INDIANA NATURAL GAS MODELING SYSTEM: A TECHNICAL REPORT

Prepared by:
State Utility Forecasting Group
Purdue University
West Lafayette, Indiana

Prepared for:
Indiana Utility Regulatory Commission
Indianapolis, Indiana

June 2003

INDIANA NATURAL GAS MODELING SYSTEM:
A TECHNICAL REPORT

Prepared by:
State Utility Forecasting Group
Purdue University
West Lafayette, Indiana

Prepared for:
Indiana Utility Regulatory Commission
Indianapolis, Indiana

June 2003

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

FOREWORD

Unlike previous reports produced by the State Utility Forecasting Group (SUFG), this document is not a forecast or a report explaining the results of SUFG's models. Instead, this is a technical description of SUFG's natural gas model, which is a work in progress. This report is intended to inform industry experts of the model's structure and capabilities in order to get constructive feedback. Such feedback will allow the model to be further improved, so that it can be a valuable tool to Indiana policy makers.

SUFG's natural gas modeling effort began in late 2001 with the goal of examining the impact of new natural gas-fired merchant generating facilities on the gas system. As this represents SUFG's first foray into modeling natural gas, SUFG has relied on experts from the Indiana Utility Regulatory Commission (IURC), the Office of Energy Policy, the Indiana Gas Association, and the local distribution companies for advice and access to data. SUFG wishes to thank all the parties that have provided such help in the past and will do so in the future.

This report was prepared by and is the responsibility of SUFG. The information contained in this report should not be construed as advocating or reflecting any other organization's views or policy position. Comments and questions should be directed to:

State Utility Forecasting Group
Purdue University
Potter Engineering Center, Room 334
500 Central Dr.
West Lafayette, IN 47907-2022
Phone: 765-494-4223
Fax: 765-494-2351
e-mail: sufg@ecn.purdue.edu
https://engineering.purdue.edu/IIES/SUFG

CHAPTER 1
INTRODUCTION AND OVERVIEW

It has been over one year since the Indiana Utility Regulatory Commission (IURC) tasked the State Utility Forecasting Group (SUFG) to study the likely impact on Indiana's natural gas transportation, distribution and storage system of the increases in natural gas use associated with new gas-fired electricity generators. Since then, one discovery and one development have taken place, which have tended to forestall if not reduce concerns over the impact. The first relates to the size of the capacity of the current gas interstate pipeline system relative to the magnitude of Indiana's gas requirements; the second is the recent decrease in short-run forecast use of gas by merchant plants in Indiana and elsewhere.

Consider first the current aggregate capacity of the Indiana interstate pipeline system to meet Indiana demands. Figure 1-1 shows the current capacity of gas pipelines into and out of the state of Indiana in million cubic feet (mmcf) per day. Over 70 percent of the gas entering Indiana is sent further downstream to serve customers in the Northeast [1]. Hence, Indiana's gas pipeline system has been sized to handle a much larger flow than Indiana's demand alone would require, which is on the order of 3,000 mmcf per day.

This has important consequences regarding the ability of Indiana's gas supply system to meet likely future increases in gas demand. It means that changes in usage outside Indiana will have a far larger impact on the adequacy of the state's pipeline system than will any envisioned changes in demand within the state. This is true even when Indiana demand increases appear large relative to historical usage in the state.

Next, at the time of the initiation of the project, if all the then announced 11,600 Megawatts (MW) of additional generation capacity were to come on line, SUFG estimated that natural gas demand in Indiana would increase 45 percent, as shown in Figure 1-2 [2]. Since then, the price of electricity in the wholesale markets has fallen rather dramatically as a result of the combination of an increase in the supply due to new plants coming on-line and a decrease in demand due to the economic slowdown. The lower electricity prices have resulted in many plant cancellations and postponements.

The Federal Energy Regulation Commission (FERC) estimates that over 22,000 MW of new capacity (almost 35 percent of announced additional capacity through 2004 -- 90 percent of which is gas-fired) have been canceled or postponed in the Midwest since January 2002 [3]. As of this writing, SUFG estimates that 5,607 MW of capacity have been canceled or delayed in Indiana alone. In Indiana 2,486 MW are operation, an additional 5,123 MW have been approved by the IURC, and an additional 3,340 MW are pending before the Commission.

In addition, the FERC issued its own assessment of the Midwest energy infrastructure in October 2002 [3]. The assessment concluded that because of five commission certified gas projects, three pending gas projects, and six major gas projects on the horizon, all of which would create new capacity to deliver gas from producing areas to Midwest markets, "adequate pipeline and storage capacity exists to meet market needs."

Nonetheless, SUFG feels that while the immediacy of the need for the results of the study has decreased, the ability to study the impact of increased gas demand specifically on Indiana, with an emphasis on the possible price effects of congestion, would be of considerable value.

Further, it is highly likely that the inevitable economic recovery will stimulate electricity demand to the point where the canceled / postponed projects start coming on-line. Therefore, it would be valuable to have in place a mechanism the IURC can use in its analysis of possible congestion effects in the future.

To this end, this report is intended to be a technical document describing the construction and characteristics of SUFG's gas model in order to provide industry experts with the framework needed to give constructive feedback. It is not intended to be a fore-

Figure 1-1. Pipeline Capacity into and out of Indiana (mmcf/day)

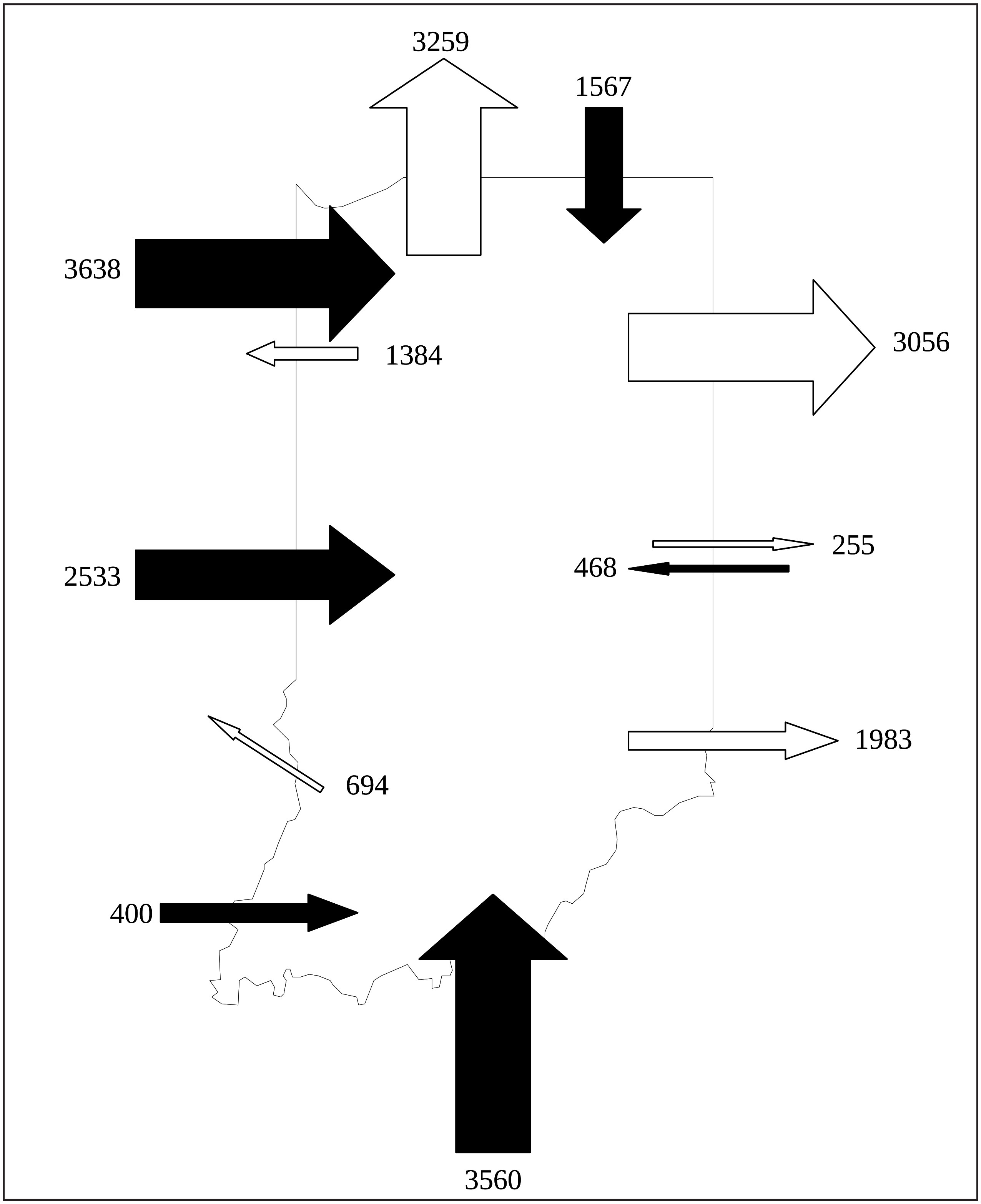
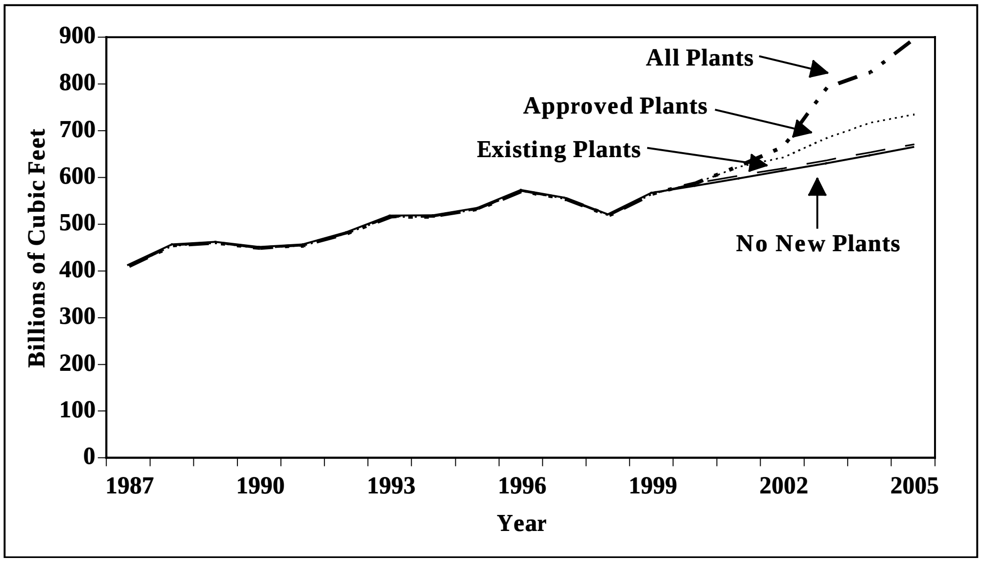


Figure 1-2. Natural Gas Usage with Varying New Generation Capacity



cast of future gas supply, demand, or prices and should not be viewed as an indication of the adequacy of the gas delivery system. Further refinements to the model and data are necessary before these types of results will be available.

In order to illustrate potential uses of the model, various scenario analyses are provided. These experiments take as the base case:

1. The Energy Information Administration's (EIA) monthly price and output projections for natural gas into the major delivery hubs over the five year (60 month) planning horizon of the model.
2. SUFG's estimated overall demand pattern for historical gas use at each of the demand points as well as a 1.8 percent per year increase in this gas demand, maintaining the historical 12-month weather sensitive cyclical nature of that demand.
3. SUFG estimates of projected costs associated with gas movement and storage.
4 The present capacity of the gas transportation and storage system plus all known additions to be added to the system at their estimated completion dates.
5. Downstream electric utility demand for natural gas arising from additional gas-fired generation construction based on a growth rate of 1.8 percent per year for electricity, with the projected share of this demand to be met by gas-fired plants as determined by a simple dispatch model.
6. Indiana merchant plant demand for gas based on current installed combined cycle (CC) and combustion turbine (CT) capacity.
7. A normal weather pattern.

In addition to the analysis of the base case, the alternative experiments discussed in the report are made up from combinations of the following assumptions.

1. Indiana CC / CT construction: (i) add approved capacity and (ii) add approved plus pending capacity.
2. Downstream gas demand: (i) alter electricity growth rate and (ii) alter the dispatch model to change the gas-fired percentage of new construction.

3. Increase capacity of the gas pipelines to interconnect with other lines, reducing congestion effects within the state.
4. An unexpected, long lasting (one month) disruption in the supply network.
5. Different weather patterns.

The model then determines the mix of monthly local distribution company (LDC) purchase, transport, and storage decisions that minimizes the sum of monthly LDC gas purchase, transport, and storage costs over the 60-month planning horizon, subject to the following constraints.

1. The customer demand at the demand nodes must be met.
2. The flow capacity of the pipelines must not be exceeded.
3. The storage capacity limits of the storage sites must not be violated.
4. The amount of gas transferred from one pipeline to another must not exceed the capability of the interconnection.

No long-term purchase and delivery contracts are included in this model. LDCs are assumed to purchase on the monthly open markets the mix of gas that will minimize the cost to consumers over the planning horizon, taking into account the purchase, delivery (transportation) and any storage costs required by their purchase patterns.

The results of the model when the optimization process is complete are of two types:

1. Optimal purchase, transport, and storage strategies for each of the LDCs in Indiana for each of the 60 months in the planning horizon; and
2. Measures of the impact of congestion in the supply network on gas costs in Indiana and elsewhere.

The presence of congestion in any supply system can impact users in two quite different ways. The first is through occurrences where there are unmet customer demands due to capacity constraints on the system, what SUFG calls "physical" congestion, and second, occurrences where demands can all be met, but because of congestion, customers have to pay more for gas than otherwise would be the case, what SUFG calls "economic" congestion. This first, more serious, but quite infrequent situation takes place when the physical capacity of the system is simply not able to satisfy the demands placed on it. In this case, some gas customers' demands cannot be satisfied because there is simply not enough pipeline or storage capacity to move the amount of gas requested by consumers.

Given that roughly 70 percent of the gas presently entering Indiana leaves it to meet Northeast gas demands, there is little likelihood that any increase, even a major one, in the 30 percent share of the gas that stays in Indiana will result in unmet Indiana demands unless increases also took place in demands downstream from Indiana.

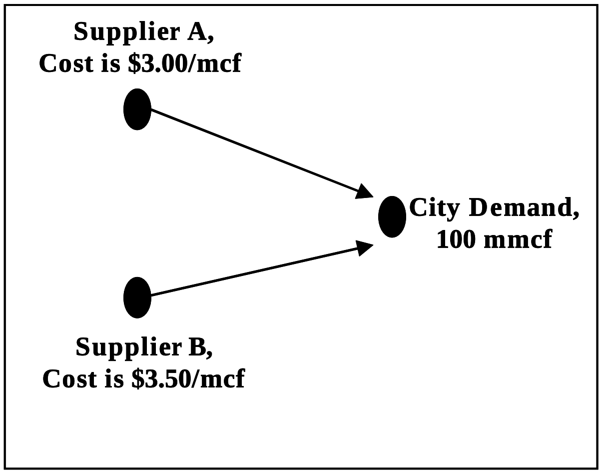
Fortunately, long before such a situation would take place, supply systems would send out warning signals of impending shortages, usually in plenty of time for the owners / regulators of the supply chain to take corrective action.

A simple example illustrating these two occurrences should clarify the distinctions between physical and economic congestion.

Figure 1-3 shows a city served by two gas companies, A and B. The city demand for gas is assumed to be 100 mmcf. Gas is available at $3.00 per thousand cubic feet (mcf) from supplier A and $3.50 per mcf from supplier B.

To illustrate the first case --physical shortages caused by congestion--suppose the pipeline from company A to the city could flow a maximum of 25 mmcf, and the line from company B to the city could flow a maximum of 70 mmcf. Then, there is no way that the demand of 100 mmcf can be satisfied since the total

Figure 1-3. Physical vs. Economic Congestion



supply capacity is 70 + 25 = 95 mmcf, and 5 mmcf of customer demand will go unsatisfied.

Now, suppose the connection between supplier B and the city was 100 mmcf, instead of 70 mmcf. In this case, the 100 mmcf demand could be met by flowing 25 mmcf from supplier A, completely utilizing their connection, and 75 mmcf over company B's line. In this case, while all customer demands can be met, customers are paying more for gas because of congestion on company A's line, $37,500 more to be exact.* They must pay this additional cost because company A's line does not have the capacity to handle all the demand. This is an example of economic congestion. Costs are forced higher than they otherwise would be because of fully utilized pipeline capacity.

The models used by SUFG provide measures of these economic costs of congestion to customers--the extra costs customers will be forced to pay because of insufficient supply chain capacity to meet demands at minimum production costs. These congestion costs, also called shadow prices, measure the increase in total costs associated with the capacity constraints including the supply, demand, pipeline and storage constraints. Occurrences of economic congestion causing increased costs are far more frequent than those of physical congestion causing some demands not to be met.

These shadow prices are then indicators of congestion points within and around Indiana, in that the higher the shadow price of a pipeline segment or storage facility, the more the limited capability of that segment or facility is contributing to higher gas costs in Indiana.

Thus, the model results focus on the cost to the gas consumer of economic congestion in the gas supply system. This is a far more important and more likely situation to consider than the more traditional, and much rarer, case where limited pipeline or storage capacity actually results in unsatisfied gas demand at some point and at some time in the system.

To some extent, the system has shown and will continue to show, self correcting, cyclical tendencies. For example, the extremely high wholesale electricity prices of the late 1990s triggered a large expansion in gas-fired generation for these markets, which triggered an increase in gas demand and price estimates, which triggered the increase in new gas pipeline and storage investment. The arrival of lower electricity prices in the last year has produced the opposite set of sequenced market responses. The task for the coming year will be to refine the gas model to allow gas and electricity price response to demand increases. This would allow prices to play a larger major role in the forecast of likely stresses on the gas system created by the introduction of gas-fired units into the wholesale markets for electricity.

* This number is calculated from the difference in the cost incurred by buying some of the gas from company B and the cost incurred by buying all of the gas from company A (if A's pipeline could handle all 100 mmcf).
(25,000 mcf x $3 / mcf) + (75,000 mcf X $3.50 / mcf) - (100,000 mcf x $3 / mcf) = $37,500.

