Modeling the US Natural Gas Network

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Abstract

In order to better understand how the US natural gas network might respond to disruptions, a model was created that represents the network on a regional basis. Natural gas storage for each region is represented as a stock. Transmission between each region is represented as a flow, as is natural gas production, importation, and consumption. Various disruption scenarios were run to test the robustness of the network. The system as modeled proved robust to a variety of disruption scenarios. However, a weakness of the system is that production shortfalls or interruptions cannot be replaced, and demand must therefore be reduced by the amount of the shortfall.

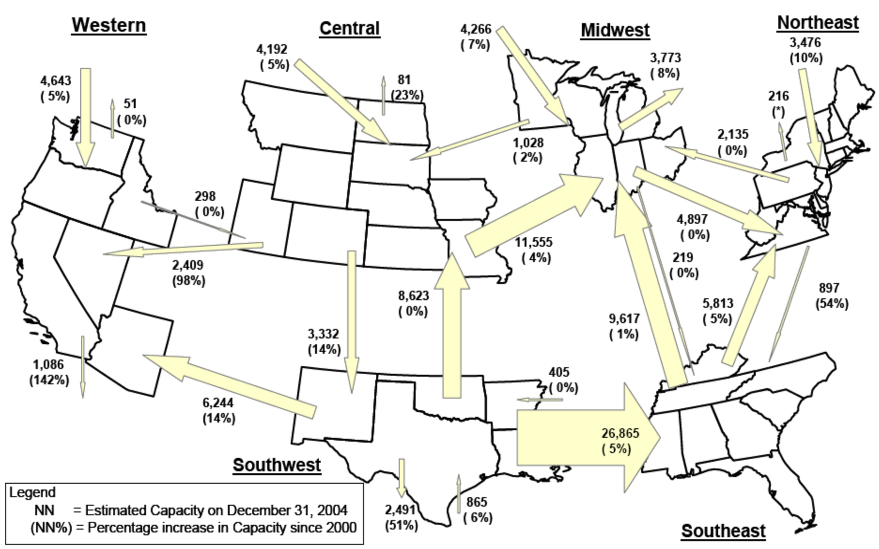
Keywords: natural gas network, disruption analysis, system dynamics

Introduction

The main area of interest in this study is how robust the natural gas system is when faced with disruptions of transmission or disruptions of supply. In order to examine the ability of the system to handle disruptions in more detail, it is helpful to build a model of the infrastructure and test it against various crisis scenarios.

The model is of a stock-and-flow type, which looks at a system as flows between a series of stocks. It has been shown that stock-and-flow models can provide valuable system and public policy insight.[1] In this case, the flows are gas flowing between regions – and the stocks are gas stored in each region.

A regional approach was taken here because the primary interest is in understanding the system on a national level, and understanding what kind of regional or system-wide impact various crisis scenarios have. This model will not be useful in understanding flows or various scenarios within a region, as the region is the smallest unit of representation. Below is the regional map and maximum capacities used by the US Energy Information Administration (EIA), which is the same used by this model. (The arrows are proportional to transmission capacity, and all volumes are in millions of cubic feet per day).



• Export capacity was not in place in 2000.
Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Pipeline Capacity Database.

Natural Gas – Background and Importance

Natural gas is almost completely comprised of methane (CH_4), and is gaseous at ambient temperatures. It burns much cleaner than any other fossil fuel, and is less carbon intensive – meaning that less CO_2 is produced burning natural gas than burning oil products or coal.

Given that natural gas provides about 25% of the total energy consumed in the US[2], it is important to insure that the infrastructure remains as robust and reliable as possible. Moreover, 57% of the US' 110m households use natural gas for heating.[3] And the fact that natural gas currently provides 17% of US electricity generation[4], and that combined cycle gas turbines (CCGTs) are expected to provide the majority of power plant capacity additions for the next ten years, makes this sector especially worthy of attention. Many CCGTs do not have alternate fuel backup, and environmental regulations frequently prohibit extended use of alternative fuels, such as fuel oil.

With the largest demand in the world for energy, and only 2% of the world's oil reserves and 3% of the world's natural gas reserves, the US has little hope of achieving "energy independence" with fossil fuels. The most logical alternative is to diversify our energy sources. A robust natural gas network is essential to a diversified energy mix.

