline capacity is relatively easy in terms of infrastructure investments. EIA notes that from announcement date to commercial start of operations averages three years.[72] Many in the electric industry will readily observe that new electric transmission capacity is much more difficult to permit or site, attracts much more objection, and can take as many as ten years to site and construct. That is not to say that adding capacity is easy everywhere; there are clearly portions of the U.S. where objections have arisen and delayed projects, such as the Northeast, the Lake Michigan south shore, and other heavily urbanized areas. And objections seem to be increasing: Rockies Express encountered objections from rural land owners in Ohio concerned about the location of river crossings and the like.

Figure 12: Total Interregional Pipeline Capacity 1990 to 2008



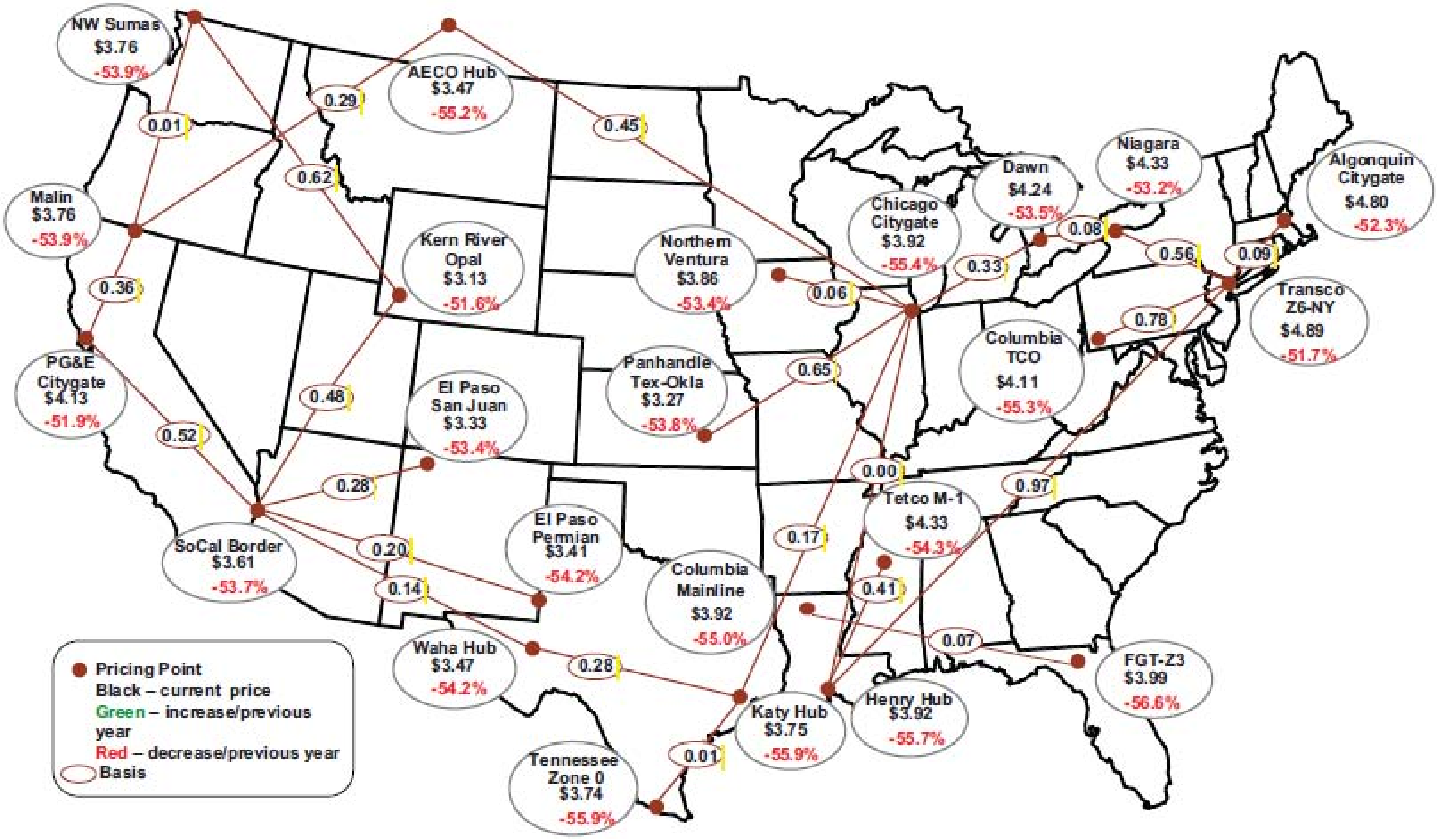
Source: Aspen Analysis of EIA data (1991 to 1993 missing from the EIA source data)

72 Found at http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/develop.html

According to EIA data, interstate pipeline capacity capable of delivering approximately 53 Bcf per day of natural gas was added between 1990 and 2008. (See Figure 12.) This is more than in INGAA's High Case but less than the 70 Bcf per day that would be required in our case in which all existing coal-fired generation is replaced with natural gas. (Depending on if or when geologic CCS becomes available, access to build and finance some of this natural gas delivery capacity might compete with construction of CO_2 pipelines.)

The relative ease with which interstate pipeline capacity can be added is a testament to the well-oiled facilities approval mechanism developed by FERC and clear market signals. Pipelines earn profit, via an allowed rate of return, on their rate base. More pipe in the ground, if you can sell the space in that pipe, means more revenue. The pipelines constantly watch market price differentials between regions (known as "basis" differentials) because the basis differentials measure the value of pipeline capacity between two locations. Figure 13 provides an example from a recent FERC Office of Market Enforcement briefing showing regional natural gas wholesale prices and basis differentials. Existing pipelines as well as potential new entrants watch this data carefully, looking for corridors for which the basis differential exceeds the cost of constructing additional capacity. Basis differentials will also change seasonally. Sometimes the winter basis between two locations shoots up dramatically while in summer the basis is unremarkable. Thus, large basis differentials are an indicator that capacity into a given region is constrained. Basis can also show when capacity exiting a supply basin in constrained: Rockies prices have long exhibited this phenomenon and have risen relative to other U.S. prices since Rockies Express entered service.

Figure 13: Regional Basis Differentials



Source: http://www.ferc.gov/market-oversight/mkt-gas/overview/2010/03-2010-ngas-ovr-archive.pdf

When the value of capacity approaches the cost to add new capacity, the pipelines begin holding what are known as "Open Seasons." An Open Season is an invitation to indicate to the pipeline that you are interested in holding and paying the annual reservation charge for firm capacity. Pipelines frequently hold Open Seasons just to test the waters, knowing that he who moves first often wins, and they may approach the market several times over a long period of years before enough shippers commit to signing contracts to pay for the pipeline.[73] When the pipeline calculates that it has enough commitments that it can make the debt service on financing of the construction cost while earning an acceptable rate of return on equity, it will apply to the FERC for a Certificate of Public Convenience and Necessity (CPCN). FERC will conduct any necessary environmental analysis and assess the project for compliance with FERC rules. Under the "let-the-market-decide" policy adopted in the early 1990s, FERC does not require all of the capacity to be contracted and it will not choose between competing projects intended to serve the same markets. Rather, FERC assumes that a pipeline willing to take market risk constitutes a showing of "need" for the facility and certificates it with appropriate environmental conditions. With a CPCN in hand and contracts to cover enough capacity to make debt service, obtaining financing is routine.[74]

Creation of new delivery points, taps, and laterals to serve new large load is even easier. Notably, FERC does sometimes require the costs for new facilities to be recovered in what are called "incremental rates." Incremental rates cover only the cost of that facility and service using it. Incremental rates are typically adopted when the addition of the proposed facilities and associated load would increase rates to all other customers. When the new facilities and load would reduce rates to all other customers FERC allows the costs to be added to overall rate base.

Different kinds of expansions require different kinds of facilities, implying different magnitudes of cost and analysis in siting. That is to say that building a wholly new pipeline in new right-of-way is more complicated than merely adding compression to an existing natural gas pipeline or even building a second pipeline in an existing right-of-way. Which is required depends on the build conditions of the existing pipeline. Some existing pipelines have not been completely optimized for maximum throughput and can achieve higher throughput for little incremental cost. Eventually all the "bell and whistle" improvements have been done and the next capacity addition can only be achieved by adding new pipelines and compressors in a potentially new right-of-way. Environmental impacts associated with construction, in particular, are minimized when previously-disturbed land is used. More river, stream and highway crossings make a project more expensive.

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[73] Many of the "potential" projects shown on EIA's map will not be able to obtain sufficient market commitments to proceed such that the map alone should not be taken as evidence of the natural gas market being able to add enough capacity to serve all demand. There are clearly markets today in which customers want gas and cannot get it because there are not enough such customers to cover the cost of new capacity.

[74] Projects that are new greenfield pipelines or that parallel existing lines are often undertaken with project financing in which the lender has no recourse to the sponsor's balance sheet; the loan is secured entirely with project revenues. In contrast, projects that represent minor increments of capacity that will be rolled into existing rates are more likely to be financed with balance sheet capital.

Existing coal-fired plants already have access to electric transmission, water, a rail right-of-way and even a small gas line to feed start-up ignition. We do not yet know how many would need to construct longer laterals to obtain the high pressure gas transmission service needed to support a large gas-fired power plant. We do know that 60 coal-fired plants are located within 25 miles of an under-utilized gas merchant plant.

Adding LDC capacity will vary state to state. State regulatory commissions will be anxious about impacts on existing gas ratepayers. In addition, while FERC will grant CPCNs with relative ease to add interstate capacity it is not at all clear that the sites on which new gas-fired generation would be located are either located close enough to existing gas pipelines or along a route that would yield demand sufficient to support financing.

It is also worth noting that the contracts firm shippers must sign to support financing are typically twenty-year agreements needed to support a twenty-year financing term. Some pipelines will present to their lenders a market study assessing the potential for long-term market developments with respect to throughput, competition from other pipelines, and changes in basis differentials, but lenders do not always require such a study and the results of the study would virtually never be used by lenders to support speculative investment.

This raises a related point about site selection. For new, greenfield gas-fired generation, a developer looks for a location within a few miles of a gas pipeline or large distribution line (greater than 12 to 16 inches) with excess capacity, water for cooling, and a substation into which it can deliver its electrical output without overloading circuits.[75] California may not be representative of the rest of the country on this point, but in a search on behalf of a developer in 2007, very few sites were found to be left available in the northern two-thirds of the state where all three requirements were present. Existing coal-fired plants obviously have access to a substation, they undoubtedly have water and they likely even have a rail right-of-way in which a natural gas pipeline lateral could potentially be constructed. But it is not clear that a gas transmission line with sufficient excess capacity is located close enough to each plant to provide gas service.

Aspen has not done for this study a review of each coal plant's location to determine how far it is to a natural gas pipeline or if that pipeline has excess capacity currently available.[76] As a proxy for that detailed analysis we have looked at a couple of different areas.

First, recall that the CRS study cited earlier found that 60 coal plants were located with 25 miles of one of the underutilized merchant NGCC plants. We take that as an indication that gas is accessible within 25 miles – clearly, the NGCC plants are connected to natural gas service. Those plants represent 28% of generation from existing coal-fired plants.[77] Second, we can compare Figure 5 identifying the location of coal-fired generation to Figure 11 that displays the natural gas transmission grid. Upon inspection, it

[75] A greenfield project site is one at which no prior industrial development has occurred.
[76] The CRS study mentioned earlier herein suggested that Congress may want to consider chartering such an analysis. Op. cit., p. 24.
[77] CRS, op. cit., p. 17

Case Study: South Dakota

South Dakota has about 481 MW of coal-fired generation located inside the state. Converting that to natural gas would increase its gas requirement by about 30% over current levels.

But South Dakota imports a large amount of electricity from Wyoming and Nebraska, some coal-fired and some nuclear.

Our analysis assumed utilities would build gas-fired generation at the site of the existing coal plant. That means, first, that South Dakota's coal generation is actually located in Wyoming. Second, utility managers would have to figure out how to replace generation coming from a different state. If utilities have to build gas-fired generation it is not clear that they would make the decision to participate in plants at the same locations, owing to the relative ease of siting gas-fired plants and vastly different size and scale requirements to build coal-fired generation, among other things.

appears there are plants along the coast in the Carolinas that may have trouble with access to gas, as would northeastern Kansas, western South Dakota, northwestern Montana, northern Nevada, central Utah, northwest New Mexico, the extreme northwestern corner of Alabama, the Appalachian ridge west of Transco Pipeline, Maine, Rhode Island (or just across into Massachusetts), and coastal Virginia. The plants located in these areas would require more extensive work to the natural gas pipeline grid in order to provide them with gas. The best way to make this assessment, of course, would be with geographic information giving longitude and latitude for the coal-fired plants and the pipelines. Such information is not publicly available and access is subject to Homeland Security constraints.

Third, we have taken the GWh generated with coal in each state and determined the amount of natural gas that would be required if the state had to replace that coal-fired generation with output from a new combined-cycled gas-fired unit.

Our results are presented in Table 5. The total gas burn equates to the 14.1 Tcf EG gas burn estimated earlier to replace the MWh generated with coal. Table 5 shows in which states the replacement of existing coal-fired generation would require more gas than the state burns now. The table is sorted in order of which state uses the most coal for electricity generation currently. Texas generated the most MWh with coal so it appears first. Converting the Texas coal burn to natural gas equates to 25% as much natural gas as Texas burns now. For 16 states located primarily in the Midwest and West, generating their coal-fired electricity with natural gas would use more gas than the state uses now – meaning that converting coal-fired generation to natural gas would more than double that state's natural gas use.

Table 5 also shows the resulting load factor in a peak demand month for pipeline capacity coming into each state. This calculation takes natural gas flows into a state in a peak month and adds to it the gas demand for converting that state's coal-fired generation to natural gas.[78] Twenty-one states would find the interstate pipeline capacity coming into their state insufficient to serve existing demand plus the conversion of coal to gas in their state. Another eight states would have load factors over 80%. These states are identified in Figure 14. As indicated previously herein, Hawaii and the territories would only have access to LNG. Alaska has indigenous gas produced in the Cook Inlet but price keeps that supply from expanding.

[78] Of course, one would also like to know the capacity utilization assuming that state and all the others downstream of it convert to coal, but that calculation would require detailed modeling that is not available to the author.

