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NATURAL GAS INFRASTRUCTURE AND CAPACITY CONSTRAINTS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY POLICY, NATURAL RESOURCES AND REGULATORY AFFAIRS

OF THE

COMMITTEE ON GOVERNMENT REFORM

HOUSE OF REPRESENTATIVES

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CONTENTS

	Page
Hearing held on October 16, 2001	1
Statement of:	
Carpenter, Paul R., principal, Brattle Group; Professor Joseph Kalt, John F. Kennedy School of Government, Harvard University; Paul Amirault, vice president, marketing, Wild Goose Storage, Inc.; and Gay Friedmann, senior vice president, legislative affairs, Interstate Natural Gas Association of America	89
Lorenz, Lad, director, capacity and operational planning, Southern California Gas Co.	56
Lynch, Loretta, president, California Public Utilities Commission	29
Moore, Michal, Commissioner, California Energy Commission	46
Wood, Patrick, III, Chairman, Federal Energy Regulatory Commission	9
Letters, statements, etc., submitted for the record by:	
Amirault, Paul, vice president, marketing, Wild Goose Storage, Inc., prepared statement of	124
Carpenter, Paul R., principal, Brattle Group, prepared statement of	92
Friedmann, Gay, senior vice president, legislative affairs, Interstate Natural Gas Association of America:	
Major projects pending	156
Prepared statement of	134
Kalt, Professor Joseph, John F. Kennedy School of Government, Harvard University, prepared statement of	106
Lorenz, Lad, director, capacity and operational planning, Southern California Gas Co., prepared statement of	58
Lynch, Loretta, president, California Public Utilities Commission, prepared statement of	31
Moore, Michal, Commissioner, California Energy Commission, prepared statement of	48
Ose, Hon. Doug, a Representative in Congress from the State of California:	
Historical Daily Spot Gas Prices	69
Prepared statement of	2
Waxman, Hon. Henry A., a Representative in Congress from the State of California, prepared statement of	7
Wood, Patrick, III, Chairman, Federal Energy Regulatory Commission, prepared statement of	11

NATURAL GAS INFRASTRUCTURE AND CAPACITY CONSTRAINTS

TUESDAY, OCTOBER 16, 2001

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY POLICY, NATURAL RESOURCES AND REGULATORY AFFAIRS,
COMMITTEE ON GOVERNMENT REFORM,
Washington, DC.

The subcommittee met, pursuant to notice, at 12 p.m., in room 2154, Rayburn House Office Building, Hon. Doug Ose (chairman of the subcommittee) presiding.

Present: Representatives Ose, Shays, and Kucinich.

Staff present: Dan Skopec, staff director; Barbara Kahlow, deputy staff director; Connie Lausten, professional staff member; Regina McAllister, clerk; Phil Barnett, minority chief counsel; Paul Weinerger, minority counsel; and Jean Gosa, minority assistant clerk.

Mr. OSE. Good afternoon. Welcome to today's hearing of the Energy Policy, Natural Resources and Regulatory Affairs Subcommittee. I'm going to dispense with my opening statement and just submit it to the record.

I would yield to Mr. Waxman accordingly.

[The prepared statement of Hon. Doug Ose follows:]

Chairman Doug Ose
Opening Statement
Natural Gas Capacity and Infrastructure Constraints
October 16, 2001

Today we will examine the adequacy or inadequacy of the natural gas capacity and infrastructure in California. California serves as a case study since the issues that today's witnesses will address apply anywhere in the United States. By examining California, I hope that the same inadequacies can be avoided in other areas of the United States.

The 1978 Natural Gas Policy Act, the 1989 Natural Gas Wellhead Decontrol Act, and Federal Energy Regulatory Commission (FERC) Orders No. 436, 636 and 637, issued in 1985, 1992 and 2000, deregulated the interstate natural gas industry. Congressional deregulation of wellhead prices and FERC's Orders introduced competition into the interstate natural gas industry; as a result, customers benefited from lower natural gas prices. Despite the last 15 years of relatively low natural gas prices, from June 2000 to May 2001, most of the country experienced very high natural gas prices, particularly in Southern California.

Several factors most likely added to these high natural gas prices. From June 2000 to May 2001, California and the West experienced a hot, dry year, coupled with a booming economy and a great need for energy. Because the last few years were exceptionally dry, the West had less hydropower than normal and States surrounding California had less excess electricity to sell to it. California found that it required more natural gas to fuel older natural gas-fired plants and less efficient peaking facilities to meet its electricity needs.

By August 2000, natural gas prices were almost double at the California border compared to April 2000. Then, on August 19, 2000, El Paso Natural Gas had a fatal explosion that reduced the amount of natural gas on its South Mainline, which feeds Southern California, by 1,100 million cubic feet per day (MMcf/d) for about a week. Natural gas prices increased after the initial announcement, but declined after the approximately 500 to 700 MMcf/d of capacity delivered to Southern California was recovered. The impact was also reduced natural gas capacity delivered to Southern California throughout the winter.

In November 2000, a cold snap occurred on the East and West Coasts and, as a result, natural gas prices increased around the country. Prices remained high through most of the winter. At that time, the California electricity and natural gas markets became intrinsically linked and, through most of November 2000 to May 2001, they were significantly higher than throughout the rest of the United States. Wellhead prices of natural gas remained relatively stable during this time period, while natural gas prices increased dramatically at the California border, especially in Southern California.

Several factors came together that added to the situation. First, California is increasingly dependent on natural gas for electricity production. Gas-fired generation accounted for

49 percent of the power in California compared to 18 percent in the New York Power Pool (NYPP) and only 4 percent in the Pennsylvania, New Jersey and Maryland power pool (PJM). Power generation and industrial facilities were previously able to switch fuels. In the 1990s, California banned the use of fuel oil and fuels that do not burn as cleanly as natural gas. The tradeoff for clean air is a lack of fuel flexibility and a greater dependence on natural gas.

The second factor is that there is not enough interstate capacity for transmission of natural gas. The California Gas Report's 20-year forecast for natural gas demand was met in the year 2000, not 2020. In addition, States surrounding California, and particularly those immediately East of California, have a growing demand that competes for the natural gas that would otherwise be delivered to the California border.

A third factor is that intrastate capacity is limited. The Department of Energy's Energy Information Administration, California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and Southern California Gas all reported that there is less take-away capacity than delivery capacity. The disconnect in infrastructure between the interstate and intrastate capacity most likely added to the supply constraints and thereby caused prices to rise more than they should have.

The fourth reason pertains to natural gas storage. As prices increased throughout the summer of 2000, little to no natural gas was injected into storage and some was withdrawn. As a consequence, California utilities entered the winter low on storage. Storage plays an important role in leveling prices and making the natural gas infrastructure more efficient and economical.

The last factor is the limited in-State production of natural gas. California regulatory provisions and company policies require most of the small producers to produce at least 10,000 cubic feet per day in order to be connected to the gathering lines. If this requirement were lifted, there would be another 60 to 200 MMcf/d of natural gas available. While it may not be a significant amount of natural gas, it is another resource in California's backyard.

Since May 2001, several factors helped to reduce the high natural gas prices including: a downturn in the economy; more interstate natural gas participants providing more competition; FERC's June 19, 2001 market mitigation plan, which helped bring down electricity prices; FERC's investigation into affiliate abuse and market power; FERC's market monitoring efforts; and, some build-out of intrastate capacity, including Southern California Gas's expanding its system by 375 MMcf/d by the end of this year. While some regulatory and industry actions took place, and prices have stabilized, I believe that now is the time to take action to improve the infrastructure, capacity, and policies to help create a healthy, competitive natural gas market.

Another issue that will be briefly discussed today is CPUC's April 2000 filing to FERC against El Paso Natural Gas and El Paso Merchant on the issues of affiliate abuse and anti-competitive practices on the delivered price of gas. There were allegations from

several entities in California that El Paso's conduct, with respect to its pipelines, was a factor in the high natural gas prices that Southern California experienced last winter and spring. Last week, a FERC administrative law judge (ALJ) found that El Paso Natural Gas and its affiliate colluded but could not conclude that they exercised market power. The entities participating in this case disagree with the ALJ's decision. Since this case could provide a precedent for future market power cases, I urge the Commission to carefully review the facts and make a decisive decision.

This hearing will also investigate the barriers to expanding natural gas capacity and infrastructure in California. The aim is to determine what policies prompted such a market situation in California, with our goal being to avoid a similar calamity in other regions of the United States.

I want to welcome today's witnesses. Panel I includes: FERC Chairman Patrick Wood III, CPUC President Loretta Lynch, and CEC Commissioner Michal A. Moore. Panel II includes: Lad Lorenz, Director, Capacity & Operational Planning, Southern California Gas Company; Paul Carpenter, Principal, The Brattle Group, Inc.; Professor Joseph P. Kalt, John F. Kennedy School of Government, Harvard University; Paul Amirault, Vice-President, Marketing, Wild Goose Storage, Inc.; and, Gay Friedman, Senior Vice President, Legislative Affairs and Secretary, the Interstate Natural Gas Association of America.

Mr. WAXMAN. Thank you very much, Mr. Chairman. This hearing addresses a crucial energy issue: the price and availability of natural gas. I hope it will shine a spotlight on one of the root causes of the Western energy crisis, the exorbitant natural gas prices that prevailed in California from the fall of 2000 to the spring of 2001.

In the year prior to June 2000, when the energy crisis started, electricity prices in California averaged around $36 per megawatt hour. By early 2001, they were averaging $300 to $400 per megawatt hour, a 150fold increase. After spending $7 billion in electricity in 1999 California spent $27 billion in 2000, and has already spent $23 billion in the first 8 months of 2001.

The results have been devastating. One of the California's three major utilities, PG&E, filed for bankruptcy. The State's bond rating was downgraded. Hundreds of thousands of jobs may have been lost.

As I investigated this issue, I learned that natural gas played a central role in causing electricity prices to soar. Like electricity prices, gas prices in California, particularly southern California, skyrocketed. When prices peaked in December 2000, natural gas was selling at the wellhead in Texas for $10.50 per million BTU. The border price at southern California, however, reached almost $60 per million BTU. Prices remained high in the first 5 months of 2001. And on May 8, 2001, for example, gas from the Permian producing basin that sold in Chicago for around $4.37 was selling at the California border for $12.55.

These expensive gas prices were used to justify high wholesale electricity prices, according to FERC Commissioner William Massey, when FERC set the so-called proxy clearing price for electricity this past February at $430 per megawatt, roughly $350 of that amount, over 80 percent of the price, was natural gas for an inefficient generator.

One of the key issues for California is whether market manipulation played a role in the State's high gas prices. Allegations of market manipulation have focused on El Paso Natural Gas Co., which owns the pipeline system that transports natural gas from the Southwest to California. Last week a FERC administrative law judge found that while El Paso and its marketing affiliate, El Paso Merchant Energy, "had the ability to exercise market power," it is, "not at all clear that they in fact exercised market power."

The judge did find that there was blatant collusion between the affiliates in the awarding of pipeline contracts. After reviewing transcripts of taped conversations in which El Paso Merchant asked for and received a secret discount from El Paso Natural Gas, the judge said, "If that's not hanky panky, there's no such thing as hanky panky."

The issue is now before the FERC Commissioners for a final decision. There is considerable evidence that suggests that the El Paso affiliates did manipulate the natural gas market in California. Beginning in March 2000, El Paso Natural Gas sold over a third of its pipeline capacity to El Paso Merchant. Soon after the contract began, natural gas prices at the California border began to rise.

The rise in gas prices correspond with remarkably low levels of capacity usage by El Paso Merchant. As Paul Carpenter points out

in his testimony, from March through October 2000, El Paso used just 44 percent of its pipeline capacity, at the same time as other large shippers on El Paso were using well over 80 percent of their capacity. As a result, California entered the crucial winter heating season with critically low levels of stored gas.

El Paso Merchant lost its stranglehold on the pipeline on May 31, 2001. Almost immediately thereafter, natural gas prices in California began to drop. Gas prices at the southern California border were around $10 per million BTU on May 31st. By June 8th they had dropped to around $3.50.

I urge Chairman Wood, who is here today, and his colleagues at FERC to carefully consider this evidence of market manipulation as they make their final decision in the El Paso case.

A second key issue is what FERC can do to prevent market manipulation in the future. The El Paso example shows that pipeline affiliates with the ability to exercise market power routinely and illegally shared information with each other. FERC needs to ensure that such abuses do not recur and that the market for natural gas remain fair and competitive.

These are important issues. They affect the pocketbook and livelihood of millions of Americans in the West and throughout the Nation. I hope today's hearing will provide some additional insight into their resolution.

Mr. Chairman, I thank you very much for holding this hearing.

Mr. OSE. Thank you, Mr. Waxman.

[The prepared statement of Hon. Henry A. Waxman follows:]

Statement of Rep. Henry A. Waxman
Hearing on "Natural Gas Infrastructure and Capacity Constraints"
October 16, 2001

This hearing addresses a crucial energy issue: the price and availability of natural gas. I hope it will shine a spotlight on one of the root causes of the Western energy crisis, the exorbitant natural gas prices that prevailed in California from the fall of 2000 to the spring of 2001.

In the year prior to June 2000, when the energy crisis started, electricity prices in California averaged around $36 per megawatt hour (MWh). By early 2001, they were averaging $300 to $400 per MWh -- a tenfold increase. After spending $7 billion on electricity in 1999, California spent $27 billion in 2000 and has already spent $23 billion in the first eight months of 2001.

The results have been devastating. One of the California's three major utilities -- PG&E -- filed for bankruptcy. The state's bond rating was downgraded. Hundreds of thousands of jobs may have been lost.

As I investigated this issue, I learned that natural gas played a central role in causing electricity prices to soar. Like electricity prices, gas prices in California -- particularly Southern California -- skyrocketed. When prices peaked in December 2000, natural gas was selling at the wellhead in Texas for $10.50 per million BTU. The border price at Southern California, however, reached almost $60 per million BTU. Prices remained high in the first five months of 2001. On May 8, 2001, for example, gas from the Permian producing basin that sold in Chicago for around $4.37 was selling at the California border for $12.55.

These expensive gas prices were used to justify high wholesale electricity prices. According to FERC Commissioner William Massey, when FERC set the so-called proxy clearing price for electricity this past February at $430 per MWh, roughly $350 of that amount -- over 80% -- was the price of natural gas for an inefficient generator.

One of the key issues for California is whether market manipulation played a role in the state's high gas prices. Allegations of market manipulation have focused on El Paso Natural Gas Co., which owns the pipeline system that transports natural gas from the Southwest to California.

Last week, a FERC administrative law judge found that while El Paso and its marketing affiliate, El Paso Merchant Energy, "had the ability to exercise market power," it is "not at all clear that they in fact exercised market power." The judge did find that there was "blatant collusion" between the affiliates in the awarding of pipeline contracts. After reviewing transcripts of taped conversations in which El Paso Merchant asked for and received a secret discount from El Paso Natural Gas, the judge said "if that's not hanky panky, there's no such thing as hanky panky."

This issue is now before the FERC commissioners for a final decision.

There is considerable evidence that suggests that the El Paso affiliates did manipulate the natural gas market in California. Beginning in March 2000, El Paso Natural Gas sold over a third of its pipeline capacity to El Paso Merchant. Soon after the contract began, natural gas prices at the California border began to rise.

The rise in gas prices corresponded with remarkably low levels of capacity usage by El Paso Merchant. As Paul Carpenter points out in his testimony, from March through October 2000, El Paso used just 44% of its pipeline capacity, at the same time as other large shippers on El Paso were using well over 80% of their capacity. As a result, California entered the crucial winter heating season with critically low levels of stored gas.

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These are important issues. They affect the pocketbook and the livelihood of millions of Americans in the West and throughout the nation. I hope today's hearing will provide some additional insight into their resolution.

Mr. OSE. Mr. Shays, do you have an opening statement?

Mr. SHAYS. Mr. Chairman, I don't, but I thank you for having this hearing.

Mr. OSE. We're going to go ahead to the witness testimonies now. I want to remind the witnesses that we received your written testimony. I know Mr. Waxman's people have read it, and I have personally read the testimony, so we'll give you each 5 minutes to summarize. You don't need to go through the entire thing. Just hit the high points, because we are on a bit of a limited time.

The ordinary course of business in this committee is we swear in our witnesses. So I would like the first panel and the second panel, to the extent they're here, to rise and take the oath.

[Witnesses sworn.]

Mr. OSE. Let the record show all the witnesses answered in the affirmative.

Our first witness today is Chairman of the Federal Energy Regulatory Commission, Mr. Pat Wood. Mr. Wood, for 5 minutes.

STATEMENT OF PATRICK WOOD III, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION

Mr. WOOD. Thank you, Chairman Ose, Mr. Waxman, Mr. Shays. The importance of natural gas in our Nation's power future just cannot be overplayed. I think the desirability of gas, not only as a domestic fuel but as an environmentally friendly fuel, in addition to the economics of natural gas and the economics of natural gas generation technology make it really the fuel of choice.

I think one of the important things that the FERC has to do, and certainly the focus of this hearing and of the testimony of my colleagues here and of the second panel is the importance of getting the gas to the electric generators so that the markets work well on the electric side. Of course, it goes without saying that getting gas to the gas consumer, whether that's a large industrial or small residential consumer, is equally important.

So we have to, on the regulatory side of the fence, make sure that there's sufficient infrastructure to get the gas from all parts of the continent to all customers on the continent.

I think in the last 10 years as the Commission has moved toward more of a market-based rate regulation system and more of a contract-oriented certification system, which definitely moves away from the world we used to live in, the report card, by and large, has been pretty positive. That has yielded significant consumer benefits across the years. There has been significant investment made in natural gas pipeline facilities and natural gas production and the associated liquids and other types of production that goes on near the wellhead.

That's not to say it's perfect. I think the focus of this hearing is what's happened in California, particularly in the southern half of the State over the last year. I might indicate there's certainly a shortfall of the market system as it works today in concert with State and Federal regulatory and environmental regimes to deliver this commodity to the public.

I take with good advice Mr. Waxman's recommendations and assure him and the committee that our Commission will look completely and thoroughly at the record of the El Paso case, as we do

of other cases. But it is important to get that one right. We will do it fairly and based on the record.

And I should add, in looking forward, it's important that any ambiguities in the Commission's current rules no longer exist. And I'm pleased to inform the committee that in our last meeting in September, we voted to publish for comment revisions to our gas and electric affiliate rules—they were stand-alone in the past—that integrate the two into one combined code of conduct and also knock out a lot of the loopholes and tighten up the language.

For those who are willing to play in the market in good faith, these rules should provide no different regime than what we had before. For those who may want to test the limits of what's right or wrong, I think these rules will come as an unwelcome surprise. I look forward to finalizing those rules in the near future.

I want to just focus on one particular piece of data that I didn't have and that we didn't have in my original testimony but I think is useful. The staff is in the process now of putting together an assessment of all the infrastructure issues in the West, both gas and electric and hydroelectric, to try to work with our fellow regulators and the western Governors and the industry out west. But one of the things that came out of this was this chart that's up on the side here.

Mr. OSE. Just a moment. Can we turn that chart? Perhaps the Members of Congress would like to see it, too. Thank you.