Objectives and Methodology of the Project

Despite the recent developments mentioned previously, the objectives of the project remain unaltered--forecast the likely impact of the added gas demand associated with new CT/CC plant construction on Indiana and the region's gas supply system, paying special attention to identifying points in the system where congestion might develop, and the likely price consequences of such congestion.

Two modeling approaches are available for the analysis -- simulation and optimization models. Simulation models can mimic the behavior of many stakeholders in the face of random events, which take place over an extended time. Optimization models assume one or two major controlling forces whose transparent decision rules will govern future decisions. Because of the familiarity of the SUFG staff with optimization models in the electric sector, and the belief that cost minimization is indeed the objective of the major players in the gas industry, optimization models were chosen.

As a result, the models being developed are all based on the assumption that the local distribution companies will choose to purchase gas for their customers from the available suppliers on the basis of minimizing the cost of such purchases. Gas costs in the model are the sum of the assumed cost of natural gas purchased from the gas producers in the United States and Canada plus the pipeline company transportation costs (proportional to distance and to flow volume), plus storage costs (a fixed percent of the value stored per month) paid to owners of storage sites.

Constructing the model from the start to make it sensitive to changes in these three costs will allow SUFG to observe how the congestion points in the gas supply system change as the costs of purchase, movement, and storage change.

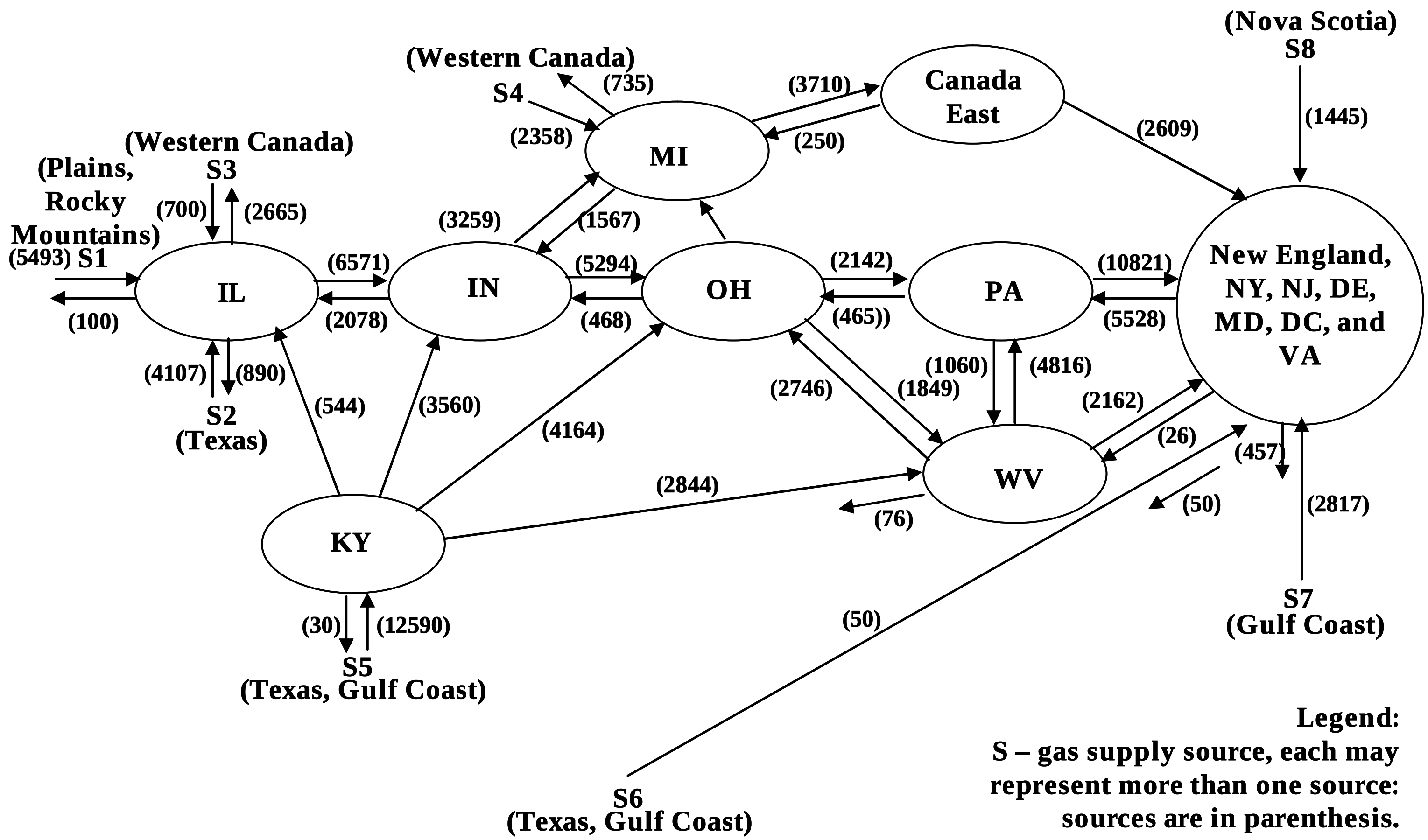
Thus, the model would expect to adjust to an increase in the gas purchase price from a particular supplier during a particular time interval by shifting purchases to an alternate supplier, and possibly choosing an alternate delivery path, as well as an alternate time pattern of gas purchases.

SUFG has been developing models capable of answering the questions posed by the IURC in two phases. The first phase, now essentially complete, involved developing a model that assumes the demand for natural gas at each of the demand points in the model is fixed, and is thus insensitive to the price of gas at these demand points. It also assumes that the supply of gas at the various delivery points is available in unlimited quantities at fixed prices, varying only from month to month according to historical patterns. The second phase, to be constructed later in the project, will drop these assumptions to allow demand at the points of use in the model to change as gas prices change, reflecting the observation that gas, electricity, and other fuels compete for energy end uses such as space and water heating on the basis of their relative price. Also, it will allow gas supply prices at the supply points in the model to change as deliveries from the locations change.

The current model first aggregates the 18 interstate entry points into Indiana to four import nodes at the state's borders. These nodes represent points where gas flows into Indiana from Canada, the Southwest, and elsewhere in the eight major gas pipelines that enter the state. Next, the approximately 160 delivery points are aggregated into 68 nodes, which serve as the delivery points for gas to Indiana and other final users in the model. Twelve of the 68 nodes have the capability to store gas, with over 32 billion cubic feet (bcf) of storage capacity. Finally, three export nodes are included at Indiana's borders to represent the eight major pipelines' exit points for gas flowing through Indiana on its way to the northeast.

In addition to these 68 nodes within Indiana, the model, as Figure 1-4 shows, includes downstream demand and in some cases, supply nodes for Michigan,

Figure1-4. The Network Topologyof the Gas Modeling System
(Numbers iin parentheses are directional capacities in mmcf/day)



Note: This includes the capacities of planned additions to the system over the planning horizon.
Source: EIA, December 2002

Ohio, Pennsylvania, West Virginia, and the New England region as well as modeling the flow of gas into and out of Illinois and Kentucky.

Finally, these supply, demand, storage, and transshipment nodes are connected with 161 arcs representing interstate pipelines with known capacities. Ninety-three arcs are inside Indiana and 68 arcs are outside Indiana. Currently, the model takes as a constraint reported interconnection capacity between the five major gas pipeline systems that pass through Indiana.

Populating this model with reliable data has been a major undertaking that is still ongoing. The effort has involved almost continuous contact with the LDCs in the state, as well as the five major pipeline companies whose lines serve the state. While the data pertaining to the physical capacities of the lines and storage facilities are in good shape, there remains more work to be done in breaking down the demands within the LDC regions into the demand nodes of the model. Furthermore, SUFG is working with the Indiana Geological Survey to improve estimates of present and future storage capacities and locations to be entered into the next version of the model.

On the demand side, SUFG is well along in the creation of the demand scenarios, which will be used to drive the current model, as well as later versions. Work is just starting on estimating the response of gas purchase prices at the eight supply points to increases in deliveries from these gas sources.

Summary of the Experiments

To illustrate the usefulness of the model, a base case scenario was developed which illustrates the possible impact on Indiana energy consumers of additional gas demand arising from the construction and operation of CC/CT merchant plants. In addition to the base case, five other possible scenarios were developed, each emphasizing a different possible use for the model. The complete set of experiments is described in Chapter 3 of this report The alternate scenarios are:

1. Higher gas usage by new merchant plants in Indiana.
2. Unrestricted flow of gas between pipeline companies.
3. Increased demand for gas by states downstream of Indiana.
4. An unexpected disruption of a major gas transfer point.
5. High gas usage due to extreme weather and new merchant plants.

These results are not to be taken as forecasts. SUFG's first forecast using this model will be available after the data and model structure have been reviewed by outside experts. They can, however, be taken for what they are -- examples of the type of analysis that will be possible using the model following the external validation process that SUFG plans to implement with the help of Indiana gas utilities and others.

The model is capable of predicting where and when transportation and storage congestion in the gas system might take place given assumptions about demand growth and supply capacity. Further, the model is capable of distinguishing between two types of congestion:

1. Congestion that results in unmet demands (physical congestion).
2. Congestion that results in higher costs to gas purchasers (economic congestion).

These scenarios provide examples of the usefulness of the model SUFG is in the process of completing. The final answer to the question posed by the Commission-- what is the impact of the additional gas demands of merchant plants on Indiana gas consumers--must await final validation of both the data sets incorporated in the model and the model itself.

End Notes

1. Energy Information Administration, "Natural Gas Annual 2000," November 2001.
2. State Utility Forecasting Group, "Indiana Electricity Projections: The 2001 Forecast." Prepared for the Indiana Utility Regulatory Commission, November 2001.
3. Office of Market Oversight & Investigations, Federal Energy Regulatory Commission, "Midwestern Energy Infrastructure Assessment," Docket No. AD02-22-000, October 2002.

SUFG'S GAS MODELING SYSTEM

Introduction

There are many types of gas network models from which to choose. They range from long-term models that minimize operating costs subject to supply / production conditions, pipeline and storage capacity limits, and nodal gas demands [1,2], to short-term models driven by differential gas pressure / temperature conditions [3,4].

The choice of model type is dependent on the questions the model is to answer. Long-term models, often called "steady state" models, are used for large regional studies with long (two to five year) planning horizons, with the model decision interval being a week or a month. The shorter term models are used when the questions revolve around the short term (two to five day) dynamics of smaller subsystems, with the model decision interval being an hour or less.

SUFG has chosen the long-term monthly decision interval approach to modeling the Midwest gas system. This is because the majority of the issues SUFG has been asked to address relate to the existence of long lasting, reoccurring congestion in the supply chain, not the short-term, transient congestion events the hourly models are designed to explore.

Hence, SUFG's gas modeling system ignores some physical properties of the gas system such as gas pressurization and variable flow speed. However, it is reasonable to believe that gas flows from the monthly model will not violate the pressurization limits because pipeline capacity limits are maintained throughout the time periods. For detailed gas system models based on pressure, readers are referred to references [3] and [4].

SUFG uses a regional approach to the Indiana gas modeling effort, modeling gas demand / supply in both upstream and downstream states. The main reason for using this approach is that Indiana is not an island -- its gas demand is about 30 percent of its overall gas pipeline flows. That is, about 70 percent of the gas entering Indiana will be trans-shipped to other states as far east as New England.

Embedded in this long term regional network model are two other model types: those that model gas demand by the final consumer at each demand node, and models of local gas production within the region. As will be discussed later, production from the major gas fields outside the region--Canada, West Texas, Gulf Coast, etc. -- are assumed to be available at a price forecast by the Energy Information Administration (EIA). Deliveries at this price are assumed to be limited only by the capacity of the pipelines from these regions to deliver the gas to Indiana and beyond.

The General Network Topology

Figures 2-1 and 2-2 show the topology of the long-term model for the region and Indiana, respectively.

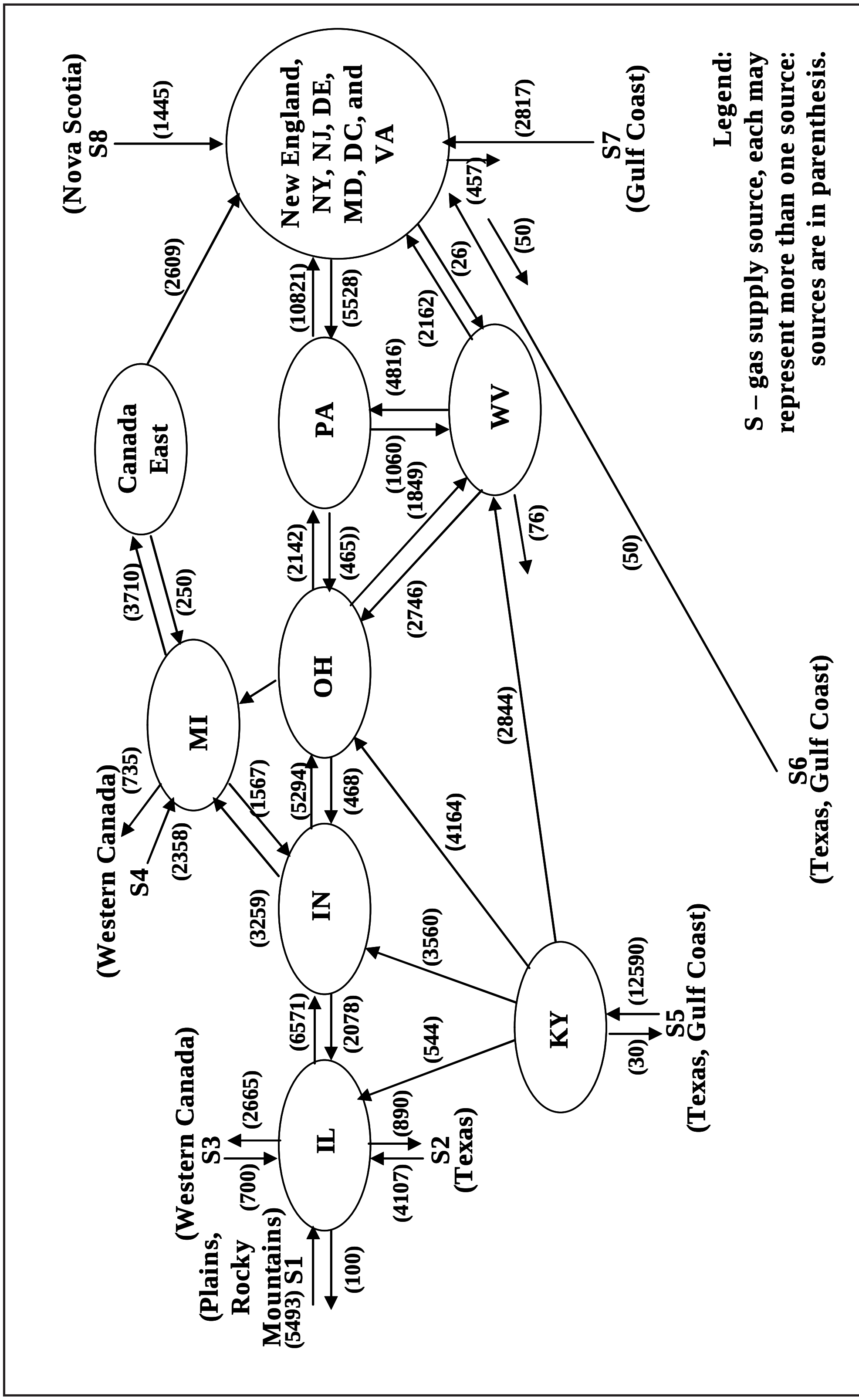
As indicated in Figure 2-1, Indiana is embedded in the national gas transmission network, surrounded by its four neighboring states -- Illinois and Kentucky predominantly "upstream" states--and Michigan and Ohio, predominantly "downstream" states. However, Michigan historically has provided a significant amount of gas to Indiana from its storage sites during the winter months.

In addition to gas flows into and out of the four neighboring states, SUFG models other states' storage capabilities in aggregate, as well as aggregate gas demand. In addition to the neighboring states, gas demand / storage / supply relationships are also modeled for Pennsylvania, West Virginia, and the northeastern states.

Gas is assumed to be available in sufficient quantity to completely utilize pipeline capacity from the eight major sources of gas production in the model, labeled S1 to S8 in Figure 2-1, each with its own price forecast.