Infrastructure Overview

The US natural gas pipeline network was designed primarily to transport gas from the producing Southwest to the consuming Northeast and Midwest. The largest capacity pipeline route is from Gulf Coast production (onshore Louisiana and Texas, as well as offshore Gulf of Mexico) to the Midwest and Northeast.

The Western part of the country uses much less gas than does the East. It is served, however, by multiple sources – namely, by pipelines from the Southwest (connecting into Southern California), pipelines from Canada, and pipelines from the Rocky Mountain gas fields.

Pipelines from gas-producing western Canada connect to the Northwestern, Central, Midwestern, and Northeastern parts of the US. A small amount of gas is exported to Mexico. There are four existing LNG (liquefied natural gas) import terminals currently in the US. Their overall baseload capacity is about 850 Bcf/year, or 2.4 Bcf/day.[5] This translates to about 4% of average daily demand. In addition, underground storage facilities, located mainly in the Southwest, Northeast, and Midwest, support demand seasonality.

Model Calibration and Logic

The model was calibrated to represent the actual system in the following ways:

a) capacities of the connections between regions were taken from EIA region-to-region data;
b) average annual consumption of each region was derived from EIA 2004 consumption data;
c) storage capacities of each region were derived from EIA storage capacity data;
d) seasonality of demand for each region was estimated by combining the seasonal consumption patterns of the four major groups of consumers (residential, commercial, industrial, and power generation), and the percent of total consumption by each of the consumer groups in each region. This information was derived from EIA data;
e) annual consumption was estimated at 22 Tcf, which results in a 60 Bcf/day annual average – slightly less than the 2004 actual consumption of 22.4 Tcf. This was done to simplify the data, as a 0.4 Tcf difference is not material;
f) domestic production was estimated to be 19 Tcf /year (or 52 Bcf/day), and imports were estimated to be 3 Tcf/year (or 8 Bcf/day); and
g) domestic production is concentrated in the Southwest, the Gulf of Mexico, and the Central region (Rocky Mountain States). This is a simplification, as in reality the Midwest, Northeast, Southeast,

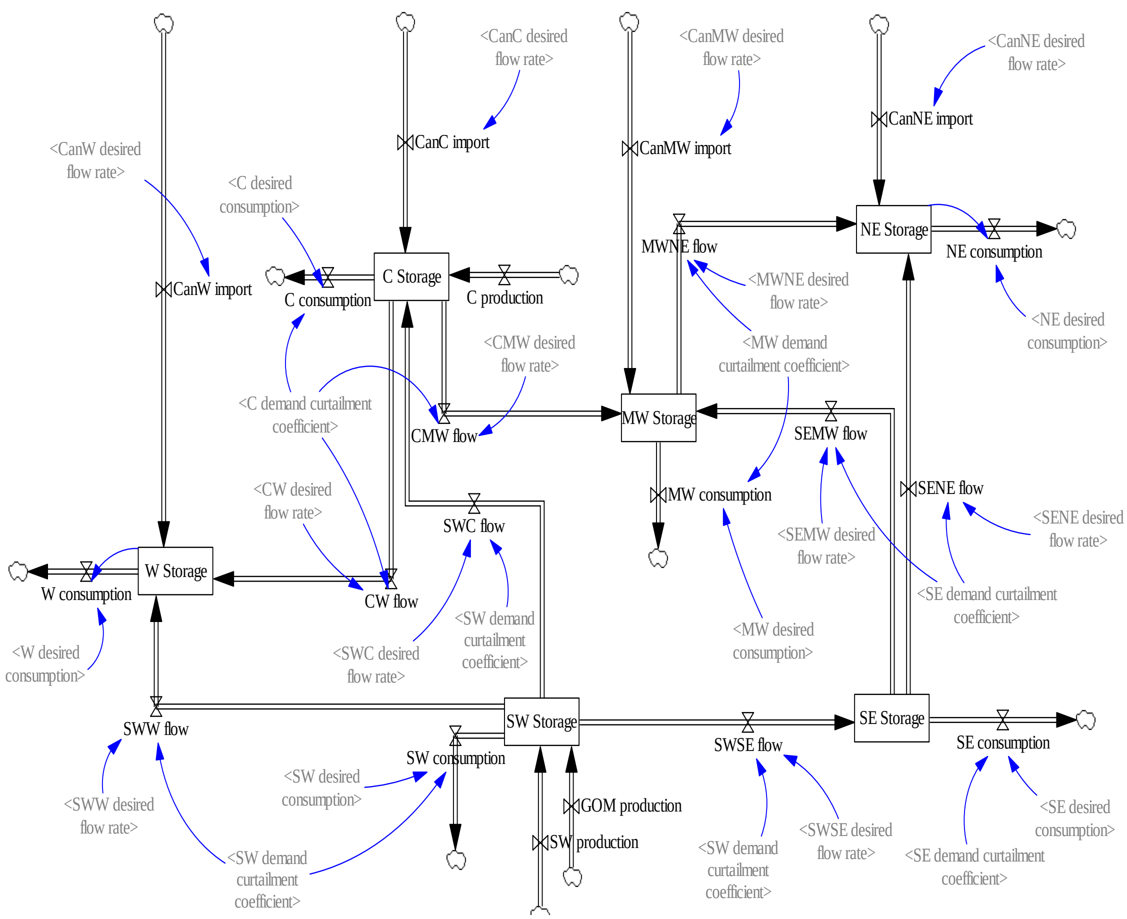
and Western regions all produce natural gas – though each region has an output of 2% or less of total domestic production.