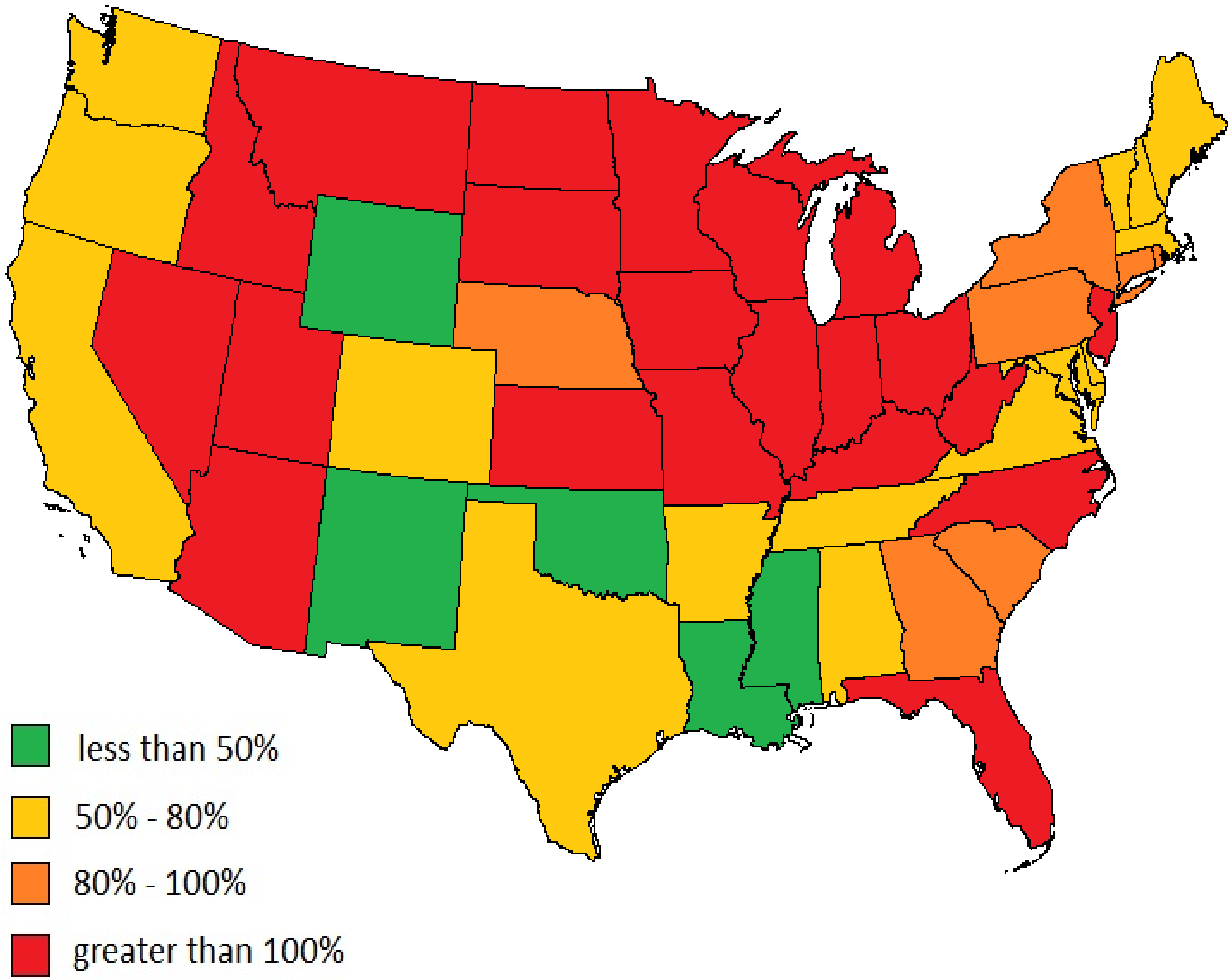
Table 5: Gas Burn by State* if Existing Coal-Fired MW Converted to Natural Gas

State	2008 Gas Use	Additional Use If Existing In-State Coal Converted to Gas	Coal Use As % of Current Gas Use	Pipeline Load Factor Into State If Convert Coal to Gas
Texas	3.546	0.893	25%	55%
Ohio	0.792	1.002	126%	130%
Indiana	0.551	0.906	164%	120%
Pennsylvania	0.750	0.861	115%	91%
Illinois	1.001	0.739	74%	126%
Kentucky	0.225	0.694	308%	116%
West Virginia	0.111	0.646	580%	123%
Georgia	0.425	0.614	144%	92%
North Carolina	0.243	0.558	230%	119%
Missouri	0.296	0.497	168%	104%
Michigan	0.779	0.542	70%	119%
Alabama	0.404	0.533	132%	49%
Florida	0.943	0.479	51%	105%
Tennessee	0.230	0.433	188%	68%
Wyoming	0.143	0.259	182%	41%
Wisconsin	0.409	0.299	73%	109%
Arizona	0.400	0.246	62%	104%
South Carolina	0.170	0.272	160%	86%
Oklahoma	0.670	0.241	36%	39%
Utah	0.224	0.214	95%	126%
Colorado	0.505	0.223	44%	76%
Virginia	0.299	0.261	87%	76%
Iowa	0.320	0.274	85%	145%
Kansas	0.283	0.230	81%	118%
Minnesota	0.401	0.238	59%	161%
New Mexico	0.247	0.184	75%	49%
North Dakota	0.063	0.179	283%	154%
Maryland	0.196	0.220	112%	76%
Arkansas	0.235	0.166	71%	72%
Louisiana	1.239	0.158	13%	37%
New York	1.180	0.180	15%	93%
Nebraska	0.168	0.134	80%	80%
Nevada	0.265	0.116	44%	111%
Montana	0.076	0.107	140%	131%
Mississippi	0.355	0.113	32%	66%
Massachusetts	0.374	0.075	20%	68%
New Jersey	0.615	0.094	15%	101%
Washington	0.298	0.061	21%	74%
Delaware	0.048	0.045	94%	50%
New Hampshire	0.071	0.026	36%	73%
Connecticut	0.167	0.026	15%	83%
Oregon	0.268	0.025	9%	66%
California	2.450	0.018	1%	66%
South Dakota	0.064	0.020	31%	138%
Hawaii	0.003	0.009	316%	N/A
Maine	0.061	0.004	7%	56%
Alaska	0.342	0.005	1%	N/A
Idaho	0.089	0.001	1%	115%
Rhode Island	0.089	0.000	0%	82%
Vermont	0.009	0.000	0%	68%
Total	23.09232	14.1214		

*** States Sorted in Order of Highest to Lowest EG Coal Use, which is NOT shown in the Table**

Source: EIA Coal-Fired MW by State and Aspen Analysis

Figure 14: Interstate Pipeline Capacity Utilization if An Individual State Switched its Coal-Fired Generation to Natural Gas



Source: Aspen and APPA

Having said that adding natural gas infrastructure is relatively easy, while noting the large investment required if coal-fired generation switches to gas, requires an additional note. There continues to be talk of potentially using natural gas as a "bridge fuel."[79] The notion is that switching to gas would be temporary, allowing us to reduce reliance on coal until other technologies were available. While the natural gas industry is clearly adept at adding new transportation capacity, it is still the case that the costs of these kinds of infrastructure investments are recovered over a relatively long period of time. Most financing or bond payback periods are twenty years or more. The useful life of a gas-fired power project is often assumed to be 40 years or more. It may turn out that these investor and cost recovery expectations are not compatible with the idea of using natural gas merely as a bridge fuel. In other words, making the investment needed to switch all or a large portion of the coal-fired fleet to natural gas may require thinking about natural gas as more than a bridge fuel.

Making the investment needed to switch all or a large portion of the coal-fired fleet to natural gas may require thinking about natural gas as more than a bridge fuel.

[79] For a more recent treatment see Brown, et. al. "Natural Gas: A Bridge to a Low-Carbon Future?" Resources for the Future, Issue Brief 09-11, December 2009.

Summary Observations Related to Natural Gas Transmission Infrastructure

1. The U.S. is served by 300,000 miles of natural gas transmission capacity.
2. More than half of it was built more than 40 years ago as the industry grew from a 5 Tcf market to a 22 Tcf market.
3. While the market is only 1 Tcf or so bigger than its prior peak in 1972, much new pipeline capacity has been built since then, primarily to deliver gas from new supply regions or as markets shifted regionally.
4. Pipelines are always looking for market opportunities that will justify adding rate base; obtaining FERC certificate approvals to construct is relatively easy.
5. Opposition to natural gas pipelines has been limited to highly urbanized, sensitive locations but appears to be growing.
6. Some pipelines are proposed multiple times and take years before the market will support.
7. INGAA's Base Case projects 25 Bcf new pipeline capacity will be needed at cost of $129 Billion.
8. Even the INGAA case with demand lower than today's estimates a need to spend $108 Billion for capacity to move supply from new producing areas.
9. The Alternative 1 Demand Case is similar to INGAA's High Case but as it is high for different reasons and may result in different facilities being needed.
10. Scaling up from the INGAA projections to the new gas demand should all existing coal be converted to gas implies a need for as much as 70 Bcf of new pipeline capacity at a cost of $348 Billion.
11. The industry added 53 Bcf of pipeline capacity from 1990 to 2008.
12. Some plants are likely to be served from interstate pipelines and others from LDC systems.
13. Twenty-one states would find the interstate pipeline capacity coming into their state insufficient to serve existing demand plus demand from their state's conversion of coal to gas.
14. Some, but not all, existing coal-fired generation generally looks like it may be located relatively near existing natural gas pipeline infrastructure; however, a detailed GIS study should be conducted in order to refine this estimate.
15. It is not clear that pipeline projects designed to serve those locations would attract sufficient load to be economic.
16. Making the investment needed to switch all or a large portion of the coal-fired fleet to natural gas may require thinking about natural gas as more than a bridge fuel.

Natural Gas Storage

One of the assets the industry will need to add to serve higher EG load is natural gas storage. Gas storage is very useful in providing flexibility to support gas burns by electric generators. Storage lets a power plant operator:

- ramp up or ramp down operations quickly;
- manage its imbalances;
- potentially hold less firm pipeline capacity; and
- maintain reliability.

As of April 2009 EIA reported roughly 400 underground gas storage fields in operation.[80] These fields, shown in Figure 15, provide 4 Tcf of working gas capacity and a total maximum daily withdrawal capability of approximately 88 Bcf per day.[81] 92% of the fields in current operation are reservoir or aquifer storage where gas is generally injected during the summer months and withdrawn during winter to serve seasonal demand (with certain exceptions); 8% are high-deliverability salt cavern facilities. Most, but not all, of the salt cavern storage is located along the Gulf Coast. Table 6 summarizes the key characteristics of U.S. natural gas storage.

Table 6: Storage Summary

Type	Reservoir/Aquifer	Salt Cavern
Characteristic	Single Turn	Multi-Turn
Owner	LDC or Pipeline	Independent
User	LDC	Marketers
Purpose	Seasonal Demand[82]	Arbitrage or Daily Peak
Price	COS	Option Value
Sites	369	31
Working Gas (Bcf)	3,918	173
Maximum Daily Withdrawal (MMcf/d)	74,523	13,703

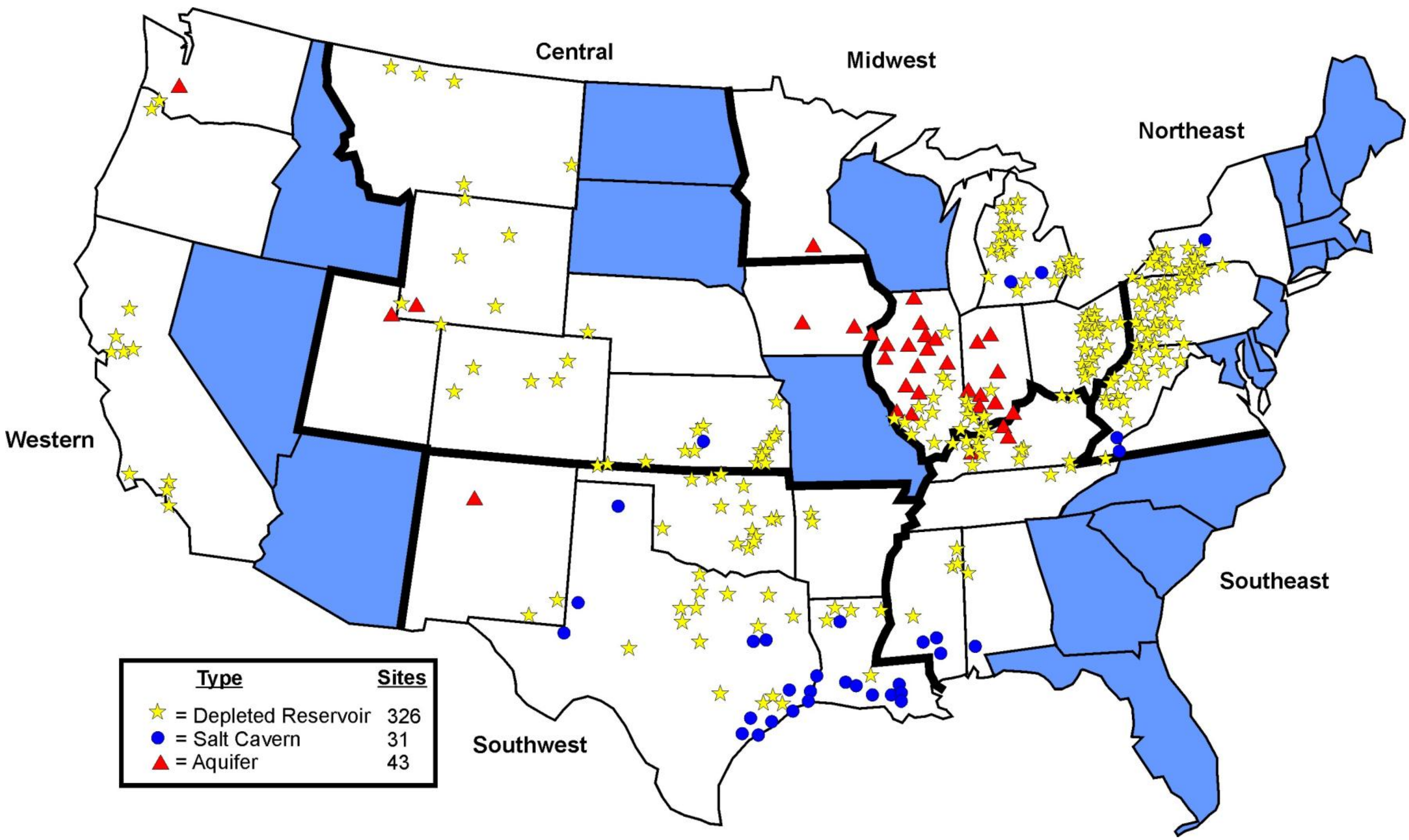
Source: Aspen Compilation of EIA Data

[80] 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.

[81] Terminology: cushion (sometimes called pad or base gas) is gas intended to stay in the formation to maintain field pressures sufficient to achieve desired withdrawal levels; working gas is the amount of gas that can be injected into or withdrawn from the field and still be able to fill it in a given period of time; withdrawal capability is the amount of gas that can be withdrawn in a given period, usually a day; the withdrawal capability is higher when the field is filled with more gas and achieves maximum field pressures; injection capability is the amount of gas that can be injected in a given period, usually a day; the injection capability falls at the field is filled and operating pressures rise.

[82] Some reservoirs can be configured for multi-turn high-deliverability storage. The Lodi and Wild Goose facilities in northern California are examples of reservoirs that provide multi-turn storage.

Figure 15: Geographic Distribution of Underground Gas Storage Facilities



Most existing storage was built before the trend towards more use of natural gas to generate electricity and tends to be located where a pipeline or a local distributor chose to build based on the accident of geology and the economics of revenue recovery.[83] Pipelines that are not connected to storage tend to impose stricter balancing rules. Stricter balancing rules make it harder or more costly for electric generators to operate.