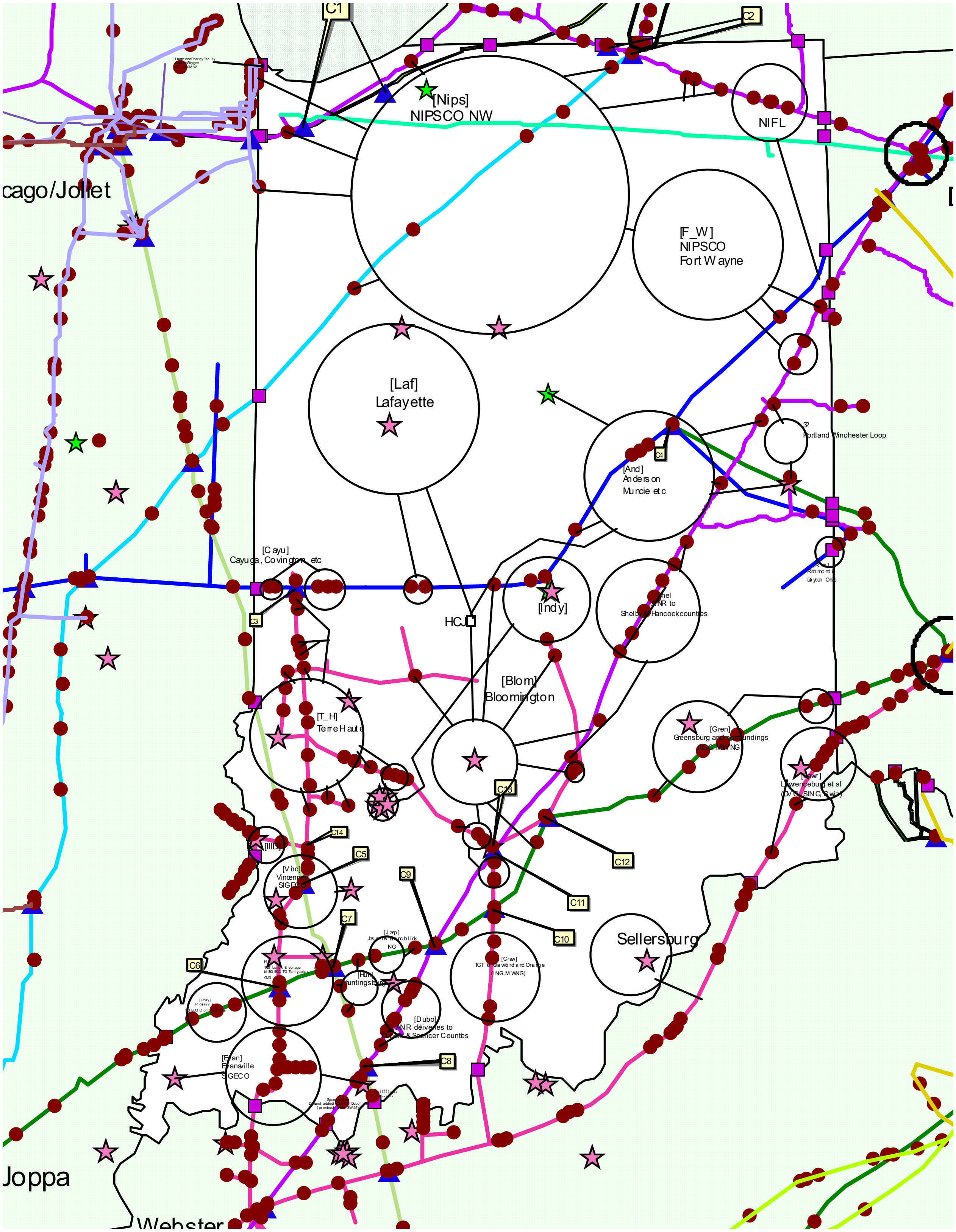
Supply node S1 in the diagram allows gas to enter Illinois from the Rocky Mountain and Plains gas fields, supply node S2 represents gas entering Illinois from

Figure 2-1. The Network Topology of the Gas Modeling System
(Numbers in parentheses are directional capacities in mmcf/day)



Note: This includes the capacities of planned additions to the system over the planning horizon.
Source: EIA, December 2002

Figure 2-2. The Detailed Map for Indiana



the Texas fields, and S3 represents gas entering Illinois from Canada. Supply Node S4 represents gas entering Michigan from Canadian fields, while supply nodes S5 and S6 represent gas from Texas and the Gulf Coast entering Kentucky and the northeastern states. Supply nodes S7 and S8 represent gas entering the northeastern states from the Gulf coast and eastern Canada, respectively.

The arcs joining the nodes in Figure 2-1 represent the collection of pipelines connecting the region. The directional arrows indicate whether these lines are one directional (e.g., Kentucky to Indiana) or bi-directional (e.g., Indiana and Michigan).

Figure 2-2 shows the much finer detail used to represent gas movement, storage, and consumption in Indiana. The circles represent demand areas; the arcs, the pipelines; and the stars, the locational storage sites.

Once the gas is in Indiana it may flow to any of the nodes within the state over pipelines within the state, all with known flow capacities. The nodes are of four types:

1. Demand / storage nodes, points where gas is delivered to city gates for either consumption or storage.
2. Storage nodes with no associated consumption.
3. Trans-shipment nodes, which transfer gas from a given pipeline company to its customer's service territories.
4. Transfer nodes, which allow a limited quantity of gas to flow between crossing pipelines of different pipeline companies.

Each demand node has associated with it a forecast of gas demand over the planning horizon. Each storage node has an associated maximum storage capacity, as well as maximum injection and withdrawal rates. Each trans-shipment node and transfer node has a maximum flow capacity. Each pipeline segment has a maximum flow capacity.

Gas Demand Forecasting Model

Forecasting gas demand within and outside of Indiana has proven to be a critical part of the project. The forecast is done using two separate models: the regular forecast without considering the large number of additional merchant plant CC/CTs, and the extra gas demand forecast considering the gas use of the CC/CTs. The two forecasts are added to form the final gas demand forecast.

Non-merchant Plant Gas Demand

Econometric models are used for predicting monthly gas demand for each node over the time horizon, excluding merchant plant demand. The primary drivers for this gas demand include heating degree days (HDD), cooling degree days (CDD), and price along with a trend variable that includes the effect of population, etc. Linear regression is used with the drivers as explanatory variables. An auto regressive (AR) error technique is employed that uses historical forecast error to correct the forecast. Historical data from 1989 to 2000 are used for fitting the models. The results for the regions outside Indiana are summarized in Table 2-1.

The goodness of fit measure, R^2, is defined as the ratio of explained variation (by the statistical model) to total variation in the dependent variable (gas demand). The value of R^2 ranges over the interval [0,1] with larger values indicating a better statistical explanation of the variation in the dependent variable. From Table 2-1, it can be seen that the R^2 values are close to 1, indicating that the models provide a good statistical fit.

To illustrate, historical gas demand for Illinois from 1989 to 2001 is plotted in Figure 2-3, together with a sample gas demand forecast for 2003 to 2007 in Figure 2-4. It can be seen that the historical peak gas demand ranges from 144,000 mmcf to about 181,000 mmcf. The forecast is for the average case with peak gas demands a bit below 160,000 mmcf. The first number (i.e., 1) on

Table 2-1. Statistics and Coefficients of the Gas Demand Forecast Models

Node	Constant (mmcf)	HDD	CDD	Price	Trend	AR	R^2
Illinois	32252	100	44.4	None Significant	-48.16	None	0.987
Kentucky	8047	30	4.4	None	0.47	0.73	0.934
Michigan	32101	77	35.3	None	-23.34	0.70	0.974
Ohio	28466	84	33.0	None	-17.02	0.87	0.981
Pennsylvania	24539	61	27.8	None	-36.42	0.79	0.983
West Virginia	5751	9	0.2	None	-10.18	0.36	0.893
Northeastern States	127066	201	170.1	None	119.57	0.73	0.934

the horizontal axis corresponds to January of the first year (1989 and 2003) of the time period. Non-merchant gas demand within Indiana was estimated in the same way but at a much more detailed level for each of the four Indiana LDCs, as discussed in Chapter 3.

Additional Gas Demand from Merchant Plants

Due to the proliferation of gas -fired CC / CTs in the country, the potential gas use increase has to be quantified. SUFG assumes that gas consumption of the additional CC / CTs will be driven by electricity demand growth in the region in the future, not by how many projects that have been built or approved to be built. This argument has been supported by observations from several deregulated electricity markets. For example, in Texas, several producers have proposed to mothball older gas-fired power plants due to the new CC / CTs [5]. Recently, Midwest Generation decided to idle 1,000 MW of gas units near Chicago [6].

SUFG assumes that electricity demand growth will be 1.8 percent per year for the base case. SUFG also assumes that electric load growth will be met by the CC / CTs for the next five years because there are few significant coal plant additions within the five-year planning horizon except in Kentucky and West Virginia, where the overall capacity of coal plants can meet the growing demand until 2007.

The problem reduces to the allocation of the incremental electric demand between CCs and CTs to determine the resultant gas demand. (This is necessary because of their differing efficiencies.) A yearly (8760 hours) dispatch model is used to allocate the gas consumption of the CCs and CTs in each region.

Local Gas Production Forecasting

Local gas production for the nodes ranges from virtually zero (Illinois) to about one third of the local demand (Michigan). The overall local gas production is about 10 percent of the overall demand in the model, and thus, cannot be ignored. SUFG uses simple, yet robust, linear regression models for forecasting the local production for each node. The statistics of the forecast is summarized in Table 2-2.

Gas Supply Price Forecast

SUFG does not use any complicated models to forecast gas supply prices. Instead, the annual wellhead price forecasts from EIA in 2001 are used. These price forecasts are adjusted for actual observations in 2002. Annual price forecasts are broken down into monthly price forecasts using historical wellhead price distribution factors. Pipeline transportation rates are added to the wellhead price forecasts to create supply prices at the boundary of the model.

Figure 2-3. Illinois Historical Demand: 1989-2001

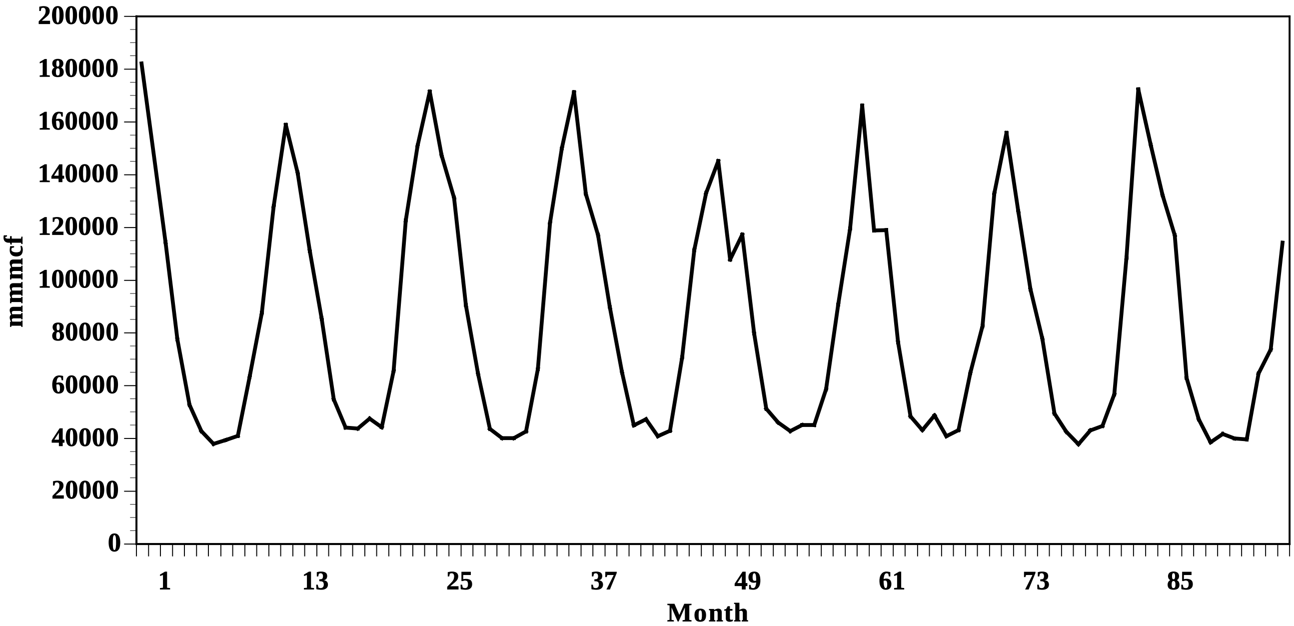


Figure 2-4. Illinois Gas Demand: 2003-2007

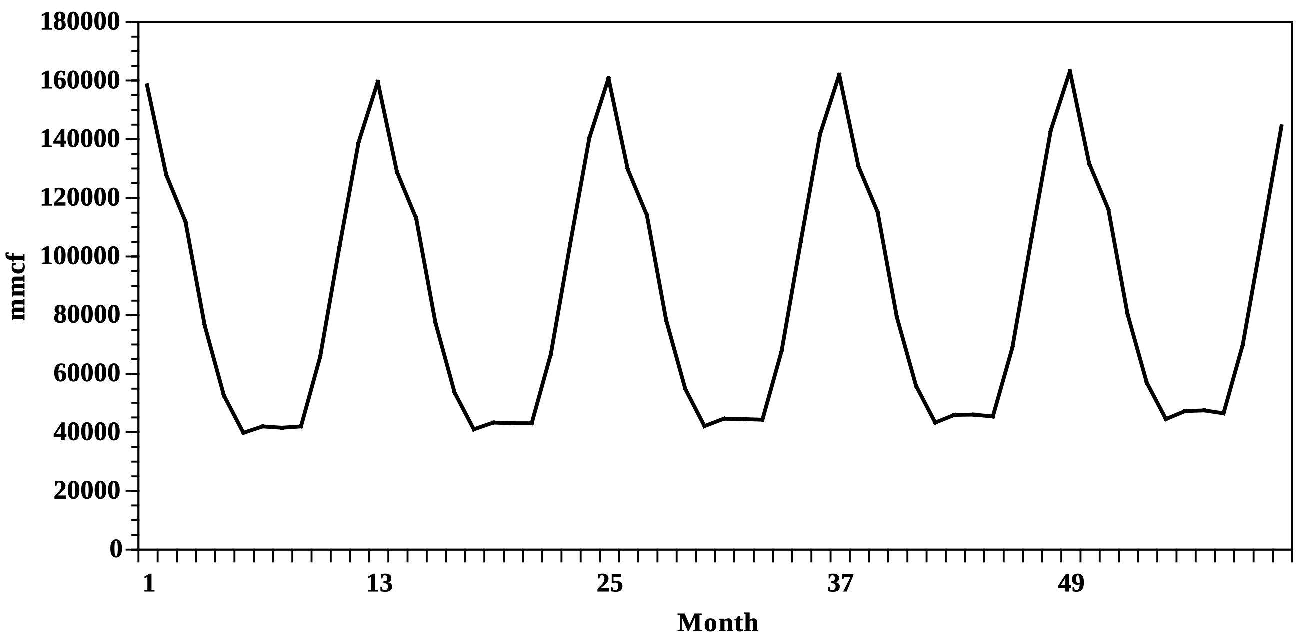


Table 2-2. Statistics of the Nodal Gas Production Forecast

Node	Constant (mmcf)	Price ($/mmcf)	Trend (Time)	Dummy*	R^2
Illinois**	200	None	None	None	NA
Kentucky	69547	511	1253.5	None	0.603
Michigan	150885	None	12282	None	0.910
Ohio	163317	None	-5025	None	0.989
Pennsylvania	37988	41322	-7657	One	0.800
West Virginia	184232	None	-781	One	0.920
Northeastern States	31528	-99	4965	None	0.933

* The dummy variable for Pennsylvania is used for correcting an abnormal data point. The dummy variable for West Virginia is used because of the discovery of a new gas bed since 2000.

**The gas production in Illinois is so small that it is kept constant throughout the forecast horizon.

The Network Models

The Cost Minimization Model

The concept of the cost minimization model is to mimic the gas purchase behavior of the LDCs in a manner that minimizes the cost of gas to the LDCs' customers. Their alternatives are limited by the gas available from the pipeline companies that serve them. Thus, if an LDC is not currently served by a pipeline company, it cannot choose to buy from that company, even though the cost of gas might be less than the cost paid to its current supplier.

The price of gas available for purchase in the model is determined by the sum of the following operating costs:

1. The purchase price of the gas itself at each of the eight gas supply nodes in the model. These prices are those forecast by EIA as explained previously.
2. The cost of moving the gas from source to the city gate of the LDC (the transportation charge), which is proportional to the distance and capacity utilization of the gas pipelines used to move the gas.
3. Any storage cost incurred for the gas as it moves from origin to destination.

The concept is to minimize these total costs of meeting forecast gas demand for the time periods, subject to various constraints. The constraints are pipeline capacity limits, storage capacity limits, pipeline flow directions, etc. The mathematical description of the model can be found in Appendix A of this report and a text description is provided here.

Minimize the present value of the total operating cost over 60 months (5 years)

Subject to:

Meeting all fixed demands (monthly forecasts)

Current pipeline capacity limits plus known additions

Directions of flows

Local gas production (forecast)

No exchange equations

Storage limits

Notice that the 'no exchange equations' are used to prohibit free gas exchange at any pipeline crossings belonging to different owners. This is the way the gas system operates and is a reflection of the operating philosophy of decentralized gas dispatch. Gas exchange between companies is conducted only on specific occasions such as a major pipeline breakdown.

Other models are proposed but have not yet been implemented due to a lack of sufficient price data. These models are welfare maximization and gaming that can be implemented later should they be desired and supported by data.

The Welfare Maximization Model

Maximize the present value of total welfare over the same time span

Subject to:

Balancing all demands with price elasticities (monthly forecast)

Current pipeline capacity limits plus known additions

Directions of flows

Local gas production (forecast)

Storage limits

No exchange equations.

Market Power Modeling: What Happens if Producers/Pipeline Owners Exercise Market Power?

This model can be similar to the gaming model SUFG developed for the electricity markets. However, minor modifications will be needed to include storage constraints.

Including Uncertainty

Uncertainty factors may include extreme weather, outages of large coal-fired plants that lead to extra gas usage by gas-fired plants, gas pipeline outages--both accidental and purposeful--gas-fired plant additions in Indiana and growth in electricity usage.

SUFG considers combinations of risk factors and the resultant impact on the Indiana gas system and gas consumers. The primary tool used for handling uncertainty is scenario analysis. Several different scenario analyses are provided in Chapter 3.

End Notes

1. R.E. Brooks, "Using Generalized Networks to Forecast Natural Gas Distribution and Allocation during Periods of Shortage", *Mathematical Programming Study*, Vol. 15, pp 23-42, 1981.
2. J.G. Wilson, J. Wallace, and P.B. Furey, "Stead-state optimization of large gas transmission systems," *Simulation and Optimization of Large Systems*, Clarendon Press, Oxford, UK, 1989.
3. A. Bopp, et al, "An Optimization Model for Planning Natural Gas Purchases, Transportation, Storage and Deliverability" *Omega*, Vol 24, No 5, pp 511-522, 1996.
4. D. De Wolfe, Y. Smeers, "The Gas Transmission Problem Solved by an Extension of the Simplex Algorithm," *Management Science*, Vol. 46(11), pp. 1454-1465, 2000.
5. Power Marketers, "Competition Favors New Efficient Power Plants in Texas, "October 8, 2002, by Greenwire.
6. Megawatt Daily, "Midwest Generation to idle 1,000 MW January 1," November 22, 2002.

Introduction and Chapter Outline

The title of this chapter--The Experiments --is chosen to emphasize the tentative nature of the results of the model to date. While SUFG feels the structure of the model is in a satisfactory state, the data that populate the model are too preliminary to warrant the results presented here to be called a forecast.