h) LNG import capacity is not considered. Given that LNG import capacity is about 4% of demand, and that actual imports are about half of capacity (due to a lack of liquefied gas production capacity overseas)[6], not modeling this capacity is a reasonable simplification.

In addition, the storage capacities of each region can be withdrawn from and added to at any rate. While in reality each individual storage facility has its own injection and withdrawal rate constraints, if we take into account that there are many such fields in a region, then the capacity to withdraw and inject gas in that region at any given time is large. Moreover, the fact that the transmission pipelines themselves have constraints also constrains the rate of injection to and withdrawal from storage. Finally, the aggregate ability of US storage fields to withdraw or inject gas is about 78 Bcf/day[7], which is more than the average daily volume on the gas transportation network (60 Bcf/day), which again indicates that representing an unconstrained ability to inject and withdraw gas is a reasonable approximation.

Last, there is no allocation by pricing in this model. As the purpose of this study is to understand whether a supply or transmission disruption would cause a curtailment of supply, we are interested more in the fact that a curtailment has occurred than how the shortage is allocated within the region or among regions. It is assumed that a region will pay the price it takes to get the gas necessary to meet customer demand, and that the constraint is whether there is enough transmission capacity into the region to supply its demand. In demanding natural gas, a region requests gas flows that result in an equal fraction of the capacity of each of the incoming transmission lines being used. That request is granted, as long as the region the gas is coming from has sufficient quantities of gas to grant the request.

Below is a diagrammatic representation of the model.