Mr. WOOD. The blue at the bottom is the hydroelectricity as a percentage of the total for California. This is just power generated within the State. California also imports up to 25 percent capacity, particularly in the summer. That's not shown here. This is just the consumption and the generation within the State of California on an annual average.

The lower three numbers are gigawatt hours, which is a unit of measure for how much energy is actually generated in the State. What it shows largely is that hydro, for the reasons we all know, that the drought coming out there, has dropped off these last 2 years of the cycle. Other, which would be coal and some renewables, primarily thermal, has increased modestly over that time period. But the middle number, natural gas, has not only increased in real number, but as a percentage of the total.

I think it's helpful to understand that, you know, this is a pretty significant ramp-up of demand for just the electric power industry in a very short period of time, and even the best planned systems would be stressed out by this.

So I think both Loretta and Michael will talk about some of the actions the State has taken on the infrastructure side certainly, recently, to try to keep up with that, as well as what I have reported in my testimony about what FERC has done. But I just wanted to kind of show this is a pretty dramatic change from probably one quarter to over one half of the gigawatt hours in a given year, in just a 4-year time span, has shifted to natural gas usage.

That concludes my testimony.

Mr. OSE. Thank you, Mr. Wood.

[The prepared statement of Mr. Wood follows:]

Testimony of
Chairman Pat Wood III
Federal Energy Regulatory Commission
before the
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs of the
Committee on Government Reform
United States House of Representatives

October 16, 2001

Mr. Chairman and Members of the Subcommittee:

Thank you for the invitation to this hearing on natural gas capacity and infrastructure constraints, and the promotion of healthy natural gas markets, especially in California. Let me begin by assuring you that the Commission will do its part to ensure that America's energy markets function smoothly and that the FERC's Commissioners and staff stand with President Bush and Congress at this pivotal time.

In my testimony today, I would like to make three basic points. First, the Commission's role in natural gas markets focuses principally on transportation, not commodity prices. The Natural Gas Wellhead Decontrol Act of 1989 completed the deregulation of the prices producers charge for gas sold at the wellhead in 1993. As a result, the Commission has no direct authority to regulate the prices charged by natural gas producers. The Commission retains only limited jurisdiction over certain sales for resale in interstate commerce. The Commission's primary natural gas jurisdiction is to: (1) authorize the construction of interstate pipeline transmission and storage facilities;

and, (2) set the rates, terms, and conditions of service for interstate transportation and storage of natural gas. In short, our central role in the natural gas industry is to serve the growing demand for natural gas by enabling the construction and use of that pipeline infrastructure at just and reasonable rates, terms and conditions of service, and without undue discrimination.

Second, since wellhead price decontrol and the advent of the Commission's open access transportation program, there has been a well-functioning, competitive market for the sale of the natural gas commodity. From the mid-1980s until last winter's heating season, competition among natural gas producers and others resulted in readily available supplies at low prices. Last winter prices rose primarily because of an imbalance between supply and demand. Since then, natural gas producers significantly increased drilling activity, and the increase in gas supplies led to lower prices, a market response that is more nimble and less expensive than any legislative or regulatory "fix." While some of the reasons that the price of natural gas has now dropped significantly are warmer weather, record storage fills, and a slow-down in the general economy, the basic demand-and-supply response we have seen is a clear sign of a well-functioning market. I will not make any predictions about what prices will be this winter (although, as I discuss later, the Energy Information Administration (EIA) has predicted lower prices for this winter), but I firmly believe that allowing the competitive wellhead market to work through a

robust continental delivery system is the best way to obtain adequate gas supplies at the lowest reasonable price.

Third, notwithstanding the fundamentally sound nature of the natural gas market, the Commission can help ensure the availability of reasonably priced natural gas by certifying new pipeline projects in a timely manner so that newly developed supplies can reach the market. One of the Commission's top priorities is to ensure that needed energy infrastructure is built. If increased gas supply is to help bring prices down, there must be adequate transportation facilities to move newly developed gas supplies to delivery markets. Also, current bottlenecks limiting the transportation of natural gas to areas where demand is highest must be eliminated. We will do everything in our power to ensure that the Commission quickly processes applications for new pipeline projects that will meet these needs. To that end, Commission staff is looking at creative ways to expedite the processing of applications for new pipeline capacity to serve critical areas of the country.

However, to the extent transportation bottlenecks fall within state jurisdiction, the states must similarly undertake initiatives to improve their infrastructure. I assure you I recognize the critical importance to your constituents, and to our country, of having an adequate natural gas transportation infrastructure.

I must note that the Administrative Procedures Act and the FERC's ex parte rules prohibit me from discussing the merits of cases pending before the Commission; therefore

I cannot discuss the merits of the complaint that was filed at the Commission by the California Public Utilities Commission and Southern California Gas Company against El Paso Merchant and El Paso Pipeline. I can tell you, however, that the Chief Administrative Law Judge has issued an initial decision and the Commission will act on this matter as expeditiously as possible.

I will now turn to the specifics of these matters in greater detail.

I. The Federal Energy Regulatory Commission's Role in Natural Gas Markets

The Commission's role in the natural gas industry is largely defined by the Natural Gas Act of 1938. This Act enables the Commission to grant construction authority to interstate natural gas pipelines and related facilities, such as storage and compression. It also authorizes the Commission to set the rates and terms of service for the resale and transportation of natural gas in interstate commerce. States regulate retail sales and local distribution of natural gas and the production and gathering of natural gas. Controls on the wellhead price of natural gas, which the Commission previously regulated pursuant to a 1954 Supreme Court decision, were gradually phased out by the Congress. This started with the Natural Gas Policy Act of 1978, and culminated in the Natural Gas Wellhead Decontrol Act of 1989, which lifted all remaining wellhead price controls as of January 1, 1993.

The Commission still retains jurisdiction over certain sales for resale in interstate commerce, but that jurisdiction now accounts for only a small portion of the overall

natural gas market. That jurisdiction is limited to sales for resale by interstate pipelines, intrastate pipelines, and local distribution companies and their affiliates, unless the sales are from their own production or from sources where we have a free trade agreement such as with Canada and Mexico. Although the Commission could amend the authorizations to provide for some other pricing method, I do not believe that this would provide effective relief from high prices to customers, as sellers would find ways to move their supply to unregulated sales. Price controls on FERC jurisdictional resales would merely distort the market in the same way they prompted the industry in the 1970's to shift supplies from the interstate market to the intrastate market before the NGPA.

The Commission also authorizes natural gas pipeline siting and construction if found to be in the public convenience and necessity under Section 7 of the Natural Gas Act. Consideration of factors under the National Environmental Policy Act (NEPA), other appropriate statutes, and landowner interests are taken into account before approving a natural gas pipeline project. In addition to its certificate jurisdiction, the Commission has authority, delegated by the Secretary of Energy, over the siting and construction of facilities for the import or export of natural gas under Section 3 of the Natural Gas Act, and authority under Executive Order No. 1045 to issue Presidential Permits for such facilities if they are located at an international border.

II. Competitive Natural Gas Commodity Markets

The oil embargo of the mid-1970s, coupled with heavy-handed price regulation by the Commission (then the Federal Power Commission), led to shortages and supply curtailments of natural gas in the interstate gas market in those years. In response to these critical supply shortages, Congress passed the Natural Gas Policy Act of 1978, which began the decontrol of natural gas commodity prices.

In 1985, the Commission required open-access, non-discriminatory transportation of non-pipeline natural gas across the U.S. natural gas pipeline grid. In 1989, the Congress enacted the Natural Gas Wellhead Decontrol Act of 1989, which ended all remaining wellhead price controls as of January 1, 1993. In 1992, the Commission took further steps to ensure a well-functioning natural gas market by requiring interstate natural gas pipelines to unbundle, or separate, their transportation service from their own sales service. That removed the opportunity for pipelines to discriminate in favor of their own "merchant" business by providing a higher quality transportation service as part of their bundled transportation and sales service. Subsequently, pipelines exited the natural gas sales business completely and transferred their sales contracts to their marketing affiliates.

The Commission also established a program to permit holders of transportation capacity to resell their unused pipeline capacity rights, called "capacity release," creating a valuable and efficient secondary transportation market. Since then, the Commission has

been monitoring the gas transportation and storage of natural gas to ensure the most efficient and effective natural gas delivery infrastructure for customers. Almost two years ago, the Commission revised its open-access transportation regulations in Order No. 637, with regard to scheduling procedures, capacity segmentation, and pipeline penalties, among other issues. When these changes are fully implemented, they should give shippers added flexibility to make more efficient use of the existing pipeline grid.

As a result of the pro-market policies pursued by Congress and the Commission, the natural gas commodity market is truly competitive. There are about 8,000 producers operating over 300,000 wells in the United States. In addition, the North American natural gas markets have been geographically integrated, permitting an increasing contribution of Canadian gas to meet U.S. market growth, and increased U.S. gas sales into Mexico. Natural gas buyers in general are no longer limited to buying from one pipeline. Instead, they have a wide range of supply options and various transportation and storage options. In addition, an active financial market has developed to allow buyers and sellers to hedge against price volatility, depending on their tolerance of risk.

Although different sources quote different numbers, no one disputes that this competition has produced substantial consumer benefits. In addition, reserve prospects for natural gas appear to be very promising. Estimates range from 1,200 trillion cubic feet (Tcf) to 1,700 Tcf, the equivalent of a 55-75 year supply at current and projected requirements. Pro-competitive policies, technological innovation, environmental policies,

and low prices have led to increased demand for this clean-burning fuel, especially in the electric power generation area.

The success of the competitive market for natural gas is further reflected in the recent behavior of spot wellhead prices for natural gas. Last winter, natural gas prices roughly tripled to about $10 per MMBtu nationwide. While the price increase focused a lot of attention on the natural gas industry by lawmakers and regulators, the market itself responded, without any need for new laws or new regulations. Producers of natural gas increased the supply of natural gas, and the number of active natural gas rigs more than doubled in the past year and a half. The EIA last week projected that spot prices for natural gas will drop to an average of $2.21 per mcf this winter from $5.78 per mcf a year ago.

In sum, the operation of the interstate natural gas market remains sound, as evidenced by the dramatic increase in drilling activity in response to market signals.

III. Why Were Natural Gas Prices So High Last Winter?

As explained above, natural gas is now a commodity that is sold in an open market where the laws of supply and demand determine the price. Weather, economic growth and the price for other fuels are all factors that affect the demand for gas. Last winter several factors converged at once to produce very high spot natural gas prices.

Demand for natural gas has increased in all sectors over the last decade due to economic growth. In addition, a significant number of new gas-fired electric generators

has come on-line in the last few years. While these generators produce power in an environmentally friendly way using clean-burning natural gas, they are creating a year-round demand for a commodity that has traditionally been used more in the winter than in the summer. Increased use of gas by electric generators has also affected overall demand in the winter.

Weather also affects the demand for natural gas. After warmer-than-normal winters in many areas of the country for several years, temperatures in November and December of 2000 were either below, or well below, normal in all but five states. This significantly increased the demand for natural gas, and other heating fuels such as propane and fuel oil. This condition was compounded in the West by the near record drought which very abruptly removed several thousand megawatts of hydroelectric power from the power market. Natural gas-fired power generation filled the sudden void, and this additional natural gas demand put a strain on both the natural gas supply and delivery systems in that region of the country.

Although the demand for natural gas has grown in recent years, supply somewhat lagged behind this demand. After the prices for natural gas and oil collapsed in 1998, producers invested less capital in the exploration and production of natural gas. In January of 1998, there were over 633 drilling rigs in operation. By April of 1999, after a sustained period of low gas prices, the rig count dropped to 362. While there are plentiful reserves in the ground, maintaining adequate deliverable gas supplies requires a steady

drilling program. The reduction in gas drilling reduced supply. This trend was reversed in late 1999. Although there were 905 active drilling rigs on February 16 of last year, historical experience shows there is a time lag (between three months to eighteen months or more) between increased drilling and a significant supply response.

Finally, while spot prices rose quite high in some areas of the country last winter, it is important to understand that local distribution companies and end-users need not, and generally do not, buy all their gas on the spot market. Today's competitive market provides gas purchasers a number of options for achieving greater price stability than is available on the spot market. Gas purchasers can, for example: (1) enter into long-term supply contracts; (2) purchase gas during cheaper, off-peak periods and place it in storage for use during peak periods; (3) forward contract using gas futures; and, (4) purchase financial hedging instruments. Through such strategies, gas purchasers can keep their overall gas costs substantially below spot market levels. For example, in January of last year, when spot market prices at New York City gates rose above $18 per MMBtu, the overall gas costs of the two major New York local distribution companies, Con Edison and Brooklyn Union, were in the $8 to $10 per MMBtu range.

IV. Pipeline Construction

Adequate natural gas pipeline transmission and storage capacity is critical to support the continued functioning of the competitive market for the gas commodity. If that market is to ensure an adequate supply of natural gas at the lowest reasonable cost, all

gas sellers must be able to reasonably reach the highest-bidding gas buyers, and all gas buyers must be able to reach the lowest-selling producers. For this to continue, it is clear that additional pipeline capacity must be built. As new gas supplies are developed in response to the continued growth in natural gas consumption and increased prices, new pipeline facilities will be necessary to allow those supplies to reach the market.

In the last seven months, the Commission has issued certificates for seven interstate projects, with total capacity of almost 962 MMcf/d of capacity, that could benefit the western area of the country, and, in particular, California. My colleagues and I are committed to moving quickly on pending projects. The Commission is actively pursuing ways to expedite the approval of infrastructure needed to serve California and the West, including raising the current dollar limit on automatic authorizations. This will allow pipelines to construct needed facilities without lengthy regulatory proceedings as long as they comply with all applicable environmental regulations. We are also encouraging applicants to work closely with our staff at the earliest stages of project development to expedite the certification process. Early staff involvement may include getting a head start on meetings with stakeholders and the preparation of environmental documents. This may significantly speed the certification of appropriate projects.

Of course, any actions the Commission takes to expedite new interstate pipeline capacity for natural gas to serve California and the West can only be effective if there is available local intrastate capacity to deliver gas downstream of the interstate pipeline to

the ultimate customer. The California Energy Commission in September issued its revised final report on Natural Gas Infrastructure Issues, which indicates that the intrastate gas transportation network in southern California is constrained; the CEC found that this constraint may, to some extent, have affected gas prices in that area, which have been among the highest in the nation. Recently certificated interstate capacity for southern California totals 755 MMcf/d, with 585 MMcf/d of intrastate take-away capacity authorized in southern California. I have attached a schematic map and a chart to my testimony to illustrate the gap between interstate and intrastate pipeline capacity. Local take-away capacity is provided primarily by local distribution companies, which are exclusively within the control of the state.

The Commission has consistently urged the State of California to eliminate any disincentives that may prevent expansion of intrastate infrastructure and provide relief to California customers. Interstate pipelines under our jurisdiction coordinate their efforts with local distribution companies, public utilities and state officials. The Commission will cooperate with the states to ensure that new facilities subject to state jurisdiction are properly integrated with the interstate grid. I should note here that recently the California Public Utilities Commission has authorized several storage-related proposals, and Southern California Gas Company has several expansions underway, totaling 375 MMcf/d.

On another California infrastructure front, there has been some significant activity this summer with respect to construction and expansion of electric generation capacity in California, although it has not matched the level of projections made earlier in the year. In August 2001, a number of organizations made projections for California power plant construction activity, including the California ISO (CAISO), the California Energy Commission (CEC) and the National Electric Reliability Council (NERC). CAISO made the most detailed projections, forecasting that up to 3,299 MW of new generating capacity would come on line during the summer, nearly two-thirds from large new plants. Almost 60 percent (1,947 MW) of the additions have actually been completed, and most of the other new capacity projected will be complete by the end of the year. The CEC had projected that 3,914 MW of new generating capacity would come on-line during the period. Similarly, in early 2001, NERC projected in its 2001 Summer Assessment that 3,471 MW of new capacity would come on line. However, late in the spring, NERC revised its projection downward to 1,500 MW, which came close to the 1,555 MW of generating capacity which actually came on line from June to August for the units included in NERC's survey.

By correlating the location of these plants to the gas pipeline infrastructure in California, it is notable that a large percentage of the new generation capacity will be served directly by interstate pipelines, rather than through local distribution company

facilities; this lessens the issue of the "mismatch" of interstate and intrastate pipeline capacity.

Aside from the current situation in California, there is also a critical need to provide transportation for newly developed gas supplies to reach all U.S. markets. For example, the EIA projects a significant increase in imports of natural gas to the United States from Canada. Delivering that gas to U.S. markets will require increased pipeline capacity. I testified on October 2nd to the Senate Energy and Natural Resources Committee on the issues surrounding the development of Alaskan natural gas, and promised Congress that we will make every effort to process and act upon any applications for Alaska gas transportation projects as efficiently as possible, working with the applicants, other federal and state agencies, Native Americans, shippers, end users, and other interested parties, to ensure timely, reasonable decisions. I pledge my continued support for the construction of new pipeline infrastructure to meet these critical needs, and I will do everything I can to ensure that the Commission processes certificate applications for proposed pipeline projects as quickly as possible, within our statutory obligations.

V. Conclusion

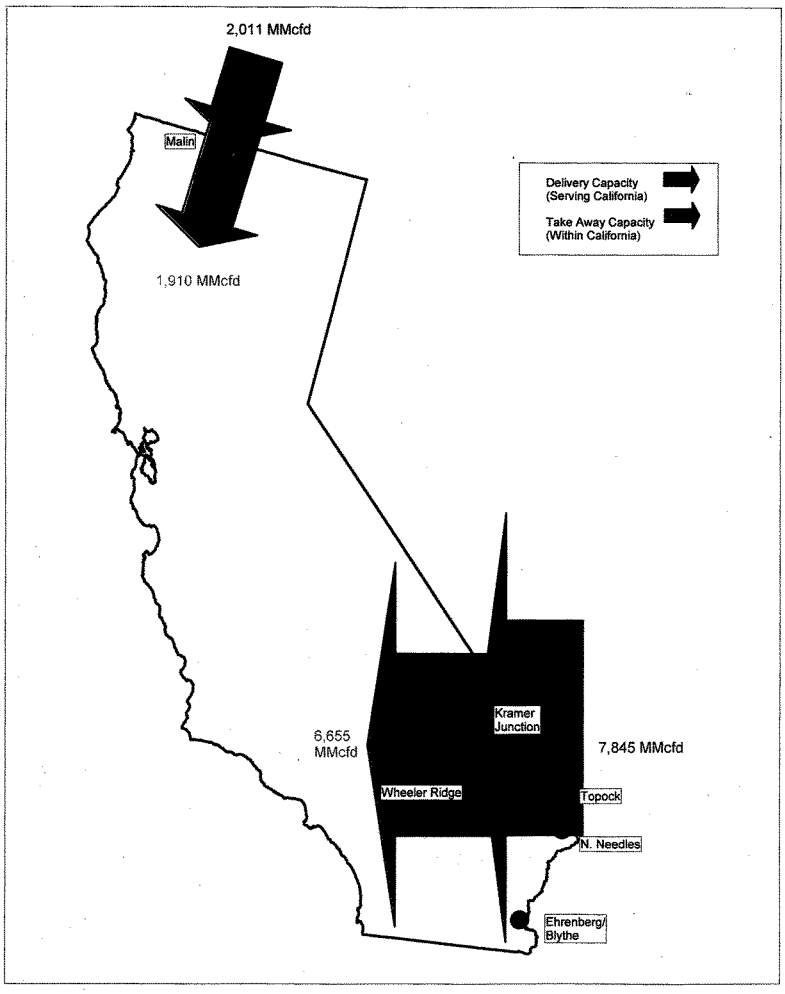
Last winter's increases in natural gas prices are a matter of serious concern for gas customers and indeed for the nation as a whole. Nonetheless, natural gas deregulation has been an extremely successful long-term policy and the fundamental structure of natural

gas markets remains sound. Beginning in 1984, competition in the natural gas industry has led to fifteen years of prices that were lower than anyone anticipated. In fact, the low prices lasted for so long that it was easy to forget the inherent tendency of energy markets towards boom and bust cycles. Last year, producers responded to higher prices with increased drilling. At the same time, customers responded as well. For example, we hear of electric generators actively reconsidering their exclusive reliance on natural gas for new plants and are equipping their plants with dual fuel (oil) capability to permit peak day switching away from gas. Everyone has a role to play in moving demand and supply toward a balance where prices are publicly acceptable. The nation's competitive policy has produced a robust, flexible and responsive natural gas market.