The organization of the chapter is as follows. First, the data now in the base case is presented, starting with the development of the gas demand excluding new gas-fired electric generation forecast for each of the demand nodes in the model. Detailed forecasts are developed for each of the four major LDCs (NIPSCO, Citizens Gas, Indiana Gas and SIGECO) and a generic forecast for the 40 smaller service territories. Then follows a description of the base case new gas-fired generation scenarios, broken down by type (CT or CC), location and hours of operation over the forecast horizon.

Next, a description of the base case supply scenario is presented, giving the capacities of the existing gas transportation and storage system.

The results of the base case experiment are then presented.

Finally, the chapter presents the results of the four variants of the base case SUFG has developed:

a. Alternate Indiana new gas-fired CTs and CCs gas demand scenarios.
b. Unlimited between pipeline transfer capability scenario.
c. Alternate out of state gas demand scenarios.
d. A supply disruption contingency scenario.

Again, the purpose of these scenarios is to illustrate the range of situations the model can address, rather than to draw any policy conclusions from the results.

The Base Case Experiment

The Base Case Non-merchant Plant Gas Demand Scenario -- Indiana

The gas demand excluding new CTs / CCs scenarios for three of the four LDC territories in the model were developed in roughly the same way. First, historical statistics on monthly gas use, heating degree days and cooling degree days for the recent past were obtained from each of the three utilities. This was also done for the other states in the model. These data were used to develop a weather-adjusted forecast of expected gas demand for each of the twelve months in each year of the five-year planning horizon.

An example of the construction of such a demand forecast is presented in Table B-1 of Appendix B. The table shows, for the three months selected (January, February and March):

1. The historical pattern (1980-2001) of gas use in Dekatherms (Dth), along with each month's heating degree days.
2. The forecast demand for each of the three months for 2002 to 2007;

The table is based on synthesized data in order to keep confidential the actual historical data provided by the LDCs: It is used only to illustrate the methodology SUFG used to perform the analyses.

One LDC provided SUFG with its own forecast of peak day demand over the 5 year forecast horizon, as well as monthly historical data; both data sets were used to create the forecast for this LDC.

The demand for the 15 smaller gas utilities in Indiana, which account for approximately five percent of Indiana demand, was estimated as follows. The EIAGIS-NG* database provides peak day and average day flow through the principal city gates for the major

* The EIAGIS-NG is a geographical information system based database maintained by the EIA for the natural gas industry. It contains digitized maps and associated facility data for the nationwide natural gas pipeline system.

interstate pipelines that deliver gas to Indiana. The base year demand for the heating months of October through March was estimated by multiplying the peak flow through the respective city gates serving each node by the number of days in each month. The base demand for the months of April through September was estimated in a similar manner using the average flow through the respective city gates. This base year demand was then grown at a rate of one percent per year over the five-year planning horizon.

This procedure results in 60 monthly gas demands (excluding new CTs / CCs) over the five-year planning horizon for each of the LDC service territories. A plot of projected non-merchant plant gas demand for Indiana showing the seasonal variation in the forecast and the slight upward time trend is presented in Figure 3-1. Table 3-1 shows the demand distribution among Indiana utilities during the projected period and Table 3-2 shows the historical demand distribution by sector. What remains is to disaggregate these 60 monthly demands into the LDC subregions contained in the model. In two cases, Citizens Gas and the smaller LDCs, this was not necessary, since their territories were entered into the model as a single demand point. However, for the other larger LDCs, each was broken up into smaller service territories, while maintaining the historical percentage of the LDCs total demand for each subregion. NIPSCO was divided into two: NIPSCO-Northwest and NIPSCO-Fort Wayne. SIGECO was divided into Vincennes, Posey, Pike, and

Table 3-1. Demand Distribution Among Indiana Utilities

	Percent of Indiana Total Annual Demand
NIPSCO	53%
Citizens	10%
Indiana Gas	29%
SIGECO	2%
Others	5%

Figure 3-1. Indiana Base Demand Projection (without Merchant Plants)

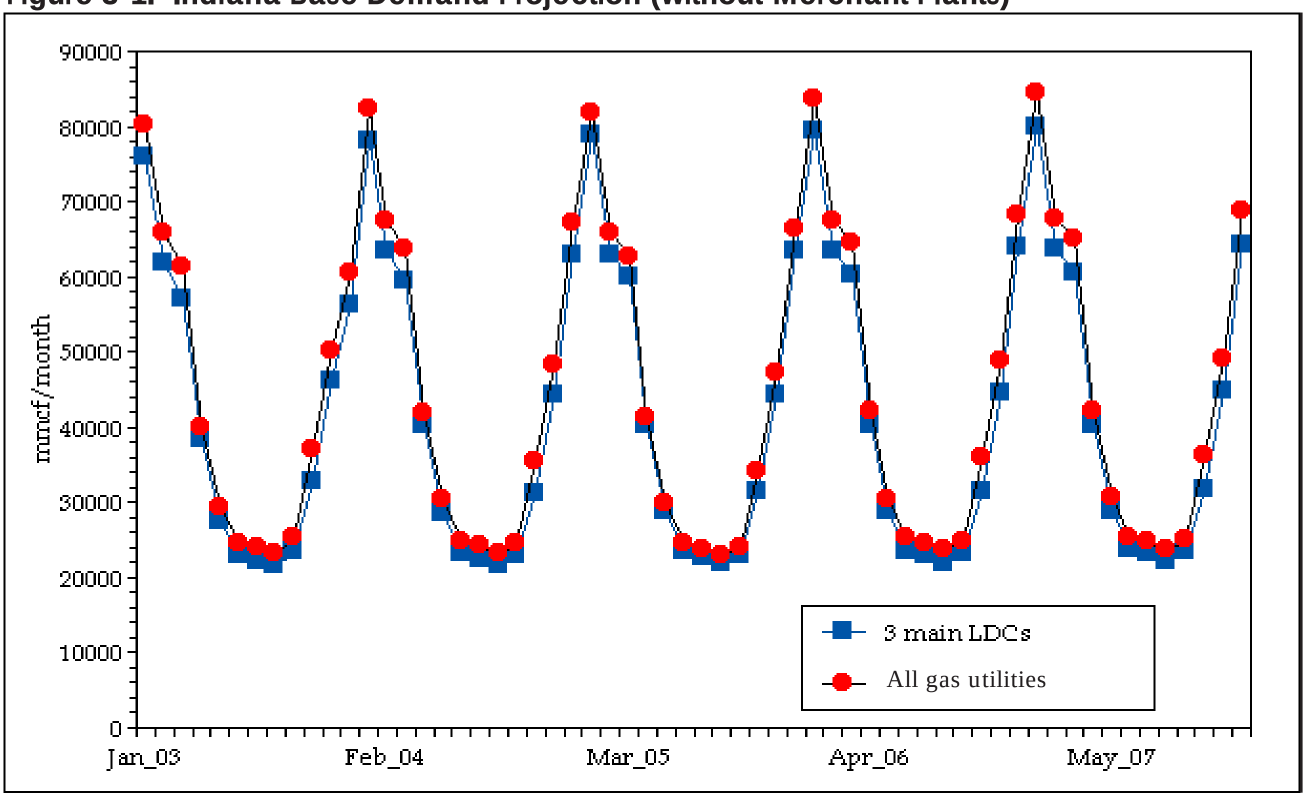


Table 3-2. Indiana Demand Distribution by Sector

	Residential	Commercial	Industrial	Electric Power
Indiana	30%	16%	51%	4%
United States	23%	15%	36%	26%
Source: EIA 2001 Natural Gas Annual, Table 16.				

Evansville subregions, with Indiana Gas separated into Lafayette, Anderson, Terre Haute, and Bloomington subregions.

The Base Case Merchant Plant Gas Demand Scenario--Indiana

The base case gas demand projection for merchant CC and CT plants in Indiana was constructed assuming only the seven plants now operating would be in operation over the horizon, representing a total of 2,486 MW (525 MW CC, 1961 MW CT).

The gas demand for the merchant plants was estimated assuming a heat rate of 7,340 British thermal units (Btu) per kilowatthour (kWh) for CCs and 11,000 Btu / kWh for CTs. The CCs were assumed to run for a total 4,392 hours in a year and the CTs were assumed to run for a total of 874 hours in a year, with the distributions shown in Table 3-3.

Assuming natural gas energy content of 1,034 million Btu per mmcf, the monthly distribution of consumption from the 525 MW CC and 1,961 CT already in operation is as shown in Table 3-4. Summing the demand excluding new CTs / CCs and merchant plant demand projections results in the total Indiana gas demand.

Figure 3-2 shows the location and capacity of these plants, as well as those plants approved (5,123 MW) and those with petitions pending (3,340 MW), which will provide the basis for alternate utility demand scenarios described later.

Base Case Gas Availability Scenario--Indiana

Gas Pipeline Capacity

Figure 3-3 shows the layout and capacities of the interstate pipelines passing through Indiana in mmcf per day. The capacities were obtained from the 2002 update of the state border crossings file that is part of the EIAGIS-NG database. These capacities are then converted to monthly capacities by multiplying by the number of days in each month.

Pipeline Interconnection Capacity

The ability of the gas transportation pipelines to exchange gas during unusual circumstances is an important element in determining Indiana's ability to meet demand during those periods. While many such interconnections exist, their present capacities are very

Table 3-3. Assumed Hours of Operation – CC/CT Units

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
CC	372	348	372	360	372	360	372	372	360	372	360	372	4392
CT	60	50	0	0	50	100	222	222	90	0	30	50	874

Table 3-4. Assumed Gas Consumption per Month – CC/CT Units (mmcf)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
CC	1386	1297	1386	1342	1386	1342	1386	1386	1342	1386	1342	1386	16367
CT	1252	1043	0	0	1043	2086	4631	4631	1878	0	626	1043	18233

Figure 3-2. Indiana Merchant Plants

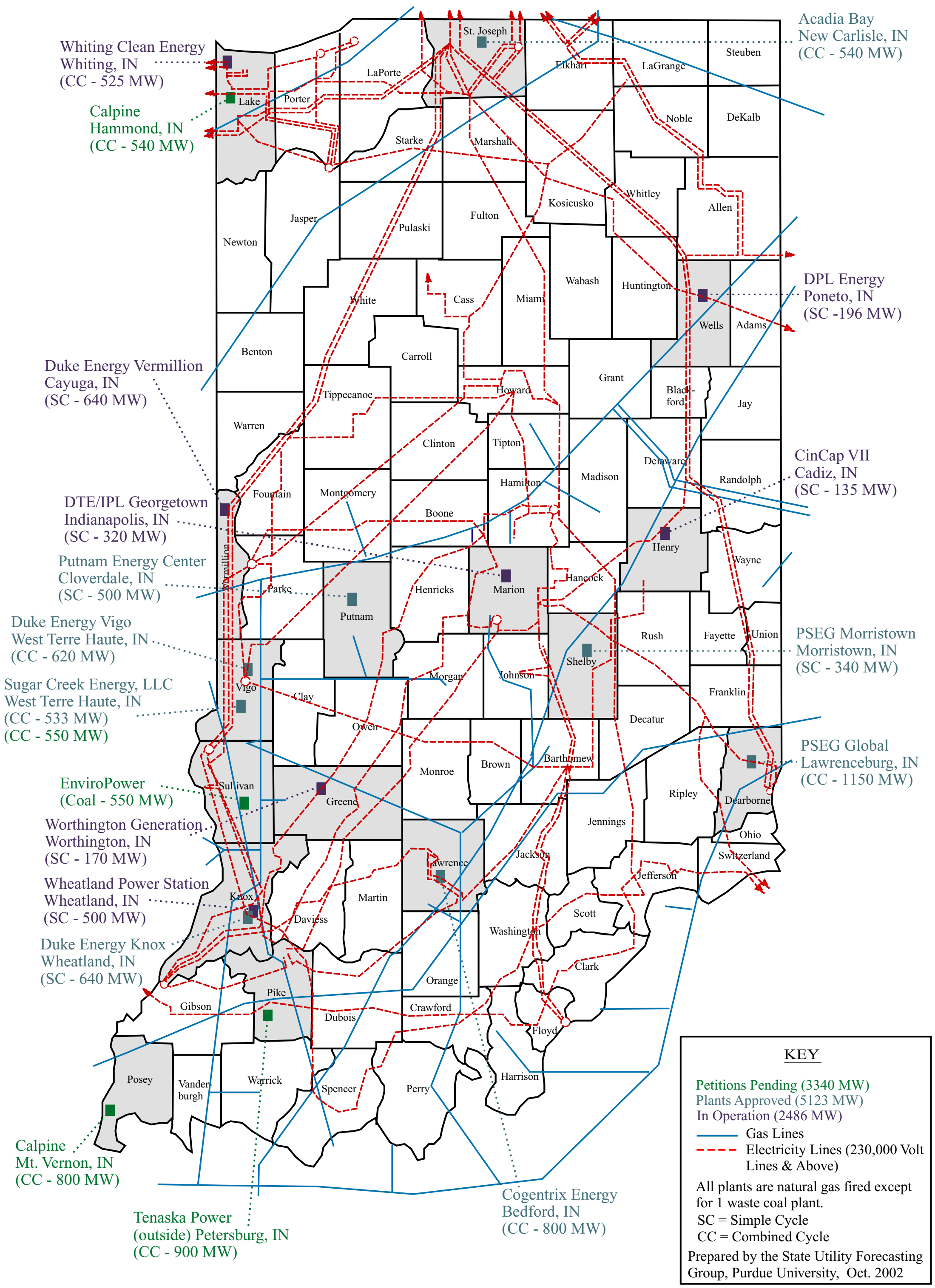
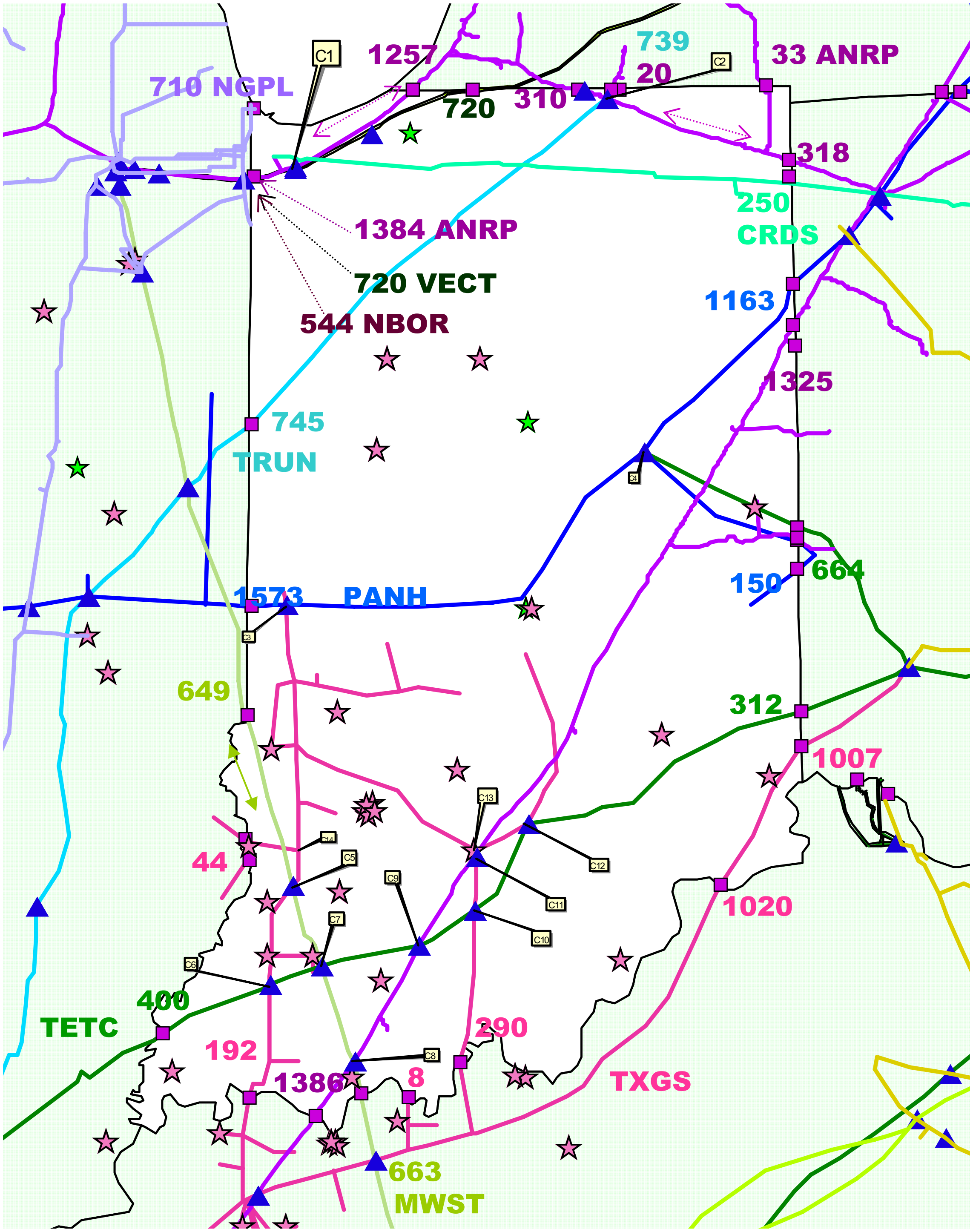


Figure 3-3. Capacities of Interstate Pipelines Passing through Indiana (mmcf/day)



MWST	Midwestern Gas Transmission Co.	ANRP	ANR Pipeline Co.
TETC	Texas Eastern Transport Co.	PANH	Panhandle Eastern Co.
TXGS	Texas Gas Transmission Co.	VECT	Vector Pipeline Co.
NGPL	Natural Gas Pipeline Co. of America	TRUN	Trunkline Gas Co.
NBOR	Northern Border Pipeline Co.	CRDS	Crossroads Pipeline Co.

limited when compared to the volumes of gas moving on Indiana pipelines. This should come as no surprise since such circumstances where interconnection capacity is critically needed are rare, given the storage capacities of the lines themselves, as well as the existence of substantial underground and tank storage facilities.