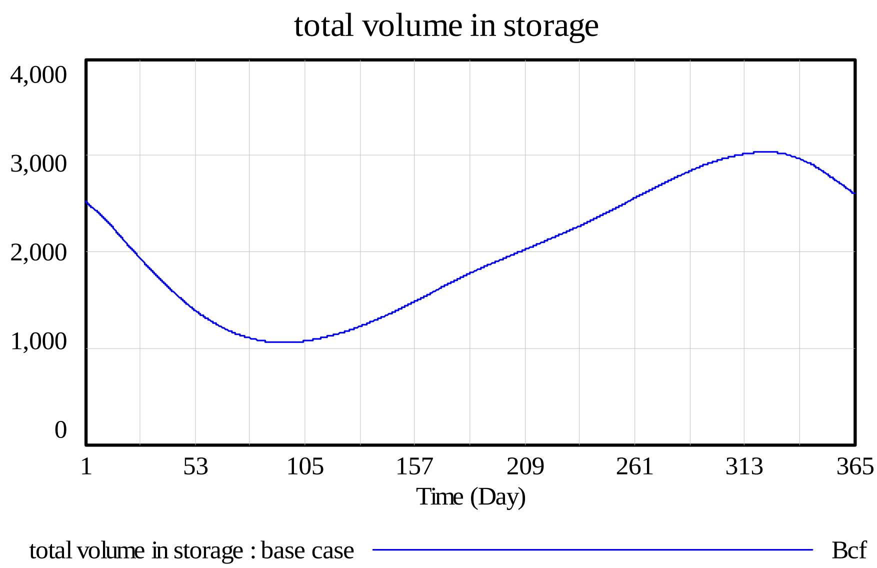


Model Scenarios

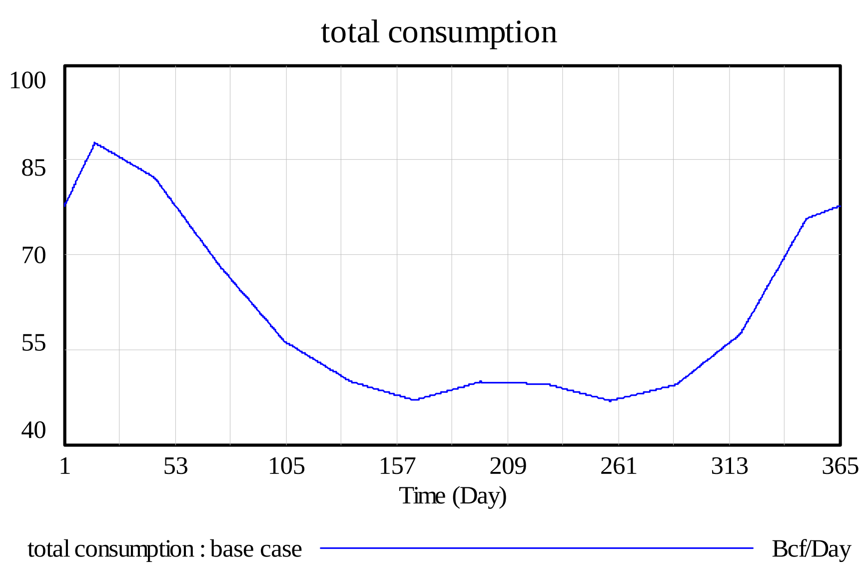
Scenario A: Normal Operation

Before doing scenario analysis of potential disruptions, it is important to examine the behavior of the model when the system is in normal operation (no disruptions).

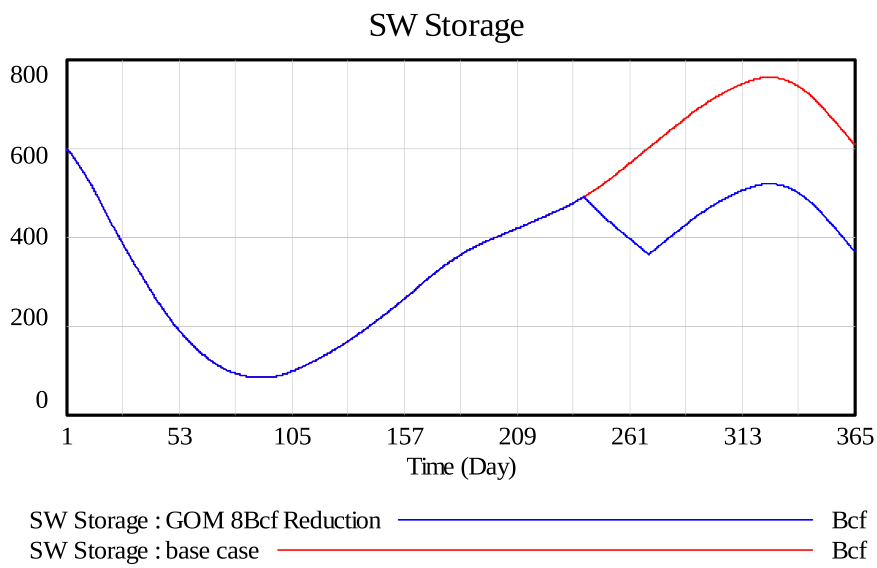
Below is a graph of aggregate storage for all regions (the lower 48 states), from day 1 to day 365. Day 1 corresponds to January 1, and Day 365 corresponds to December 31.



In the model, base gas (which serves to provide pressure) is not represented – only the working gas, which is the amount that can actually be used, is explicitly represented. We see that the curve exhibits the same shape as we see in reality, with a trough in early spring, and a high point in fall, just before the onset of winter. The volumes here are also very close to actual storage volumes. In addition, the total consumption per day for all the regions in aggregate closely follows actual system data, as it was designed to do.