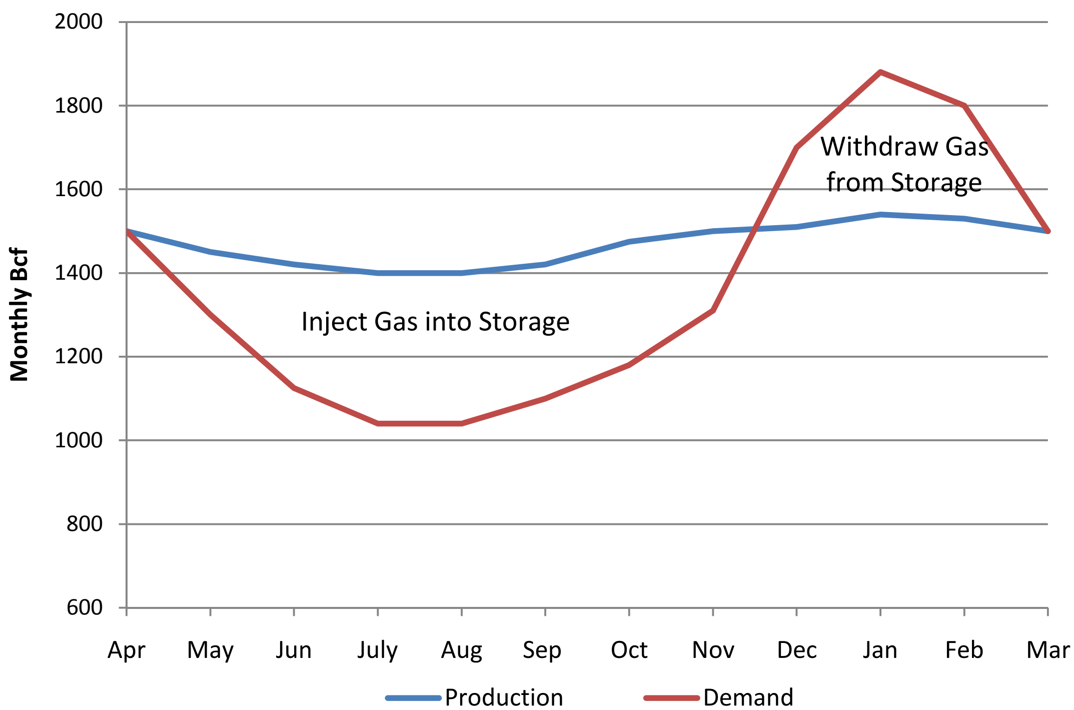
Fundamentally, storage balances demand against production. We use it particularly to allow producers to operate their wells on a relatively levelized basis: when demand is lower than production, the excess gas goes into storage. We then withdraw it when demand exceeds production. Figure 16 provides an illustration of this concept. Storage also allows local demand to be met with gas stored near the load center, thus reducing the need to size trunkline transmission capacity into the load center large enough to meet peak day demand. Some types of storage also lend themselves to either medium-term price arbitrage or to intraday peaking service.[84] Another use of storage is to remedy imbalances between deliveries into a pipeline against the quantity of gas burned by end-users. As explained elsewhere in this paper, those two quantities often differ. They often differ by fairly large amounts for electric power plants. When they differ by more than the pipeline operator can address with linepack or offsets by other shippers, the excess or shortage of gas must be addressed with gas in or out of storage.[85]

[83] New storage being added today tends to be added by local distributors who can make incremental investments to existing facilities or by independent merchant storage providers who charge market-based rates for storage service assuming several cycles, or turns, of gas are made through the inventory space.

[84] It used to be common for summer natural gas prices to be lower than winter prices; thus, LDCs would purchase gas under levelized take contracts and store the excess gas until winter. Even recognizing the carrying cost on the inventory, consumers routinely benefited from these transactions. With the kind of price volatility that exists today, however, that can result in winter prices being lower than summer prices, these seasonal transactions cannot be sure to provide price benefits. Instead, we see marketers using short-term storage to capture the intrinsic and extrinsic, or real option value of storage. The intrinsic value is based on the cost of spot gas today versus today's forward value. One can buy gas, inject into storage, and assure a profit spread by locking in today the sale upon withdrawal. The extrinsic value is based on changes one might realize due to the future movement of prices until the gas is withdrawn, e.g., actual spot prices being higher or lower than the purchase price or the locked-in forward price on the day of purchase.

[85] Linepack is an amount of "extra" gas in a pipeline or distribution line relative to maximum anticipated load. It can be increased by using a compressor to squeeze a line's gas molecules more closely together. Gas distribution companies routinely pack their lines at night or in advance of predicted cold weather to meet higher demand in the morning when furnaces and hot water heaters are more heavily used. Linepack can be thought of as a system's first form of temporary gas storage.

Figure 16: How Storage Balances Seasonal Demand with Monthly Production[86]



Source: Aspen

Electricity generators can benefit from multi-turn storage by subscribing, for example, to enough storage to meet its total gas requirements for the five days that might be the maximum likely interruption in the case of a gas curtailment. The generator could use the space to inject or withdraw gas to cover its daily imbalances or for price arbitrage in the meantime. Multi-turn storage costs more, but most of the costs are fixed, so the more times the generator cycles gas in and out, the lower the amortized cost per MMBtu.

Three different types of geologic formations are used to provide storage service: a) depleted oil or gas reservoirs, b) underground aquifers, or c) salt formations. The different formation types are depicted using different types of marker symbols in Figure 15: the stars are depleted reservoirs, triangles are aquifers and circles are salt caverns.

As a general rule depleted reservoir or aquifer storage operates on a single-turn basis in which the reservoir is filled over the course of the summer and the gas is withdrawn over the course of the winter. Reservoirs that can operate at higher field pressures can be fitted with additional injection compressors or withdrawal wells to provide multi-turn service, but most of the reservoir storage in operation today is single-turn storage that is filled and drained once over the course of a calendar year. This storage tends to be used

[86] Note that the injections do not exactly equal the withdrawals; this difference ends up as left-over gas inventory at the start of the next annual cycle. This outcome is not that uncommon.

most by local distributors or pipelines and is priced on a cost-of-service basis.

Salt formation storage, either salt cavern or salt dome, can withstand higher operating pressures and therefore operates on a multi-turn basis.[87] It is most often developed by merchant storage providers who seek an unregulated rate of return and price the service on a value-of-service basis, meaning market-based rather than cost-based rates if they can show no ability to exercise market power. Storage that is more flexible is of greater use to electric generators, but investors providing merchant storage understand the value of their service and are in business to capture that value from customers.

Figure 15 shows that storage is not evenly distributed, either geographically or relative to demand around the country. Most storage is used relatively close to the region in which it is located, and geology does not always provide sites where they are needed. Certain pipelines and regional markets currently don't have access to underground gas storage at all. Figure 15 plainly shows that Nevada, Idaho and Arizona have none. The Central Plains states and Missouri have virtually none. The entire east coast has none other than far upstream in western New York, western Pennsylvania and West Virginia. (The above-ground storage tanks at the LNG terminals located at Elba Island, Georgia; Cove Point, Maryland; and Everett, Massachusetts do provide some important storage peaking benefits but are operated more for the benefit of the LNG tanker and regasification schedule management than to provide storage service to pipeline shippers. These facilities are not shown in Figure 15 in any case.) To the extent that there is a small amount of storage in the Southeast, Figure 15 shows that none of it is in the eastern coastal states.[88]

Figure 15 shows areas without easy access to underground gas storage to include:

- **Central Plains states (except Kansas)**
- **Missouri**
- **Wisconsin**
- **Arizona**
- **Nevada**
- **Idaho**
- **Southeastern states**
- **Most of Mid-Atlantic**
- **Northeastern states**

As can be seen in Table 7, roughly one-third of U.S. gas storage is located in the Midwest, virtually all in reservoir storage; of 121 Midwest storage facilities, 2 are salt caverns or domes. The two salt caverns are located in Michigan along with 43 reservoir fields; together Michigan possesses more than half the region's total withdrawal capability. Illinois has 29 sites, but they are much smaller fields, on average, offering only 6 Bcf of combined withdrawal capability. Indiana has almost as many fields but they are even smaller, adding to provide less than 1 Bcf combined withdrawal capability. Ohio's fields are captured in the Midwest totals but are all in the eastern half of the state.

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87 To reiterate, single-turn storage is used to inject and withdraw generally once per year; multi-turn storage allows several cycles of injections and withdrawals over the course of the year. Reservoir storage is generally single-turn storage, but certain reservoirs can be developed to provide multi-turn service. Salt cavern storage generally provides multi-turn service.

88 The states without storage now are largely without the depleted reservoirs or salt formations that can economically be turned into storage.

Table 7: Storage Working Inventory and Daily Deliverability Capability by Region

	Total By Region			Average Field Size	
Region	Number of Sites	Working Gas Inventory	Daily Deliverability	Working Gas Inventory	Daily Deliverability
		Bcf	MMcf per day	Bcf	MMcf per day
Central	49	557	6,224	11	127
Midwest	121	1,200	28,524	10	236
Northeast	110	796	15,203	7	138
Southeast	33	195	6,850	6	208
Southwest	66	1,040	23,203	16	352
West	20	303	8,222	15	411
Total (Avg)	399	4,091	88,226	10	221

Source: Aspen Analysis of EIA Data

The average salt cavern/dome facility is twice as large as the average reservoir storage facility. They tend to cost roughly 20% more to develop than reservoir storage. They contain gas at much higher pressure, allowing greater deliverability from a smaller inventory. They also require virtually no cushion gas. A downside is that the caverns are created by dissolving the salt in water. This creates a brine that must be disposed of properly. Development of some potential sites has been foregone due to the disposal issue.

Pipelines that appear to have no access to storage along long portions of their route 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**
- **Williston Basin Pipeline**

Virtually all of these pipelines would end up with new gas-fired load if utilities had to switch existing coal over to gas.

In very rough terms, the 4 Tcf of working capacity versus total natural gas demand of 23 Tcf implies a nearly 6:1 ratio of annual market demand to storage working gas capacity. Crudely applying this ratio to a 31 Tcf market implies the nation needs 5.4 Tcf of working storage capacity, or that we need to add 1.4 Tcf to existing storage working capacity in order to maintain the current ratio between total demand and storage working capacity. The idea that this ratio must be maintained may be overly simplistic because we know that the industry has served this level of demand before, with far less storage; storage working capacity in 1972, when U.S. demand last reached the 23 Tcf range, was approximately 2.4 Tcf.

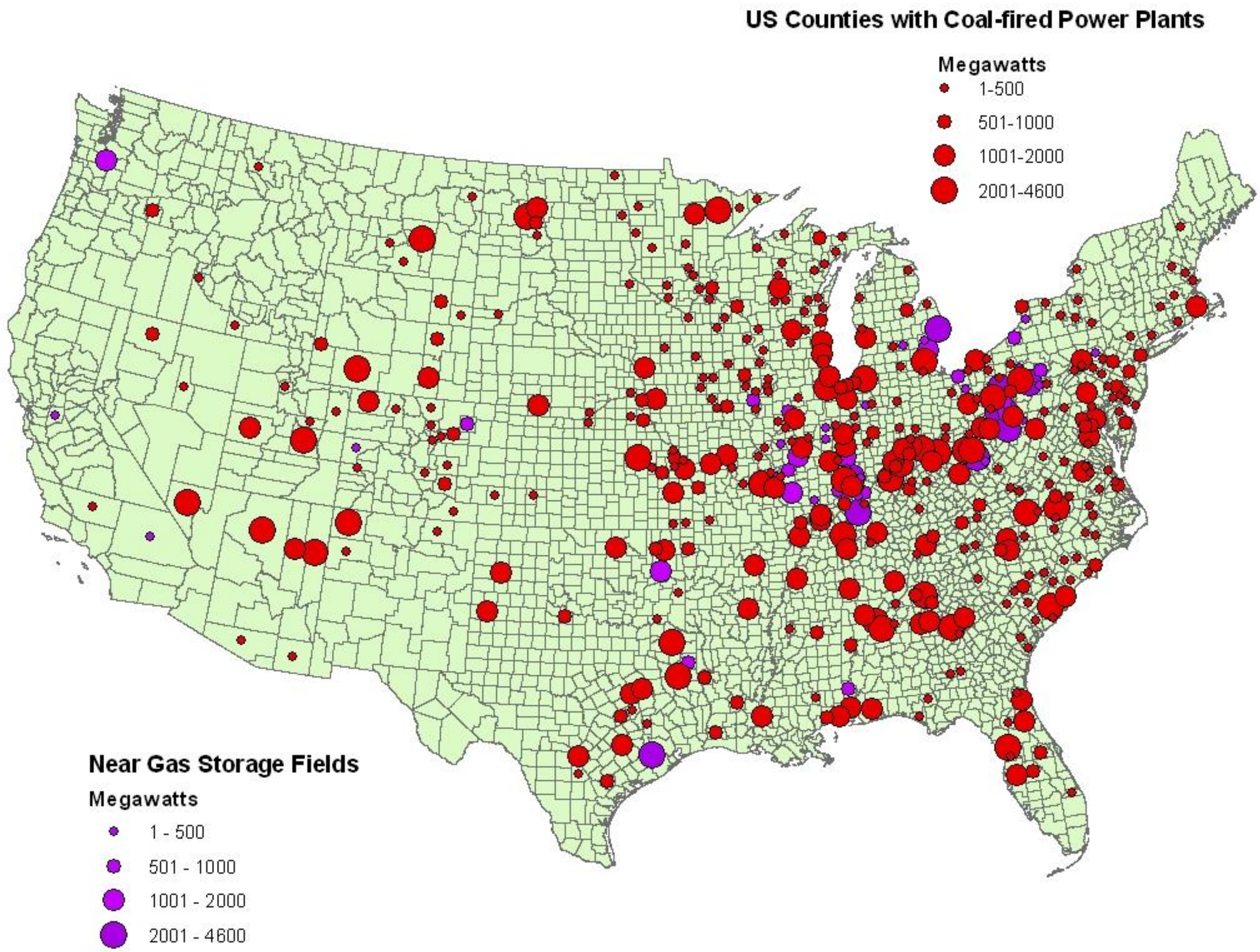
Another approach would be to look at growth in storage relative to the shift towards greater use of gas for electric generation over the last ten or so years. Over that period, EG demand grew from 5.34 Tcf in 2001 to 6.85 in 2008, or approximately 1.5 Tcf. Storage working capacity, in that period, grew by only about 0.3 Tcf. Applying that implied relationship to a projected EG demand increase of say, 8 Tcf, also yields an estimate of 1.4 Tcf more storage needed to support higher EG gas burns. Of course, both these approaches assume existing storage is adequate to serve existing gas-fired EG demand, which may not be true. At an average working gas field size of 11 Bcf, that translates to 127 new gas storage fields needing to be added.