The Commission's recently adopted Strategic Plan rests upon three pillars: development of an adequate energy infrastructure, adoption of clear and balanced rules that allow efficient trading between market participants, and ongoing market oversight. These key elements will allow for robust competition in energy markets, with resultant benefits to customers. We at the Commission will do our part to ensure that new pipelines can be built to support a growing industry and that natural gas transportation supports flexible, innovative markets. By our continuing work together I am confident that states and other federal agencies will also do their part to put in place needed infrastructure and to mitigate short-term hardships.

Thank you. The Commission is always available to assist Congress in its deliberations about the nation's crucial energy industry.

California Pipeline Capacity (total possible by 2004)



FERC 10/11/01

California Pipeline Capacity	Delivery Capacity (MMcf/d)	Take-Away Capacity (MMcf/d)	Difference (MMcf/d)
Existing Pipeline Capacity (Today)			
Northern California			
Interstate (w/o Tuscarora)	1,800	0	
Local Distribution Companies	0	1,910	
	1,800	1,910	(110)
Southern California			
Interstate	5,080	540	
Local Distribution Companies	600	4,990	
Local Production	470	0	
	6,150	**5,530**	**620**
Under Construction Pipeline Capacity (Incremental On-line by 2003)			
Northern California			
Interstate	211	0	
Local Distribution Companies	0	0	
	211	**0**	**211**
Southern California			
Interstate	755	203	
Local Distribution Companies	40	475	
Local Production	0	0	
	795	**678**	**117**
Pending Pipeline Capacity (Incremental On-line by 2004)			
Northern California			
Interstate	0	0	
Local Distribution Companies	0	0	
	0	0	**0**
Southern California			
Interstate	900	282	
Local Distribution Companies	0	165	
Local Production	0	0	
	900	**447**	**453**
Existing, Under Construction and Pending Pipeline Capacity (Total Possible On-line by 2004)			
Northern California			
Interstate (w/o Tuscarora)	2,011	0	
Local Distribution Companies	0	1,910	
	2,011	**1,910**	**101**
Southern California			
Interstate	6,735	1,025	
Local Distribution Companies	640	5,630	
Local Production	470	0	
	7,845	**6,655**	**1,190**

FERC 10/10/01

Mr. OSE. Joining us also is the President of the California Public Utilities Commission, Ms. Loretta Lynch. You're recognized for 5 minutes.

STATEMENT OF LORETTA LYNCH, PRESIDENT, CALIFORNIA PUBLIC UTILITIES COMMISSION

Ms. LYNCH. Thank you, Mr. Ose, Mr. Waxman, Mr. Shays. My testimony addresses three primary themes.

First, California looks to the Federal Energy Regulatory Commission to define and enforce clear standards for determining when market power exists in the natural gas market and also when it's exercised in the interstate natural gas markets.

Second, a so-called mismatch in intrastate and interstate capacity was not and could not have been a factor in last year's high California border prices for natural gas.

And, finally, the facts demonstrate that California's intrastate capacity has been and, despite the increase in electric generation generated from natural gas, continues to be more than adequate to accommodate the State's natural gas demands.

Rather, the California Public Utilities Commission submits that last year's extraordinarily high natural gas prices resulted largely from the illegal exercise of market power on an interstate pipeline, not inadequate intrastate infrastructure. And that is precisely the reason that we look to FERC now to both remedy past wrongs and to define and enforce a clear standard for market power abuse.

In fact, California relies on one of four methods that have been established by the FERC to acquire and transport natural gas over the interstate systems to our in-State utility systems at the border. As California discovered only too clearly this past winter in an unhealthy natural gas market where market power is being exercised, the normally adequate options collapsed with disastrous consequences. Last winter, California endured natural gas border prices double those faced by the rest of the Nation, and at times those prices climbed to levels seven to eight times the national average. The cost to Californians ran into the tens of millions of dollars both for higher natural gas costs and for higher electric costs driven by the high gas costs on the margin.

Thus, the FERC has a golden opportunity now in the pending decision before it in our complaint against El Paso Pipeline and its marketing affiliate, to both provide a remedy for past illegal actions and also to prevent future price spikes by defining clear standards for identifying market power where it occurs in the interstate markets and also in preventing its exercise.

Some parties have put forward the inaccurate theory that California's natural gas infrastructure is inadequate and that lack of infrastructure caused last year's price increases. However, an accurate understanding of the California infrastructure and its operation, I believe, leads inescapably to the conclusion that a so-called capacity mismatch cannot have been a factor in last year's border price increases. California utilities do not build their systems to match the delivery capacity of the interstate pipelines, as those interstate pipelines suggest that they should. Rather, California's gas utilities build the natural gas infrastructure to reliably meet anticipated demand of their California customers at a reasonable

cost. Overbuilding means price increases to California's businesses and families.

Considering Southern California Gas's actual operation of its system and the PUC's actions over the last 10 years, interstate takeaway capacity into southern California actually exceeds the certificated interstate capacity into southern California. Further, it's critical to know that at the other California points where nominal intrastate capacity is less than the nominal delivered interstate capacity, the intrastate pipeline has more than enough capacity to take the full volumes at the point of interconnection.

Despite continuing high utilization of transmission capacity into southern California, California border prices have declined dramatically since May, when El Paso's contract with its affiliate expired. Even during the high natural gas demand driven by this past summer's air-conditioning needs, PG&E, SoCalGas and San Diego Gas & Electric combined all continued to meet all their customers' needs. California's gas utilities have met these needs even as they transported additional gas through their system to inject gas into storage for this winter's heating reserves. The PUC had required the utilities to overinject, to make sure that what happened last year would not happen this year in terms of inadequate storage. And now those levels are 20 to 30 percent higher than this time last year.

But California has not stopped there. Over the last year, the PUC has worked with the California natural gas utilities to identify and implement a number of strategic infrastructure expansions across the State. Those expansions are listed in my written testimony and they show that we will add 455 million cubic feet of capacity a day of intrastate capacity by the end of this year, which is an unprecedented expansion that added a full 10 percent to southern California's gas capacity.

These and other potential intrastate expansions we're considering also will help the State to benefit from some of the interstate pipelines that FERC is currently considering. Basically, California has been vigilant in managing the evolution of its in-State infrastructure to match changing patterns of demand. But California needs its approach of careful vigilance to be matched at the Federal level as well.

Mr. OSE. Thank you, Ms. Lynch.

[The prepared statement of Ms. Lynch follows:]

Testimony of Loretta M. Lynch
President, California Public Utilities Commission
Before the House Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs
October 16, 2001

Thank you for the opportunity to testify before the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

California wholeheartedly joins the Subcommittee in pursuing a healthy natural gas marketplace, both within the state and outside our borders, which provides just and reasonable prices to all consumers. My testimony will address three primary themes. First, California looks to the Federal Energy Regulatory Commission (FERC) to define and enforce clear standards for determining when market power exists and is exercised in the interstate natural gas markets. Second, a so-called "mismatch" in intrastate and interstate capacity was not and could not have been a factor in last year's high California border prices. Finally, the facts demonstrate that California's intrastate capacity has been – and continues to be – more than adequate to accommodate the state's natural gas demands. Rather, last year's extraordinarily high natural gas prices resulted largely from the illegal exercise of market power on an interstate pipeline, not inadequate intrastate

infrastructure. That is precisely the reason that we look to FERC now to both remedy past wrongs and to define and enforce a clear standard for market power abuse.

BACKGROUND

California consumes approximately 5.7 billion cubic feet per day. We import about eighty-five percent of that load from out-of-state sources. Four interstate pipelines deliver natural gas to California from supply basins in Canada, the Rocky Mountains, and the U.S. Southwest: Pacific Gas Transmission-Northwest, Kern River, El Paso and Transwestern pipelines. The majority of our state's natural gas requirements are served by our in-state utilities through our utilities' interconnections with these interstate pipelines.

Through the 1990's, natural gas prices in California generally hovered in the $1.50-$3.50 per million BTU range. Beginning last fall, prices increased nationwide, but they increased much more dramatically for California. In December, for example, prices at the California border increased sharply to almost $60 per million BTU, while prices for the rest of the nation only spiked to $10 per million BTU.

FERC HAS FAILED TO ARTICULATE AND ENFORCE A CLEAR MARKET POWER STANDARD and MUST DO SO IN THE FUTURE

Californians rely on one of four methods established by the FERC to acquire and transport natural gas over the interstate systems to the in-state utility systems at the border. A consumer must either (A) buy gas and 1) buy firm capacity directly from an interstate pipeline for transport to the border, 2) buy "released" capacity on a secondary market, 3) use "interruptible" capacity that is available from the pipeline on a day-to-day basis, or (B) buy natural gas at the border from a third party who has transported it there (bundled interstate service). In a healthy natural gas market, these bundled and unbundled options compete against each other to provide consumers with a robust market for natural gas at the California border.

As California discovered only too clearly this past winter, in an unhealthy natural gas market – in which market power exists and is exercised – those normally adequate options collapse with disastrous consequences. Last winter, California endured natural gas border prices double those faced by the rest of the nation, and at times prices climbed to levels seven or eight times the national average. The costs to Californians ran into the tens of

billions of dollars, both for higher gas costs and for higher electric costs driven by high gas costs on the margin.

The FERC has a golden opportunity now, in the pending decision on the California Public Utilities Commission's (CPUC) complaint against El Paso Pipeline and its marketing affiliate, to both provide a remedy for past illegal actions and prevent future price spikes by defining clear standards for identifying market power where it occurs in the interstate markets and preventing its exercise.

However, under a FERC Administrative Law Judge initial decision the market power standard is self-contradictory and therefore is impossible to meet. In previous decisions affecting the El Paso Pipeline, for example, the FERC has ruled that it would be much easier to exercise market power if demand for the capacity were higher than the level that existed at that time. The FERC Judges's initial draft decision in the El Paso complaint, however, acknowledges that prices last year increased due in part to El Paso's collusion and market concentration, but stops short of concluding El Paso exercised market power. Instead, the FERC Judge attributes last year's price

increases to higher demand. The question is, if market power does not exist when demand is low, and does not exist when demand is high and a pipeline is found to have colluded with its own affiliate, when does market power exist?

The facts of the CPUC's El Paso complaint demonstrate why FERC or this Congress must establish a clear and enforceable market power standard. Competition at the California border began to erode as of January 1, 1998, when El Paso entered into three anticompetitive contracts with Dynegy Marketing and Trade ("Dynegy") for approximately one-third of El Paso's firm capacity to California (the "El Paso-Dynegy Contracts"). Although in three separate orders the FERC agreed with the CPUC that the El Paso-Dynegy Contracts contained an anticompetitive feature, the FERC nevertheless approved this arrangement, *while warning against similar arrangements in the future if there was greater demand for natural gas*[1].

[1] See El Paso Natural Gas Company, 83 FERC ¶61,286 at pp. 62,196-97 (1998) reh'g order, 88 FERC ¶ 61,139 at pp. 61,411-14 (1999), reh'g order, 89 FERC ¶ 61,073 at p. 61,226 (1999), petitions for review dismissed as moot, Public Utilities Com'n of California v. FERC, 236 F.3d 708 (D. C. Cir. 2001) (Hereinafter, the "Dynegy Orders").

This anticompetitive arrangement, which allows one marketer to hoard an enormous amount of El Paso firm capacity and which also provides a disincentive for El Paso to compete with discounted interruptible rates, was repeated thereafter in a short-lived transaction between El Paso and Enron North America Corp. ("Enron"). While the FERC approved the El Paso-Enron Contracts, the FERC also warned that if Enron withheld capacity in an unjust or unduly discriminatory manner, the FERC would consider "imposing a remedy such as the mandatory capacity release requested by the California PUC". Enron subsequently terminated those contracts.

This set the stage for El Paso's open season from February 7 – February 14, 2000 for this 1,220 million cubic feet per day (approximately one third of the total El Paso capacity to California) of El Paso firm capacity to California. Although 24 shippers bid for portions of this capacity, they were all outbid by El Paso's affiliate, El Paso Merchant, which bid for the entire amount at a price of $38.5 million.

A marketer acquiring that much capacity is doing so in order to exercise market power so that it can artificially drive up the basis differential and California border prices by withholding discounted firm capacity from the

market. The marketer can then cash in either on the higher bundled natural gas sales prices at the California border, on unreasonably high capacity release prices, in the financial market, or in higher electric prices, which is something that the pipeline itself cannot do. For such a strategy to work, however, it is critical to the marketer that El Paso not compete by discounting interruptible rates.

Not only did El Paso Merchant hold more firm capacity rights on El Paso and Transwestern than did Dynegy, two other very significant factors made it much easier for El Paso Merchant to exercise market power compared to the time when Dynegy held this enormous amount of El Paso capacity: 1) demand for natural gas had increased in California and El Paso's East of California ("EOC") markets beginning in June, 2000; and 2) El Paso, the operator of the interstate pipeline, was (and is) affiliated with El Paso Merchant.

Indeed, in the D.C. Circuit's dismissal of the CPUC's petition for review of the FERC's Dynegy Orders, the Court recognized these two significant factors when it found that there was not a "reasonable expectation" that the FERC would approve anti-competitive contracts and conduct in the future.

In Public Utilities Com'n of California v. FERC, 236 F.2d 708, 715 (D.C. Cir. 2001), the Court declared that:

> "in approving the El Paso-Dynegy contracts, FERC made clear that its future balancing of competition concerns with the goals of the NGA and existing FERC policies may yield different results that those of the El Paso-Dynegy order: 'A change in market conditions, for example, a significant increase of the demand for firm transportation to California, or a change in [FERC] policies on the right of pipelines not to discount, might result in a different conclusion'. *El Paso III*, 88 F.E.R.C. at 61,414." (emphasis added)

In this regard, the Court explicitly found that "the relationship between El Paso and El Paso Merchant would trigger different concerns than a transaction between unrelated parties." Id. at 716.

The judge's draft decision in the pending El Paso complaint indicates that the CPUC has not met the standard for demonstrating market power, but does not define the standard. Perhaps the FERC Judge will just know it when he sees it, but that provides no help to states like California who are battling illegal activities between natural gas pipelines and their affiliates. The judge found that El Paso colluded to share information with its affiliates, and amassed market concentration that gave El Paso's affiliate that

ability to exercise market power in an increasing demand market. If this does not warrant a finding of market power, what does? If the FERC Judge is not overruled by the Commission, consumers lose if demand is low, and they lose when demand is high. At the very least, businesses and consumers deserve an opportunity and a fair standard for winning. California looks to FERC to provide appropriate guidance on this critical issue going forward, and we will look to the Congress if the FERC fails in this critical mission.

THE CALIFORNIA "CAPACITY MISMATCH" IS A MYTH, NOT A FACTOR IN HIGH CALIFORNIA BORDER PRICES

Some parties, including El Paso, have put forward the inaccurate theory that California's natural gas infrastructure is inadequate and therefore played a causal role last year's price increases. That theory reflects a fundamental lack of understanding of California's in-state capacity. Rather, an accurate understanding of the California infrastructure and its operation leads inescapably to the conclusion that the so-called capacity "mismatch" cannot have been a factor in last winter's border price increases.

California utilities do not build their systems to match the delivery capacity of the interstate pipelines, as those interstate pipelines suggest they should. Rather, California's gas utilities build the natural gas infrastructure to

reliably meet the anticipated demand of their California customers at reasonable cost.

Considering SoCalGas' actual operation of its system, and CPUC action taken over the last ten years, intrastate take-away capacity into southern California actually exceeds the certificated interstate capacity into southern California. Furthermore, it is critical to know that, at the other California points where nominal intrastate capacity is less than the nominal delivered interstate capacity, the intrastate pipeline has more than enough capacity to take the full volumes at the point of interconnection. However, currently the **total** amount of certificated interstate capacity to California does slightly exceed the **total** firm "take-away" capacity into the state.

A few of the California "mismatch points" illustrate how capacity mismatches can go both ways. First, the majority of the excess interstate capacity is located at PG&E's interconnect with Transwestern Pipeline near Topock. Although this is a delivery point geographically located in Southern California, this capacity is designed primarily to take interstate gas from Southwest producing basins into Northern California. PG&E has a total of 1,140 MMcf/d combined take-away capacity from Transwestern and

El Paso near Topock. Prior to 1992, PG&E's 1,140 MMcf/d matched the El Paso capacity, but in 1992 Transwestern expanded its capacity to California by 340 MMcf/d. PG&E did not add capacity to match that interstate expansion. Nevertheless, despite the "mismatch" in capacity near Topock, PG&E's 1,140 MMcf/d is more than adequate to deliver all volumes nominated at that delivery point. There have not been constraints at this point; indeed, PG&E never flowed close to 1,140 MMcf/d from this point during its peak this past winter.

Another significant capacity mismatch – this time where intrastate capacity exceeds upstream capacity -- occurs at SoCalGas' interconnect with El Paso at the California/Arizona border near Blythe. Until 1990, the El Paso and SoCalGas certificated capacities matched at 1,210 MMcf/d. Then, in 1990, the CPUC authorized SoCalGas to expand it transmission system to accept an additional 200 MMcf/d from El Paso, with the understanding the El Paso would undertake the necessary modifications to its facilities to enable it to deliver an additional 200 MMcf/d to SoCalGas (In Re Interstate Natural Gas Pipeline Supply and Capacity, 35 CPUC 2d 196 (1990)). SoCalGas expanded its system shortly thereafter. El Paso did not and has not made available matching firm capacity to California. The official design capacity

of SoCalGas remains 1,210 MMcf/d because El Paso cannot deliver more than the 1,210; however, SoCalGas can take up to 200 MMcf/d more than El Paso can deliver. This excess capacity has mostly gone unused, even during the last nine months' extraordinarily high prices at the California border.

Finally, SoCalGas' system interconnects with the PG&E and Kern River pipelines at Wheeler Ridge. The design capacity of this interconnect is certificated at 680 MMcf/d, which is 80 MMcf/d less than the combined firm delivery capacity of PG&E and Kern River into SoCalGas. However, when the two upstream pipelines can deliver higher volumes, the actual operating capacity of the Wheeler Ridge interconnect has reached 800 MMcf/d. therefore, there does not appear to be the operational mismatch suggested by certificated capacity ratings. In any case, the CPUC has directed SoCal Gas to increase rated capacity at Wheeler Ridge, which should be on-line by the end of this year.