Nonetheless, as in the case of electric utilities, the use of such interconnection capability to allow freer movement of gas between pipelines for economic purposes, rather than for reliability objectives, may become important as the demand for gas in the region develops.

The location of the 14 existing interconnection points are shown in Figure 3-3. Each is indicated by a blue triangle, and labeled in boxes C1 to C14. As will be seen later in this chapter, the impact of additional interconnection capacity on gas availability and cost in Indiana is one of the experiments included in the results section of the chapter.

Gas Storage Capacity

Figure 3-4 shows the spatial distribution of storage capacity in Indiana. The red stars show the location of the approximately 20 underground storage facilities and the green stars the three LNG facilities in the NIPSCO, Kokomo, and Citizens Gas territories. The capacities of the storage facilities owned by the four main Indiana LDCs was supplied by these LDCs while the rest was obtained from the EIAGIS-NG database.

Base Case Demand and Supply Assumptions -- Outside Indiana

Demand Assumptions

As has been mentioned, over 70 percent of the gas entering Indiana leaves Indiana to satisfy downstream demands. The forecast magnitudes of these downstream demands play an important, indeed dominant, role in determining the ability of Indiana's gas supply system to meet anticipated demand increases.

Figure 2-1 in Chapter 2 shows the eight demand nodes outside Indiana now in the model. Forecasts have been prepared for both gas-fired merchant generation and other demand for Indiana's four neighbors--Illinois, Kentucky, Michigan, and Ohio, as well as Pennsylvania, West Virginia, and the Northeast region.

Gas demand forecasts arising from gas-fired electric generation plant construction outside Indiana have been constructed using the following assumptions:

1. Gas demand from CC / CTs will be driven by electricity demand growth.
2. CCs and CTs will compete for the gas demand induced by electricity demand growth.

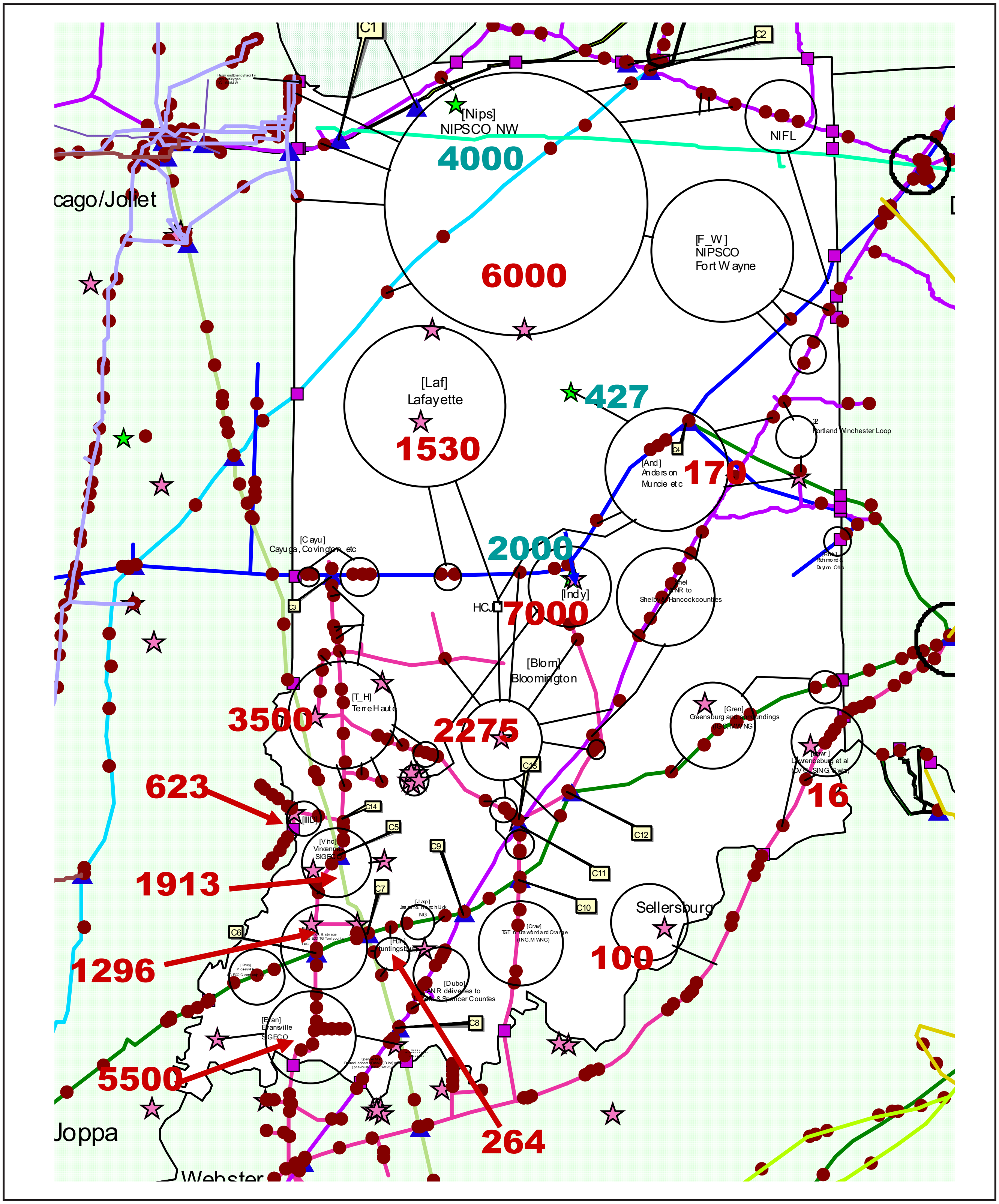
The results of these manipulations are provided in Table B-2 of Appendix B, which shows, for each state outside Indiana, the total base case gas demand for each month of the model horizon.

Supply Assumptions

As Figure 2-1 indicates, the model assumes gas flows into the system at eight distinct supply nodes:

- S1: Gas entering Illinois from the Plains and Rocky Mountain sources
- S2: Gas entering Illinois from Texas
- S3: Gas entering Illinois from Western Canada
- S4: Gas entering Michigan from Western Canada
- S5: Gas entering Kentucky from Texas and the Gulf Coast
- S6: Gas entering the Northeast from Texas and the Gulf Coast
- S7: Gas entering the Northeast from the Gulf Coast
- S8: Gas entering the Northeast from Nova Scotia

Figure 3-4. Node Storage Capacities (mmcf)



The model assumes that the only physical constraints on gas flow from the sources are the pipeline capacities of the lines joining these sources to the demand points. The capacities of these pipelines in mmcf / day are given in Figure 2-1, which again emphasizes that Indiana is to a large extent a throughway for gas destined elsewhere.

Gas Purchase Price Assumptions

Forecasts of gas purchase prices by month over the forecast horizon have been prepared for each of the eight supply nodes. All forecasts are based on wellhead price forecasts published by EIA as part of their 2001 forecast [1]. These wellhead prices were converted into price forecasts at each of the major gas supply hubs contained in the model using the following method. If a supply source has only one supply price (wellhead price), the supply price at the source is the wellhead price plus a transportation rate. On the other hand, if a supply source has multiple supply prices, a single supply price is obtained by using the average wellhead prices plus an average transportation rate.

The price forecasts themselves for each of the eight supply nodes for the 60 month planning horizon are shown in Table B-3 of Appendix B.

Results of the Base Case Experiment

As was mentioned previously, the outputs of the model of most interest to Indiana policy makers are the congestion points in the gas pipeline system that develop as a result of increased demands.

Figure 3-5a-d show the results of the base case. The results are presented in map form, one map for each of the forecast years-- 3-5a for 2003, 3-5b for 2004, 3-5c for 2005, and 3-5d for 2006. (The last year of the forecast period, 2007, will not be shown for the base case and all other experiments.)

Recall that the model results distinguishes between two distinct types of congestion-- congestion that results in the inability of the system to meet demands--physical congestion--and congestion that results in the system being unable to meet demands at minimum cost--economic congestion.

Physical congestion on the maps is indicated by large red circles at the demand points where unmet demand occurs, as well as the month in which the shortage is expected to take place by red numbers next to the red circles.

Economic congestion on transmission lines will be indicated by red directional arrows, with the number of the month(s) during which the economic congestion occurred indicated by red numbers next to the red arrows.

Economic congestion at storage points will be indicated by blue numbers next to the storage area, the blue numbers indicating the month(s) the economic congestion occurred.

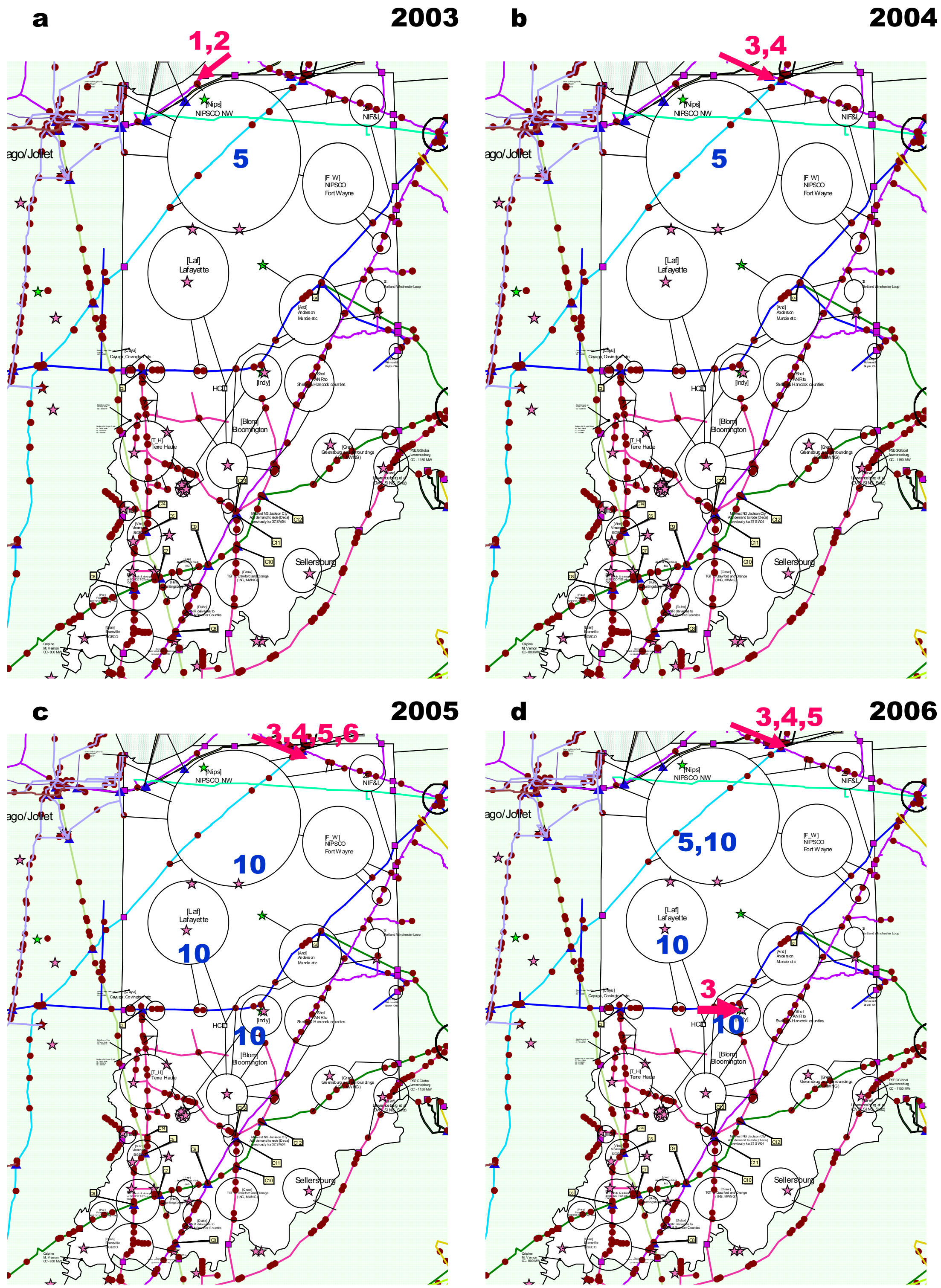
An examination of Figures 3-5a, b, c , and d show that no physical congestion takes place over the horizon -- all demands can be met.

Some economic congestion takes place in all years, but the frequency and extra costs are very minor. Figure 3-5a shows that in 2003, only a single line that joins the Michigan storage system to Western Indiana, both in January (1) and February (2) prevent flows from Michigan storage from meeting demands at minimum cost.

In subsequent years (Figure 3-5 b, c, and d), only two pipeline segments cause economic congestion. In 2004, 2005, and 2006, the figures show the pipeline segment connecting the Michigan storage system to eastern Indiana (March and April in all years, May in 2005 and 2006, and June in 2005) is congested, as is the Panhandle segment connecting the Lafayette city gates to Indianapolis in March of 2005 and 2006.

In the month when the impact is predicted to be the largest, the increase is only 2.8 percent of the average cost of gas purchased at the source; average price over the entire four-year period increases only 0.5 percent.

Figure 3-5. Base Case Average Demand Plus Operating Merchant Plants Only



525 MW CC in node NIPSCO-NW, 640 MW CT in node Cayuga; 820 MW CT in node Indianapolis, 196 MW CT in node Anderson; 170 MW CT in node Terre Haute, 135 MW CT in node Shelby; 500 MW CT in node Vincennes

Figure 3-5 also shows the same information for Indiana reservoirs; the blue numbers indicate the months the limits are binding on the storage sites in each year.

In 2003 and 2004, the capacity of only one storage facility prevents demands from being met at minimum cost, and that only in May and September of both years. In 2005 and 2006, the capacity of three storage sites bind the system. This occurs only in the month of October, except for the NIPSCO node where the storage capacity constraint is binding in both May and October. Again, the additional costs to the LDCs caused by these limited capacities were small when compared to the purchase cost of gas -- at 3.9 percent of its assumed cost during the month the increase was the largest; on average over the four-year period, costs increase only 0.3 percent due to limited storage capacity.

At this point, it might be well to mention that the existence of economic congestion in and of itself does not indicate that additional gas storage or transmission capacity should be built. The reason is the presence and magnitude of economic congestion indicates only the benefits of increases in capacity; it says nothing about a comparison of those benefits with the costs of such expansion. Economic congestion simply raises the possibility that the benefits of expansion might outweigh the costs. The presence of economic congestion suggests that further study is needed to see if the benefits exceed the costs of expansion.

The Alternate Scenarios

But, what if the base forecast of gas use by CC / CTs is incorrect, or if SUFG's estimates of demand excluding new CTs / CCs are low? Is it possible that Indiana gas consumers could see gas prices rise considerably or worse yet, experience gas shortages?

That is the purpose of three of the four experiments presented here--to see if the system's capacity would be exceeded if more extreme gas intensive, demand / supply scenarios were assumed.

Alternate CC/CT Gas Use Scenarios

Two sets of alternate scenarios for increased gas use in Indiana by merchant plants were developed--one assuming existing (2,486 MW) plus approved plants (an additional 5,123 MW) would be in operation over the planning horizon, and the second assuming existing plus approved plus planned (an additional 3,340 MW) merchant plants would be in operation over the horizon.

Only the results of the second scenario are shown in Figure 3-6a-d since there is very little difference in the two results. What these experiments show is that while this increased gas use by merchant plants will increase economic congestion, no true shortages can be expected.

The reason is simple. Indiana's pipeline system is sized to carry the (relatively) large demands downstream from Indiana, not just Indiana's use.

As a result, even if the additional capacity approved or planned were to come online, the resultant pipeline congestion would increase average costs by only 0.9 percent over the horizon, and 8 percent in the single month when the increase was highest.

As the figures show, six rather than three pipeline segments experience economic congestion. The time pattern of the economic congestion--March through June--present in the base case is repeated in this scenario, which suggests that the "shoulder" months, rather than the winter periods of peak gas consumption, could be expected to cause economic problems in Indiana.

The impact of limited storage capacity on the cost of gas for the LDCs is also relatively small and restricted to three months, amounting to at most an increase of 3.7 percent in gas costs during October of 2005 and an average increase of only 0.3 percent in cost over the entire horizon.

Unrestricted Flow Between Pipeline Companies

The blue triangles in Figure 3-3 show the 14 locations where interstate pipelines owned by different companies cross one another. In the base case scenario presented earlier in this chapter, the pipelines are modeled as having no interaction at these interconnections, such that they serve a reliability back-up role only. The exception to this rule is interconnection C1, which serves as the starting point of the crossroads pipeline and interconnection labeled C4 in Delaware County where a Panhandle lateral and a Texas eastern lateral branch off towards the Lebanon, Ohio hub.

A logical question to ask is what the impact would be on congestion if this situation were changed to allow free movement of gas from one pipeline company to another. Consequently, a variant of the base case was prepared that allowed such unlimited transfer with the following results.

As might be expected, allowing free movement of gas between different companies' lines at their crossings reduced the total costs to LDCs of delivered gas and reduced the number of economic congestion points in Indiana, but not by as much as was anticipated.

Figures 3-7a-d show the economic congestion points if free gas exchange were permitted at all crossing points. A comparison of those figures with the base case show that:

1. In 2003, additional economic congestion shows up on the pipeline joining Michigan to eastern Indiana in January and February; the timing of economic congestion at storage sites is unchanged.
2. In 2004, economic congestion moves downstream to the link connecting to Ohio and only in March.
3. In 2005 and 2006, economic congestion moves downstream from Michigan and is reduced in duration; the number of occurrences of economic congestion at storage sites is reduced, only occurring in the NIPSCO node.

In this experiment as expected, the total number of economic congestion events in Indiana was reduced from 18 to 13, reducing the cost to gas purchasers.

What was unexpected was the small savings to the LDCs associated with the free exchange of gas between lines. Average additional costs for both pipeline and storage congestion decreased 0.52 percent of the purchase cost over the project horizon; it was 0.8 percent in the base case. The apparent reason is instructive, and can best be understood by examining what happened in the Northern part of the state when gas flowing on the Trunkline Gas pipeline was allowed to flow on the ANR pipeline at interconnection C2 in Elkhart County.