Notably, ICF's 2009 study on behalf of INGAA, estimated 2030 natural gas EG demand in a base case 4 Tcf higher than today's and a high case EG demand 8.1 Tcf higher than today. The associated increases in storage working capacity are 0.45 Tcf and 0.6 Tcf, far lower than the ratios calculated above imply the industry might need. The National Petroleum Council's 2003 study "Balancing Natural Gas Policy" projected a need for 1 Tcf of storage to meet higher demand by 2030, some 0.7 Tcf of which they estimated needed to be new storage additions after optimizing use of existing capacity.[89] Note that because storage cannot necessarily be built where the new demand will be located, additional storage necessitates additional pipeline capacity in order fill that storage and deliver from it to local distribution company citygates.[90]

Given that storage provides electric generators with more flexibility this study considered how close existing coal-fired units are to underground gas storage. The data publicly accessible to answer this question is rudimentary in that it is only identifies the county in which the storage facility is located. Using that as an inexact proxy for distance between a coal-fired unit and a gas storage facility, Figure 17 identifies the coal-fired units for which a gas storage facility is located in the same county. Aspen's count is that approximately 70 coal-fired plants are located in the same county as an underground gas storage facility. A more refined estimate should be developed using facility-specific geo-positioning satellite data.

[89] Volume V, Transmission and Distribution Task Group Report, p. T-55.
[90] A citygate is an interconnection between a pipeline and a local distribution company.

Figure 17: Existing Coal-Fired Generation Located In Same County as Underground Gas Storage



Cost to Build and Use Storage

ICF's INGAA study estimated its forecast storage additions to cost $4.0 to $5.2 billion, respectively. The estimate was based on 2007 costs for actual storage projects built between 1997 and 2007, with costs other than cushion gas escalated from 2007 at 2% per year.[91] Scaling up from the 0.45 and 0.6 Tcf ICF found needed, implies a cost for additional storage working capacity of $8.9 Billion per Tcf added, although costs will differ by field type. The 1.4 Tcf additional storage working capacity estimated herein translates to a capital cost of $12.5 Billion.

The impact that use of storage or subscribing to more firm pipeline capacity will have on utility electricity rates depends on how those costs change the utility's weighted average cost of gas (WACOG).

To convert $ per MMBtu to cents per kWh on a ballpark basis, multiply the WACOG by the utility's system's average heat rate per MWh and divide by 1000.

A $1 per MMBtu increase in the WAOCG for a utility with a 10 MMBtu per MWh heat rate will change rates by $0.01 per kWh.

Black & Veatch (B&V) did a study released in late 2009 (but actually done in 2007 for the California Energy Commission's Public Interest Energy Research Program) that contained capital cost estimates for storage. B&V looked at costs for relatively recent storage projects in California. These reservoir projects are configured for high-deliverability, multi-turn use. B&V came up with a capital cost, again excluding cushion gas, of $37 million for an 8 Bcf working gas, three-turn per year field. Ignoring the multi-turn aspect, this translates to $4.6 Billion per Tcf added, or $6.5 Billion for the 1.4 Tcf estimated here as needed.

Note again that costs to develop storage are unique to the reservoir or salt formation and the optimal combination of injection compressors, withdrawal wells, dehydration equipment, distance to interstate pipeline or LDC lateral cost and so forth.

A natural gas storage user would evaluate the costs to use storage as shown in the example presented in Table 8. The table works out the cost per MMBtu for both single-turn reservoir storage and high-deliverability storage. There are essentially four fees associated with use of storage: a) reservation charge; b) injection charge; c) withdrawal charge; and d) compressor fuel charge. The reservation charge to "rent" or reserve the storage space is paid once, for each MMBtu of space reserved. In the example, the provider of simple reservoir charges $0.40 per Dth per month to reserve storage space. The high deliverability storage costs more than twice that, $1.00 per Dth.[92]

The next two fees are for injection and withdrawal. The provider charges an additional fee is paid for every MMBtu the customer injects into the storage inventory space and again for every MMBtu later withdrawn. In the example the injection and withdrawal fees shown are the same for both injection

[91] ICF INGAA, page 73.

[92] A 2004 FERC report entitled "Current State of and Issues Concerning Underground Gas Storage" reviewed tariff filings for jurisdictional storage facilities (p. 34). It found 100% load factor rates ranging from $0.21 per MMBtu to $0.96 per MMBtu. This wide range is indicative of how the different field characteristics and equipment configurations affect consumer cost.

and withdrawal and for the two types of storage: $0.02 per Dth. This is not always true, as some providers will have incurred slightly different costs in terms of the number of withdrawal wells or injection compressors installed. The key point is that there is usually a big annual fee to rent the space and then a small fee for entry and exit.

Now suppose the customer is a 500 MW NGCC that wants to reserve inventory space to satisfy 5 days worth of gas requirements. That unit, operating all 24 hours per day at an assumed heat rate of 7 MMBtu per MWh would consume 84,000 MMBtu per day.[93] 5 days worth of gas would be 420,000 MMBtu. For reservoir storage, the annual reservation fee for inventory space would add up to $2 million. (An annual reservation fee is paid each year, regardless of whether the space ends up being used or not.) For the reservoir storage, the customer's gas will be injected over the 180 days of summer (April 1 to October 31) and withdrawn during the 120 days of the winter season (November 31 to March 31) – basically the customer is going to pay 2 cents to inject 420,000 MMBtu (spread over a 180-day period) and then 2 cents for each MMBtu as it is withdrawn. Spreading the reservation charge and the injection and withdrawal charges over the 420,000 MMBtu creates an average cost per Dth to use the reservoir single cycle storage of $4.84 per Dth. If the customer reserved 420,000 MMBtu of inventory space but only injected 15,000, its reservation charge would remain unchanged, but its total injection and withdrawal fees would be lower.

Switching over to the high deliverability storage, the annual reservation fee for the same 420,000 Dth of inventory space works out to $5 million. This time the customer might put the 420,000 MMBtu (recall that a Dth and MMBtu are equivalent) in and withdraw it five times per year. That means that the customer spreads the $5 million over 420,000 MMBtu. It still has to pay the 2 cents for every MMBtu injected and every MMBtu withdrawn. The total cost averaged over using the 420,000 MMBtu of space five times is $2.41 per MMBtu. The other charge listed was the compressor fuel charge. It is usually delivered "in-kind," meaning that the customer delivers enough extra gas to cover that needed to run the injection compressor. Some providers will roll this into the injection charge.

[93] 500 MW * 7 MMBtu/MWh *24 hours = 84,000 MMBtu

Table 8: Illustration of Consumer Costs to Use Underground Gas Storage

Assumption	Reservoir	High Deliverability
Annual Reservation Charge ($ per Dth per Month)	$0.40	$1.00
Injection Fee	$0.02	$0.02
Withdrawal Fee	$0.02	$0.02
Compressor Fuel[94]	1%	1%
No. Days of Injection to Fill Inventory	180	20
No. Days of Withdrawal to Deplete Inventory	120	10
No. of Cycles per Year	1	3 to 5
Assume Reserve 5 days Worth of Supply (420,000 MMBtu per Day) Inventory Capacity		
Total Fixed Cost	$2,017,105	$5,042,763
Total Variable Cost	$16,800	$16,800
Average Cost per MMBtu	$4.84	$2.41

Source: Aspen Analysis

A further example will illustrate the implications for an electric generator. Assume the same 500 MW unit with a heat rate of 7 MMBtu per MWh, resulting in a daily gas requirement of 84,000 MMBtu per day. Assume again that the unit purchases enough inventory to meet its full 24-hour gas requirement for five days, or 420,000 MMBtu. Different storage providers may offer service at substantially different fees, owing to the unique characteristics of the facilities they own, how they have structured their services and how their respective regulators allow them to recover costs for storage service. Table 9 shows the inventory, injection and withdrawal charges for three large gas local distribution companies with fairly large amounts of underground storage that they offer to customers, including electric generators, in three different regions of the country: Pacific Gas and Electric Company, Union Gas of Ontario, and Dominion People's.[95]

In the example of the electric generator reserving 420,000 MMBtu, the reservation charge for the same quantity provided by these three representative companies differs hugely: $680,000 for PG&E versus $3.3 million for the same quantity of space from Dominion. PG&E doesn't have an injection or withdrawal fee (nor does Union Gas) but Dominion's is a nickel per MMBtu injected or withdrawn. The cost for reserving and using a single cycle on PG&E works out to $1.62 per MMBtu but nearly $8 per

[94] The compressor fuel is excluded from the calculation for the sake of computational simplicity. It would be charged typically as a % of the MMBtu injected. Some providers allow it, like pipeline compressor fuel, to be paid with an in-kind delivery of additional gas molecules while others require a cash payment. The cost of the fuel or value of the cash payment will vary as the price of natural gas varies.

[95] Union Gas does sell storage service to U.S. customers from its vast storage pool at Dawn Hub located in and around Windsor, Ontario.

MMBtu on Dominion. There is no a one-size-fits-all for the fees electric generators will incur to use storage: they vary considerably and generators will have to learn to "do the math."

The illustration highlights not only how different effective per Dth storage costs are going to be to different electric generators, depending on the costs of the storage they can access, but that the annual fixed costs for even a small amount of storage inventory amount to several million dollars per year and represent a significant commitment on the part of the generator.

Table 9: Effective Cost of Storage

	PG&E		Union Gas		Dominion	
Inventory Charge (per Dth)	$	0.135	$	0.538	$	0.650
Resulting Annual Reservation Fee	$	680,400	$	2,580,000	$	3,276,000
Injection (per Dth)	n/a		n/a		$	0.05
Withdrawal (per Dth)	n/a		n/a		$	0.05
Effective Cost per Dth[96] Single Cycle	$	1.62	$	6.14	$	7.90
Effective Cost for Five Cycles	$	0.32	$	1.23	$	1.58

Source: Aspen Analysis of Utility Tariffs

Impediments to Adding Storage

Storage that connects directly to an interstate pipeline is subject to FERC jurisdiction. FERC applies to storage the same "let the market decide" policy that it applies to pipeline capacity: having some of the capacity contracted combined with an applicant willing to bear the remaining financial risk is sufficient to win FERC certification. A relatively easy showing of market alternatives to storage allows FERC to find that the applicant cannot exercise market power so that the project can charge market-based rates. Since 2000, FERC has certificated more than 76 projects for a combined 860 Bcf of new working gas capacity. [97]

Still, the number of storage facilities added in the years post-Order No. 636 and since establishing general parameters for allowing market-based rates is not overwhelming. Convincing subscribers to commit to pay market-based rates for multi-turn storage is not be as easy as it may look – the rates entail a significant commitment to pay firm reservation charges and are high enough that using the capacity for a single turn is typically not economic.[98] Not only does the cost to use storage add to a utility's overall cost of gas, but the cost of the gas stored imposes a carrying cost and risk that prices will have changed between the time the gas is purchased and injected and when it is used. The opportunity to cycle provides flexibility but it must be managed carefully to determine when to cycle versus when to trade imbalances, when to sell excess gas into the market instead of storing it versus when to rely on

[96] This is the effective 100% load factor cost assuming one cycle.
[97] http://www.ferc.gov/industries/gas/indus-act/storage/certificated.pdf
[98] Multi-turn storage allows the user to inject gas in and withdraw it repeatedly during a year.

short-term "park and loan" services.[99] It takes a sophisticated user to manage multi-turn storage in a way that assures an economic benefit to the buyer. 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.

In addition, geology matters.[100] It takes the right kind of permeability to create field pressures that can operate at economic levels of injection and withdrawal while minimizing the amount of cushion gas that must remain in the field year-round. Investors have been looking for a suitable field, for example, along the Kern River pipeline that runs from southwestern Wyoming through Utah and Nevada to southern California since the pipeline entered service in 1993. Whether the old Ten Section field in California's Kern County will finally be configured to work properly and gain market acceptance remains to be seen.

Local opposition has stalled natural gas storage development in some places. Difficulty disposing of salt brine is one reason. A salt cavern project in Arizona just outside Luke Air Force Base resulted in state law temporarily prohibiting storage development. Opponents argued that the compressor building and wells were too close to the runway for safety and feared that an aircraft hitting the building would ignite the storage facility. A project in suburban south Sacramento has attracted local neighborhood opposition that gas could leak from the storage field and catch fire or explode. Two separate fires lasting many days at PG&E's McDonald Island facility in 1974 and 1993, as well as leaks from Southern California Gas fields at Whittier, Montebello and Playa del Vista, along with the highly visible August 2004 fire that burned for 6 days in Moss Bluff, Texas, increase resident concerns.[101]

Projects that get certificated don't necessarily proceed to construction. FERC won't require a developer to have sold all of its capacity before granting a certificate but project finance lenders will want enough of the capacity subscribed to demonstrate that revenues will be more than sufficient to cover debt service. Even in Florida, which with its dramatically increased gas use and its role there in electric generation, a certificated project at Indiantown for above-ground LNG tanks has not proceeded to construction because it cannot obtain enough subscriptions to its inventory capacity.[102]

[99] Park and loan can be thought of as short-term storage; some pipelines offer it as a discretionary service on an interruptible basis, meaning that if they have capacity to allow the short-term storage they will and if they don't, they won't.

[100] It should not escape notice that some of the same geologic formations used to storage natural gas underground are potential sequestration sites for CO_2.

[101] Weatherwax, R. and Weatherwax M., "California Natural Gas Storage Incidents: A Contemporary History of Incidents," Sierra Energy and Risk Assessment, Inc., 2007. Storage fields that produced both oil and gas seem to pose higher risk than ones that produced only gas, both in terms of contributing to the incident and the environmental consequences of the incident.

[102] Floridian Gas Storage won its FERC certificate in 2008 with an expected in-service date of 2011. As of March 2009 construction had not begun and there is no update on the company website indicating when construction will begin.

In a 2004 presentation to NARUC, independent storage provider Encana noted that most storage in the U.S. and Canada had been built during the "dramatic" growth period of the industry from 1950 to 1970. In planning for the future it advised that:

"New storage will be increasingly:

in poorer quality reservoirs

farther from ideal locations

using higher cost cushion gas

and therefore more costly to develop and provide service."

Summary Observations Related to Gas Storage

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 West Virginia).
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 EG demand implies a need to add 1.4 Tcf of storage.
10. A recent study for 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.

Operational Considerations

Several operational realities need to be considered as we contemplate additional use of natural gas to generate electricity. First is the general disconnect between the way the unbundled natural gas system works versus independently-controlled electricity markets. Second is that during circumstances demanding interruption (otherwise known as curtailment) of natural gas supplies, large customers (including electric generators) are among the first asked to curtail consumption. Third is the risk of natural disasters such as hurricanes that can strike the Gulf of Mexico and cause large decreases in domestic production.

Nominations and Balancing

Other than in Canada's Province of Ontario, the North American gas system doesn't make it easy to be an electric generator. Ontario is the exception, having made a decision to replace its coal-fired generation with natural gas. It has worked over the last seven years to develop tariffs, services and rules to allow its electric generators greater flexibility. These innovative services were developed as a result of a proceeding conducted by the Ontario Energy Board known as the Natural Gas Electricity Interface Review (NGEIR). If the U.S. seriously intends to use natural gas as a bridge fuel until more renewables or CCS are available or if we simply require conversion of the coal-fired fleet to natural gas, the entire U.S. transmission and distribution system needs to look seriously at the approach used in Ontario. Notably, that approach relies on the vast amount of natural gas storage that exists in and around Union Gas' Dawn Hub.