CALIFORNIA HAS ADDED INCREMENTAL CAPACITY AT STRATEGIC LOCATIONS

Despite continuing high utilization of transmission capacity into southern California, California border prices have declined dramatically since May, when El Paso's contract with its affiliate expired. Even during the high

natural gas demand driven by this past summer's air conditioning electric generation, PG&E, SoCalGas and SDG&E continued to meet all their customers' needs. California's gas utilities have met these needs even as they transported additional gas through their systems to inject gas into storage for this winter's heating reserves at levels 20-30% higher than last year.

California has not stopped there. Over the last year, the CPUC has worked with the California natural gas utilities to identify and implement a number of strategic infrastructure expansions across the state. Those expansions include:

- The San Diego Gas & Electric (SDG&E) Line 6900 expansion of 70 MMcf/d began operation on May 18, 2001, over a month ahead of schedule. Since that time, the CPUC and California's natural gas companies have taken several additional actions to ensure adequate natural gas capacity and supply, including:

- On June 28, 2001, the CPUC authorized Southern California Gas Company (SoCalGas) to begin withdrawing up to 27 bcf of working gas (3 bcf) and cushion gas (approx. 24 bcf) from its Montebello storage field over the next 5 years, and to begin selling that gas into the California market. As early as mid-July, approximately 50 MMcf/d is now available to the California market as a result of this action.

- Also on June 28, 2001, the CPUC authorized SoCalGas to begin work to redesign its La Goleta and Aliso Canyon storage fields, to reduce the amount of cushion gas necessary to maintain current operations

and increase injection rates. This action will make up to 14 bcf additional gas available to the California market during this winter's heating season. The CPUC believes these actions to more efficiently use SoCalGas' storage fields should help to reduce the pressure on inter/intrastate capacity to and within California, and thereby help lower California border prices.

- SoCalGas is on target to increase its firm pipeline capacity at three existing California receipt points by an additional 175 MMcf/d by December 2001. These expansions focus on both interstate and in-state supply sources, and include:

  - 85 MMcf/d at Wheeler Ridge near Bakersfield to take gas from either the Kern River-Mojave or PG&E gas pipelines;
  - 50 MMcf/d at North Needles, to take additional gas off the Transwestern system; and
  - 40 MMcf/d to enhance SoCalGas' Line 85 ability to receive California supplies from the San Joaquin Valley.

- In addition to increasing capacity at existing receipt points, the CPUC has worked with SoCalGas to add a SoCalGas interconnect with the Kern River-Mojave pipeline at Kramer Junction. This addition is on target to go on-line by January 2002, and will increase SoCalGas' firm receipt point capacity by approximately 200 MMcf/d (and as much as 500 MMcf/d on an interruptible basis). The CPUC expects this additional receipt point to provide shippers with an alternative to the Wheeler Ridge receipt point, which as noted above is also being expanded.

- Lodi Gas Storage, a competitive natural gas service provider in the PG&E service territory, is currently on target to go online with 12 bcf storage capacity in 2002.

- Wild Goose Storage, another competitive natural gas service provider in PG&E's service territory, filed a proposal with the CPUC on June 18, 2001 to expand its total storage capacity to 29 bcf by mid-2003.

These infrastructure additions will help meet California's changing natural gas demand in the future. These and other potential intrastate expansions also will help the state to benefit from some of the interstate projects the FERC is currently considering. It is important to note, though, that California's existing physical infrastructure adequately meets California's current demand for natural gas if it is operated reasonably and prudently and if interstate facilities are also operated reasonably and prudently.

Natural gas is a significant strategic resource for California. As a net consuming state (a gas "have-not") California depends on a robust and well-managed interstate system to secure this important resource. California has been vigilant in managing the evolution of its in-state infrastructure to match changing patterns of demand and has directed the investment of billions of dollars in needed projects over the past ten years. California needs its approach of careful vigilance to be matched at the federal level to prevent manipulation of prices and delivery capacities. The primary actor should be the FERC. If not the FERC it should be the Congress. But it should be someone.

Mr. OSE. Also joining us today is the commissioner from the California Energy Commission, Mr. Michael Moore, who has prepared a rather comprehensive report which we have read. Mr. Moore, you're recognized for 5 minutes.

STATEMENT OF MICHAL MOORE, COMMISSIONER, CALIFORNIA ENERGY COMMISSION

Mr. MOORE. Thank you, Mr. Chairman, Mr. Waxman, Mr. Shays. It's a great privilege to be here. I thank you very much for the opportunity. I am Michael Moore. I am an economist by trade, and I occupy that seat on the California Energy Commission. And in that position, I oversee data collection, market structure issues, and the electricity and natural gas issues in terms of reporting or information generation for the State.

In that role, we did produce a report called "Natural Gas Infrastructure Issues," which has been vetted quite widely and is the subject of many comments from a lot of different parties. You have summaries of it in my prepared testimony, but I'd like to go to four of the major conclusions and recommendations, then highlight them as we proceed here today.

First, I'd like to point out that when reviewing market conditions that affect California in establishing new rules and procedures, the FERC should take into account the fact that California lies at the end of a long and rather narrow corridor. Upstream demand claims on gas can be disruptive and introduce volatility in the California market, and I believe that my colleagues at FERC should be very cognizant of the impact that can have when they're establishing their new rules and oversight.

Second, we're subject to weather permutations in the West, and what happens in the Northwest, for instance, can dramatically affect the State. Shifts which emphasize generator demand for natural gas doubled demand in some periods and produced a secondary planning peak that was unforeseen in the past and which has to be accommodated in terms of planning backbone infrastructure expansion within the State. We've been using the wrong model, and it's time for us to move to accommodate a new model which is more realistic.

Third, slack capacity both in the intrastate and interstate system is very important, needs to be built into all of our calculations. We suggest, and I believe we have broad concurrence in this, that 15 to 20 percent is the right amount of slack capacity that will allow some gas-on-gas competition and provide a more open and transparent market as we go forward.

And fourth, we very much support the market monitoring activities that have been proposed by Chairman Wood, and we would like to cooperate in those. We have a great deal of expertise and talent at our disposal. We plan to use that in conducting new hearings and workshops in the near future, which we will initially use to produce a risk assessment of the gas system where we literally test it, at least mathematically, and test it in public in our hearings and make that information available to our colleagues and to the PUC and also at the FERC. We hope that in the expansion of the market monitoring activities that the FERC undertakes they'll

utilize the experience and talent at the State and use it to augment and bolster their own reporting.

Mr. Chairman, I believe that the other observations that we've made about the market are pretty well known by now, but we did not take on the question of price manipulation. We very specifically stayed away from that. It's not in our purview. As a consequence, we didn't comment on it. But we did comment on the likelihood that there were different series of events that could have affected the market, and you'll find those in our summary.

Thank you for allowing me to come.

[The prepared statement of Mr. Moore follows:]

HOUSE OF REPRESENTATIVES
COMMITTEE ON GOVERNMENT REFORM

Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs
Hearing on Natural Gas Infrastructure and Capacity Constraints

Prepared Testimony of Commissioner Michal C. Moore
California Energy Commission
October 16, 2001

NATURAL GAS INFRASTRUCTURE ISSUES

Good afternoon, Mr. Chairman and members of the Subcommittee. I am pleased to provide testimony on behalf of the California Energy Commission (Energy Commission) for today's Subcommittee hearing: "Natural Gas Infrastructure and Capacity Constraints."

As you are aware, California bore some of the highest natural gas prices in the nation during late 2000 and early 2001. Over the same period, the natural gas infrastructure serving California strained to meet unusually high natural gas demand. In response to these conditions, the Energy Commission undertook an assessment of the state's natural gas infrastructure. As a culmination of that effort, the Energy Commission adopted the ***Report on Natural Gas Infrastructure Issues*** on October 3, 2001, which we have provided to the Subcommittee.

Current natural gas prices in California are considerably lower than they were last spring, and natural gas is much more available to California. Californians' concerted efforts to reduce demand this last summer, coupled with favorable weather conditions and actions by the Governor, the State legislature, regulatory agencies, including the Federal Energy Regulatory Commission (FERC), and utilities, can take

substantial credit for this improved situation. The Energy Commission, nevertheless, remains concerned about future prices and the adequacy of natural gas supplies to meet California's needs.

Following is an overview of the important findings and conclusions from the Energy Commission's report and recommendations for future FERC attention.

Insufficient natural gas infrastructure contributed to high prices in California.

The Energy Commission has concluded that both insufficient natural gas receipt capacity *within* California and insufficient capacity on El Paso's interstate pipeline system contributed to the high natural gas prices of late 2000 and early 2001. The report makes note of the fact that the California Public Utilities Commission (CPUC) has filed a complaint with the Federal Energy Regulatory Commission (FERC) that high natural gas prices in California were the result of market manipulation. However, determining the extent to which high prices were the result of: 1) a free market's rationing of scarce supplies through higher prices; 2) price manipulation; or 3) some combination of the two factors was beyond the scope of the Energy Commission's report.

A combination of demand-related events strained California's natural gas infrastructure.

In November 2000, uncommonly cold weather drove heating-related natural gas demand in the residential and commercial sectors to very high levels. California also saw a dramatic increase in electric generators' demand for natural gas in late 2000 and

early 2001. Limited hydroelectric resource availability, brought about by a west-wide drought, was a major driver in this increase.

Several other factors also influenced California's natural gas prices in 2000 and early 2001.

First, large natural gas consumers in Southern California began last winter's heating season with record-low storage inventories. Second, California shippers are not currently able to use all of the firm interstate pipeline capacity for which they have contracted and paid. Third, wellhead natural gas prices increased significantly across the United States, affecting gas prices in California, as well. Finally, electric generators were relatively indifferent to high natural gas prices since they could pass through all gas costs to retail electricity providers.

Enhancing the natural gas infrastructure helps protect consumers from high prices.

Adding to or upgrading the natural gas infrastructure — i.e., receipt capacity, storage, or interstate pipelines — is highly cost effective and can be brought on line relatively quickly. By contrast, natural gas is relatively expensive and natural gas consumers are subject to sometimes-dramatic price swings. As a result, the report supports expansion of California receipt capacity, California backbone infrastructure, including storage, and interstate pipeline capacity into California.

California is taking steps to assure adequate natural gas supplies and infrastructure to meet near-term needs.

Under CPUC oversight, California utilities are expanding their intrastate natural gas infrastructure, including additional receipt capacity and storage facilities, to assure that they can meet future natural gas demand reliably. For example, Southern California Gas Company is constructing 375 million cubic feet per day (MMcfd) of additional receipt capacity that will be on line by the end of this year. Pacific Gas & Electric Company (PG&E)also plans to add to its receipt capacity (between 200-600 MMcfd); however, given PG&E's bankruptcy status, it is not clear when this would be completed. In addition, California is adding to its natural gas storage facilities, including expansion of the Wild Goose independent storage facility. These infrastructure expansions should help to assure adequate supplies for California in the near term.

California can no longer plan for its future as if we lived in a regulated, cost-plus environment.

Under price regulation, adverse hydroelectric conditions and extreme temperatures did not lead to extreme price spikes. However, in today's environment, either factor could lead to extreme prices. California's virtually complete reliance on gas-fired generation for its future needs, taken together with price deregulation, adds further to the state's vulnerability to price increases.

California plans to examine its natural gas infrastructure-design criteria.

The design criteria and reliability standards that utilities currently use to plan the state's natural gas infrastructure are outdated and should be revised to account for the changing nature of California's natural gas demand. Two examples are noteworthy:

- First, California gas utilities designed their systems in an era when many industrial customers and electric generators maintained dual-fueling capability. Air quality regulations and the economic advantages of burning natural gas have caused these consumers to dispense with this fuel-switching capability except in isolated cases.
- Second, the natural gas utilities designed their intrastate systems to meet peak residential and commercial heating loads, caused by extreme cold temperatures. However, electric generators' demand for natural gas to meet summer electricity peak demand has created an additional peak on the natural gas system that was not evident before 2000.

Because of the increasing interrelationship of Western natural gas and electricity markets, California needs to take a more integrated approach to analyzing the two markets and the need for infrastructure enhancements. The Energy Commission has begun to investigate risk analysis as a means to develop recommendations for design criteria better suited to today's environment. The Energy Commission's Electricity and Natural Committee, which I head, will hold a hearing on the application of risk assessment to natural gas design criteria in mid-December.

Increasing upstream natural gas demand will be a major concern in examining California's need for infrastructure enhancements.

Interstate natural gas pipelines supply about 85 percent of the natural gas that California consumes. Since California is at the end of these interstate pipelines, upstream demand in the West can divert natural gas supplies that might otherwise meet California demand. As natural gas demand in the Pacific Northwest and Southwest, Mexico and Canada increases, more gas gets diverted away from California.

Already this past winter, upstream demand, at times, caused constraints on the El Paso system, reducing the effective capacity into California from gas production basins to the east. These constraints could become more acute if FERC authorizes generators in Arizona and other Southwestern states to become full-requirements customers,[1] and other generators outside California sign long-term firm contracts for natural gas shipping services. Growing demand in the Pacific Northwest, especially during unusually cold winters, will also divert natural gas from production basins in Canada away from California.

FERC will need to undertake additional steps related to natural gas markets to assure that price volatility is minimized and adequate interstate supplies are available to California and the other Western states in the future.

The Energy Commission is encouraged by interstate pipeline companies' announcements concerning planned expansions and construction of entirely new pipelines. Also, we are encouraged by FERC's intent to expedite review of these projects. However, we believe the State of California must continue to work with FERC

[1] In June, FERC approved a plan by El Paso Corp. to supply 620 million cubic feet of natural gas per day to fuel two new gas-fired electric power plants in Arizona; the 2,100 MW Redhawk facility and the 1,000 MW Arlington Valley facility as full requirements customers.

to assure adequate natural gas supplies reach California. To this end, I encourage California to work cooperatively with FERC on the following:

1. In reviewing interstate pipeline expansions or construction of new pipelines, consider the implications of the increasing upstream gas demands on the interstate pipeline system and how they affect the flows of natural gas and electricity between California, the Pacific Northwest and Southwest, Canada, and Mexico.

2. In addition, when examining the need for new or expanded interstate natural gas infrastructure, consider the types of weather- and demand-related risks posed to the natural gas and electricity systems throughout the West. Moreover, the Energy Commission believes that building cost-effective slack capacity into the interstate pipeline system helps to address these risks. Slack capacity also promotes competition. When there is no slack capacity, customers lose the benefits of competition, and prices increase overall or spike upward. Therefore, in determining the need for slack capacity on interstate pipelines, risks and economic benefits need to be explicitly considered.

   The Energy Commission's integrated assessment and risk analysis activities in this area could provide information and new methodologies for FERC and other Western states when considering natural gas infrastructure improvements. I will commit to work with FERC and other Western states to assure that regional conditions and slack capacity are adequately assessed and incorporated into decision-making regarding the need for infrastructure throughout the West.

Thank you for allowing me to appear before you today. To the extent I am able, I would be happy to answer any questions you may have.

Mr. OSE. Thank you, Mr. Moore.

Our final witness on the first panel is Lad Lorenz who is the director of capacity and operational planning for Southern California Gas Co. Welcome. You're recognized for 5 minutes.

STATEMENT OF LAD LORENZ, DIRECTOR, CAPACITY AND OPERATIONAL PLANNING, SOUTHERN CALIFORNIA GAS CO.

Mr. LORENZ. Thank you, Chairman Ose, and members of the committee. I appreciate the invitation to testify regarding the important issue of California's natural gas infrastructure. I understand that there have been some challenges to the adequacy of the intrastate transportation system in southern California. I want to try and clear up some of the misperceptions.

Let me state from the outset that despite any allegations to the contrary, the SoCalGas pipeline system has adequate infrastructure, both pipeline capacity and storage capacity, to meet the needs of its customers. In fact, last year when we faced unprecedented record demand for gas, the SoCalGas system operated at an overall 87 percent load factor. That means that despite these record high demands the SoCalGas system still had available our slack capacity.

What caused that record high demand on the SoCal system? There were a series of events almost analogous to a perfect storm that created the record high gas demand. Are those events likely to repeat themselves? We think it's unlikely, but nonetheless the SoCal system was adequate to meet even that demand, with some capacity to spare. We haven't curtailed any customers, firm or interruptible, on the SoCalGas system for over 10 years.

To maintain our strong commitment to reliable service, we are undertaking some key expansions to our system at the California/Arizona border in Kern County, south of Bakersfield, and in western San Bernadino County near Victorville. These expansions are going to add 11 percent to our capacity; 375 million a day of new backbone capacity is being created, and this will ensure that the system continues to have adequate capacity to meet the needs of our customers and provide an adequate level of slack capacity.

In light of this information, you may wonder what all the fuss is about, why questions regarding the adequacy of our system have arisen. The key issue looking forward is the expected significant increase in natural gas demand from new electric power plants being constructed throughout the western United States. What are the implications of these new power plants for gas infrastructure systems in the West, and particularly for the SoCalGas system?

First, most of these new power plants are planned for outside of southern California and off the SoCalGas system. Of the 72,000-plus megawatts of announced new power plants, only about 9,300 megawatts, or 13 percent, are proposed even for location in southern California. While it's not expected that all of these new power plants will actually get built, it's telling to note that of the 27,000 megawatts of new power plants that are currently under construction in the WSCC, only about 2,900 megawatts, or less than 10 percent, are located in southern California. Because the new out-of-state power plants will export power to California and are more efficient than the existing units served by the SoCalGas system, we

project an overall decline in gas demand and capacity utilization for the SoCalGas infrastructure. Not one new baseload power plant has yet signed up to take service directly from the SoCalGas system.

How will those new out-of-state power plants be served? Through direct connection to the expanded interstate pipeline system. The new interstate pipelines argue that our infrastructure is inadequate. Clearly, that is not the case. What the interstates want is for intrastate utility systems like SoCalGas to expand their takeaway capacity solely to have somewhere to dump excess supplies when the new electric generation customers are not operating. But that safety net for the interstate pipelines would cause a huge cost to California consumers without regard to whether or how often that capacity would actually be utilized.

Putting pipe in the ground is an expensive proposition and one that we don't take lightly. Ramifications of overbuilding our intrastate system are too great for our customers. The question is how much slack capacity and who is going to pay for it. The pipeline expansions on the SoCalGas system that I and Commissioner Lynch have mentioned earlier ensure that we will be able to maintain the 15 to 20 percent slack capacity that Commissioner Moore mentioned on the SoCalGas system. We believe that's the appropriate amount for our system and for our customers.

Congress has sought to address the confusion and controversy between FERC and the States regarding the need for pipeline infrastructure, and we think that's a valuable effort. Any solutions must consider what demand growth is expected, where that demand is expected to occur, whether the current infrastructure can serve that current and forecasted demand, and how planned expansions compare to each other and with anticipated growth.