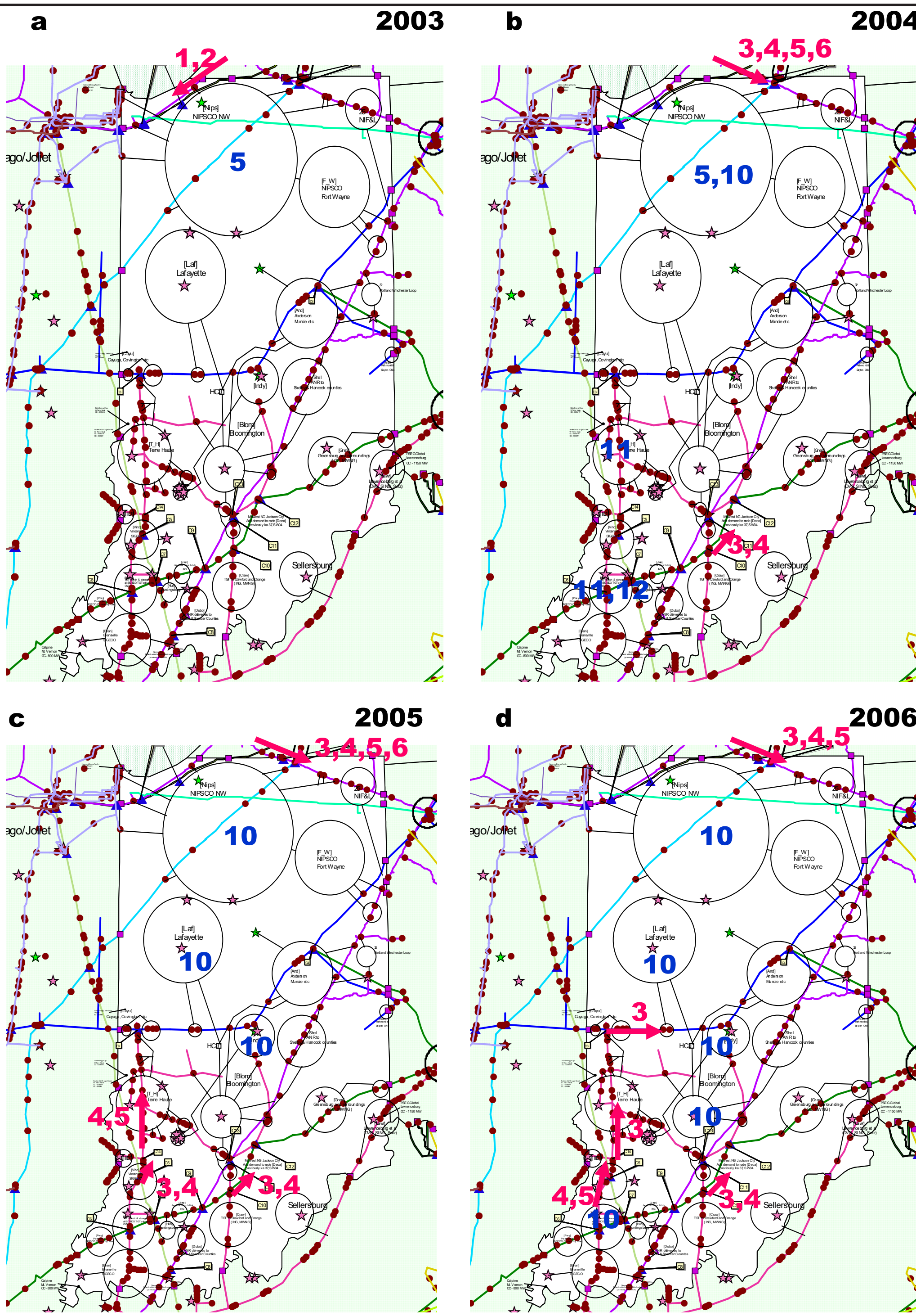
The interchange allowed cheaper gas from the Trunkline Gas pipeline to substitute for stored gas in Michigan to meet downstream demands in Ohio and the Northeast. But, the savings associated with this substitution turned out to be minimal since the volume of gas substituted was limited by the capacity of the ANR pipeline immediately downstream of C2 to the NIF&L city gates in Steuben County.

What is instructive about the example is that the system capacities are not now sized to take advantage of such interconnections. While some cost reductions could be expected with the creation of such interchange capability, the large savings expected would not be forthcoming until pipeline capacity expansions designed to capitalize on the interchanges were made.

On the other hand, the increase in the ability of the system to respond to unexpected short-term line segment outages associated with such interchanges could be substantial.

SUFG is not advocating that such changes in operations or capacity are necessarily prudent, but should be considered if feasible and increased gas demand warrants further study.

Figure 3-6. Base Case Plus All Merchant Plants

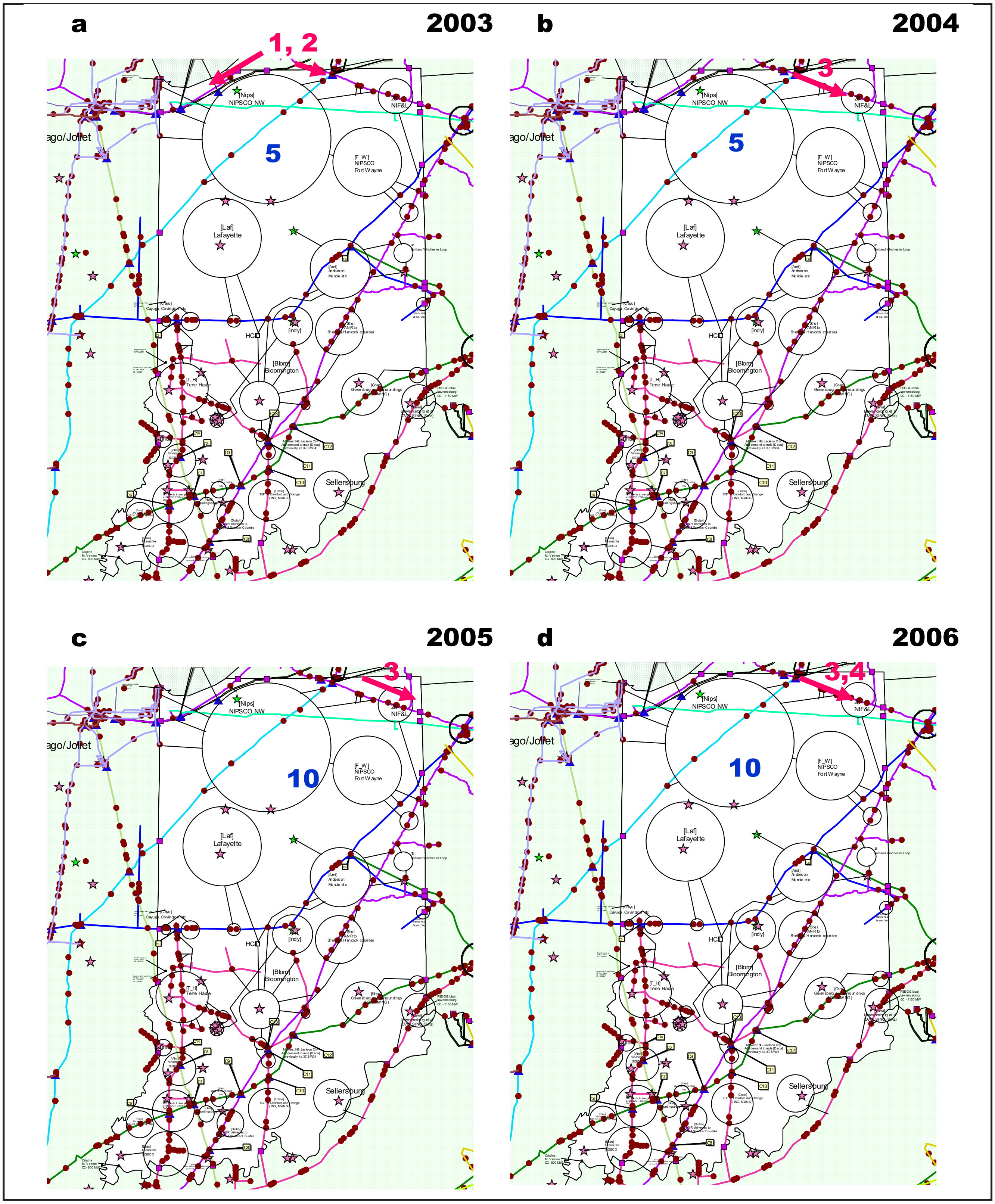


Assumed added in 2004: 1153 MW CC in node Terre Haute, 800 MW CC in node Bloomington, 1150 MW CC in node Lawrenceburg, 340 MW CT in node Shelby

Assumed added in 2005: 550 MW CC in node Terre Haute, 900 MW CC in node Pike, 800 MW CC in node Evansville

Assumed added in 2006: 540 MW CC in node NIPSCO_NW

Figure 3-7. Base Case Plus Free Exchange



Demand Increases Downstream from Indiana

While the previous experiments indicate it appears unlikely that gas demand increases in Indiana associated with Indiana merchant plant construction alone will cause major shortages or price increases, they may occur due to increased Northeast gas demand triggered by increased CC / CT gas use.

This is the object of the next set of experiments--to measure the impact on Indiana of significant increases in gas use by CC / CT units downstream from Indiana. This scenario has the following characteristics.

As a contrast to the base case, SUFG assumes in this scenario that the winters would be colder than average. That is, the HDDs will be the average HDDs plus a standard deviation for each month. In addition, the electricity growth rate is assumed to be 2.2 percent per year for all the nodes outside Indiana as opposed to the 1.8 percent rate used in the base case.

The impact of these demand increases is shown in Figures 3-8a-d. This significant increase in the downstream demand begins to seriously impact the costs Indiana LDCs would be expected to pay for their gas as a result of economic congestion. While there still are no unmet demands caused by this increase, an examination of the figures show that the location and instances of economic congestion have both increased.

In particular, the number of storage capacity constraint congestion events is very high in 2003 and drops off suddenly in 2004. This phenomenon is explained by the assumed commissioning of a total of 3,443 MW of gas-fired merchant plants in 2004. The cost minimizing response of the model is to try and store as much gas as possible in 2003 in anticipation of that jump in demand. A further 2,250 MW of capacity is assumed commissioned in 2005 and 540 in 2006. A schematic diagram that helps to explain this phenomenon is illustrated in Figure 3-9.

The model indicates that in the month when pipeline capacity most limits the system, costs could increase by over 10 percent; the average increase for all months in the planning horizon was 1.7 percent. Similarly, in the month when storage capacity most limits the system, costs could increase by over 15 percent. The average increase caused by limits on storage capacity is 0.9 percent. Thus, for this case, Indiana gas costs increase on the average 2.6 percent over the horizon; 1.7 percent due to limited pipeline capacity and 0.9 percent due to limited storage capacity.

Unexpected Texas Gas/ANR Junction Disruption

Finally, the model is capable of simulating the impact of an unexpected short term (1 month) or longer supply disruption on Indiana gas consumers.

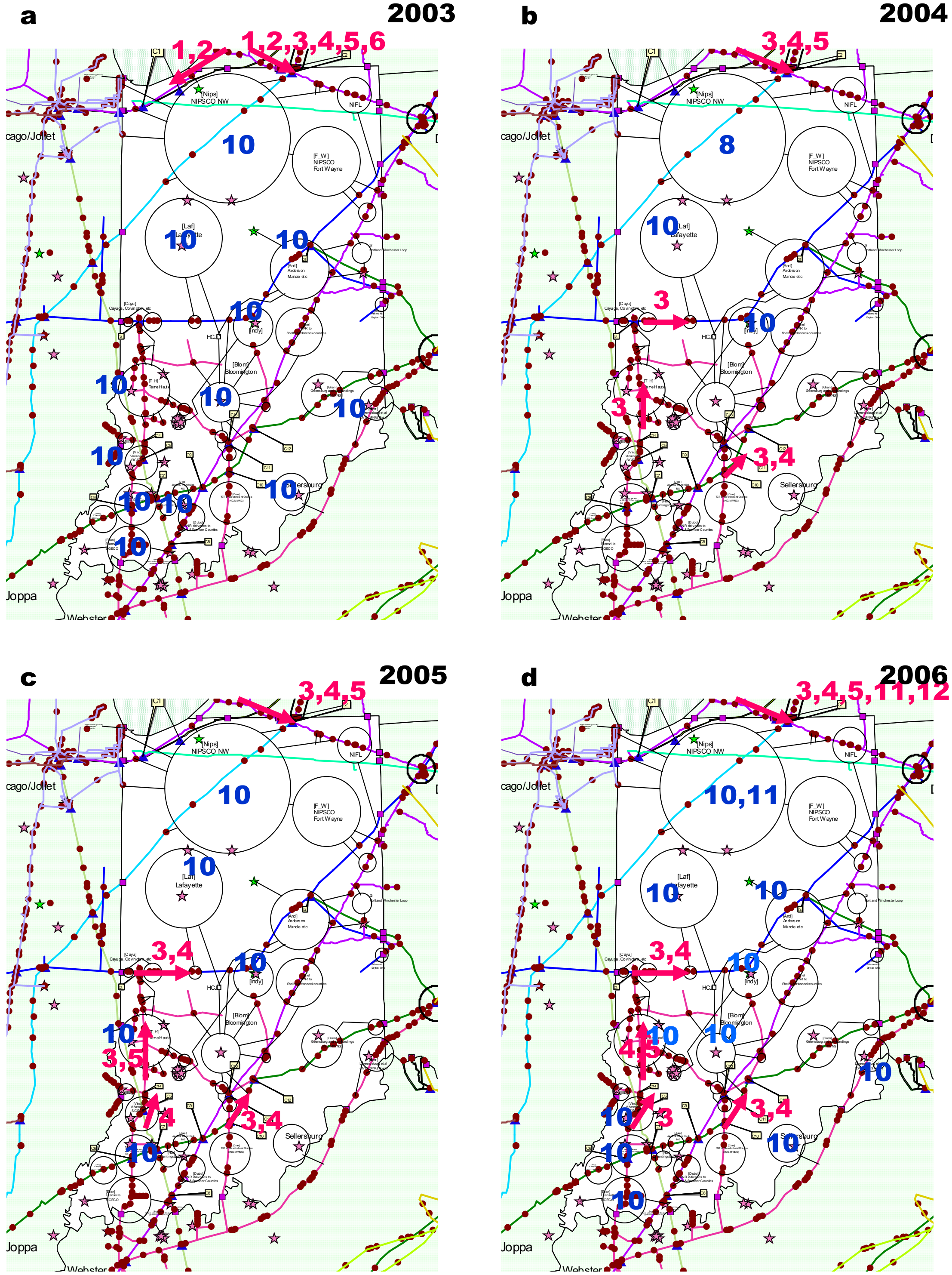
Suppose the impact of unexpectedly losing one of the major gas transfer points -- say, the Texas Gas / ANR junction in Webster, KY-- for one month was to be determined, and suppose it was to happen on the first of January 2004 without warning.

The structure of the model makes it easy to analyze this case. First, the normal base case levels of storage for December 2003 immediately prior to the disruption would be determined, as they would be the storage levels in the system on the eve of the unexpected event. Next, these opening storage levels would be used for a new experiment, which would start in January 2004 with the Texas Gas / ANR interconnection point removed from the system for the month of January, and then reinstated for the remainder of the shortened horizon.

The disruption caused by the event could then be measured by a comparison of the costs and systems behavior between the base case for the 48 month period and the new run with the Texas Gas / ANR interconnection out of operation during January 2004.

The results of this comparison are shown in Figure 3-10a-d. Figure 3-10a is identical to Figure 3-5a, the base case since the outage was not anticipated in 2003.

Figure 3-8. Above Average Demand Plus All Merchant Plants

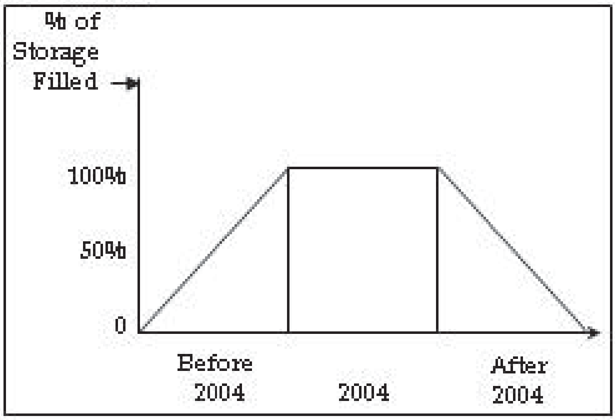


Assumed added in 2004: 1153 MW CC in node Terre Haute, 800 MW CC in node Bloomington, 1150 MW CC in node Lawrenceburg, 340 MW CT in node Shelby

Assumed added in 2005: 550 MW CC in node Terre Haute, 900 MW CC in node Pike, 800 MW CC in node Evansville

Assumed added in 2006: 540 MW CC in node NIPSCO_NW

Figure 3-9. Storage Capacity Constraint Schematic



What happens in 2004 is instructive and encouraging. It develops that while there are unmet demands in the month immediately following the disruption, the system is able to recover quickly, and by early 2004, there are no remaining economic consequences of the interruption within Indiana. Outside of the cost of unmet demands, which is considerable, Indiana costs for the case increase by only 0.9 percent over the horizon, compared to 0.5 percent for base case.

To see the lessening of the impact of the disruption if the event was expected, as would be the case if the exchange were to be down for scheduled maintenance, an experiment assuming this was carried out. Figure 3-11a-d shows the congestion points in the system, and the months when congestion appears within each year.

What is surprising is the small decrease in the cost of the disruption if it was anticipated, when compared to the unanticipated disruption case.

Average costs increase 0.75 percent in the anticipated outage case, while in the unanticipated disruption case, costs increase 0.9 percent on average. This result will need further study before it can be taken as an indication of the real situation.

Extreme Weather Plus All Indiana Merchant Plants Experiment

The regional demand in this experiment was arrived at by assuming weather, both winter and summer, two standard deviations more severe than the base case. In addition to this, all the gas-fired merchant plants proposed in Indiana are assumed to come on line at their proposed dates. The results of this experiment, shown in Figure 3-12a-d, are compared with those of the above average demand combined with all merchant plants being online in Indiana. This experiment results in approximately 20 percent more pipeline and storage congestion events than the above average plus merchant plants case. The Crossroads pipeline, which does not have congestion events any other experiment has one month when its capacity is binding in 2004.