Issues include the fact that the "gas day" doesn't match the "electricity day." The gas day begins at 9:00 A.M. Central Clock Time (CCT). The gas industry nominates natural gas a day ahead using four nomination windows (except in Ontario where Union Gas allows 13 and TransCanada offers a service that allows 96 nomination windows per day).[103] Table 10 shows the four nomination windows agreed upon by the industry via the North American Energy Standards Board (NAESB). Some pipelines have "no-bump" rules. A no-bump rule means that nominations later in the gas day cannot "bump" earlier nominations, even if they were from a shipper with interruptible capacity. In other words, it prevents a firm shipper who does not nominate all of their firm capacity in the Timely nomination window from bumping the interruptible customer who nominated to use that available capacity in a subsequent period. It effectively means that a firm shipper who does not nominate to use all of their firm capacity when they submit a nomination in the first cycle of the day are not guaranteed access to it in the later nomination windows of the cycle.

The cycle's initial gas nominations are due in the morning the day ahead of consumption, but the generators in competitively-dispatched electricity markets will only generally know how much gas the unit will need until they get dispatch orders, often in the afternoon of the day-ahead. Even then, ambient temperature conditions can change the efficiency of a gas-fired unit or actual electricity

[103] A nomination for gas can be thought of as placing an order for delivery. It is notification to the pipeline and to the supplier of how much gas it should expect to receive for a shippers' account and how much gas that shipper should burn at a facility.

requirements the next day such that the actual gas burn is different than the amount of gas the generator "ordered" from the pipeline. A difference between what the shipper caused to be delivered into the pipeline versus what it accepted at its meter and burned is called an "imbalance." Shippers who deliver more gas than they burn can cause the pipeline operating pressure to exceed maximum design levels. Shippers who deliver less gas than they burn can cause the pipeline operating pressure to drop too low. (Even when the sum of over-deliveries or under-deliveries do not cause an operating problem, per se, leaving too much gas on the pipeline or taking too much out of it is effectively using the pipeline as storage.) On most, but not all pipelines, balancing is measured daily, with a tolerance. The tolerance is often 10% of monthly usage and is available because of the ability to "pack and draft" a gas pipeline, and depends on how much storage is connected to the pipeline system and/or that the pipeline operator retains for managing imbalances.[104] Similarly, the fact that gas moves through a high pressure pipeline at a speed of about 30 miles per hour means that an operator can give shippers more time to manage imbalances if storage is more closely located.

Imbalances outside tolerance must be resolved. Most pipelines allow shippers to trade their imbalances with other shippers. When that isn't feasible, they must usually be managed using storage. There are also what are called "cash out" provisions under which a shipper may sell its imbalance to the pipeline or buy gas to make up an under-delivery from the pipeline. Most pipelines also have provisions imposing penalties for failing to resolve a balance outside tolerance. Penalties vary by pipeline but can be several times the prevailing commodity price of gas. Pipelines often also impose an additional charge for having "over-pulled" or "under-pulled" that is separate from the imbalance charge. A shipper who contacts the pipeline and gets his over-pull or under-pull authorized will usually face a different charge than one who does so on an unauthorized basis. Finally, pipelines and some LDCs can call what are called "Operational Flow Orders," or OFOs. An OFO directs all shippers who are out of balance to get into balance immediately or otherwise immediately imposes penalties on all imbalances.

10% of monthly usage is roughly 3 days worth of gas:

0.1 * 30 days = 3 days

At a speed of 30 miles an hour, gas from 2,160 miles away could reach a customer in those same 3 days. Many pipelines require users to take gas in even hourly increments.

Some pipelines, usually those without storage connected to their systems, require hourly balancing. Even pipelines that do not require hourly balancing will have a requirement that gas be delivered and taken in even hourly increments, usually 1/24th of a shippers' maximum daily delivery. Again, pipelines connected to storage are more likely to offer more flexibility. The sum result of all these provisions is that shippers who will bring a variable quantity of gas onto the system or whose takes vary day-to-day (like electric generators) have to pay special attention to managing their imbalances.

[104] Pack and draft refers to the ability to use compression to pack gas molecules closer together in the pipeline and alternatively, the ability to reduce pressure and spread the molecules apart. Pipeline operators use this as their degree of freedom in managing the system.

LDCs often offer more flexibility than a pipeline because of the diverse load on their systems and the fact that they tend to be network systems in contrast to interstate pipelines that tend to be trunklines. LDCs, however, often have rate structures in which large customers subsidize the rates of smaller customers or other public goods charges are added to the rates. A generator may be able to get more flexibility from an LDC but will pay a premium for it.

Union Gas, in Ontario, offers 13 nomination windows (9 additional plus the four shown below in Table 10) so that electric generators have more opportunities to match their usage with what they deliver into the system. TransCanada Pipelines Limited, also responding to the NGEIR, offers the ability to change nominations every 15 minutes. It does so only at delivery points in which load is connected to a single meter taking gas off the pipeline which it says is necessary in order for it to manage the system. Union Gas also offers specialized services that allow generators the ability to balance a few hours additional gas each day, for an additional fee.

Table 10: North American Energy Standards Board Gas Nominating Windows

Nomination	Hour CCT	Day
Timely	11:30 AM	Day PRIOR to gas flow
Evening	6:00 PM	Day PRIOR to gas flow
Intraday 1	10:00 AM	Day OF gas flow, effective @ 5pm Day OF
Intraday 2	5:00 PM	Day OF gas flow, effective @9pm Day OF

Source: Aspen Compilation

Some U.S. pipelines have moved to daily or hourly balancing unless the shipper buys an enhanced service. A survey of 10+ interstate pipelines' balancing provisions confirms that the provisions vary widely, as shown in Table 11. Certainly there is a sense that more constrained provisions arise when the pipeline has less physical flexibility to manage imbalances or when the pipeline does not have a storage service it wants to sell: priced to cause sufficient pain, more constrained balancing provisions push shippers to purchase storage.

Table 11: Interstate Pipeline Balancing Periods

Pipeline	Balancing Period
El Paso Natural Gas Company (EPNG)	Hourly unless buy Firm Daily Balancing Service
ANR Pipeline Company (ANR)	Daily unless buy Enhancement Service
Florida Gas Transmission (FGT)	Monthly
Texas Eastern Transmission Corporation (TETCO)	Daily
Transcontinental Gas Pipeline Company (Transco)	Daily
Dominion Transmission Company	Monthly
Kern River Gas Transmission (KRGT)	Daily
Trunkline Gas Company	Daily unless aggregate imbalance all shippers < 10%
Panhandle Eastern Corp	Daily unless aggregate imbalance all shippers < 10%
Columbia Gas Transmission Company (TCO)	Monthly
Northern Natural Gas Company	Unclear, rate charged to monthly out-of-balance volumes

Source: Aspen Analysis

Curtailment

Akin to water that flows seeking its lowest altitude spot, natural gas "moves" from higher pressure to lower pressure locations. Any valve open to a lower pressure circumstance will allow gas to flow. When the pressure inside a pipeline drops to the same pressure as at open valve, the molecules will "float" in place and stop flowing towards the valve. Pipeline and LDC operators will seek to curtail service to end-users before this condition occurs. LDC gas control employees are taught to avoid letting low pressure "float" conditions occur not only because they view their mission critical duty as being to keep homes warm, but also because restoring service means crews must go neighborhood-by-neighborhood and house-to-house, closing distribution valves and then reopening at each meter, relighting pilot lights as necessary, as they restore service. In some cases they may need to purge distribution lines of air. It is time intensive, expensive, inconvenient to home owners, and a burden on crews of a much more massive scale than electric service restoration. It is therefore avoided at all costs.

The alternative implemented by gas system operators is to invoke call-ahead curtailments of a few large gas users who have knowledgeable staff on-site and who can curtail their own use of gas before the line pressures drop precipitously low. In many situations, that one-call customer with a knowledgeable staff on-site traditionally has been a gas-fired power plant. In addition, there are locations today in which year-round firm capacity is either not available to existing gas-fired power projects or where it would not be available to a new gas-fired power project. Sometimes these projects rely on residual fuel oil or propane for back-up; in other instances they simply shut down. Calculations of new capacity requirements in this report undoubtedly do not consider changes like this that existing gas-fired generators might prefer to allow them to operate more securely.

On the interstate pipelines, firm is firm. That is to say that except with regard to a no-bump rule or circumstances that plagued the El Paso Natural Gas system because of its failure to expand its system as commitments to "full requirements" customers grew, when a shipper commits to a reservation change for firm capacity, FERC requires the pipeline to honor that commitment except in a *force majeure* situation which is one generally caused by an emergency outside the pipeline's control.[105] But because LDCs have to protect service to "human needs" customers and maintain the integrity of their gas main operating pressures, they tend to use a different standard. [106]

The National Association of Regulatory Utility Commissioners (NARUC) published in 2005 a technical assistance brief prepared by the Institute of Public Utilities at Michigan State University reviewing state curtailment rules.[107] The review is based on a survey of state utility regulatory commissions; 31 commissions responded to the survey. The following findings are salient:

- All 31 states responding to the survey provide some authority for either the state commission or the Governor to respond to a natural gas shortage. More put that authority with the Governor than the Commission; in many cases the authority is collaborative.
- Where there is an adopted curtailment order the order varies considerably by state; the emphasis is generally on protecting service to residential customers.
- About a third of the states don't require the LDCs to file a gas curtailment plan. Of those that do there is no required periodic update to the plans or rules.
- Only about a third of the states that responded hold docketed hearings to review the plans.
- Only a third of the states specify the end-use curtailment rules in the LDC tariffs.

Any inability to get gas is not properly called a curtailment. Customers who choose to hold interruptible transportation rights explicitly choose to bear the risk of interruption when gas supplies are tight. But LDCs that need to curtail will tend to call upon electric generators to curtail even if they have firm service because they are large loads that can protect service to many other gas customers.

[105] Full Requirements service is often offered to smaller utilities, which are often municipal utilities, and may be less able to predict their usage because it doesn't make sense for them to hire the staff to maintain the analytic data and forecast demand with a high degree of accuracy. The service is a hold-over from the days when pipelines purchased gas on behalf of their customers and sold it on a bundled basis with transportation service. While FERC does not generally allow pipeline to sell natural gas today (known as the "merchant function"), some independent gas marketers will offer Full Requirements service under which the supplier delivers to the customer whatever its gas requirements turn out to be. That supplier will usually have reviewed the customer's historical load data and the service agreement will specify a maximum delivery quantity set high enough that it will never be exceeded; the supplier then holds the interstate transportation capacity needed to consummate delivery. Certain of the pipelines, among them El Paso Natural Gas (EPNG), provided a transportation-only analog to their smaller customers in which the pipeline is committed to deliver to the customer whatever amount of natural gas the customer delivers into the pipeline. In the early 2000's EPNG was ordered to convert its full requirements customers to fixed capacity entitlements.

[106] We know of no source that compiles further information about the frequency and duration of LDC curtailments. Disallowing service to customers using interruptible capacity is not a curtailment of service, by definition, either on an LDC system or an interstate pipeline.

[107] Institute of Public Utilities, "NARUC Inventory on Gas Curtailment Planning," April 2005.

- Some states, about a third of respondents, require a customer to have alternate fuel capability in order to select interruptible LDC service.[108]
- Most of the Commissions have authority to prescribe specific actions by the LDCs during a shortage whether there is a plan on file or not.
- Only four of the states have examined the impact to electricity generation from a gas curtailment.
- Half the states understand that electric generators often do not hold firm interstate pipeline capacity.
- No state indicated that gas utilized for electricity generation would receive priority during a gas curtailment; in fact half the states said that electric generators with non-firm gas transportation contracts definitely would be curtailed prior to other users (the others either didn't respond or didn't know).

More than half the states responding to NARUC's survey realized that electric generators with non-firm gas transportation contracts would have their service cut first, but only four states have examined the impact to electric generators from a curtailment. Only some states require a generator to have alternate fuel capability in order to select interruptible transportation.

In some states, gas-fired electric generation has been installed with alternate fuel capability.[109] This occurred largely because those specific locations were known at the time of construction to not have sufficient access to natural gas. Such alternate fuel capacity is typically diesel fuel or residual fuel oil. Those petroleum products cost more and have higher emissions than natural gas. Adding alternate fuel capability increases construction cost and facilities must be added to handle the fuel on-site. A small amount of on-site liquid fuel storage is typically built. Often, containment berms are required around those storage tanks. No cost-effective way to store the few days worth of natural gas that most contingency plans call for is available that we know of. In some instances it may be possible to add small peaking plants that liquefy natural gas and hold it for a peak day or to truck in LNG. AGL Resources owns LNG peaking plants near Macon, Georgia and Chattanooga, Tennessee that can deliver 70,000 and 90,000 MMBtu, respectively, into the local pipeline system. Nonetheless, if the U.S. is to rely on ever increasing amounts of natural

[108] State commissions could also presumably order jurisdictional electric generators to subscribe to firm interstate transportation in order to protect transportation priority upstream of the LDC. They would not have that authority over municipal generators, of course, or unregulated "merchant" generators.

[109] While the Power Plant and Industrial Fuel Use Act of 1978 was largely repealed in 1987, it still requires that new natural gas-fired baseload power plants self-certify to the Secretary of Energy that they can burn coal or another alternate fuel as a primary fuel source. The requirement applies only to plants in the lower-48 states and District of Columbia. A baseload unit is defined as having a capacity factor of 40% or higher. The self-certification must merely confirm that the proposed gas-fired plant "(i) has sufficient inherent design characteristics to permit the addition of equipment (including all necessary pollution devices) necessary to render such electric powerplant capable of using coal or another alternate fuel as its primary energy source; and (ii) Is not physically, structurally, or technologically precluded from using coal or another alternate fuel as its primary energy source." See Public Law No. 100-42 and 10 CFR 501.60, 61. Gas-fired plants with back-up fuel capability appear to have it to protect against interruption of supply and not because of the Fuel Use Act.

gas for electricity generation, states will need to revisit their curtailment rules in order to maintain the reliability of electricity.

Curtailments can happen for another reason that likely needs some revisiting should utilities need to switch large portions of their generation fleet over to natural gas. When a customer signs up for service on an interstate pipeline, they specify what is known as a Maximum Daily Quantity, or MDQ. The fixed reservation charge that customer pays is based on the capacity reserved for its use as specified by the MDQ. The customer is not allowed to take more gas than the space reserved under its MDQ will allow it to transport. The customer would have analyzed various cost versus risk tradeoffs when it selected its MDQ. Many customers, naturally, will not want to reserve and pay for the extra capacity that they will only use for 1 day perhaps every 8 years when very cold weather occurs. But now suppose that extreme cold weather does occur. The pipeline may, with a penalty charge, allow the customer to pull from the pipeline more natural gas than her share (her share being the amount reserved in the MDQ). But then again, the pipeline may not; it may not be able to due to the need to honor the MDQs of other customers who are also experiencing higher-than-normal demands.

A municipal utility located in the Midwest curtailed deliveries to its own gas-fired power plant during a cold snap in order to preserve deliveries to its other natural gas end-users. The limiting factor was not a curtailment called by the interstate pipeline but rather was the utility's MDQ on the pipeline. Increasing MDQs to obtain certainty of enough gas to protect electric generation reliability will cost electric utilities and their customers more in pipeline demand charges.