As you can see, I don't believe there's any truth to the charges that SoCalGas is unwilling to build new pipeline or expand its system. Clearly, we will expand our system when there is a market and it is in the interest of our customers. The SoCalGas system has adequate capacity to meet the needs of its customers. And, without additional demand on the system or long-term contractual commitments for capacity, it doesn't make sense to build more capacity on our system. Thank you.

Mr. OSE. Thank you, Mr. Lorenz.

[The prepared statement of Mr. Lorenz follows:]

UNITED STATES HOUSE OF REPRESENTATIVES
COMMITTEE ON GOVERNMENT REFORM
SUBCOMMITTEE ON ENERGY POLICY, NATURAL
RESOURCES AND REGULATORY AFFAIRS

TESTIMONY OF LAD LORENZ
DIRECTOR OF CAPACITY AND OPERATIONAL PLANNING
SOUTHERN CALIFORNIA GAS COMPANY

OCTOBER 16, 2001

Good morning. I am Lad Lorenz, Director of Capacity and Operational Planning for Southern California Gas Company (SoCalGas). SoCalGas is a California Public Utilities Commission (CPUC) regulated subsidiary of Sempra Energy, a San Diego-based Fortune 500 energy services holding company. SoCalGas is the nation's largest natural gas distribution utility, serving 18 million customers through 5 million meters. The company's service territory encompasses 23,000 square miles, from San Luis Obispo on the north to the Mexican border on the south.

Thank you, Chairman Ose, for convening this hearing. We value the opportunity to testify today regarding California's natural gas infrastructure. This important subject has been debated here in Congress, and we appreciate your effort to explore the questions regarding California's infrastructure in a constructive manner.

SoCalGas' system was originally designed to meet peak customer demand for natural gas in the winter, since the principal driver of peak gas consumption is residential heating. Over the past 20 years, however, the nature of the demand has changed. As a result of abundant supplies, low prices and the air quality benefits of natural gas compared to other conventional fuels, Californians have increasingly relied upon natural gas as their key energy source. Most significantly, Los Angeles-area electric generation, originally dual-fuel capable, has been converted to run exclusively on natural gas, and new power plants being built in California and throughout the western U.S. are primarily natural gas-fired generators.

Consequently, demand for natural gas today, especially by electric generators, is higher than ever. The SoCalGas market is comprised mainly of core customers (small commercial/industrial and residential customers) and non-core customers (large commercial/industrial customers, electric generation and wholesale customers). SoCalGas now designs its system to meet the greater of core peak day demand or the 1 in 10 year estimated demand of the entire market, both core and noncore. The question your committee has raised is whether the infrastructure is capable of meeting that demand.

Recent Congressional debate has focused upon two allegations made by interstate pipeline companies:

1. California's existing pipeline capacity is inadequate to meet current needs, and

2. The state is not making appropriate regulatory decisions to determine whether additional pipeline capacity should be built.

1. Adequacy of Existing Infrastructure

Let me say emphatically that the SoCalGas system has adequate infrastructure to meet the needs of all its customers, core and noncore, firm and interruptible. SoCalGas' firm

transmission capacity is 1,280 Bcf/year. Last year, due to an unforeseeable confluence of unusual events, total receipts were 1,114 Bcf, the highest ever on the SoCalGas system. However, even under these unusual conditions, the utility's system operated at only an 87 percent load factor. There are three key reasons why last year was so unusual in terms of gas demand. First, southern California experienced the coldest winter in the last 19 years, with heating degree-days (HDD) of 1588 compared to a normal winter of 1252 HDD. This factor increased demand by approximately 33 Bcf. Second, there were a series of planned and unplanned nuclear plant outages that significantly increased gas demand by approximately 30 Bcf. Finally, and most significantly, the western U.S. experienced a 1 in 75 year drought condition that severely limited the availability of hydro-electric power exports to California. In southern California, since gas is the marginal generation source, the loss of hydropower increased gas demand by 225 Bcf, compared to average hydro conditions. Yet, even under these conditions, the SoCalGas system had adequate capacity and no curtailments of firm or interruptible gas service occurred. In fact, there have been no customer curtailments of gas service for the last 10 years on the SoCalGas system, and none are projected. The utility has sufficient capacity to meet the needs of its customers under all anticipated demand scenarios.

As you may be aware, last year there was a localized problem with the San Diego Gas & Electric (SDG&E) pipeline system serving the San Diego area. SDG&E's natural gas infrastructure was also built to serve the winter residential peak. Last winter, SDG&E experienced coincidental gas demand peaks, when the residential winter peak coincided with an electric generation peak. SDG&E experienced unprecedented electric generation demand during the winter equal to the summer peak days, a condition that had never before occurred. To address the problem, SoCalGas expanded the transmission pipelines linking the two utilities.

Thus, when one looks at the adequacy of our two systems and the ability to meet the needs of our customers, it is clear that we have sufficient capacity. The interstate pipelines, however, have not focused their concerns on whether our system is adequate to ensure reliable supply to our customers, but rather on whether our system is matched up to their system. Why are so many interstate pipelines considering expansions? The answer is that they want to serve the growing demand from new gas-fired electric power generation plants. But where are these plants to be located? Unfortunately, not on the SoCalGas system. Therefore, if demand is not increasing in our service territory, we do not believe our customers should pay to match the interstate expansions. We are in business to serve our customers. If new power plants want to commit to locate on the SoCalGas system, we will gladly execute a long-term contract with them and make any necessary expansions to provide the level of service for which they are willing to pay. When we determine that an unmet need exists, we build the necessary infrastructure to fulfill that need.

While some mismatches on the utility system exist, mismatches occur on less than 10 percent of the system. In fact, the Energy Information Administration EIA) found in its "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply Report (issued on June 12, 2001) that the total intrastate California mismatch was only 8 percent

compared to California's total interstate receipt capacity of about 7.3 Bcf. Of the 8 percent, only 140 MMcfd (or 2 percent) is attributable to the SoCalGas system. However, in reality, mismatches are not the issue. The real issue is the adequacy of the intrastate utility infrastructure to meet the needs of its customers.

Adequate intrastate capacity (3500 MMcfd) currently exists to serve the market (which has a projected a capacity requirement of less than 3000 MMcfd), leaving about 500 MMcfd of slack capacity. SoCalGas has a policy of maintaining 15 -- 20 percent slack capacity on its intrastate system and is moving forward with least-cost expansions and interconnections to ensure that we maintain this excess. Southern California Gas is undertaking expansion projects that will add 375 MMcfd (11 percent) of firm backbone transmission capacity to its system. These expansions will include:

- 50 MMcfd at North Needles (on California-Arizona border) from Transwestern/Questar pipelines;
- 85 MMcfd at Wheeler Ridge (in Kern County, south of Bakersfield) from Kern-Mojave, Elk Hills production or Kern pipelines, and
- 40 MMcfd on Line 85 (in Kern County, south of Bakersfield) from California production, and
- 200 MMcfd at Kramer Junction (in western San Bernardino County near Victorville) via a 32 mile pipeline expansion from the Kern-Mojave pipeline system.

The North Needles and Wheeler Ridge expansion projects are expected to be completed by December 31, 2001. The 40 MMcfd expansion on SoCalGas line 85 is expected to be completed by the end of January 2002. This project is intended to increase our ability to accept gas produced from California sources. The largest expansion is the Kramer Junction pipeline, a 32-mile pipeline that will add 200 MMcfd of firm transportation capacity and help to diversify supply sources for SoCalGas customers. To date we have received all of the necessary state permits to construct the Kramer pipeline. We are waiting to receive federal environmental permits and the right-of-way grants from the Bureau of Land Management and the U.S. Fish and Wildlife Service. Unfortunately, we have not received any projected completion date for these permits or the right-of-way grants. Hence, the completion of the project has been delayed at least until January 31, 2002 until we receive the federal permits.

Ultimately, completion of the expansions will ensure that the SoCalGas system continues to have 15 – 20 percent slack capacity.

2. Planning for Future Capacity

SoCalGas has repeatedly expressed concern that there has not been sufficient focus on where the proposed interstate pipeline capacity expansions and extensions are being

planned, and on whether the planned capacity is in alignment with where demand is likely to increase or decrease. For example, the majority of the new power plants planned or under construction in the western U.S. will be outside the state of California: in Arizona, Nevada, New Mexico and across the border in Mexico. Moreover, these new power plants are to be directly served by new interstate pipelines or expansions. Of the approximately 27,000 MW of new gas-fired power plants under construction in the western U.S., only about 2,900 MW are to be located in southern California. The new out-of-state plants, due to their higher efficiency and lower cost generation, will displace current electric power generation demand on the SoCalGas system. Of the new power plants that are to be located in southern California, most are also taking direct service from interstate pipelines and not off the SoCalGas system. Thus, total gas demand on the SoCalGas system is projected to decline in the future.

The efficiency of our infrastructure investments must be maximized. Simply put, pipeline construction is not without significant cost. Requiring in-state utilities to build pipelines to match the ultimate carrying capacity of interstate pipelines, only to find the capacity unutilized, would raise our customers' bills and saddle small businesses and residential customers with stranded capacity.

Despite SoCalGas' efforts, the interstate pipeline companies contend that even more intrastate capacity is needed. Allegations have been made that the planned intrastate capacity is not sufficient to meet the anticipated load growth. These arguments are self-serving. Interstate pipelines are expanding to serve electric generation load directly. The interstate pipeline companies simply want intrastate utility systems to expand their take-away capability solely to have somewhere to dump surplus supplies when the electric generation plants are not operating. Although it is clear that a policy supporting expanded growth of the utility infrastructure would benefit interstate suppliers, it is unclear why utility ratepayers should fund excess capacity.

During the floor debate on H.R. 4, a Manager's Amendment was added to the bill that sought to address the confusion and controversy between the FERC and the states regarding the needs of California's pipeline infrastructure.

H.R. 4 would require DOE to undertake a study that would consider these issues and report back to Congress with any recommended actions. The amendment also directs FERC to inform Congress how the information from the study is being used in their interstate pipeline certification process. From SoCalGas' perspective, this would help in the identification of future infrastructure needs of the western region of the U.S.

In addition, I want to thank Chairman Wood for convening the Commission in Seattle early next month to discuss critical infrastructure needs in the west. We hope this will be the beginning of the coordinated approach we have long advocated.

Conclusion:

Over the past 20 years, California has increasingly relied upon natural gas as a key energy supply source. As a result, Southern California Gas Company has made expansions and modifications to its system to ensure that the intrastate capacity remains adequate to meet the needs of our customers. Today, our system has adequate pipeline capacity.

SoCalGas is continuing to work with state regulators to ensure that any additional capacity that is built reflects a merging of in-state needs with external delivery capabilities. Randomly overbuilding the intrastate infrastructure will impose significant costs on business and consumers, and will threaten our weakened economy. For that reason, we appreciate your decision to hold this hearing to examine this issue more fully, and for the House's decision to urge state and federal authorities to better coordinate on assessing the adequacy of future infrastructure.

Mr. OSE. Many of you have testified in front of Congress before. Those little boxes in front of you have a green, yellow and red light. The green light denotes that we're in the first 4 minutes of a 5-minute period. The yellow light indicates that you're in the last minute. The red light means stop. Now we're going to go around the panel here through 5-minute question periods. You'll probably have a variety of questions because I know that the questions in the Northeast, for instance, may be a little bit different than the questions for the Pacific Coast. I'm going to go ahead and take 5 minutes. So if you'll start the clock.

Mr. Wood and the others, you have varying opinions as to whether or not there is a surplus or a deficit of capacity on the interstate lines going into California? I just want to make sure I get a yes or a no answer.

Mr. Wood, is there a deficit of interstate capacity going into California for transmission of natural gas?

Mr. WOOD. Is there a deficit today?

Mr. OSE. Yes.

Mr. WOOD. Yes.

Mr. OSE. Ms. Lynch.

Ms. LYNCH. I think we have all we need as long as we incorporate storage and in-state capacity.

Mr. OSE. Mr. Moore.

Mr. MOORE. I think the conditions are tight. I think depending on the day and the demand, you could describe it either way, but it's tight enough to reveal either case.

Mr. OSE. Mr. Lorenz.

Mr. LORENZ. There is adequate capacity in the SoCalGas system to meet even unexpected demands like we had last year.

Mr. OSE. All right. My second question has to do with how people acquire capacity on the line to transmit or convey gas from point A to California. I'm confused a little bit when I talk with staff about the manner in which people acquire capacity, and I'm hopeful you can help me. Apparently, there are two different systems by which capacity is allocated on the lines going into southern California versus the lines going into northern California? Am I accurate on that, Mr. Wood?

Mr. WOOD. I might have to defer on that one. There are traditional ways to get transportation. There are numerous ways to get interruptible or shorter-term transportation. As far as the interstate lines going into the State, that regime should largely be the same, whether it's the south or the north.

Mr. OSE. Is it the same, though?

Mr. WOOD. Well, the El Paso one has a little bit different history. I think the opinion that Mr. Waxman pointed to is probably the best way to teach that. But El Paso's about in the middle of a 10-year settlement as to its rates and terms. The nature of some of the rates on the El Paso is different than they are on Pacific Gas going into California for some customers, historically grandfathered customers, that have, I think, what is properly characterized as more expansive rights to use firm capacity on the system than a newer customer might have.

Mr. OSE. FERC controls the nomination process on the interstate lines. Maybe my question is more properly directed to one of the

three of you. Who controls the nomination process on the intrastate lines?

Ms. LYNCH. On intrastate it's the Public Utilities Commission.

Mr. OSE. OK. Is the nomination process for firm capacity the same in the North as it is in the South?

Ms. LYNCH. We have slightly different systems in the North and the South depending primarily on how PG&E has used its system and prior Commission decisions versus how Southern California Gas uses its system. We have before us now the question of changing, to what extent to change the overall process of pricing in the South.

Mr. OSE. There's something before the PUC right now to look at that.

Ms. LYNCH. Correct.

Mr. OSE. OK. Mr. Lorenz, Southern California Gas Controls apparently has this pleading in front of the PUC. Can you just give me a layman's explanation of the nomination process—you're smiling—on SoCalGas's capacity right now.

Mr. LORENZ. It would be complicated Congressman, but I will try.

Mr. OSE. We've only got a minute. We can come back to it on the second round if you like.

Mr. LORENZ. On the interstate pipeline system parties subscribe for and hold long-term capacity commitments. Then customers on the SoCalGas system have contracts with us for service and they're on all volumetric rates. Customers nominate deliveries on our system, then we confirm those nominations to the upstream interstate pipelines. It's that nomination and confirmation process that determines which gas will flow and also how gas gets cut.

So it is a complicated process, but it's a matching of nominations on the SoCalGas system with nominations on the interstate pipeline system.

Mr. OSE. So the end user actually contracts for gas on both the interstate line and the intrastate line.

Mr. LORENZ. That's correct.

Mr. OSE. And apparently the system you're using for nomination purposes is different than what's used, for instance, on PG&E's lines.

Mr. LORENZ. No, the process is exactly the same. But on the PG&E system, there is an unbundled backbone intrastate transmission system, that provides firm receipt point rights into the PG&E system. We have proposed a similar structure in southern California to the CPUC, but it has not yet been acted upon. So we don't have firm receipt point rights on the SoCalGas system like PG&E does in northern California.

Mr. OSE. I want to come back to this question, but my time has expired. Mr. Waxman for 5 minutes.

Mr. WAXMAN. Thank you, Mr. Chairman.

Ms. Lynch, I'd like to walk through with you the key allegations against El Paso. I'm going to start with the awarding of the El Paso contract in the spring of 2000. The administrative law judge's decision quotes directly from telephone transcripts the conversations between El Paso Natural Gas and El Paso Merchant, which demonstrate blatant collusion to keep secret a discount for service

on the El Paso pipeline. This deal gave El Paso Merchant an unfair advantage during the bidding season when it bid for the entire block of pipeline capacity that El Paso was auctioning off. In fact, the judge found that there was a general sharing of information between the affiliates in violation of the FERC standards of conduct.

Ms. Lynch, can you tell us how the collusion between the El Paso affiliates allowed them to exercise market power?

Ms. LYNCH. Well, basically if the affiliates have inside information that other sellers or other bidders don't have, then they have superior information to be able to bid the price up or profit from that. So it's essentially inside information that in that context, for instance, in front of the Securities and Exchange Commission, it would never be allowed, because then it's not a fair market. So if the affiliate has in essence illegal information, they then can profit handsomely to the detriment of both—all the other participants in the market and also California consumers.

Mr. WAXMAN. The El Paso contract ran for 15 months starting in March 2000. The PUC presented evidence indicating that during the summer and fall of 2000, El Paso Merchant used a fraction of its available pipeline capacity to deliver gas to California. While other shippers on the El Paso pipeline were using 80 to 90 percent of their available capacity, El Paso Merchant used less than 50 percent of its available capacity.

Ms. Lynch, how significant was El Paso's decision to use a fraction of its capacity?

Ms. LYNCH. It was quite significant, because that meant that there wasn't gas available in that pipeline because the affiliate was holding it back. I'm not remembering the exact percentage, but I believe it's about 40 percent of the total capacity on that pipeline was controlled by the affiliate. So if they're not using it, that means all of a sudden there's an artificial shortage which will raise prices, and then that has a ripple effect throughout the entire California gas market.

Mr. WAXMAN. Did El Paso's actions affect storage of gas in southern California?

Ms. LYNCH. Absolutely. As the prices rose last summer, many of the utilities, as well as other purchasers, electric generators, saw that there was an unusual rise in prices, expected that price to go down after the summer peak, so therefore in the summer of 2000 did not buy gas to inject into storage and were caught short in the winter of 2000 because they didn't buy gas to inject. The price rose dramatically to 10 times what it had been the year before, and they didn't have gas in storage to use.

Mr. WAXMAN. California gas prices began to rise in the summer of 2000, hit record heights in the winter of 2000, 2001. It is only after the El Paso contract expired on May 31, 2001 that prices in California began to decline. Why did gas prices in California start to go down after the El Paso contract expired?

Ms. LYNCH. We believe that gas prices went down because now there were many sellers who could use the capacity that was being withheld by the El Paso affiliate. So instead of a one-to-one relationship where that one seller got illegal information, many sellers then could compete appropriately. And, frankly, one of the reasons that went down because FERC, with the addition of new commis-

sioners including Commissioner Wood, then allowed our Commission, the PUC, to put on its evidence. Until then, we were not allowed to even show our evidence. And I think that hearing, that allowing of the hearing, gave El Paso a signal. They dropped their collusive contract and the market became more competitive.

Mr. WAXMAN. So to sum up, the judge found that there was blatant collusion between El Paso affiliates, which gave them the ability to exercise market power. The result, according to the judge, was tremendous profits for El Paso Merchant, at least $148 million.

Ms. Lynch, given the collusion between the El Paso affiliates, given their ability to exercise market power, given El Paso's decision to use so little of its capacity, how did the judge conclude that there was not clear evidence of market manipulation? And do you agree with the administrative law judge's decision?

Ms. LYNCH. Well, the administrative law judge came to the brink of allowing refunds for Californians and then stepped back. I believe that stepping back was not consistent with FERC precedent which would show that in periods of high demand the FERC needs to look very carefully at whether market power that is available, as the ALJ found it was, was in fact exercised. So although this is in front of Mr. Wood and his colleagues, I hope that they look very carefully at the evidence, including the evidence under seal, which I believe does establish California's case for refunds.