Concluding Remarks

The experiments included in this report were chosen to illustrate the types of issues the model is capable of investigating and do not represent a forecast of future industry condition. Refinements to the model, that take into account the sugguestions given by various parties in the gas industry, will continue. The main conclusion from the experiments is that the occurrence of economic congestion in the interstate pipelines supplying Indiana and the storage facilities inside Indiana is dependent on the demand in the states downstream of Indiana.

End Note

1. Energy Information Administration, "Annual Energy Outlook 2002," December 2001.

Figure 3-10. Forced Outage Case

(The flow on the Williams Texas Gas Transmission & ANR Pipelines is stopped at the junction in Webster, Kentucky)

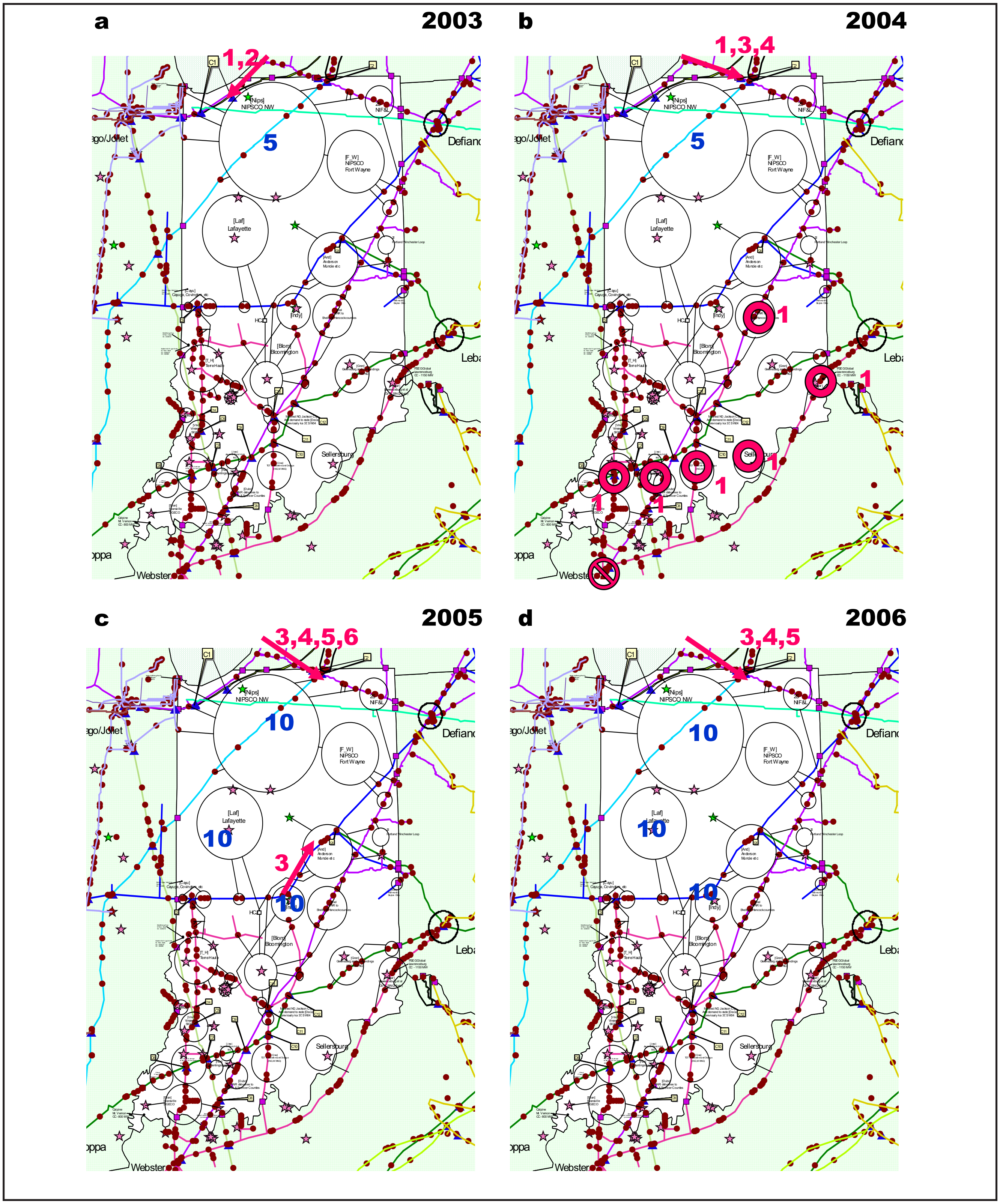


Figure 3-11 Planned Outage Case

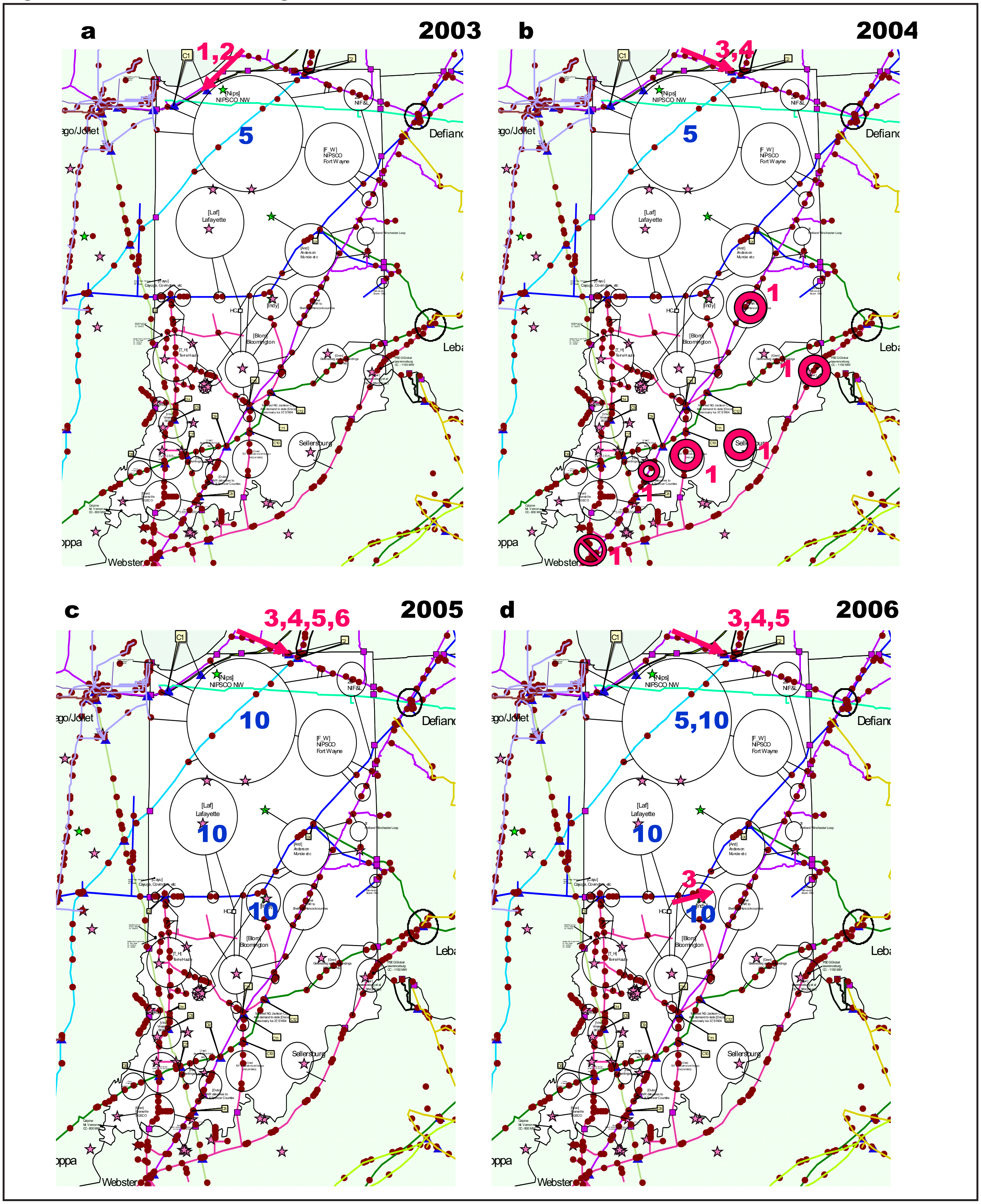
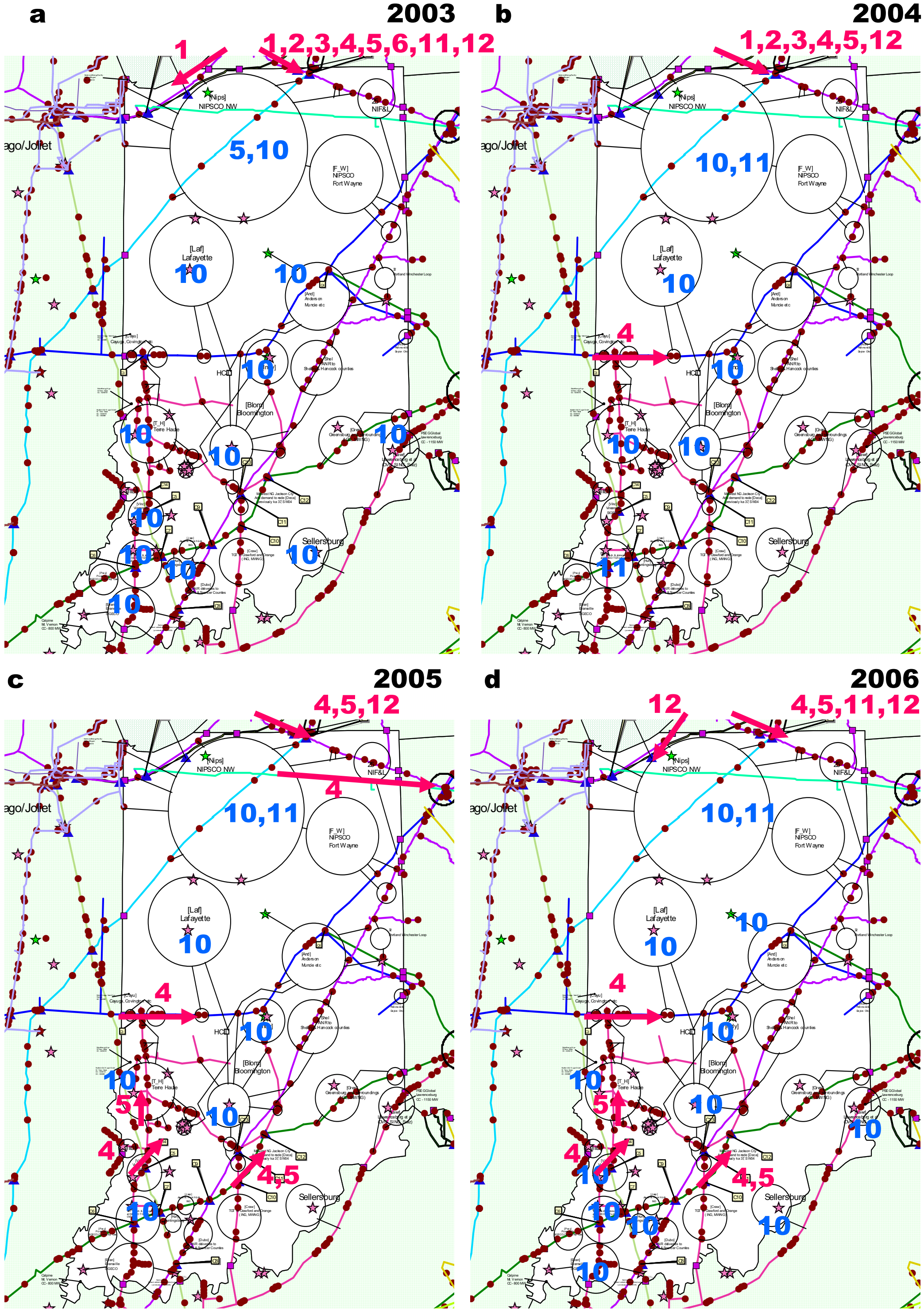


Figure 3-12. Extreme Weather Plus All Indiana Merchant Plants



Assumed added in 2004: 1153 MW CC in node Terre Haute, 800 MW CC in node Bloomington, 1150 MW CC in node Lawrenceburg, 340 MW CT in node Shelby

Assumed added in 2005: 550 MW CC in node Terre Haute, 900 MW CC in node Pike, 800 MW CC in node Evansville

Assumed added in 2006: 540 MW CC in node NIPSCO_NW

THE MATHEMATICAL MODELS

Cost Minimization

Notation

i	Node index (city gate, boundary injection, etc.)
j	An alias of i
t	Time index (e.g., day, week or month) --currently in month t=1,2,...T (60 months)

Parameters to be Estimated

d(i,t)	Total nodal gas demand
gpl(i,j)	Gas pipeline losses coefficient
gstl(i)	Gas storage losses coefficient (in % or a linear function of storage level)
gpmax(i)	Maximum production or supply at i in bcf
pip max(i,j,t)	Gas pipeline capacity (no pressure and storage are considered at this time)
strL(i,0)	Initial gas storage of LDC(s) -- not used yet
str(i,0)	Initial gas storage of interstate pipeline company(s)
strL(i,T)	Ending gas storage of LDC(s)--not used yet
str(i,T)	Ending gas storage of pipeline company(s)
strLmax(i)	Maximum gas storage at i of LDC(s) -- not used yet
strmax(i)	Maximum gas storage of i of pipeline company(s)
strLmin(i)	Minimum gas storage at i of LDC(s) -- not used yet
strmin(i)	Minimum gas storage of i of pipeline company(s)
wh(i,j,0)	Gas transportation (wheeling) charge $/bcf or $/mmcf for gas flow not approaching pipmax
wh(i,j,k)	Incremental gas transportation charge $/bcd or $/mmcf, k-1,2 for cases when flow approaches pipmax
a(i,f)	Intercept of the inverse demand function -- aggregate (for welfare max and gaming)
b(i,t)	Slope of the inverse demand function -- aggregate (for welfare max and gaming)
p0(i,t)	Aggregate price forecast for node i at t--used for the construction of the inverse de mand function
Ep(i,t)	Price elasticity -- used for the construction of the inverse demand function
a0(i,t)	Price forecast for cost min, fixed for each time and each supply node
b0(i,t)	Slope of the supply price forecast
Int(t)	Interest rate for time t
Cc(t)	Capacity charge for gas stored at time t
lp(i,t)	Local gas production forecast
Cunsr	Unserved gas cost (for cost min)

Variables

gp(i,t)	Natural gas production or supply in bcf (billion cubic feet)
gf(i,j,t)	Gas flow from i to j at t
gsti(i,t)	Gas flow into the storage at t
gsto(i,t)	Gas flow out of the storage at t
gpo(i,t)	Gas storage cost (incremental) -- the cost of operating storage pumps
q(i,t)	Gas demand (for welfare max and gaming)
str(i,t)	Gas storage at i and t in bcf
unsr(i,t)	Unserved gas (for cost min)
wh(i,j,t)	Variable transportation cost; can be a linear function with a positive slope
pcp(i,j,k,t)	Pipeline capacity use variable when flow approaches pipmax (k-1,2), incremented in mmcf

The following are for categorical demands and not used yet.

gsp(i,t)	Gas supply price at i and t, expressed as a linear function:
	gsp(i,t) = a0(i,t) + b0(i,t)gp(i,t)
gdi(i,t)	Gas price industrial customers willing to pay (a function of demand)
	gdi(i,t) = ai(i,t)-bi(i,t)di(i,t) where di(i,t) is actual consumption
gdc(i,t)	Gas price commercial customers willing to pay
	gdc(i,t) = ac(i,t) - bc(i,t)dc(i,t)
gdr(i,t)	Gas price residential customers willing to pay
	gdr(i,t) = ar(i,t) - br(i,t)dr(i,t)
gdp(i,t)	Gas demand of power producers (gdp(i,p,t) can also be used where p is index for a specific power producer)

Program control switches: U Switch on / off the quadratic term of the supply price function

Model Assumptions

1. Gas flow is as fast as electricity
2. No expansion of storage facilities
3. Fixed storage cost is ignored

Model 1: Cost Minimization without Extra Pipeline Capacity Use But with Variable Transportation Charge

$$Min \sum_t \sum_i \{a0(i,t)gp(i,t) + U * b0(i,t)gp(i,t)^2 + Cunsr * unsr(i,t)$$
$$+ \sum_{j \mapsto i} wh(i,j,t)gf(i,j,t)\} + str(i,t)Cc(t) + [gsti(i,t) + gsto(i,t)]gpo(i,t)\} / (1 + Int(t))^t$$

Subject to:

$$d(i,t) = lp(i,t) + gp(i,t) + unsr(i,t) + gsto(i,t) - gsti(i,t)$$
$$- \sum_{j \mapsto i} [gf(i,j,t)(1 - gpl(i,j)) - gf(j,i,t)], \forall\, i,t$$

(demand balance)

$$str(i,t) = (1 - gstl(i))[str(i,t-1) + gsti(i,t) - gsto(i,t)], \forall\, i,t$$

(storage balance)

$$gp(i,t) \le gp\max(i,t), \forall\, i,t$$

(gas production or supply upper bound)

$$str\min(i,t) \le str(i,t) \le str\max(i,t), \forall\, i,t$$

(gas storage upper bound)

$$gf(i,j,t) \le pip\max(i,j,t), \forall\, i,j,t.$$

(gas flow upper bound)

$$gf(i1, jc, t) = gf(jc, i1, t)(1 - gpl(i1, jc)), \forall\, i1, jc, t.$$

(Zero gas exchange at any pipeline intersection of different companies. Note $i1$=set of intersection nodes, jc=set of nodes belong to one company and directly connected to $i1$.

$$gsti(i,t) \le gi\max(i,t), \forall\, i,t.$$
$$gsto(i,t) \le go\max(i,t), \forall\, i,t.$$

Upper limits for gas fill-in and withdrawal from storage.