Scenario B: Loss of Gulf of Mexico Production Capacity -- 8bcf shortfall from day 240 to day 270 (the month of September)



Since the model assumes storage is used to serve current demand in the event of a shortfall, here we see storage being used from day 240 to day 270, which is the duration of the production restriction. There is no difference in the flows to the other regions, therefore there is no restriction on gas supplied to customers.

It would seem, therefore, that this is a benign scenario. However, there is a problem. Storage should be built up during September in order to have maximum volumes stored coming into winter. Instead, it is being used. The Southwest will not have the stored volumes it needs to meet the full demands of the other regions for the coming winter heating season. In order to balance supply and demand, prices would have to rise.

In fact, what happened in the aftermath of Hurricanes Katrina and Rita was that there was relatively little disruption to current consumption of natural gas, but that shut-in offshore wells meant that gas was not being produced and put into storage. Due to weak production, increased demand, and storage inventories 5% below last years' levels, the EIA has projected that natural gas prices for the winter of 2005-2006 will be 43% higher than last year.[8]

This scenario highlights both the strengths and the weaknesses of the model. The weakness is that in reality, some customers have interruptible contracts, and during a supply shortage, those contracts would be interrupted. Moreover, stored gas is owned by some party, and that party may not be willing to sell at any price. Therefore, we would actually see a combination of reduced flows and withdrawal from storage. Also, spot prices for natural gas would increase, which would have a dampening effect on consumption.

At the same time, the model has helped us to understand the fundamental dynamics of the natural gas system. Even if an interruption in production causes no large problems in the summer, when consumption is low, the natural gas infrastructure is designed to have a balance of gas on an annual basis – and large interruptions in production will either cause pain now, or cause it later when winter comes. The US currently has no way to import 8Bcf/day to compensate for such a large loss of Gulf of Mexico gas production – Canadian imports cannot go much above their current 3.5 Bcf/day, and current LNG capacities are too small to make much of a difference. And it would be physically impossible to, say, double the output of the Gulf of Mexico wells when they come back on line – the production days that were lost are lost.

Model Caveats

Other scenarios were tested, with most showing a high degree of robustness of natural gas supply. That result may give a false sense of security. This is primarily because the model does not attempt to take into account the commercial realities of the natural gas sector.

For example, there may be sufficient capacity on a transmission line to quickly ramp up natural gas volumes in the event of a disruption elsewhere or unseasonably cold weather. However, that capacity could be already contracted for by another region that is not experiencing an emergency, but is simply putting gas into storage. Logically, the emergency would take precedent and the storage gas could be made up later – but legally, there may be no way to alter the contractual arrangements in place.

In addition, in the event of a transmission or production shortage, the model provides for the drawing down of storage to meet that demand. In reality, gas in storage is owned by some party. That party may not be willing to sell that gas at any price, as might be the case with a LDC (local distribution company) in a cold climate that must have high reserves going into winter. Also, there are two main types of natural gas contracts: interruptible and firm. In the event of a transmission or production failure, the interruptible contracts would most likely be interrupted, as it would cost too much to deliver them stored gas at a time when gas prices are likely high. Natural gas sellers would likely withdraw gas from storage to supply their fixed contracts, if there were not enough current production to meet the contract volumes. Essentially, the model treats all contracts as fixed, which means that we see more storage withdrawal in the model in the event of a disruption than we would in reality.

Conclusions

The resilience of the modeled system to a variety of transmission disruption scenarios suggests that the US natural gas network itself is fairly robust. This conclusion is tempered by the fact that this model, as any model, is a simplification of the actual system, and in this case does not include the contractual aspects of gas delivery. Including these aspects would likely worsen the reliability picture for electrical power and industrial facilities, though residential consumers (as they have firm contracts) would likely not be affected.

A weakness of the US natural gas infrastructure is that it is essentially a closed system: significant shortfalls in production due to hurricanes or other events cannot be made up by LNG imports at this time, due to both the small number and low capacity of US LNG import terminals, and the small amount of liquefied natural gas production facilities in exporting nations. Until this situation is rectified, small changes in production and demand will likely cause large swings in natural gas pricing. The model created in support of this paper, while not designed to produce precise predictions, was instrumental in developing the deeper understanding of the system behind these conclusions.

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