Mr. WAXMAN. Mr. Wood, I know it wouldn't be proper for you to comment on all this, but I'd like to underscore the seriousness of these allegations. As I mentioned, the administrative law judge's decisionmakes some troubling findings, and despite these findings the judge found it is not at all clear that El Paso in fact exercised market power. It seems to mean that, right or wrong, these allegations deserve a better answer than it's not clear. Now it is, of course, up to you. Thank you, Mr. Chairman.

Mr. OSE. Thank you Mr. Waxman. I'll use my time for that. Mr. Shays for 5 minutes.

Mr. SHAYS. Mr. Chairman, I'm happy to have both of you go another round because I am going to be talking about things that are more important, like what's happening in New England, So I'll let the less important issues go forward. So I'm going to just pass this time and take the second round.

Mr. OSE. Where is New England?

Mr. WAXMAN. East of Sacramento.

Mr. OSE. East of Sacramento. That's a small part of the country. I want to followup with Mr. Waxman's comment. I want to make sure I'm clear. The June 1st decision that you referenced, we have evidence here that indicates that the price dynamic was actually broken on May 29th, following adoption of FERC's market mitigation plan which would have been prior to the June 1st date that you just cited.

This is a data chart of the prices for the past, from May to October, at the five entry points for natural gas. We're going to enter this into the record. I think it is important to understand exactly the chronology here.

I want to go back to Mr. Lorenz on something. This nomination process for capacity on your line, is the current system helpful or hurtful or is there a competitive advantage or disadvantage? Why are you seeking a change in the nomination process that you use?

[The information referred to follows:]

NGI Intelligence Press, Inc. Natural Gas Intelligence® NGI's *Weekly* Gas Price Index® NGI's *Daily* Gas Price Index® **Power Market Today** published by NGI, Inc.

Data History Home | NGI Home Page

Historical *Daily* Spot Gas Prices

key for the following report :

CALM400= California - Malin
CALPGCG= California - PG&E Citygate
CALSAVG= California - Southern California Border Average
CALSPGE= California - Southern Border, PG&E
SLAHH= Louisiana - Henry Hub

select additional points

	Month	*Day*	*Year*	
Start Date:	May	01	2001	Get Historical Data
End Date:	Oct	15	2001	

Issue Date	Trade Date	CALM400	CALPGCG	CALSAVG	CALSPGE	SLAHH
2001-05-01	2001-04-30	7.58	12.11	14.43	12.08	4.73
2001-05-02	2001-05-01	7.88	10.81	13.23	10.64	4.54
2001-05-03	2001-05-02	6.75	9.31	12.94	9.13	4.53
2001-05-04	2001-05-03	5.77	8.68	12.71	8.54	4.46
2001-05-07	2001-05-04	5.00	7.88	12.38	7.79	4.48
2001-05-08	2001-05-07	4.92	7.54	12.80	7.24	4.31
2001-05-09	2001-05-08	4.73	8.88	12.55	8.58	4.23
2001-05-10	2001-05-09	4.66	8.36	12.42	8.33	4.14
2001-05-11	2001-05-10	5.97	6.50	12.31	6.48	4.16
2001-05-14	2001-05-11	4.11	4.26	11.93	4.23	4.24
2001-05-15	2001-05-14	4.55	5.23	11.12	5.35	4.27
2001-05-16	2001-05-15	4.81	6.08	10.73	5.88	4.45
2001-05-17	2001-05-16	4.77	6.18	10.50	6.02	4.47
2001-05-18	2001-05-17	4.14	4.62	9.92	4.45	4.18
2001-05-21	2001-05-18	3.89	3.97	9.87	3.93	4.15
2001-05-22	2001-05-21	5.04	7.70	12.53	7.66	4.14
2001-05-23	2001-05-22	5.26	9.43	13.20	9.40	4.03
2001-05-24	2001-05-23	5.91	9.28	13.75	9.20	4.09
2001-05-25	2001-05-24	7.32	8.55	12.61	8.37	4.12
2001-05-29	2001-05-25	3.80	4.06	10.39	4.05	3.84
2001-05-30	2001-05-29	4.24	4.41	11.13	3.81	3.85
2001-05-31	2001-05-30	4.37	5.17	10.16	- -	3.66
2001-06-01	2001-05-31	4.23	5.80	9.98	4.24	3.72
2001-06-04	2001-06-01	3.28	3.35	7.93	3.06	3.71
2001-06-05	2001-06-04	3.74	4.10	9.24	3.47	3.95
2001-06-06	2001-06-05	3.63	4.24	9.37	3.74	3.98
2001-06-07	2001-06-06	3.27	3.40	8.06	3.08	3.75
2001-06-08	2001-06-07	3.13	3.37	5.86	3.14	3.68
2001-06-11	2001-06-08	2.69	3.10	3.54	2.96	3.62
2001-06-12	2001-06-11	3.82	5.22	6.74	3.39	3.84
2001-06-13	2001-06-12	3.63	5.19	7.57	3.89	4.00
2001-06-14	2001-06-13	3.85	4.15	8.42	3.62	4.13
2001-06-15	2001-06-14	3.67	3.91	6.94	3.53	3.94
2001-06-18	2001-06-15	3.43	3.43	3.83	3.04	3.87
2001-06-19	2001-06-18	4.25	5.19	8.12	4.39	3.89
2001-06-20	2001-06-19	4.11	5.32	7.33	4.03	3.94
2001-06-21	2001-06-20	3.69	4.66	6.86	4.13	3.82
2001-06-22	2001-06-21	3.50	4.77	6.49	4.31	3.69
2001-06-25	2001-06-22	3.38	4.06	3.93	3.83	3.69
2001-06-26	2001-06-25	3.52	4.44	5.94	4.13	3.56

2001-06-27	2001-06-26	3.13	3.80	4.65	3.38	3.45
2001-06-28	2001-06-27	2.92	3.36	4.74	2.94	3.39
2001-06-29	2001-06-28	2.81	3.34	4.29	3.00	3.21
2001-07-02	2001-06-29	2.60	2.82	3.78	2.56	3.00
2001-07-03	2001-07-02	2.68	3.65	5.00	3.25	2.92
2001-07-05	2001-07-03	3.50	4.76	5.59	3.72	3.00
2001-07-06	2001-07-05	3.74	4.77	6.62	3.86	3.10
2001-07-09	2001-07-06	2.65	3.11	5.80	2.86	2.99
2001-07-10	2001-07-09	3.11	4.13	5.84	3.47	3.10
2001-07-11	2001-07-10	3.14	4.20	5.61	3.70	3.18
2001-07-12	2001-07-11	3.02	4.22	4.70	3.76	3.20
2001-07-13	2001-07-12	3.00	4.19	4.48	3.77	3.30
2001-07-16	2001-07-13	2.57	2.83	3.10	2.71	3.15
2001-07-17	2001-07-16	2.79	3.52	3.71	3.48	3.08
2001-07-18	2001-07-17	2.68	3.69	3.79	3.21	3.12
2001-07-19	2001-07-18	2.67	3.76	4.00	3.32	3.14
2001-07-20	2001-07-19	2.64	3.74	3.76	3.40	3.02
2001-07-23	2001-07-20	2.46	2.62	2.90	2.38	2.95
2001-07-24	2001-07-23	2.86	3.80	4.06	3.40	3.02
2001-07-25	2001-07-24	3.19	4.03	4.43	3.67	3.01
2001-07-26	2001-07-25	3.40	3.88	3.96	3.63	3.06
2001-07-27	2001-07-26	3.02	3.41	3.59	3.23	3.27
2001-07-30	2001-07-27	2.63	3.08	3.09	3.09	3.07
2001-07-31	2001-07-30	3.18	3.66	3.79	3.39	3.27
2001-08-01	2001-07-31	3.31	3.67	3.70	3.36	3.32
2001-08-02	2001-08-01	3.35	3.71	3.75	3.44	3.26
2001-08-03	2001-08-02	3.30	3.82	3.88	3.51	3.15
2001-08-06	2001-08-03	3.25	3.65	3.60	3.31	3.06
2001-08-07	2001-08-06	3.31	3.71	3.67	3.35	3.05
2001-08-08	2001-08-07	3.32	3.71	3.65	3.38	3.13
2001-08-09	2001-08-08	3.21	3.51	3.48	3.25	3.09
2001-08-10	2001-08-09	3.06	3.43	3.34	3.20	3.09
2001-08-13	2001-08-10	2.82	3.19	3.10	2.99	2.98
2001-08-14	2001-08-13	2.97	3.29	3.18	3.02	3.00
2001-08-15	2001-08-14	2.99	3.42	3.08	3.17	3.03
2001-08-16	2001-08-15	3.10	3.48	3.20	3.21	3.14
2001-08-17	2001-08-16	3.44	3.72	3.54	3.59	3.44
2001-08-20	2001-08-17	3.15	3.46	3.28	3.23	3.23
2001-08-21	2001-08-20	3.02	3.48	3.19	3.20	3.16
2001-08-22	2001-08-21	3.09	3.50	3.29	3.27	3.16
2001-08-23	2001-08-22	3.12	3.51	3.38	3.29	3.19
2001-08-24	2001-08-23	2.84	3.24	3.11	3.03	2.86
2001-08-27	2001-08-24	2.65	2.94	2.94	2.84	2.77
2001-08-28	2001-08-27	2.53	2.92	2.88	2.76	2.59
2001-08-29	2001-08-28	2.55	2.88	2.74	2.69	2.56
2001-08-30	2001-08-29	2.52	2.76	2.59	2.58	2.44
2001-08-31	2001-08-30	2.52	2.70	2.56	2.54	2.46
2001-09-04	2001-08-31	2.12	2.26	2.15	2.12	2.16
2001-09-05	2001-09-04	2.02	2.34	2.21	2.12	2.21
2001-09-06	2001-09-05	2.08	2.41	2.33	2.30	2.36
2001-09-07	2001-09-06	2.22	2.45	2.39	2.32	2.40
2001-09-10	2001-09-07	2.09	2.36	2.20	2.18	2.35
2001-09-11	2001-09-10	2.15	2.36	2.30	2.24	2.38
2001-09-12	2001-09-11	2.16	2.24	2.34	0.00	2.45
2001-09-13	2001-09-12	2.15	2.27	2.32	2.19	2.45
2001-09-14	2001-09-13	2.02	2.21	2.27	2.14	2.40
2001-09-17	2001-09-14	1.97	2.20	2.22	2.11	2.41
2001-09-18	2001-09-17	2.01	2.26	2.31	2.18	2.35
2001-09-19	2001-09-18	1.96	2.29	2.16	2.15	2.17
2001-09-20	2001-09-19	1.90	2.15	2.05	2.07	2.13
2001-09-21	2001-09-20	1.84	2.08	1.94	2.01	2.07
2001-09-24	2001-09-21	1.48	1.75	1.80	1.66	2.04
2001-09-25	2001-09-24	1.48	1.93	1.84	1.81	1.99
2001-09-26	2001-09-25	1.45	1.91	1.80	1.80	1.95
2001-09-27	2001-09-26	1.53	1.96	1.77	1.79	1.90
2001-09-28	2001-09-27	1.54	1.80	1.80	1.67	1.89
2001-10-01	2001-09-28	1.58	1.91	1.87	1.72	1.84
2001-10-02	2001-10-01	1.56	1.88	1.87	1.69	1.77
2001-10-03	2001-10-02	1.59	1.97	1.86	1.79	1.83
2001-10-04	2001-10-03	1.79	2.04	1.95	1.92	1.98
2001-10-05	2001-10-04	1.96	2.13	2.11	2.03	2.13
2001-10-08	2001-10-05	1.78	1.91	2.02	1.78	2.12
2001-10-09	2001-10-08	1.77	1.90	1.90	1.75	2.04
2001-10-10	2001-10-09	1.67	1.89	1.86	1.75	2.12
2001-10-11	2001-10-10	1.89	2.04	2.03	1.93	2.24
2001-10-12	2001-10-11	2.21	2.33	2.31	2.26	2.41
2001-10-15	2001-10-12	2.11	2.23	2.26	2.11	2.31

CSV format

Mr. LORENZ. It is very important for customers to have the ability to acquire firm rights on the local transmission system and that's what we're proposing. That would allow customers to have assurance not only with regard to the volumes that they're delivering but the point at which those volumes are going to be delivered and received into the SoCalGas system. Right now, our system is utilized in total without any specific firm rights that can be acquired by parties. And so the reliability of supplies at a particular receipt point are always in question. With a system of firm receipt point rights, then customers can be guaranteed of receiving the gas volumes that they want at the point that they want them delivered. In other words, having access to the supply bases that they're choosing to acquire their gas at.

Mr. OSE. Is one of the things that you're attempting to address in the filing you have before PUC whether or not someone is a core or a non-core customer? In other words, do they have interruptible or non-interruptible gas?

Mr. LORENZ. The proposal we made to the CPUC always has provisions that provide for firm capacity on behalf of the core market. They are our primary customers. But we think it's important for noncore customers to also have access to firm capacity if they choose that.

Mr. OSE. I think that strikes right at the comment you made earlier about 13 percent of the generating capacity or the proposed generating capacity only being built in the southern California area. Is it the uncertainty of a firm delivery ability of natural gas that is an impediment here that you're attempting to address?

Mr. LORENZ. I think yes, that is one of the factors that we're trying to address, that reliability is important for electric generation customers. We're competing vigorously with the interstate pipelines for new power plants in southern California. We believe we offer a competitive product with superior services, balancing services and storage services that interstate pipelines can't offer. But there has been rate uncertainty, there has been delivery uncertainty, and there has been long-term contracting uncertainties and we're trying to address those through a variety of proposals to the PUC.

Mr. OSE. If I understand your point, then, the competition on the interstate pipelines is that perhaps out-of-state and interstate pipelines will deliver directly to a facility a firm commitment for natural gas in such and such a volume for their generating facility, and then they'll burn that fuel to generate the electricity and then send it over high voltage lines into California. The choice is whether to build in, say, Arizona or in southern California.

Mr. LORENZ. That's certainly one of the issues that's being addressed. And, of course, it's the issue of natural gas transmission capacity versus electric transmission capacity.

Mr. OSE. Right. Ms. Lynch, in terms of Southern California Gas's filing, do you have any idea—is it agendaed? What's the timetable for looking at it?

Ms. LYNCH. We have a significant piece. It was on our agenda for October 25th. My colleague, Commissioner Bilas, is the assigned commissioner and has, I believe, has just put out a proposed decision last week regarding the structuring of that.

Mr. OSE. So it's moving forward.

Ms. LYNCH. It's moving forward. I hope to have that decided by the end of the year.

Mr. OSE. Mr. Waxman for 5 minutes.

Mr. WAXMAN. Thank you, Mr. Chairman. Mr. Moore, the California Energy Commission's natural gas report makes it an interesting and important finding, and I want to quote it:

> The deregulation of electric generation in California contributed to the high prices of natural gas compared to the rest of the United States. The deregulation scheme adopted by California required all the Merchant power plants to bid into a spot market. When drought conditions were experienced and generation supply became tight, the Merchant power plants were able to set the price for electricity. Knowing they would receive whatever price necessary to cover their costs, the Merchant generators became indifferent to the price of natural gas. This dynamic was a major contributor to the extraordinarily high natural gas prices.

Mr. Moore, do you agree that the ability of generators to name their price was a major contributor to California's high natural gas prices?

Mr. MOORE. I think it contributed to it and I believe that the ability of the generators during that period literally to walk past what might have been considered reasonable market behavior, and to exercise what would at least on the surface appear to be some degree of market power, certainly contributed to that. I think that the gas market responded predictably when the generators were willing to pay, with indifference almost, any price that they wanted.

Mr. WAXMAN. Ms. Lynch, do you agree?

Ms. LYNCH. Absolutely. They just passed it right through, or tried to.

Mr. WAXMAN. What's your view, Commissioner Wood?

Mr. WOOD. I think it's hard to argue with the fact that as the CEC report pointed out, Mr. Waxman, that as the last user of gas, the electric generator in that market as it was set up last year really did not have an incentive on their side to manage the upside risk of the price, because it really could be transferred to the—well, at that point the host utility, and then later the DWR. So yes, there was really no incentive in a market that is really driven by scarcity, certainly at points, with the absence of hydroelectricity to the tune of several thousand megawatts—that there would not be really much management of risk on the system and to shove it on the customer at the very end.

Mr. WAXMAN. Thank you. I would add that FERC's order addressing electricity prices in California may have exacerbated this problem by basing their proxy price formula on inflated spot market prices for natural gas. In fact, some have suggested that those orders created an incentive for generators to drive up spot market prices for gas in order to justify high electricity prices.

Commissioner Wood, I'd like to note that the PUC's initial complaint against El Paso was filed in April 2000. Had FERC acted on it sooner, California might have been spared the skyrocketing natural gas prices for the winter of 2000, 2001. It took over a year for the Commission to set a date for hearing the complaint. It took 18 months for an initial decision.

I know you weren't there and I also know that—in fact, I believe one of your first official acts after joining the Commission this year

was to take the Commission to task for taking so long to act on a complaint like this. I very much appreciate that.

What concrete steps have you and the Commission taken to ensure that petitions like the El Paso complaint don't sit on hold for months or even longer?

Mr. WOOD. Well, two actions, Mr. Waxman. One is an internal process to make sure when we have complaints that do raise issues of contested fact, which this was clearly one, that those go to a law judge to be tried in the light of day.

Second is hiring some more law judges. We've now hired two just in the last week. I expect as we move into a competitive era, the most important thing we can provide to maintain a marketplace is a rapid court of justice so that allegations be proven; if they're not proven, that a defendant's name can be cleared as fast as possible so that the market can move forward.

Mr. WAXMAN. I appreciate that. I think that's the right way to proceed.

There are several other important matters pending before FERC including the complaint from the California PUC that the State's consumers are not receiving all the gas capacity that they contracted for. I hope the Commission is able to deal with these matters as expeditiously as possible. One of the lessons of the California experience seems to be that State regulators need more complete and more immediate access to information about gas transmissions.

Do you believe that State regulators should have access to any information that FERC obtains from market participants about their gas transactions?

Mr. WOOD. I do. I think we've got to ensure that to the extent there are business confidentiality protections that are provided by the Freedom of Information Act, that those are mirrored by the State as well, so that the protections that a market participant has under Federal law would be the same protections they have would have even when we share it with our colleagues on the State level.

Mr. WAXMAN. Thank you. Thank you, Mr. Chairman.

Mr. OSE. Mr. Shays for 5 minutes, assuming you can find New England.

Mr. SHAYS. Actually I'm getting drawn into this. One of the most courageous folks I thought that a politician ever made was Lowell Weickert during the energy crisis years and years ago, who did something contrary to what people would have thought Lowell Weickert would have done if they didn't know him. That was, he voted to deregulate energy prices in the Northeast, natural gas. The reason was we were just simply having a shortage. What ultimately happened was that prices went up a bit, there was more produced, there was more brought up. And we had the supply, we had no shortage, and ultimately we also had lower prices over time. It seemed to make sense.

My looking at California on the outside just blows my mind. I, for the life of me, can't understand how you could deregulate part and not deregulate all of it. And so when I look at it, and people say we need to help California, while I'm coming from that part of the country where the chairman doesn't know where it is, I say why would I want to do anything to help California? So someone

just tell me in simple terms why I would want to help California deal with an issue that they basically created?