Initial conditions (e.g., initial storage levels)
Ending conditions (e.g., terminating storage levels)
Non-negativity of variables.

Note: Demand must be lower-bounded or fixed.

Model Ia: Cost Minimization Without Extra Pipeline Capacity Use But With Stepwise Transportation Charges

Transportation cost can be stepwise or piecewise linear. Since there are many different transportation costs observed for each pipeline, at least three pieces should be used for a reasonable approximation. If stepwise pieces are used, the model can then be modified as follows. (This is actually a price discrimination model since prices are different for different levels of gas flows.)

$$Min \sum_t \sum_i \{a0(i,t)gp(i,t) + U * b0(i,t)gp(i,t)^2 + Cunsr * unsr(i,t)$$
$$+ \sum_{j \mapsto i} wh(i,j,t)gf(i,j,t)\} + str(i,t)Cc(t) + [gsti(i,t) + gsto(i,t)]gpo(i,t)\} / (1 + Int(t))^t$$

Subject to:

$$d(i,t) = lp(i,t) + gp(i,t) + unsr(i,t) + gsto(i,t) - gsti(i,t)$$
$$- \sum_{j \mapsto i} [gf(i,j,t)(1 - gpl(i,j)) - gf(j,i,t)], \ \forall\ i,t$$

(demand balance)

$$str(i,t) = (1 - gstl(i))[str(i,t-1) + gsti(i,t) - gsto(i,t)], \ \forall\ i,t$$

(storage balance)

$$gp(i,t) \le gp\max(i,t), \ \forall\ i,t$$

(gas production or supply upper bound)

$$str\min(i,t) \le str(i,t) \le str\max(i,t), \ \forall\ i,t$$

(gas storage upper bound)

$$gf(i,j,t) \le pip\max(i,j,t), \ \forall\ i,j,t.$$

(gas flow upper bound)

$$gf(i1, jc, t) = gf(jc, i1, t)(1 - gpl(i1, jc)), \ \forall\ i1, jc, t.$$

(Zero gas exchange at any pipeline intersection of different companies. Note $i1$=set of intersection nodes, jc=set of nodes belong to one company and directly connected to $i1$.

$$gp(i,t) \le gp\max(i,t),\ \forall\ i,t$$

(gas production or supply upper bound)

$$str\min(i,t) \le str(i,t) \le str\max(i,t),\ \forall\ i,t$$

(gas storage upper bound)

$$gf(i,j,t) \le pip\max(i,j,t),\ \forall\ i,j,t.$$

(gas flow upper bound)

$$gf(i1,jc,t) = gf(jc,i1,t)(1 - gpl(i1,jc)),\ \forall\ i1,jc,t.$$

(Zero gas exchange at any pipeline intersection of different companies. Note *i*1=set of intersection nodes, *jc*=set of nodes belong to one company and directly connected to *i*1.

$$gsti(i,t) \le gi\max(i,t),\ \forall\ i,t.$$

$$gsto(i,t) \le go\max(i,t),\ \forall\ i,t.$$

Upper limits for gas fill-in and withdrawal from storage.

Initial conditions (e.g., initial storage levels)
Ending conditions (e.g., terminating storage levels)
Non-negativity of variables.

Note: Demand must be lower-bounded or fixed.

PRIMARY DATA FOR THE GAS MODELING SYSTEM

The primary data for the gas modeling system is summarized in this appendix. The first is a sample gas demand forecast that is listed in Table B-1. Assumed historical data is used in fitting linear demand forecast functions and the sample forecast is produced using the functions and the average HDDs and CDDs as necessary. Table B-2 shows the gas demand projections for the states other than Indiana. These projections have been explained in detail in Chapter 2 of this report. Finally, Table B-3 presents city gate gas price forecasts that are based on the yearly gas forecast by EIA.

Table B-1. Example of Forecasting Techniques

Year	Jan HDD	Jan Demand Dth	Year	Feb HDD	Feb Demand Dth	Year	March HDD	March Demand Dth
1980	1172	15561012	1980	1195	16741026	1980	908	7780506
1981	1282	17199825	1981	915	16209836	1981	749	8599912
1982	1523	17275539	1982	1178	17445712	1982	922	8637769
1983	1100	20198357	1983	886	11787830	1983	760	10099178
1984	1431	17078494	1984	838	12901726	1984	1080	8539247
1985	1401	16972657	1985	1153	14096272	1985	727	8486328
1986	1208	15942677	1986	1117	13204873	1986	760	7521339
1987	1224	13570402	1987	950	11266525	1987	766	6785201
1988	1347	17151470	1988	1220	15304551	1988	851	8575735
1989	972	13874002	1989	1190	14580231	1989	865	6937001
1990	954	14109688	1990	936	12579758	1990	751	7054844
1991	1260	16928236	1991	910	12891643	1991	722	8464118
1992	1104	15532687	1992	915	13470165	1992	850	7766343
1993	1130	16499179	1993	1130	15613534	1993	925	8249589
1994	1505	19705456	1994	1186	16044310	1994	875	9852728
1995	1224	17654433	1995	1105	15969767	1995	759	8827216
1996	1258	18196859	1996	1072	16279521	1996	1005	9098429
1997	1370	20610202	1997	983	15166566	1997	844	10305101
1998	1026	16959098	1998	775	14365288	1998	824	8479549
1999	1305	21625701	1999	893	16774325	1999	968	10812851
2000	1218	21025771	2000	863	16796831	2000	646	10512886
2001	1242	15944873	2001	1026	13635176	2001	951	7972436
Forecast						**Forecast**		
2002	1239	18992611	2002	1020	15600982	2002	1239	15906248
2003	1239	19147239	2003	1020	15681500	2003	1239	16076798
2004	1239	19301867	2004	1020	15761019	2004	1239	16247347
2005	1239	19456495	2005	1020	15840537	2005	1239	16417897
2006	1239	19611123	2006	1020	15920056	2006	1239	16588446
2007	1239	19765750	2007	1020	15999574	2007	1239	16758996

Table B-2. Demand Projections Used in the Base Case Outside Indiana (mmcf/month)

Year	Month	Illinois	Kentucky	Michigan	Ohio	Pennsylvania	West Virginia	Northeastern Demand
2003	Jan	158096	28814	134486	146384	95421	13921	372766
	Feb	127454	23303	115741	121873	82618	12018	333708
	Mar	111620	21411	104860	106988	72837	11078	306433
	Apr	76211	14581	80813	79711	54952	8289	249362
	May	52225	11112	53098	53028	36079	6112	191503
	Jun	39469	9399	40763	37757	26884	4681	168497
	Jul	41665	9683	39322	36403	27509	4515	178305
	Aug	41235	9569	38462	33774	26801	4598	167144
	Sept	41650	9915	38365	35335	28791	5324	169827
	Oct	65519	14213	57549	53613	40462	7189	195601
	Nov	102802	20279	88183	88319	57258	9851	248119
	Dec	138659	26105	107028	117276	75159	12261	293258
2004	Jan	159273	28820	135448	146235	96738	13799	380543
	Feb	128445	23308	116592	121724	83750	11896	340541
	Mar	112681	21416	105735	106839	74039	10956	313205
	Apr	77168	14586	81599	79562	56050	8167	256008
	May	53352	11117	53995	52879	37347	5990	198763
	Jun	40636	9405	41780	37608	28192	4559	175970
	Jul	42969	9689	40319	36254	28953	4393	185958
	Aug	42699	9575	39593	33625	28406	4476	174558
	Sept	42778	9921	39290	35186	30060	5202	176564
	Oct	66530	14218	58427	53464	41614	7067	202386
	Nov	103853	20285	89032	88169	58449	9729	255149
	Dec	140007	26110	107976	117127	76647	12138	301018
2005	Jan	160449	28826	136411	146086	98055	13677	388320
	Jan	129436	23314	117443	121575	84882	11774	347374
	Feb	113743	21422	106611	106690	75241	10834	319978
	Mar	78126	14592	82384	79413	57149	8045	262655
	Apr	54479	11123	54892	52730	38615	5868	206024
	May	41803	9411	42797	37459	29500	4437	183443
	Jun	44272	9694	41316	36105	30397	4270	193612
	Jul	44162	9581	40723	33476	30011	4354	181972
	Aug	43906	9926	40214	35037	31329	5080	183301
	Sept	67542	14224	59304	53315	42766	6945	209170
	Oct	104904	20290	89881	88020	59641	9607	262179
	Nov	141355	26116	108925	116978	78136	12016	308778
	Dec	161625	28831	137374	145937	99372	13555	396098
2006	Jan	130427	23320	118295	121426	86014	11651	354206
	Feb	114804	21428	107486	106541	76443	10712	326750
	Mar	79083	14598	83170	79264	58247	7923	269302
	Apr	55606	11129	55789	52581	39883	5746	213284
	May	42971	9416	43814	37310	30809	4314	190915
	Jun	45575	9700	42314	35955	31841	4148	201266
	Jul	45626	9586	41854	33327	31615	4232	189386
	Aug	45034	9932	41138	34887	32598	4958	190038
	Sept	68553	14230	60181	53166	43918	6823	215955
	Oct	105955	20296	90730	87871	60833	9485	269209
	Nov	142702	26122	109873	116829	79624	11894	316538
	Dec	162801	28837	138337	145788	100689	13432	403875
2006	Jan	131419	23326	119146	121277	87146	11529	361039
	Feb	115865	21433	108361	106392	77646	10590	333523
	Mar	80041	14604	83956	79115	59345	7801	275948
	Apr	56733	11134	56685	52432	41151	5624	220544
	May	44138	9422	44831	37161	32117	4192	198388
	Jun	46878	9706	43311	35806	33285	4026	208920
	Jul	47090	9592	42985	33178	33220	4109	196800
	Aug	46162	9938	42062	34738	33867	4836	196775
	Sept	69564	14235	61059	53017	45070	6700	222740
	Oct	107005	20302	91579	87722	62025	9362	276239
	Nov	144050	26128	110821	116680	81113	11772	324298
	Dec	158096	28814	134486	146384	95421	13921	372766

Table B-3. Supply Price Forecast ($/mmBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Year 1												
S1	3.5	3.5	3.2	3.1	3.3	3.4	3.5	3.4	3.5	3.4	3.5	3.7
S2	3.2	3.2	3.0	2.9	3.1	3.1	3.2	3.1	3.2	3.1	3.2	3.4
S3	3.1	3.0	2.8	2.8	2.9	3.0	3.0	3.0	3.1	3.0	3.1	3.3
S4	3.6	3.5	3.4	3.2	3.1	3.1	3.1	3.2	3.2	3.2	3.4	3.5
S5	3.4	3.3	3.3	3.5	3.6	3.4	3.2	3.1	3.1	3.3	3.5	3.6
S6	3.2	3.1	2.9	3.0	3.3	3.5	3.5	3.5	3.6	3.4	3.6	3.5
S7	3.2	3.1	2.9	3.0	3.3	3.5	3.5	3.5	3.6	3.4	3.6	3.5
S8	3.1	3.0	2.9	3.0	3.3	3.5	3.5	3.4	3.3	3.3	3.5	3.4
Year 2												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
S1	3.5	3.4	3.2	3.1	3.3	3.4	3.4	3.4	3.5	3.4	3.5	3.7
S2	3.2	3.1	2.9	2.8	3.0	3.1	3.1	3.0	3.2	3.1	3.2	3.3
S3	3.1	3.0	2.8	2.7	2.9	3.0	3.0	2.9	3.0	2.9	3.0	3.2
S4	3.5	3.4	3.3	3.1	3.0	3.0	3.1	3.1	3.1	3.2	3.3	3.4
S5	3.3	3.2	3.2	3.4	3.5	3.3	3.2	3.0	3.1	3.2	3.4	3.5
S6	3.1	3.0	2.9	3.0	3.3	3.5	3.5	3.4	3.6	3.3	3.6	3.4
S7	3.1	3.0	2.9	3.0	3.3	3.5	3.5	3.4	3.6	3.3	3.6	3.4
S8	3.1	3.0	2.8	2.9	3.2	3.4	3.4	3.3	3.2	3.2	3.5	3.3
Year 3												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
S1	3.4	3.3	3.1	3.0	3.2	3.3	3.3	3.3	3.4	3.3	3.4	3.6
S2	3.2	3.1	2.9	2.8	3.0	3.1	3.1	3.0	3.1	3.0	3.1	3.3
S3	3.0	2.9	2.8	2.7	2.8	2.9	2.9	2.9	3.0	2.9	3.0	3.2
S4	3.4	3.3	3.3	3.1	3.0	3.0	3.0	3.1	3.1	3.1	3.3	3.4
S5	3.3	3.2	3.2	3.4	3.5	3.3	3.1	3.0	3.0	3.2	3.4	3.5
S6	3.1	3.0	2.8	2.9	3.3	3.5	3.5	3.4	3.5	3.3	3.5	3.4
S7	3.1	3.0	2.8	2.9	3.3	3.5	3.5	3.4	3.5	3.3	3.5	3.4
S8	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.1	3.2	3.4	3.3
Year 4												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
S1	3.4	3.3	3.1	3.0	3.2	3.3	3.3	3.2	3.4	3.3	3.4	3.6
S2	3.1	3.0	2.8	2.7	2.9	3.0	3.0	3.0	3.1	3.0	3.1	3.3
S3	3.1	3.0	2.8	2.7	2.9	3.0	3.0	2.9	3.0	3.0	3.1	3.2
S4	3.5	3.4	3.3	3.1	3.0	3.0	3.1	3.1	3.1	3.2	3.3	3.4
S5	3.2	3.1	3.1	3.3	3.5	3.2	3.1	2.9	3.0	3.1	3.3	3.4
S6	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.5	3.2	3.5	3.3
S7	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.5	3.2	3.5	3.3
S8	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.2	3.2	3.5	3.3
Year 5												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
S1	3.4	3.3	3.1	3.0	3.2	3.3	3.3	3.2	3.3	3.2	3.3	3.5
S2	3.2	3.1	2.9	2.8	3.0	3.0	3.1	3.0	3.1	3.0	3.1	3.3
S3	3.1	3.0	2.8	2.7	2.9	3.0	3.0	3.0	3.1	3.0	3.1	3.2
S4	3.5	3.4	3.3	3.1	3.0	3.0	3.1	3.1	3.1	3.2	3.3	3.4
S5	3.2	3.1	3.1	3.3	3.5	3.2	3.1	2.9	3.0	3.1	3.4	3.5
S6	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.5	3.2	3.5	3.3
S7	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.5	3.2	3.5	3.3
S8	3.0	2.9	2.8	2.9	3.2	3.4	3.4	3.3	3.2	3.2	3.4	3.3

bcf Billion cubic feet.

Btu British Thermal Unit. The quantity of heat required to raise one pound of water, one degree Fahrenheit.

City Gate Physical location where gas is delivered by an interstate pipeline to a local distribution company.

Combined Cycle A combustion turbine installation using waste heat boilers to capture exhaust energy for steam generation.

Combustion Turbine An electric generating unit in which the prime mover is a gas turbine engine. (Also referred to as Simple Cycle.)

Congestion A gas flow loading condition in which flow reaches the pipeline capacity.

Constraint A physical or artificial (such as government policy) condition / boundary that is not allowed to be violated or that must be respected under a normal environment.

Cubic Feet The most common unit of measure of gas volume. One cubic foot roughly equals 1,000 Btus.

Curtailment Reduction of gas deliveries because of a shortage of supply or because demand for service exceeds a pipeline's capacity.

Degree Day, Cooling (CDD) A measure of the hotness of the weather experience, based on the extent to which the daily mean temperature falls above a reference termperature, usually 65 degrees F.

Degree Day, Heating (HDD) A measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below a reference temperature, usually 65 degrees F.

Dekatherm 10 therms or 1 million Btu's. Very roughly: 1 mcf = 1 MMBtu = 1 Dth.

Dispatch The operational control of an integrated electric system to: (1) assign generation levels to specific generating stations and other sources of supply to effect the most reliable and economical supply as the area load rises or falls; (2) control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures; (3) operating the interconnection; and (4) scheduling energy transactions with other interconnected electric utilities.

Distribution Local pipeline delivery of natural gas.

Energy Information Administration (EIA) Since October 1977, the Energy Information Administration (EIA) of the Department of Energy (DOE) has been responsible for collecting and publishing statistical data on energy production, consumption, prices, resources and projections of supply and demand. The EIA serves as an independent statistical and analytical agency within the DOE.

Federal Energy Regulatory Commission (FERC) An independent agency created within the Department of Energy, FERC is vested with broad regulatory authority. Virtually every facet of electric and natural gas production, transmission and sales conducted by private investor-owned utilities, corporations or public marketing agencies was placed under the commission through either direct or indirect jurisdiction if any aspect of their operations were conducted in interstate commerce. As successor to the former Federal Power Commission (FPC), the FERC inherited practically all of the FPC's interstate regulatory functions over the electric power and natural gas industries.

Interstate Pipeline A federally regulated company engaged in the business of transporting natural gas across state lines from producing regions to end use markets.

Kilowatthour (kWh) The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatthour equals 1,000 watthours.

LDC Local Distribution Company (i.e. the utility).

LNG Liquified Natural Gas. Natural gas converted to a liquid state, usually for storage purposes, by pressure and severe cooling.

Megawatt (MW) One megawatt equals one million watts.

mcf 1,000 cubic feet.

mmcf A million cubic feet.

Pipeline Capacity The maximum amount of gas that can be transported through a pipeline in a given period of time.

Therm Unit of measure of heat content, equivalent to 100,000 Btu's.

Uncertainty Falling short of complete knowledge about an outcome or result. SUFG uses this term in context with forecast outcome.

Wellhead A term to describe the production fields. It is the wellhead price of natural gas at the source. Usually, this is the total price delivered to the city gate minus transportation and storage costs.

References

1. Natural Gas Glossary. Website: http://www.allenergy.com/natural.gas.
2. Natural Gas Glossary. Website: http://www.gaa.org/content/NavigationMenu/.
3. Natural Gas Desk Book, Mobile Natural Gas Inc., 3rd printing, February 1994.
4. EIA Glossary. Website: http://www.eia.doe.gov/pub/oil_gas/natural_gas/.