Suppose this customer were a local utility serving both gas end-users and the power plant that utility uses to deliver electricity to those same gas end-users. Gas demand shoots up above the amount it can obtain, pursuant to its MDQ, from the pipeline. What does the combined utility do in this case? Virtually all would choose to curtail gas deliveries to their power plant so that they could protect service to local end-users. If we are to truly switch coal-fired generation to natural gas, utilities all over the country will need to revisit their MDQs, the analysis that they performed in selecting those MDQs and the risk/cost tradeoff embodied in choosing an MDQ that is lower than total requirements on a very cold day. Holding the higher level of interstate pipeline capacity to preserve access to natural gas under extreme conditions and enable the utility to continue generating electricity using natural gas will impose higher costs on electricity and natural gas end-users.

Hurricane Risk to Supply and Prices

Hurricanes striking the U.S. coast in the Gulf of Mexico can damage production facilities and create risk to both natural gas prices and supply.[110] 10 Bcf per day, which is approximately 20% of U.S. domestic production and 15% of U.S. average day requirements, comes from low-lying areas of the Gulf Coast or offshore. As even relatively minor or tropical storms approach, the crews working on the Gulf's 4,000 platforms are evacuated. They close safety valves to assure that no oil or gas can spill or escape should facilities be damaged, thus shutting-in production as they leave. The platforms are connected via more than 33,000 miles of sub-sea pipelines to onshore infrastructure consisting of surface-level piping, valves, metering stations and compressors. Key facilities include 47 natural gas processing plants and 17 gas liquids fractionation plants that are located in coastal counties. In addition, Henry Hub, which is not only the physical location used to clear the NYMEX gas futures market but is the physical interconnection of four intrastate and five interstate pipelines sites is located quite near the coast. Tropical storms and less intense hurricanes simply cause a couple of days interruption to production and attendant price spikes as traders use virtually any excuse to bid up prices.

The roughly 8 Bcfd of gas supply shut-in due during and immediately after Katrina was enough to meet about 13% of U.S. daily average demand.

While most storms cause little damage beyond the inevitable price run up that occurs in advance of the storm, intense hurricanes can cause damage to production, processing and off-shore delivery infrastructure such that as crews return to the rigs repairs must be made before production can be restored. Hurricane Katrina destroyed 44 platforms and damaged 20 more. Four days after Katrina, most Gulf offshore production—representing about 13% of U.S. daily average gas demand—remained shut in. Sabine Pipeline declared *force majeure* on deliveries and because the control room at Henry Hub was underwater (no gas could flow) and trading of the NYMEX futures contract was suspended as physical delivery of gas under futures contracts occurs at Henry.[111] Several other pipelines declared *force majeure* on portions of their lines or at specific delivery points; however, situation reports and assessments from the Department of Energy and EIA show that none shut down completely. More than 36 large diameter pipelines in Federal waters were damaged and 8 gas processing plants remained closed. A week later, half of Gulf offshore production (about 4 Bcf) remained shut-in. Repair crews

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[110] Reductions in supply due to well freeze offs (which occur under very cold conditions in which the water produced in association with gas freezes in the top of the wellhead, blocking production) can also occur. Wells in areas that expect freezing weather are built to withstand this. Wells in parts of Texas, Louisiana and locations where cold weather occurs seldom do from time to time experience freeze offs. The last reportedly occurred in 2007 and took out 1.5 Bcfd of production. An outage of that magnitude could be expected to be overcome with gas from storage. Another potential source of disruptions arises from earthquakes. Natural gas pipelines in known earthquake zones are engineered to withstand shaking. Pipelines built in the Midwest or East in zones with little recent seismic activity may not be. Sandia National Laboratory is reported to have a study underway to evaluate this risk.

[111] *Force Majeure* is the term used in contracts to indicate a major event beyond any party's control. An explosion of a pipeline is beyond the control of shippers and the pipeline and thus is considered a *force majeure* event. Most contracts will give examples of what constitutes *force majeure* under that particular contract.

were impeded by lack of access to boats, crews, divers, and other equipment, lack of electric power, lack of access to transportation fuels needed to travel to facilities in the hurricane impact zone and long lead time required for delivery of repair materials and components such as custom-built valves or flanges. As shown in Table 12, a month later 3.5 Bcf was still shut-in. The day after Hurricane Rita's landfall on September 24, the shut-in quantity had returned to 8.0 Bcf per day. When Minerals and Management Service issued its final shut-in statistics report eight months after the hurricanes, a total of nearly 1 Tcf of gas that otherwise would have been available for production instead had been shut-in and was unavailable to the market.[112] Figure 18 shows the asymptotic approach of Gulf production to pre-hurricane levels.

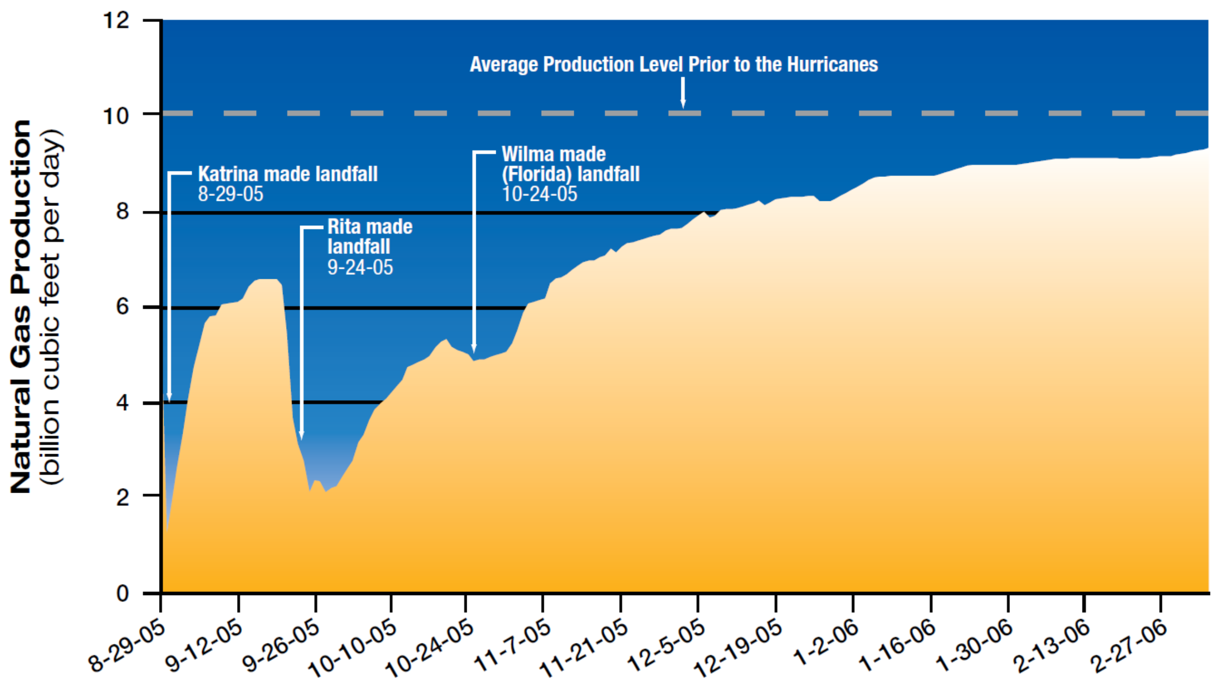
Table 12: 2005 and 2008 Hurricane Oil and Gas Damage Summary

		Platforms		Outages	
	Landfall	**Destroyed**	**Damaged**	**Max Day**	**30-day +**
Katrina	8/29/2005	44	20	8.3 Bcfd	3.5 Bcfd
Rita	9/24/2005	69	32	8.0 Bcfd	5.5 Bcfd
Gustav	9/1/2008	n/a	n/a	7.1 Bcfd	3 Bcfd
Ike[113]	9/13/2008	60	124	7.3 Bcfd	3 Bcfd

If the resource portfolio relies on more natural gas, then our ability to provide electricity is at risk when natural gas supply is disrupted. Other fuels do not appear to impose this risk.[114] Yet in the 2005 hurricane incident what also happened is that electricity and natural gas demand declined. Comparing natural gas demand to natural gas production using monthly data (daily data is not publicly available) in Figure 19 shows that demand actually dropped by more than the supply lost such that there was little net negative impact beyond the price volatility.

[112] 1 Tcf in a 23 Tcf annual market is 4.35% of the market and somewhere between one-quarter to one-third of the quantity the industry likes to see in storage inventory at the start of each winter.
[113] The platforms destroyed or damaged apply to both Ike and Gustav together. EIA reported the platforms damaged and destroyed for hurricanes Gustav and Ike on a combined basis likely because damage assessments for Gustav were still underway when Ike arrived.
[114] In fact, coal is delivered in advance to most electric power plants such that they maintain a 30-day or more average supply on site. Single facility natural gas storage has not proven itself cost-effective.

Figure 18: Hurricane Impact on Production



Source: U.S. Department of Energy, "Impact of the 2005 Hurricanes."

But that is not the end of the story. The lack of recorded demand in the EIA data may be not because there was no "demand," but because there was no "consumption" as the hurricane completely disrupted normal life. In other words, the recorded consumption data does not capture demand that would have been served absent the disruption. Florida issued an emergency order allowing gas-fired plants with alternate fuel capability to burn those fuels even if it violated their air permits; South Carolina curtailed some interruptible customers with alternate fuel capability and allowed its pipeline to purchase higher-priced replacement gas for customers who wished it to do so.[115] Yet our search has returned no other published reports of gas service being curtailed.

To the contrary, post-hurricane review reports make no mention of consumer curtailments associated with shut-in Gulf production.[116] Even the Situation Reports published each day for some months after

[115] Florida Department of Environmental Protection, "Emergency Authorization for Deviation From Permit and Certification Requirements at Power Plant Facilities Made Necessary by Hurricane Katrina," OGC No. 05-2068, September 1, 2005; and Public Service Commission of South Carolina, Docket N0. 2005-261-G, Order No. 2005-483, September 8, 2005. Florida has long been gas constrained such that power plants there have alternate fuel capability; the gas-fired "merchant" fleet constructed elsewhere, however, generally does not have alternate fuel capability except in specific instances where lenders required it due to insufficient local natural gas access.

[116] See, for example, Department of Energy, "Impact of the 2005 Hurricanes" found at: http://www.fossil.energy.gov/programs/oilgas/publications/naturalgas_general/hurricane_report05.pdf, or Energy and Environmental Analysis, "Hurricane Damage to Natural Gas Infrastructure and its Impact on the U.S. Natural Gas Market," sponsored by The Energy Foundation, found at: http://www.ef.org/documents/hurricanereport_final.pdf

the hurricanes noted which pipelines were experiencing interruptions, the number of electricity customers still without power, and which refineries were and were not able to operate, but none of them mention customers without natural gas other than with respect to Entergy in flooded-out New Orleans.[117] Perhaps remarkably, the largest interruption to Gulf Coast production likely to occur appears to have not resulted in disruption to natural gas deliveries.

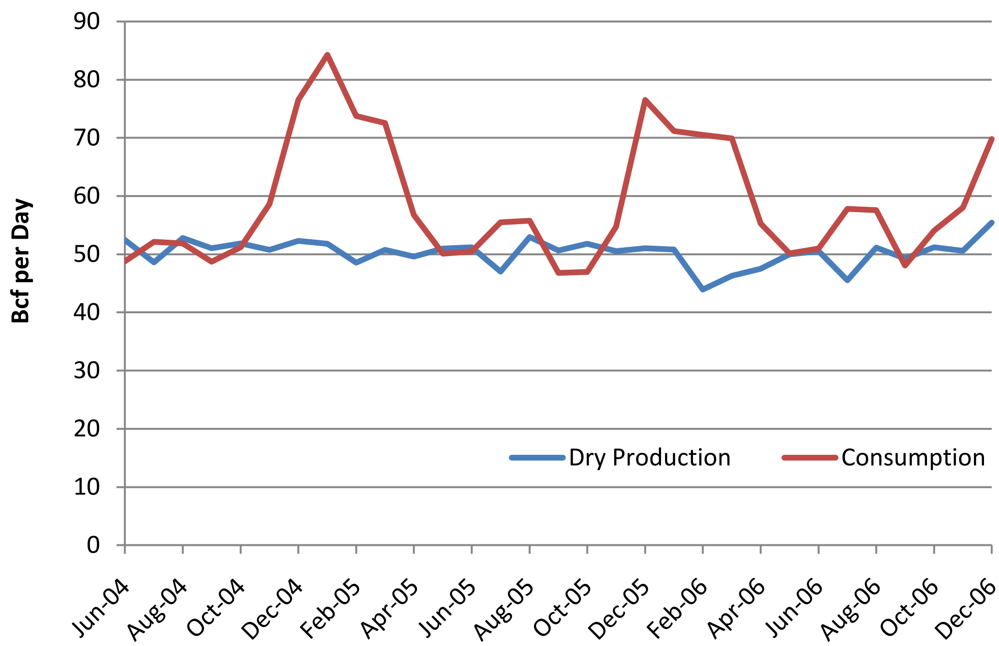
NISAC's conclusion that hurricanes pose little risk to end-user natural gas deliveries does not consider the impacts should we switch existing coal to gas or the specific locations of new gas-fired power plants relative to the specific pipeline receipt and deliver points that could be affected.

The National Infrastructure Simulation and Analysis Center (NISAC) at Sandia National Laboratory also has done an analysis of access to natural gas after a major hurricane. The Sandia analysis concluded that enough natural gas was available from storage to offset production limitations post-hurricane. It notes further that "what happened in the aftermath of Hurricanes Katrina and Rita there was relatively little disruption to the current consumption of natural gas, but that shut-in offshore wells means that gas was not being produced and [thus not] put into storage."[118] Were coal-fired plants switched to natural gas, some of those plants would likely be located in areas in which natural gas was unavailable after the hurricane. (Figure 5 shows several plants located along the coast between New Orleans and Pensacola, for example.) For this reason, NISAC should conduct a more detailed analysis in which it looks at precise receipt and delivery points at which gas might or might not be available relative to utility citygates and potential coal-fired power plants and determine which are upstream versus downstream of storage in order complete its findings.

[117] Electricity was disrupted due to some plant damage but mostly due to substation and line damage. Refineries had to wait for electricity to operate. Some disruption to gasoline supplies occurred as the refineries assessed damage, made repairs and waited for electricity to operate the key petroleum products pipelines used to deliver product from refineries to local market tank farms. These disruptions were not a function of lack of access to natural gas.