Ms. LYNCH. I'll take that one, Mr. Shays. I agree that California made many mistakes in setting up a market that did not have effective market manipulation rules and in setting——

Mr. SHAYS. Market what?

Ms. LYNCH. Manipulation rules, and rules against that, and also in setting up a system where essentially the market participant is self-regulated. What we have seen is there has not been self-control exercised in many markets. California has now taken many steps to fix some of the glaring problems in its own system. But in creating that deregulated system, we handed off important regulatory functions to the Federal Government, which is why the PUC needs to work with the Federal Energy Regulatory Commission much more than ever to make sure that our market functions.

Actually, in terms of deregulation, we didn't deregulate. What we did was we Federalized our pricing regulation by creating a wholesale market, the pricing which is now controlled at the Federal level not at the State level. So the retail market is still controlled at the State level, the wholesale market is controlled at the Federal level. When the wholesale market went out of control, the State had inadequate tools to respond, which is why we need Federal help now both on the natural gas side as well as the electric side.

But I'd like to clear up one misnomer, I think, which is that we set up a system that did not allow a raise in retail rates because we could raise retail rates. What that freeze was, was actually a high level. It was a floor, not a ceiling, in that effect. Because at the time that California Federalized our regulation of electric prices through creating a wholesale market, the price of electricity in California was about 3½ cents. We set the price at 6½ cents, almost double what the actual price was.

So consumers were overpaying for years to allow the utilities to accelerate the depreciation of their capital assets and essentially buy those down in advance. And then when the market went out of control, when the price caps were blown out by the previous FERC, at that point prices went up in California to 30 or 40 cents. So, of course, the 6½ cents couldn't cover it.

But no economy, no State's economy is going to be able to take that kind of a price shock in real time. We borrowed against our general fund and we'll pay that back over time. And because the market was so volatile and there were many mistakes made along the way by a variety of players, we now need Federal help to correct those mistakes and put in a market that works. Because we handed off those Federal tools—or we handed off the tools that used to reside with the State now to the Feds, which is why we have to work together and we need your help.

Mr. SHAYS. Can anyone else——

Mr. MOORE. Mr. Shays, can I add something to that? There are a couple of lessons that are perhaps coming, unwelcomed, to some of the other areas. I know Commissioner Wood is well aware of these and will be on the lookout for them. But just let me mention a couple. One is the question of whether or not there is a surplus in capacity as markets go forward, whether they use that up and adequately create incentives to bring in new supply that is acces-

sible. And second is the question of market mitigation or market monitoring.

Mr. SHAYS. Just explain to me excess supply. That's a new concept.

Mr. MOORE. What happened in the California marketplace——

Mr. SHAYS. If you have excess supply, doesn't your price basically lower because——

Mr. MOORE. One of the things that has protected some of the eastern markets, for instance in the PJM market, is the fact that they have a surplus in capacity. And as demand grows and as that surplus diminishes, as the relative surplus diminishes, then you can have a tightening of the market, so——

Mr. SHAYS. But when you have a surplus, don't prices drop?

Mr. MOORE. Prices will be lower than they would be if there wasn't, or if it was a tighter market. So all I'm——

Mr. SHAYS. When the prices drop, I would think demand would increase.

Mr. MOORE. No, I'm suggesting to you that as the market was created and it was moving forward, there was enough surplus capacity to make sure that prices stayed low.

Mr. SHAYS. The chairman is hitting his gavel. With three members, it strikes me we could probably go beyond 5 minutes, but I'll wait. Thank you.

Mr. OSE. The chairman will claim his time and yield it to the gentleman from Connecticut.

Mr. SHAYS. I just would love someone—maybe, Mr. Wood, you would explain to me the concept of surplus capacity. I don't quite understand the concept.

Mr. WOOD. Let's take an example of—well, let's just take the electric market in California. Say one company has 10 percent of all the generating plants in that market, but due to the hydro and all these other issues that really crunch down the reserve margin or the cushion—we've just always called it the cushion—if weather came and ran a tidal wave into a nuclear plant, as happened during this perfect storm, or if the rain doesn't show up and fill up the reservoirs in the North for the hydroelectricity or whatever, there has always been a cushion around 15 percent in the regulated world to make sure if something trips or something falls back or the weather is unusually hot, we have enough power to keep the lights on.

The same philosophy actually carries forward into the competitive market, but for an additional reason, not just for reliability but for wiggle room for competition to actually work. If that 10 percent market share person was playing in a market that only had 5 percent excess capacity, he could say I'm going to keep buying 10 percent off and put it on at the very last minute and get $500 a megawatt hour for it instead of $50, because he's got market power.

Mr. SHAYS. When you're using the term "excess capacity" over "surplus capacity," are you using them interchangeably?

Mr. WOOD. Yes, sir, I am.

Mr. SHAYS. Because the term excess capacity, for us in New England, basically says the plants that are the most costly and the most inefficient are the ones that are going to be least likely to be

used. And then they're drawn in at the time you need a surge in usage. Is that how you——

Mr. WOOD. Yes, sir. Eventually those plants in New England, as in my home State of Texas, which have also very high reserve excess margins because they never get turned on at all, will ultimately just be mothballed or shut down. So at some point, your original question to Michael is correct. I mean at some point, that excess goes away because demand comes up or because that supply is retired or goes down. So it is kind of a constant urge on the part of all of us to make sure of that build-ahead margin. You can't build a plant overnight. It takes usually 2 to 3 years, at fastest, to get up a relatively small simple gas plant which is fast; but you know if you need it next week, that's not fast enough.

Mr. SHAYS. Yes.

Ms. LYNCH. The problem is that's not how it worked in the California market. What happened would be that peaker plant that was really expensive to run would put their bid in at a really high price and it would be accepted because we didn't do least cost dispatch, meaning the cheapest or the most environmental sensitive goes first. It was first in goes first.

The State kind of stepped back and said we're not going to run a market rule there. Whoever is in goes first. Then the market was set up that the person who bid the highest, everybody else got that too. So there was an incentive for the most expensive plants to bid in and everybody else enjoy a windfall profit. But because we handed off our pricing tools to FERC, California alone couldn't just go fix that. We needed to have FERC's consensus to go fix that.

Mr. SHAYS. You could have claimed back that power, couldn't you? You handed it off. Why didn't you just grab it back?

Ms. LYNCH. Well, because what happened was by State law and by prior PUC decision, before I was on the Commission, the utilities sold off their power plants, by and large. So the new generator, the new private owner is called by FERC, not the State. We would have taken by eminent domain or brought back at market value those power plants back into the utility system to reclaim that power. As long as that private generator owned the plants, Mr. Wood was in the control of the pricing, not the PUC.

Mr. SHAYS. Thank you, Mr. Chairman, for giving me the opportunity to get the complete answer. Thank you.

Mr. OSE. Mr. Waxman for 5 minutes.

Mr. WAXMAN. Thank you, Mr. Chairman. I won't take 5 minutes. I think this panel has been very helpful. I very much appreciate your being here. As Mr. Shays' questions pointed out what we have known for a while, in California we created a mess. And we had to sort through it as best we could. A lot of it now has been in the FERC and, Mr. Wood, I'm pleased with the reforms you're making there. I know you're going to be looking at some of these issues that very much affect us. I hope you'll take all these issues very seriously, and I know you'll use your best judgment.

Mr. Chairman, I appreciate your having this hearing so that we can get a lot of this information out on the record, because you are—I think people need to be able to put it all in some kind of perspective.

I yield back the balance of my time.

Mr. OSE. Thank you, Mr. Waxman.

Mr. Shays for 5 minutes.

Mr. SHAYS. Thank you. Thank you, Mr. Chairman. God works in strange and mysterious ways. I've gotten my time back.

To now just focus on a more important side of the equation, Mr. Wood, what did we learn in California and what do you fear nationwide that you are going to be alert to, to make sure we don't see this repeated elsewhere? First off, is this being repeated elsewhere?

Mr. WOOD. No. There are things that are not going as well as they should elsewhere, and I really view that as our task to really straighten that up. In the debate that the House and the Senate are having as we speak on the structure and nature of the wholesale electric market and how competitive it will be and the structures that are needed to make that work, we might hear a debate about something called the RTOs, regional transmission organizations, which really are recognizing that electricity doesn't recognize a State's borders. It really is a regional commodity, perhaps not totally national but, in California, for example, is integrated with the western grid.

During the peak days of the summer, the hydroelectricity from the West keeps the lights on in California. During the peak days of the winter, the excess, we hope, power from California makes up for the fact that the hydro was short in the Pacific Northwest. So it is really an integrated grid, and the Commission in recognizing that has really pushed for regional—not just Federalized but regional solutions that are as close to the market as they can be.

A big part of that is providing good incentives for infrastructure investment, both in generation and in transmission lines, and also, as I think the State of California has shown, demand. People can respond by not consuming as much when the price signal is sent, as was sent this year in California. So that is just as viable a resource as a new power plant.

Those three things, transmission, generation and demand, are an important factor of making a competitive market work. In fact, we're having a full series of workshops at the Commission. My colleagues and I are presiding over them. We've got what we call the really smart guys, the really smart gals in the industry coming to the table to talk through a lot of these issues so that we make sure, as your question points out, Mr. Shays, that we have learned collectively from what didn't work real well out in California these past couple of years, and make sure that in fact is not replicated, but is improved upon dramatically so that customers get real benefits.

Mr. SHAYS. Let me ask you, as it relates to the regional transmission organization where FERC is proposing creating that, which would include New York, New Jersey, Pennsylvania and Maryland, that will—and noting that in Texas I think you basically have a totally isolated system in Texas—is ultimately New England going to see its prices rise because of this, because of the extra demand that New York and New Jersey and Pennsylvania and Maryland will have? How is this going to impact New England, in your judgment?

Mr. WOOD. We are in the process of doing our own independent cost-benefit analyses, as I think good common sense requires, but

I would reference one that was done by a market participant in the whole Northeast that indicated that the savings from having an integrated grid, as opposed to three independent grids that work alongside each other but not necessarily with each other, in the Northeast would save on the order of $400 million per year. That would be spread, as the report stated, roughly——

Mr. SHAYS. That because you would not, in one of those three, utilize the power generation that was not cost effective? In other words——

Mr. WOOD. Right. Rather than having the marginal plant in Massachusetts set New England, it might be the marginal plant that is the lower cost in New York or Pennsylvania set the clearing price for the whole region.

Mr. SHAYS. Would that be a disincentive, though, for New England to increase its power generation if we could—or vice versa if we can basically say, you know, we can draw it from another State?

Mr. WOOD. Well, I think at some stage distance starts to impact the ability. I mean, that is why we couldn't draw it as big as the whole East. I mean, the reason Texas is separate is because electrically it is not on the same synchronicity with the entire eastern grid or with the entire western grid. It's just an artifact of history. But that eastern grid ideally would be all under one. But as a practical matter, both for economics and for physics, the transmission electricity over tremendously long distances, it really is just—is not pragmatic. And so we have circumscribed into natural markets—or at least what we—appear to be natural trading markets—what these RTOs should be.

Mr. SHAYS. Thank you very much.

Thank you, Mr. Chairman.

Mr. OSE. If I might offer a couple of observations for the benefit of my friend from New England, one of the difficulties we've struggled with in California is the manner in which we've approached deregulation. The law approving deregulation was written in such a way that precluded in the end the ability of utilities to engage in forward contracting to hedge their exposures, and then we got into a position where demand, for whatever reason, exceeded supply.

Now the concern that I have today, as it relates to natural gas, is that with New England being a finger pretty much outside the middle of the country, how do we get natural gas supplies there? How do we avoid a repeat of what occurred in California at the other end of the pike? And that is really what the purpose of this hearing is about.

Mr. Wood, in terms of interstate pipelines, whether it be California at the end or Maine at the end, what are the barriers to approving the installation of those pipelines?

Mr. WOOD. They're primarily at this stage two, and they are not barriers. They're just the way it is. One is landowner concerns, which oftentimes tie back to safety concerns about, you know, volatile product, and environmental concerns, and the Congress has passed a number of environmental laws over the years that must be observed by any company that is wanting to construct a natural gas pipeline or any other public facility. So those are the barriers primarily.

At this stage, the Commission's certificate policy, in the 10 years since I was there as a staffer and now, has substantially moved to a much more market-oriented, where if you have sufficient contract and people who are willing to pay for the pipeline or to the expansion of a pipeline, for example, then that really establishes the need. The market establishes the need. In prior days, that used to be a complicated regulatory process, where you'd have economists back and forth and State commissions back and forth, and it would be years before you'd get a pipeline built, you know.

In most instances, even relatively large pipelines, I think our average is now below 240 days to do a full pipeline project. There are a few outliers that are very controversial, but, by and large, those are not the rule. They're the exception. So the barriers are substantially lower than they've ever been.

Mr. OSE. One of the things that gets missed here is that the construction of pipeline capacity is not the only solution to a supply issue. In other words, you can build storage to balance your peaks and valleys.

The same question they just asked regarding interstate pipelines, does FERC have jurisdiction over storage facilities being built?

Mr. WOOD. We do, although there are some that are outside our jurisdiction. If they're owned, for example, by a local gas distributor, such as SoCalGas, and they're used within the California region, those would not be under our jurisdiction but under President Lynch's jurisdiction.

Mr. OSE. I presume that would be the same then for something in New England?

Mr. WOOD. Same in New England. By and large, we do have a number of interstate storage facilities that the Commission does certificate, and, again, those are processed relatively routinely and usually in a very—less than 1-year timeframe.

Mr. OSE. But that is gas dedicated to the interstate market, not to an intrastate market?

Mr. WOOD. Right, and basically it's one of those jurisdictional fine lines that we have been pretty deferential to States, that in the State PUC said, you know, we just have one in Ohio, for example, of a couple of meetings back where it was really probably a close call, and if there was mingling of gas in the interstate and intrastate markets, but because it was under the State jurisdiction and State regulatory regime, then the Commission said at that point we will disclaim jurisdiction over that and let that be regulated by the State.

Mr. OSE. Mr. Moore, you're the economist, if I recall. On the storage issue—I see my time is about to evaporate, but I want to get to this. The existence of a storage facility, whether it be dedicated to interstate or intrastate gas storage, allows a purveyor of the end product to contract for a steady flow at a relatively low price, for instance, because of the certainty involved. And then on the far side of the transaction, when demand comes up, they have a much larger pipe coming out of the storage facility than, say, going in, and they can surge their supply.

Now, what is the impact on pricing for having that ability in the general sense?

Mr. MOORE. Perhaps the better way to put that is what is the impact of not utilizing it? Right now, the State is set up so that we achieve a balance between storage and the pipeline system, part of which can be packed so as to get a short-term response from more gas in the pipe that can be released in a shorter period of time. So, when the purveyors balance the use of storage as well as the pipeline, then the system works really up to capacity. And with the mist that prevails, then we can have some shortages and, as a consequence, have some price increases that were unexpected. So they have to be used in tandem. They have to be used in balance to make sure that we achieve the lowest possible price regime.

Mr. OSE. So it's not all pipeline, neither is it all storage? I mean, that is not the answer?

Mr. MOORE. No. Congressman, that is not the answer.

Mr. OSE. All right. Mr. Shays for 5 minutes.

Mr. SHAYS. Thank you.

Mr. OSE. Mr. Wood, in terms of the issue that Mr. Moore just highlighted in California that it's not all storage and it's not all pipeline, does that also exist in other parts of the country, that particular dynamic?

Mr. WOOD. Absolutely. My first client as a lawyer was a bunch of distributors in Wisconsin, and they depended very heavily on gas storage fields in Michigan, which they filled up in what we call the shoulder months, March, April, August, September, October. They injected gas into those Michigan storage fields to take them out in December, January, February when they really were burning a whole lot of gas. So they took full out from the pipeline that went south, and I believe one went to Canada, they took full out in the winter and took gas from storage. Storage becomes in effect a third pipeline into that region, just like the case in California.

Mr. OSE. Now, you have jurisdiction over interstate storage and interstate pipelines?

Mr. WOOD. Yes, sir.

Mr. OSE. Why is it that if my memory serves, there is only one interstate pipeline that comes into California.

Mr. WOOD. Kern, Mojave.

Mr. OSE. What is the issue in terms of an interstate line coming into California to serve a dedicated need?

Mr. WOOD. Well, I guess you don't really—as I think the issue that you walked through with Mr. Lorenz a moment ago, you don't really need to do two kinds of books, basically. You just buy the capacity on the one line, and it's really a seamless transaction.

I think that's certainly what the shippers that have taken service from Kern want, is that ability to have the same level of firmness of capacity from their burner tip all the way back to some point, perhaps all the way back to the wellhead, and I think the offering of that service has made at least those pipelines more attractive to certain types of customers than the need to perhaps have a less firm product on SoCalGas and some product combined with that from either El Paso or Transwestern.

Mr. OSE. I want to go back to the storage. This dynamic between storage and transmission intrigues me. You have jurisdiction over utility storage or just private company storage?

Mr. WOOD. I think the best way to think about it is, if it's retail, it's theirs. If it's wholesale, which means you're doing storage on behalf and for—to sell it to somebody else, sales for resale, I guess is the best way. So if I run the storage cavern and it's attached to an interstate gas pipeline and I'm selling that gas to a marketer or to a local gas utility for their ultimate resale to an end-use customer, then it would be FERC. There are exceptions to that, but, by and large, retail, wholesale are probably the best way to split the universe there.

Mr. OSE. So an end user who's drawing out of storage would go through the Public Utilities Commission of a State?

Mr. WOOD. Yes, sir.

Mr. LORENZ. All storage in the State of California is regulated by the CPUC at this time.

Mr. OSE. OK. So if I'm going back to your point earlier about locating generating facilities in a State, whether it be California or Nevada or Colorado or New Mexico or wherever, I'm trying to understand whether or not the CPUC allows—and this is for Mrs. Lynch—a direct connection between a storage facility for a peaker plant or a connection between a peaker plant and a storage facility for surge of gas? In other words, can that be a direct connection, or does the peaker plant have to go through a utility to get the gas?

Ms. LYNCH. Many of the utility storage fields are reserved for core customers to a certain percent, which would be the nonelectric generators and nonlarger customers, and then also some of their capacity is reserved for the larger customers. So I would actually—in terms of how SoCalGas specifically allocates that, I'd defer to Mr. Lorenz.

But we also have a couple of additional private facilities that the PUC is either working on or has in fact approved. So, for instance, Lodi Gas Storage, which we approved in 2000, I believe will be up and running into this year or at least during this winter of 2002—2001, 2002.

Then there is another petition for an additional private gas storage facility in front of us that was filed this summer by Wild Goose Storage, who is one of the panelists on the next panel.

Mr. OSE. They're on the next panel, right.

Now, the gas that goes into the storage facilities, do the contracts for the acquisition of that gas by the storage facility come before the PUC? In other words, I mean, they're going to take a steady flow over a course of time to fill their facility.

Ms. LYNCH. Right.

Mr. OSE. Does the contract for that steady flow come before the PUC?

Ms. LYNCH. It is the approval to build the storage facility itself.

Mr. OSE. But not the flowage?