[118] Ellison, J. "Modeling the U.S. Natural Gas Network," Sandia National Laboratories Critical Infrastructure Modeling and Simulation Group. Found at: http://www.sandia.gov/nisac/docs/IERC06JEa.pdf

Figure 19: Katrina and Rita Impact on Monthly Natural Gas Production and Demand

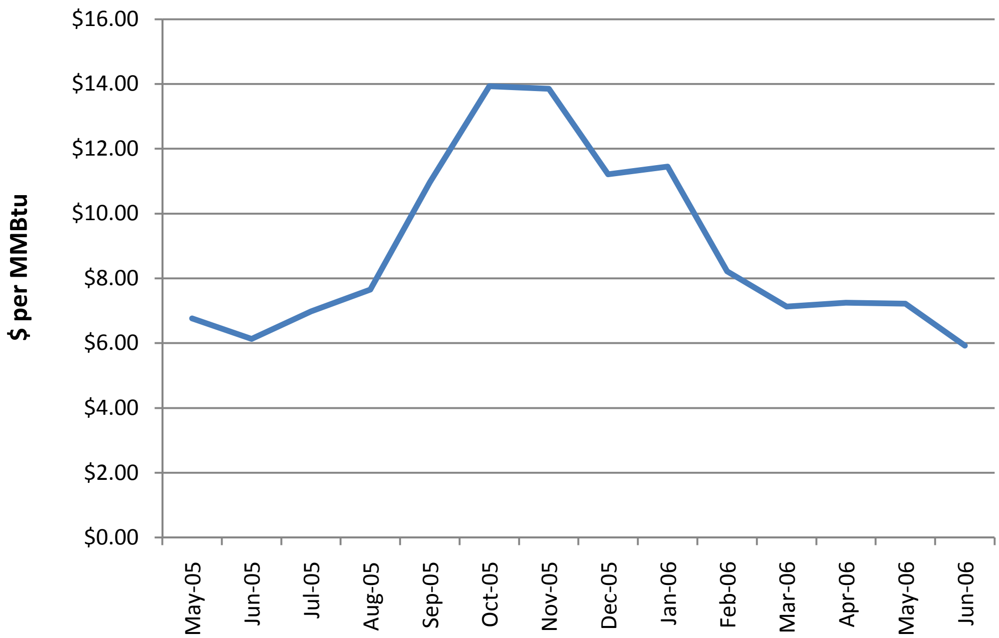


Source: EIA, *Natural Gas Monthly*

While there is a somewhat surprising lack of evidence of even local utility curtailments after Katrina and Rita (likely owing to the natural gas system's flexibility and redundancy along the Gulf Coast as visible in Figure 11) an additional note is worth making: winter 2005-2006 was extraordinarily warm– "the winter that never was." Had cold weather occurred or occurred early (the natural gas market tends to react more strongly in the early part of the season), the reduced storage inventories might well have caused curtailments to utilities in the Northeast, Midwest, and mid-Atlantic. FERC staff's 2005 – 2006 winter assessment worried about how tight supply could magnify price effects.[119] Spot prices stayed above $10 per MMBtu until well into the winter based on fear that cold weather would prove too much for fragile supply to withstand. As shown in Figure 20, by Bidweek ending January 2006 the market recognized that temperature conditions to date had left enough gas in storage to get through any lingering cold and prices finally fell below double digits; by the summer of 2006, prices were back to their pre-hurricane levels. Without that warm weather, we undoubtedly would have a very different view of the industry's ability to withstand the kind of damage caused by Katrina and Rita. Should electric utilities replace coal-fired generation with natural gas, they will not want to rely on warm weather providing a silver bullet should major storms cause damage that reduce production and prevent filling of natural gas storage.

[119] October 20, 2005 Winter Energy Market Assessment, Found at: http://www.ferc.gov/market-oversight/mkt-views/2005/10-20-05.pdf.

Figure 20: Katrina and Rita Impact on Natural Gas Prices



Source: Monthly NYMEX Closing prices Compiled from Variety of Published Sources including Wall Street Journal and Bloomberg

The ability to get natural gas to specific locations after strong hurricanes requires further study, particularly if coal-fired generation has to switch to natural gas.

Based on the evidence, the major impact borne by natural gas users as a result of Gulf coast storms appears to be a price impact – an impact that would be felt more severely as the proportion of electricity generated with natural gas increases. The severe supply disruption after Katrina and Rita did not result in a broad inability to obtain natural gas. Whether this result would obtain in a market half again or nearly twice as large (as might occur if coal-fired plants switched to gas) is unclear. Moreover, whether deliveries to specific the locations of those plants could be maintained is also unclear. The ability to get natural gas to specific locations after strong hurricanes requires further study, particularly if coal-fired generation switches to natural gas.[120]

[120] Some readers may wonder if the six-month drilling moratorium on OCS deepwater drilling related to the Deepwater Horizon accident will have an impact on production. It should not reduce current production because it affects only the drilling of the well prior to production. "Workover" drilling is still permitted. A workover is drilling done to an existing well to enhance production or fix a problem in an otherwise producing well rather than a new well. The drilling moratorium applies to only 33 rigs.

Staff Expansion

Some electric utilities burn natural gas today to generate electricity. Many, however, do not burn natural gas to generate electricity or burn a relatively small quantity, meaning they don't have in-house expertise in natural gas operations, regulatory issues or markets. Coal, for example, is typically purchased under long-term contracts in a market in which prices are stable. Gas isn't. Even those utilities that today burn gas are likely to find their staff facing expanded responsibilities as they scale up their operations. The new or expanded activities an electric utility would likely face include:

- Monitor Market Conditions
- Assess Gas Requirements and Plan Operations to Minimize Electricity Cost/Maximize Reliability
- Purchase Natural Gas, Transportation and Storage
- Submit Daily Gas Nominations and Manage Imbalances
- Manage Risk (i.e., hedge)
- Monitor and Participate in Regulatory Cases Related to Natural Gas
- Manage Contract Execution, Accounting and Settlement

To some degree utilities may rely on joint action agencies or contract out for certain services. For a relatively small utility, it probably takes three people to conduct these activities. Costs for a staff that size, including salaries, benefits and overhead, might amount to $1 million per year. For a bigger utility it would take more. Professional fuel managers might contract to manage fuel for a power project often charge 1 to 5 cents per MMBtu. They wouldn't cover quite the full range of services listed above; their offering is more the daily nomination and imbalance effort. Using that 1 to 5 cents per MMBtu as a starting point proxy for the cost electric generators might face to manage their gas supply, for a 14 Tcf incremental gas burn, works out a range of $140 million to $700 million per year. Over twenty years and allowing for a ramp up over the first five years yields an estimated gas management cost of $2.5 to $12.6 billion cumulatively; somewhere past the mid-point of that range is $8 billion.

Summary Observations Related to Operational Considerations

1. The Gas Day does not link up well with the Electricity Day, meaning that gas nominations have to be submitted many hours before electric dispatch decisions are made.
2. Even relatively slight changes in temperature and humidity conditions can cause a gas nomination that was "right" when made to end up causing an imbalance anyway.
3. Some pipelines have "no bump" rules that mean a firm shipper who doesn't nominate to use all of its available capacity can effectively lose it if an interruptible shipper in the same nomination window requests it.
4. Ontario's NGEIR proceeding resulted in the creation of innovative services to make it easier for electric generators to match their gas nominations with their use.
5. Pipeline balancing provisions vary considerably pipe-to-pipe.
6. State rules determining priority of service if there is not enough gas supply are all over the map but generally preserve service to residences first.
7. Not all LDC tariffs include priority of service rules.
8. As of 2005, very few states had looked at the impact to electricity generation from a natural gas curtailment, but many state commissions knew that generators tend to not hold firm interstate pipeline capacity.
9. Roughly 10 states said they require electric generators who subscribe to interruptible LDC service to have alternate fuel back-up capability.
10. Greater reliance on natural gas to generate electricity means states need to revisit their curtailment rules and utilities will need to revisit their pipeline MDQs.
11. Strong hurricanes that cause damage to above-ground and sub-sea gas facilities in the Gulf can shut-in as much as 20% of U.S. gas supply.
12. The severe natural gas supply disruption after Katrina and Rita did not result in a broad inability by consumers to obtain natural gas but it significantly increased prices and impeded the ability to fill storage in advance of winter. The ability to get natural gas after strong hurricanes requires further study, particularly if coal-fired generation is switched to natural gas.
13. Electric utilities will need to expand or create gas savvy staffs that can plan and manage all of the activities associated with burning natural gas to generate electricity.
14. Electric utilities will not want to rely on warm weather providing a silver bullet should hurricanes or other storms cause damage that reduce production and prevent filling of natural gas storage.

Retrofitting Coal Plants to Burn Natural Gas

The electricity industry can theoretically switch to natural gas by either retrofitting existing coal-fired units to burn natural gas or by closing the coal plants and replacing them with new gas-fired plants. Our research uncovers no instances of coal plant retrofits to natural gas (we did find some references to retrofits to allow firing of biomass converted to charcoal-like pellets). One can find headlines and press reports about "switching" or "converting" to natural gas but upon reading closely it becomes clear that the conversion will in fact be implemented by replacing the coal-fired unit and not by retrofitting it.

Legislatures in Minnesota and Colorado, for example, are reported to have either passed or are considering bills supporting conversion of coal-fired units to natural gas. The Minnesota legislature, in 2001, passed a bill providing that any utility that "converted" from coal to gas could pass the costs through to ratepayers without review of the proposed rate change.[121] Xcel Energy subsequently proposed spending $1 billion to "convert" some plants to gas. What Xcel actually did was build 1100 MW of new combined cycle gas-fired generation at the sites of existing coal-fired plants located in Minneapolis and Saint Paul.[122] Colorado has a similar bill before its legislature this year supporting so-called conversion but reviewing the details reveals that the plants Xcel owns there would likely either be retrofit to burn biomass or be replaced with natural gas combined cycle units. Even the Minnesota Public Utilities Commission decision approving the Xcel investment referred to the change as a "conversion" before proceeding to explain that the coal unit would be replaced by a new gas unit. In short, the idea of retrofitting or converting a coal-fired plant to burn natural gas is a misnomer; proposals to convert are nearly always plans to completely replace the coal-fired generation with a new gas-fired unit at the same location.

The idea of retrofitting or repowering coal-fired plants to burn gas turns out to be a misnomer. Retrofitting or converting coal-fired generation to gas may be technically feasible, but most conversions are accomplished by replacing the coal unit with a completely new gas-fired unit at the same site.

In 2008, the Government Accountability Office (GAO) delivered a report looking at the economics of converting the U.S. Capitol complex from coal to natural gas and discussing various aspects of doing so

[121] Minnesota Statutes § 216B.1692. The Minnesota Pollution Control Agency's report to the Minnesota Public Utilities Commission can be found at: http://www.pca.state.mn.us/publications/reports/xcelenergy-metroemissionproposal.pdf.

[122] These were the High Bridge and Riverside plants. The Riverside "Repowering Project" consisted of retiring three existing coal burning boilers and repowering steam turbine 7 by adding two gas-fired combustion turbines (CTs) each with a heat recovery steam generator (HRSG). The new CTs and HRSGs were constructed where the original Riverside Units 1-5 once stood. At High Bridge, Xcel demolished the coal plant, removing boilers, turbine-generators and auxiliary systems including buildings and foundations and termination of all linear facilities but retained the existing water supply and return from the river.

for the country as a whole.[123] The GAO reported that not only is switching all coal-fired generation to gas infeasible because insufficient natural gas supply and the impracticality of adding the additional gas industry infrastructure required to do so but that retrofits of existing coal-fired plants to allow them to burn gas made no sense: "it would be more feasible and cost-effective to construct new natural gas units or to dispatch excess capacity at existing natural gas units than to convert a coal plant because of technical and economic factors, among other reasons."[124] GAO further stated that the switching from coal to gas that has been done has not been done via retrofits but by building new gas-fired plants.[125]

A study performed in 2000 by the Interlaboratory Working Group on Energy-Efficient and Clean-Energy Technologies for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy considered the economics of retrofitting coal-fired generation to burn gas versus greenfield NGCC construction. It found the "all-in" cost from the repowered unit to be between a half-cent per kWh to one cent per kWh, depending on the unit's capacity factor. It concluded: "[g]iven the other uncertainties in repowering a plant this cost differential is not sufficient to choose repowering over greenfield."[126]

In terms of retrofitting specifics, the boilers designed to burn coal are different from the ones designed to burn gas. Retrofitting would involve installing a new combustion system and a new heating surface. Due to these changes, the retrofitted unit would operate at a lower rate of efficiency, which GAO cites as 10 to 12 %.[127] Some other pieces of the coal-fired station could potentially be re-used, subject to an engineering review of their operating condition, in either a retrofit or a new combined cycle replacement. These include:

a) the existing steam cooling infrastructure;
b) the existing linear structures to the site such as for water, sewer and transmission, although new interconnections would need to be made within the site;
c) the existing administrative and control buildings including phone and internet access (but the main computer control systems (including SCADA) would likely be replaced if not updated recently and would have to be revised to match the new unit);
d) the existing road access and security infrastructure;
e) the existing safety/emergency infrastructure consisting of fire water tanks, emergency generators and fire pump engines;
f) the existing onsite switchyard or substation; and potentially
g) the existing emission stack(s), unless it has to be replaced to meet the new EPA NOx hourly NAAQS.

[123] GAO, "Implications of Switching from Coal to Natural Gas," GAO-08-601R, May 1, 2008. Found at: http://www.gao.gov/new.items/d08601r.pdf
[124] GAO, op. cit., pp. 5 – 6.
[125] GAO, op. cit., p. 16
[126] Interlaboratory Working Group, "Scenarios for a Clean Energy Future," Oak Ridge National Laboratory and Lawrence Berkeley National Laboratory, ORNL/CON-476 and LBNL-44029, November 2000, p. E-7.4.
[127] GAO, op. cit., p. 15

Another potential obstacle to retrofitting existing coal units to burn gas, as pointed out in the GAO study, is that some coal-fired units are essential to local reliability and reserve margins. They cannot be taken out of service for the four to six months required to do the retrofits as doing so would leave certain geographic areas with insufficient system reserves, leading to brownouts or blackouts. GAO did not identify what those locations are but further study to identify them would likely be useful.

In terms of economics, the installed cost for a new combined-cycle gas-fired unit of 1000 MW is the range of $1 Billion, or roughly $1 million per MW.[128] Accordingly, the estimated first order cost to replace the existing 335,000 MW worth of coal-fired generation in the U.S. is roughly $335 Billion—for the power plant only. In other words, the cost of the additional natural gas infrastructure such as long distance transmission pipelines and storage that this study has discussed that would be needed to serve massive replacement of coal-fired generation with natural gas would be on top of the construction cost for the plant itself. This figure also does not include any environmental remediation or plant decommissioning costs (or savings) for the coal-fired unit being replaced; there may also be SOx or NOx or carbon credit values or lower water costs to take into account. The $1 million per MW would, however, include the cost to construct short service laterals to a high pressure gas transmission mainline assumed to be nearby.[129] Locating replacement natural gas plants at the site of the existing coal-fired generation makes the most sense since the site would already have transmission to deliver its generated energy into the power grid. It would also have access to water and a rail line (the rail line right-of-way could well be used to locate the bigger lateral pipeline that will be required to deliver gas to the site).

The installed cost to replace the existing coal-fired fleet is approximately $335 Billion – before adding the new gas infrastructure or paying for the annual services needed to support those plants.

The cost estimate above does not include that outstanding debt service on existing coal units that would need to continue to be paid or recovery of investment from ratepayers in coal-fired facilities done on utility balance sheets that may remain to be recovered. Many utilities have outstanding debt or unrecovered costs for coal-fired units that may have been built years ago. Power plants, regardless of whether they belong to an investor-owned utility, a municipal utility or an electric co-operative, are routinely financed over 20- or 30-year periods.[130] Based on data reported to EIA, about 30% of the U.S. coal-fired fleet is 30 or fewer years old. Other plants have made retrofits for pollution control technology that may have been financed. To the extent that utilities have outstanding debt service

[128] EIA used in its *AEO 2010* an "overnight" installed cost for natural gas combined cycle plants of $984 per kW, in $2008. See Table 8.2, "Assumptions to the Annual Energy Outlook 2010." Found at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3

[129] Most gas-fired power plant construction estimates include the cost of a short service lateral out to a mainline as part of the capital cost. If the service lateral were longer or if a compressor were needed to bump the pressure up for the gas turbine or if no high pressure transmission mainline were nearby, then the capital costs would increase further. Note that this estimate does NOT include the annual fixed costs to reserve interstate pipeline capacity, LDC capacity, storage service, or the cost of increased personnel or services to manage all of the above.

[130] Some utilities might pay off the debt on their plants more quickly than 20- to 30-years, but there are also examples of plants being refinanced past that timeframe, including instances when the utility may have invested in control technology for one pollutant or another and financed that cost.

obligations, they are not simply a "sunk" cost but must be paid in current time from utility cash flow. The need to complete paying off this debt and the impact on utility cash flow is rarely highlighted but needs to be recognized as part of the cost of potentially replacing the coal-fired fleet. Moreover, the first order estimate above further assumes that only the existing fleet is "converted;" it does not include the cost of power plants that must be built to meet future load.

Modifying the coal plant to burn gas or building a new gas-fired unit will also require new or revised permits in the areas of air, water, and waste. According to internal Aspen staff and outside experts, challenges in getting those permits will be site-specific and depend on the scope of changes made at the project site.

With respect to solid waste, retirement of a coal plant would not impose any federal requirements today unless environmental contamination subject to the Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) were present. States may have solid waste permits or regulatory requirements, however. The coal ash rule recently proposed by EPA, however, may add a new obligation to obtain a Resource Conservation and Recovery Act permit to close the on-site ash management unit and trigger facility-wide corrective action to remediate any solid waste contamination within the facility fence line. Note that building a new NGCC at the site does not necessarily require retirement and abandonment of the existing coal-fired unit; the plant could instead be closed and allowed to stand for some period of time.

Revised or new water permits will depend on whether the physical changes to the facility are sufficiently wholesale that the facility is deemed to create a "new source" of wastewater or a "new facility" for the intake cooling water. This could occur with respect to waste water effluent, if, for example, the site uses a waterbody that has been listed as impaired for one or pollutants discharged by a "new source." Alternatively, if the cooling water intake structure has to be changed significantly such as to limit the design velocity through the intake screens or the proportion of the source waterbody that may be withdrawn, those changes could be enough to create a "new facility." EPA also has rules that would limit flows at "new facilities" to levels consistent with wet re-circulating cooling.

Air permits for a natural gas-fired facility under existing regulation are well-known to be easier to obtain than for a coal-fired unit. $SO_{2,}$ as one example, is little problem for gas-fired power plants because most sulfur is removed from natural gas in a processing plant relatively near the wellhead. Yet there are at least three air permit issues that mean converting to natural gas a) may not be as simple as it appears, and b) that create additional costs not included in the $335 billion NGCC construction cost estimate presented herein that should be recognized nonetheless.

First, consider particulate matter (PM). To the extent that the size of the new gas-fired unit is larger than the coal-fired unit that it replaces or that it operates in more hours, particulate emissions may be higher than for the coal-fired unit the gas unit replaces. Standards for PM2.5 have become increasingly stringent, forcing more parts of the U.S. into nonattainment, which triggers more-stringent permitting requirements, like offsets. Controlling NOx with the selective catalytic reduction introduces ammonia emissions, which may be subject to limits or monitoring, because ammonia is a primary component in forming PM2.5 as ammonium sulfate and ammonium nitrate particles. Achieving accurate and reliable PM data during emissions monitoring and stack testing is also a challenge. The unit facing these issues would then incur additional costs to achieve PM compliance.

Second, EPA finalized a new National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO_2). The rule created a new 1-hour standard for ambient NO_2 at 100 parts per billion.[131] The concern is that NGCCs may be compliant independent of current background emissions, but the background ambient NO_2 levels will be determined by monitors placed near highways. This will force urban areas into nonattainment and trigger more stringent permitting requirements for NGCCs. EPA's list of counties that would be in nonattainment (found at: http://www.epa.gov/air/nitrogenoxides/actions.html) is conservative as the rule requires the new dispersion monitors to be placed in more counties where monitors do not exist and near highways where NO_2 emissions would be higher. Alternatively, if the NGCC is sited in an NO_2 nonattainment county, emission offsets and/or use of some sort of control equipment not currently envisioned or higher stack may be needed. Those costs are not included in this study's estimates of the cost to replace coal-fired generation with new natural gas combined-cycle units. Figure 21 illustrates the potential configuration of an NGCC relative to property lines, a highway and dispersion model receptor grid under the proposed 1-hour NOx standard.

Third, is the great unknown of how CO_2 will be regulated and what CO_2 emissions standard could apply. As long as the Clean Air Act regulates CO_2 and GHGs, Best Available Control Technology (BACT) requirements at power plants will force some type of controls on CO_2 emissions. The EPA PSD "Tailoring Rule" (May 2010) did not alleviate this regulatory requirement for fossil-fuel fired utilities. Also, combustion of natural gas emits only half as much CO_2 as coal, but if those emissions are regulated plant by plant (instead of by utility portfolio), it is unclear whether CO_2 control would occur under New Source Performance Standards (NSPS) or BACT. Utilities today don't know if that will include some type of emissions or performance standard potentially set near or below the emissions of an NGCC or a requirement that can only be met with geologic sequestration (assuming geologic sequestration is demonstrated to be commercially feasible and deployable) or something else. That cost of compliance is also currently unknown for geologic sequestration at coal plants <u>or</u> natural gas plants.

Another issue just emerging now is potential regulation of hydrochloric acid (HCl). EPA currently plans to regulate HCl from smaller combustion units under the Industrial and Commercial Boiler Maximum Available Control Technology (MACT) requirement. EPA has not proposed any HCl limit for utilities burning natural gas; however, the proposal for the smaller combustion units leaves utilities reluctant to assume that they will not eventually have to add equipment for HCl MACT, notwithstanding being unsure what that equipment would be or what MACT for HCl even means. The point is that some expectation should be made for future compliance obligations.

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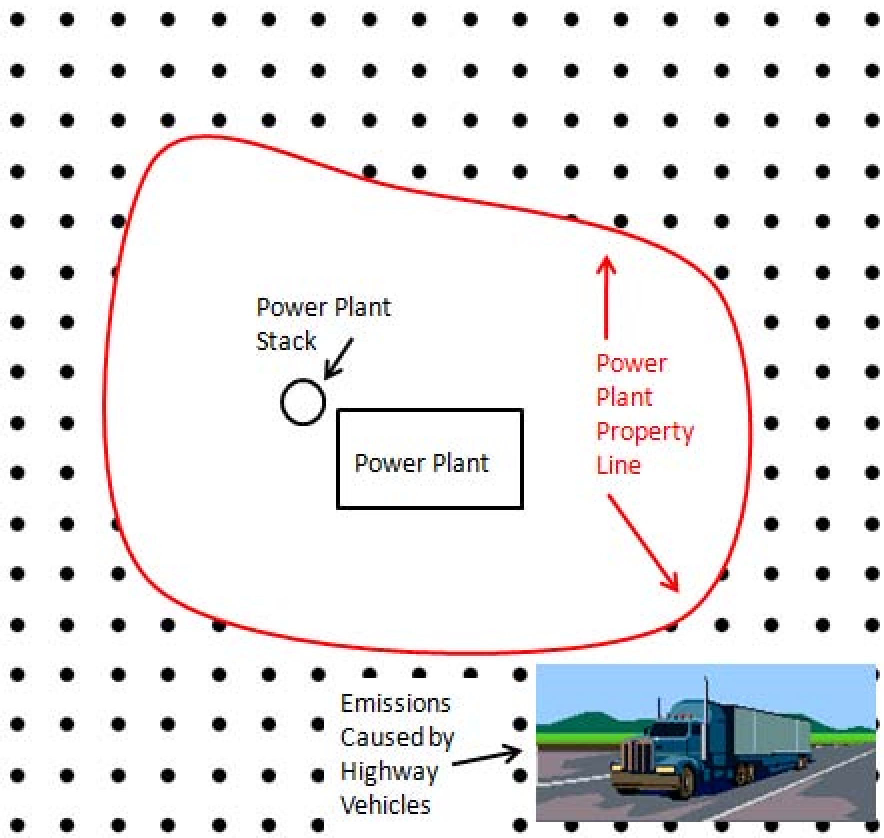
[131] See Docket ID: EPA-HQ-OAR-2006-922. INGAA filed written comments that the one-hour standard "could require emissions levels beyond the capability of current control technologies."

Figure 21: Dispersion Model Receptor Grid Used for Proposed EPA 1-hour NOx NAAQS



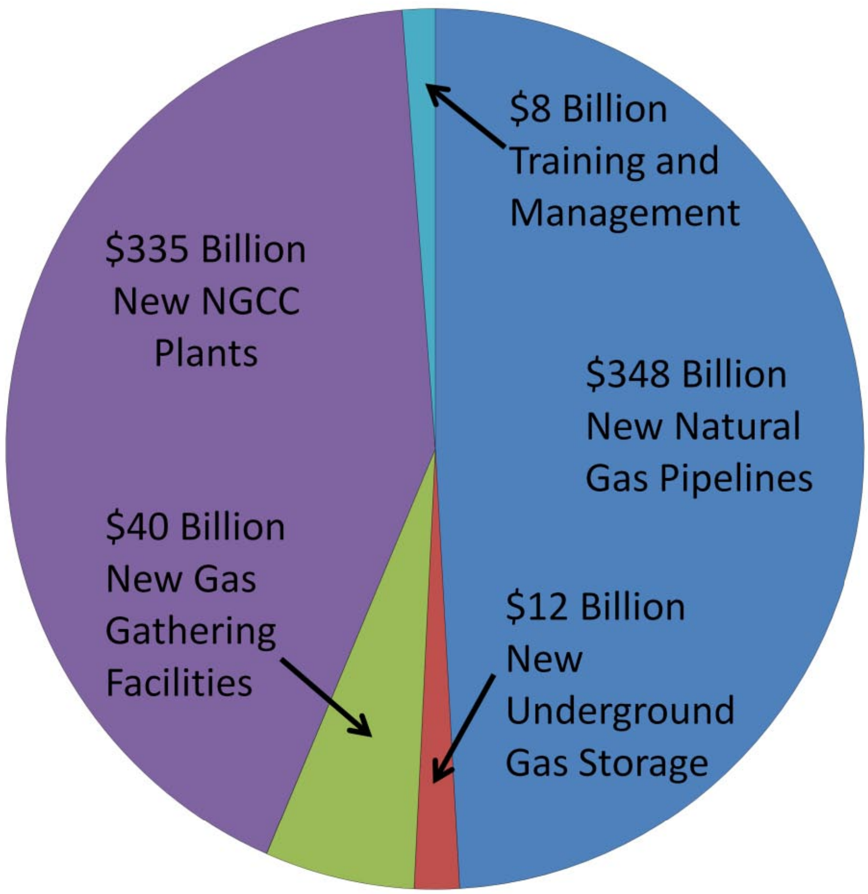
Conclusion

The purpose of this study is to inform current and future users of natural gas and policy makers what to expect should much greater reliance on natural gas to generate electricity become a reality. This could happen if Congress enacts new laws or EPA adopts new rules to regulate greenhouse gas emissions. In addition, the costs to comply with other regulations (shown in Figure 4) EPA may adopt to reduce levels of other pollutants from electricity generating sources is already pushing many electric utilities to consider switching to natural gas. In this study, Aspen evaluated the projected quantity of gas that could need to be burned by electric generators under several potential scenarios. Aspen also identified the operational issues and natural gas infrastructure investment that would be required to support much higher gas burns.

Comparing and contrasting the projected gas burns from those studies that have evaluated potential economy-wide cap and trade programs to reduce greenhouse gas emissions is informative. Some of the studies assume geologic CCS will be available; some not. Some add nuclear generation; some don't. Most increase Renewables in the resource mix but it becomes clear that even at 20% Renewables and low load growth (as in Duke CCPP, for example), no new nuclear power leaves only CCS and low load growth as the tools to reduce carbon emissions. The comparison highlights the fact that the resource mix assumptions made in these studies with respect to load growth, nuclear generation, CCS, Renewables and access to offsets – assumptions that may not be achievable – drive the resulting natural gas burn. Aspen's own analysis developing additional scenarios suggests a need to burn roughly twice as much natural gas as today if carbon emissions were regulated. And if regulation of carbon and other pollutants lead electric utilities to switch potentially all existing coal-fired generation to gas, then the additional gas burn also ends up close to 14 Tcf, or roughly double today's 6.9 Tcf. The new gas burn plus that plus burned by existing gas-fired resources would cause virtually as much natural gas as is burned today in the entire economy to be used for electricity generation alone. In some states the current amount of natural gas consumed would be double or triple the amount delivered to that state today.

The need for additional natural gas infrastructure to deliver that higher quantity of natural gas is addressed in a recent comprehensive study by ICF for the INGAA Foundation. The INGAA study found a need for $108 billion worth of new pipeline capacity even if demand for natural gas declined owing to the fact that new supply would come from new basins needing new inter-regional delivery capability. That study's Base Case projected $129 billion. Scaling up to replace all existing coal-fired plants implies a need to build more than 70 Bcf per day of new delivery capability costing $348 billion. Additional storage would be necessary, too, costing perhaps $12.5 billion. Gathering and processing facilities of another roughly $40 billion would also be necessary.

Figure 22: Total Cost to Implement Switch from Coal to Natural Gas



Source: Compiled by Aspen

The capital cost to replace the 335,000 MW of existing coal-fired units with new combined-cycle gas-fired units amounts to $335 billion. This cost plus the natural gas infrastructure improvements combines to total over $700 billion should natural gas need to fully displace coal-fired generation, the breakdown of which is shown graphically in Figure 22. Costs of this magnitude suggest that natural gas must be more than a bridge fuel because utilities are not likely to invest in and financial institutions are not likely to finance this magnitude of investment other than on a long-term basis. Moreover, some debt service on plants less than 30 years old (representing 30% of the existing coal-fired fleet) likely remains outstanding. Utilities must make these payments out of current cash flow; estimates of these costs as well as costs for the new NGCCs to comply with additional emissions regulation should be included in the total cost to switch from coal to natural gas.

Electric utilities that today may not have gas-fired resources in their resource mixes will have a lot to adjust to as they switch to gas, or, similar to Ontario, will need help convincing the natural gas industry to adjust its policies as more natural gas is used to generate electricity. Many pipelines do not offer services customized to serve electric generators whose usage changes more frequently than pipelines prefer. New services will need to be developed and the two industries will need to become much more aligned in their common practices. In addition, states will likely need to review their curtailment policies and think about how gas-fired electricity generation fits into a priority of service order so that electricity generated with so much natural gas does not become less reliable.