Ms. LYNCH. No, I don't know at any particular point in time what SoCalGas's contracts look like. We know the percentage generally between what they're storing for their core customers and what the noncore customer storage is, but I can't tell you today who all their noncore customers are who pull from SoCalGas's storage.

Mr. OSE. It just doesn't make any difference to you in terms of who's supplying that gas? I mean, from a regulatory standpoint, you don't care how the gas gets in——

Ms. LYNCH. Well, from a regulatory standpoint, we want to make sure that there's adequate storage and that there's adequate storage for the core customers at a reasonable price. Because our statutory job is to ensure just and reasonable prices at the retail level. So we need to make sure that there's enough capacity to keep that price reasonable.

Mr. OSE. So I guess I'm back to my original question. Do you look at those actual transactions for the acquisition of the gas that goes into storage, or do you not?

Ms. LYNCH. We don't approve those actual transactions, no. We may know some of them. So, from time to time, we know who's transacting with the various storage fields, but it's not who injects gas into SoCal's storage field. It's not a regulatory approval by the PUC.

Mr. OSE. New England disappeared.

In terms of drawing the gas out of storage for use by a third party—let's say in Mr. Lorenz's instance, a generator and maybe this question is for Mr. Wood—is that a transaction that is subject to FERC's jurisdiction or the PUC's jurisdiction?

Mr. WOOD. Again, you're referring to the example we've just been talking about where you've got some part of storage that's dedicated to large customer use? That would not—it's unbundled. It's an unbundled rate that Loretta and them approved. That would not be under FERC.

Mr. OSE. But that would be under the PUC?

Ms. LYNCH. Or it would be a private contract with SoCalGas. But generally we set the utility's rates such that I think that really establishes the playing field for the contracts——

Mr. OSE. So they just domino backward to the pricing on their transaction at the pump head, so to speak?

Ms. LYNCH. Well, for instance, we set a peaking rate and we set a firm transition—or firm capacity rate, things like that. So I guess in context then you add up all those various rates depending on the kind of service that contractor is going to be getting, and it comes down to the rate.

Mr. OSE. Mr. Lorenz, I mean——

Mr. LORENZ. Let me——

Mr. OSE [continuing]. Illuminate this for me.

Mr. LORENZ [continuing]. Try and add a little bit more.

The SoCalGas system currently has 105 billion cubic feet of storage capacity; 70 billion of that is dedicated to the core; 30 billion is unbundled and made available on a contract basis to noncore customers, and then 5 billion is used for balancing services. That 30 billion that is unbundled and made available to noncore customers is done on a contract basis. The maximum rates are set by the CPUC for all three classes of storage services.

Mr. OSE. On the sales side?

Mr. LORENZ. On the sales side. For the inventory space, for the injection capacity and for withdrawal capacity, the CPUC sets the maximum rates for those, and then we are at risk for the recovery

of that revenue that is being unbundled, and we operate it like a business.

Mr. OSE. Even now that you have a cap that you're going to get, you can sell it for this much revenue, so you've got to buy it for something less, because you've got costs between here and there?

Mr. LORENZ. That's correct.

Mr. OSE. OK.

Mr. LORENZ. Now, we don't buy the gas that goes into that unbundled storage. That is, those transactions are done by the parties that hold that capacity. So we sell the capacity to them at rates that are regulated by the PUC and then they utilize it as they see fit. They determine when they want to buy gas and put it in, when they want to take it out. They use it to balance their load between seasons and also on a daily basis to balance their load——

Mr. OSE. In effect, you're just holding the commodity for somebody else?

Mr. LORENZ. That's correct. Our field is the bank.

Mr. OSE. Now, the storage facility itself, on an intrastate basis, is subject to CPUC review and approval?

Ms. LYNCH. On an intrastate basis, yes.

Mr. OSE. There can be in your storage facility both intrastate gas and interstate gas, though?

Mr. LORENZ. The gas would all have come across an interstate system and then across the intrastate system in order to go into storage——

Mr. OSE. At which point it is all intrastate gas——

Mr. LORENZ. That's correct.

Mr. OSE [continuing]. Subject to the PUC jurisdiction?

Mr. LORENZ. That's correct.

Ms. LYNCH. Well, theoretically, there is—15 percent of the gas that we use is produced inside California. So, theoretically, any of the storage fields could hold California-produced gas as well.

Mr. OSE. All right. Here's the essential issue that we all struggle with up here, and that is what can Congress do, regardless of region, based on what we've experienced in California, to prevent these capacity problems from replaying themselves elsewhere? The collective wisdom here is significant. Give us some guidance for the record. Mr. Wood.

Mr. WOOD. I think the steps that we have collectively taken over the last 12 months, unfortunately in a reactive mode and not a proactive mode, are probably the right ones—making sure that market rules are clear, making sure that investment signals are sent and that, in fact, investment is done.

Then, finally, and I don't know that we do enough of this in our job, listen to what the customers want, and if customers want to have firm rights, they want to have interruptible rights or they want to have some version of the two, they want to have access to Canadian or Alaskan or Mexican or San Juan or Texas or midcontinent gas, then let's go there, as long as they're willing to pay the fair rate for it. And I think—excuse me—there are plenty that do. In fact, customers are willing to do that, because the gas cost is relatively competitive.

That listening to the customers probably is the wisest step of all. Plenty of them have spoken out lately.

One of my first visitors was a set of dairies and farmers from California and some of the issues they had with respect to their natural gas costs. I mean, they weren't there as mad electricity consumers. They were there as mad gas consumers, because it affected everybody.

So infrastructure, tariffing and customer rules and also, you know, as I think are pointed out, the policing of the market to make sure that everybody is playing by the rules. So those three things. I think we've got the authority to do that at the Federal level. I think the State does. Loretta and Michael can speak clear to that.

But I think, as far as further legislation, I don't suggest any, but if the Congress would like to go in that direction we can certainly provide any technical assistance you like.

Mr. OSE. I want to ask specific questions about this.

In the financial markets, people hedge their exposures. Some areas of this country, utilities are able to hedge, and in some they are not. Is that a tool that needs to be provided to utilities, or can that exposure be addressed in some other manner?

Mr. WOOD. Well, the other manner is politically not feasible, so I think the answer is it's possible, but it's not very popular.

So I think allowing utilities to have the kind of tools that any other customer should have to be able to—I could manage my risk by buying insurance. In effect, buying a long-term contract for power, for gas, is something that—when I was a former State regulator, we didn't really—in an age when there was a lot of gas, you didn't really reward a utility for getting a long-term contract.

In fact, there were a lot of people that showed up at the Texas Commission to try to second-guess utility X for having a long-term contract. Having a $2.50 contract in a 97 cent market usually meant that the utility was going to take something in the shorts. So that was something utilities just said, "Forget it. We get no reward for taking an advantageous position in the long term. So we don't do it at all. We'll live on the spot market."

Well, that's great when there's a lot of gas, there's a lot of electricity. The spot market is a great place to be. But when conditions get tight, for whatever reason, lack of an investment or bad weather or something like hydroelectricity shortfall, then you start to have—you start to have those thoughts that a $2.50 gas contract sure would have been nice to have.

That's the most crude form of hedging. The financial tools that are available today are much more sophisticated and quite a bit more varied than a long-term contract. But that is an example of the type of things that State regulators—and I think President Lynch can speak for what they do.

Mr. OSE. You're saying having the flexibility to do it, but not having the mandate to do it or not do it is the piece that needs to be included?

Mr. WOOD. Yes, because the mandate really—you—a regulator is never as good as a businessperson at really balancing the risk in the portfolio. And I think allowing utilities to have tools, allowing them to keep some reward for when they make good decisions and

penalize them when they make bad decisions, just like a market would do, is kind of what we do. And so we'd like to replicate the market as much as we can, and providing both carrot and sticks is a good way to do that.

Mr. OSE. All right. Ms. Lynch, same question, recommendations to Congress on how we address these things going forward, including the last question about the tools given the utilities.

Ms. LYNCH. Certainly. One is just exactly what you're doing now, which is adhering to make sure that the State and the Feds are working together. And I would tell you that, under Chairman Wood's leadership, we're working together much better than we have worked together in the past several years, because I think that Chairman Wood, as a former State regulator, understands the State's concerns and is appropriately listening to us, which we really appreciate, and also moving forward our complaint at the FERC rather than, as the prior FERC had done, was really just sitting on them or we'd get in the queue.

But, also, I would just urge you to make sure that you work with FERC to make sure that they have adequate remedies available in the Natural Gas Act to provide refunds where appropriate where market power has been exercised for past behavior.

Now, the PUC has certainly taken the position that they have that authority. Other parties have questioned whether the FERC has that authority. But Congress can make certain that the FERC has the full panoply of tools available when they find market power to make sure that Californians essentially don't find a violation without a remedy. And we want to make sure that the Natural Gas Act provides all the remedies that the FERC believes it needs to make sure that our markets are competitive going forward and also so that they can deter practices that have happened in the past.

Then, finally, as to utility hedging, I'm a firm believer in a power procurement portfolio. You can't have all long-term contracts. You can't have all spot prices. California has kind of swung by a pendulum back and forth now, but what certainly the long-term contracting of recent times has shown us is that you need some kind of review, as the chairman said, so that you can reward folks who are making good decisions and penalize them for making bad. What you don't want to do is per se find reasonable any price made in a long-term contract because then you could have the El Paso situation where they contract with their own affiliate for a higher price than otherwise would be reflected in the market. So I think that California PUC has that authority to move forward with a power procurement portfolio.

We were working with the legislature on a bipartisan basis, the State legislature, to come up with standards for power procurement. That bill did not pass, but, nonetheless, the PUC is moving forward. And on our next agenda, on October 25th, we're sending out a consensus rulemaking on trying to figure out some boundaries for long-term contracts as well as medium-term contracts, as well as spot prices, so that the utilities can have some more certainty along with being rewarded and penalized for really blatantly good or bad decisions moving forward so that they can once again do what they were doing before, which is provide appropriate

power procurement portfolios for their whole load; and a mix of power structures and hedging tools would be part of that.

Mr. OSE. Within the portfolio, do you have any sense of what percentage should be dedicated or provided by long-term contracts versus spot acquisition? Is that one of the issues you——

Ms. LYNCH. That is one of the issues, and I don't think that you can—and I don't think that the PUC should set absolute mandates on those points because the market is going to change and the utility needs to be able to exercise its business discretion as the markets change, because you don't want to be caught in what happened in 2000, which is the markets changed rapidly. We were locked into a legislative structure that did not allow rapid response to that change, and the utilities kind of got caught holding the bag there. So you want to make sure it's flexible enough but put boundaries on their actions so that the consumers aren't caught holding the bag.

Mr. OSE. So, in effect, you're going to define a safe harbor for a utility that wants to enter into a forward contract?

Ms. LYNCH. Potentially. We're just starting the rulemaking, hopefully on the 25th, and then we'd have parties come in and make proposals. What we would do would be essentially to ask the utilities to come in and make proposals about what their power procurement portfolios would be and also ask them to make a proposal very specifically that would align with a bipartisan bill sponsored by Assemblyman Wright that died in the last days of session but which was a consensus proposal between the utilities, the sellers, the PUC and the consumers. So we're hoping to move along the lines of that bill, although it may not look exactly like that once it goes through our public process.

Mr. OSE. So creating those standards is probably one of the objectives—I mean, you're going to start the process for creating those standards——

Ms. LYNCH. Right.

Mr. OSE [continuing]. Here in late October? Any idea what kind of timeframe it will take to get to the end?

Ms. LYNCH. Well, frankly, we want to do that on an expedited basis, which would mean just a few months rather than a year, which would be the normal process for the PUC, because we want to get the utilities back into the power procurement business and, frankly, get the State out of that power procurement business to the extent possible. That is complicated by the PG&E bankruptcy, but we believe we can move forward, nonetheless.

Mr. OSE. OK. Mr. Moore, same question.

Mr. MOORE. Mr. Chairman, I'll make it very, very short.

I think that Chairman Wood has proved that he's got the tools that he needs and that it takes a will and some foresight to be able to exercise them to make the market move and to let's say corner the market into the proper behavior. I think that it's probably not the need—there's not a time right now to institute new rules from the congressional level. I think that they got what they need at FERC, and frankly I think if you look at the circumstances in California it has showed that the regulators ought to be left a little bit more alone from the legislature to be able to do their job and to be able to perform their functions.

I, for one, am certainly not speaking for Commissioner Lynch, but it seems to me I would have felt happier with the PUC being able to do their job with a little less legislative interference. I think the outcome might have been a little quicker and perhaps a little cleaner. My guess is that the role of the Congress is exactly what we're doing today, which is to provide the oversight and provide the forum in which these kinds of debates can go forth. Because when you do invite the actors here in these Chambers, you tend to get a more open airing of the facts, a more open airing of the circumstances, and, frankly, I think you give the regulators more room and more incentive to do their job. So what you provide is really the muscle behind the regulators being able to do an effective and impartial job over time.

The last piece of the puzzle is information, and it's the area where I think we and the States can cooperate and give a tremendous additional tool to the FERC, because they're not staffed in volume to be able to look at all the different markets in all the different States. So when we can provide the impartial and up-to-date and timely information on the trends and on the market niche activities, I think that the market surveillance, the oversight in terms of market manipulation or market power will be just that much more powerful at the FERC with our cooperation; and I think that is the right forum.

Mr. OSE. One of the things that your written testimony that I read, I found very interesting, was that along these interstate lines demand fluctuates depending on seasonality and temperature and what have you. But over the long term, it's an increasing level of demand, that it just—the angle is up. Now, if the capacity of the line is X and demand, for instance, at the start is like 0.5 X, but then over 10 years grows to 1.25 X, how do we integrate that growth in demand along the line so that FERC approves the added capacity so that the person at the end of the line, specifically California, doesn't end up short of gas in an untimely manner? Is that the information kind of issue that you're talking at?

Mr. MOORE. Mr. Chairman, that is part of the information.

Certainly, I think we were surprised to see some of the upstream demand occurring at the rates that it did or the rates that it is increasing. The two new plants in Arizona are a good example. We cited those in the testimony. And I think that we need to be cognizant of that, being at the end of the line, and so does the FERC.

I guess the best example of how to get there, for me as a commissioner, is to refer to Commissioner Wood's suggestions for RTOs, the regional transmission organizations, and to say that to begin to imagine our participation in a regional context is probably more important than anything, because—than anything else that we can do in the information world, because we are not alone. We operate under the influence of and we influence behavior in our neighboring States.

And so, using the RTO model just as an icon for a second, I'll tell you that if we don't start thinking more broadly about some of the upstream demands that will impact us, we will find ourselves short. We in the information generating business can supply a lot of that to FERC ahead of time and, frankly, I think influence the nature of their decisions and the mitigation measures that they

might impose on any of the approvals and certification that they give at their end.

Mr. OSE. Thank you.

Mr. Lorenz, same question.

Mr. LORENZ. I'll also try and be brief.

I believe the storage market in California is operating effectively at this stage. There were some important lessons learned last year. Parties that contracted for storage elected not to fill that storage. Last year, they relied on the forward price curve that said prices were going to continue to decline, and so where's the incentive to store now when the forward price curve says prices are going to decline? Well, that curve turned out to be wrong, and they paid the price. Associated with—that storage now is 50 percent higher at this time on our system than what it was a year ago. So I think the market has made those adjustments, has learned those lessons and is operating effectively.

I think utilities ought to have all the tools that are available in the marketplace to manage their risks—hedging, contracting on a forward basis, long-term contracting. All of those opportunities should be available, and a portfolio is an important element to have——

Mr. OSE. So you would applaud the PUC taking this up and trying to define those, as Ms. Lynch indicated?

Mr. LORENZ. Absolutely.

Mr. OSE. You're supportive of that?

Mr. LORENZ. Absolutely. We have a very effective mechanism on the gas side already in place that provides exactly that kind of incentive mechanism. That cost of gas is compared against a market price. The cost that the utility purchases the gas at is compared against a market price to determine how effective we are in buying. If we're doing real well, we get to share in those benefits along with the ratepayers; and if we're not so good, we get penalized.

Thus we have aligned those ratepayer and shareholder interests through an incentive mechanism that works very effectively on the gas side.

Mr. OSE. So as far as what Congress might do or consider doing, you think the market's responding a lot more efficiently than the Congress ever will?

Mr. LORENZ. I believe that the market is responding appropriately at this stage.

Mr. OSE. All right. We have additional questions, but, in the interest of time, I told Commissioner Wood we'd be out of here at 1:40 with this panel, so I'm 7 minutes late, but we have some additional questions. To the extent that we didn't get to them, we'd like to send them to you. We would like to have your written responses.

I do appreciate the four of you taking the time to come and visit with us today. I know that you are very busy, but your input is appreciated. So thank you all.

Mr. WOOD. Thank you.

Ms. LYNCH. Thank you.

Mr. OSE. We're going to take a 5-minute recess here, and then we're going to have the second panel.

[Recess.]

Mr. OSE. OK. We're going to go ahead and convene the second panel. I see Mr. Kalt is not—Mr. Kalt? Mr. Kalt? We have sworn everybody in. We have lost a witness. Maybe he went to New England.

I want to thank you for your patience, first of all, in getting to this point.

Our second panel is comprised of four individuals. We have Paul Carpenter. He's principal in the Brattle Group. We have Professor Joseph Kalt from the JFK School of Government at Harvard University; Paul Amirault, vice president, marketing, Wild Goose Storage, Inc., best storage facility in the country. Then we have Gay Friedmann, the senior vice president, legislative affairs, for the Interstate Natural Gas Association.

You've heard my explanation earlier. Green light, yellow light, red light; 5 minutes for your opening comments. We've got each of your statements here, and we have reviewed them.

I want to welcome you. Professor, thank you.

Mr. Carpenter, for 5 minutes to summarize.

STATEMENTS OF PAUL R. CARPENTER, PRINCIPAL, BRATTLE GROUP; PROFESSOR JOSEPH KALT, JOHN F. KENNEDY SCHOOL OF GOVERNMENT, HARVARD UNIVERSITY; PAUL AMIRAULT, VICE PRESIDENT, MARKETING, WILD GOOSE STORAGE, INC.; AND GAY FRIEDMANN, SENIOR VICE PRESIDENT, LEGISLATIVE AFFAIRS, INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. CARPENTER. Thank you, Chairman Ose, for the invitation to be here today. I'm very honored to do so.

The success of future regulatory oversight of U.S. natural gas and electricity markets will depend on the ability of our regulators to monitor the performance of these markets and, thus, the conduct of participants that may possess market power, which we define as the power to profitably raise prices by restricting output. As Chairman Wood's recent draft strategic plan for the FERC recognizes, sufficient oversight of market conduct is necessary if we're to rely increasingly on competition to determine prices and output in these industries.

California's natural gas and electricity market experience in 2000 and 2001 provides perhaps the first significant test of that regulatory challenge. Earlier this year, my colleagues and I conducted a comprehensive study for Southern California Edison Co. on the question of whether El Paso Merchant Energy, the largest holder of interstate pipeline capacity rights to California at that time, possessed and exercised market power so as to drive up the price of natural gas and, thus, electricity to California during the period March 2000 through March 2001. This study was submitted to the Federal Energy Regulatory Commission in the complaint proceeding brought by the CPUC. I testified in that proceeding this summer on the results of our study.

Last week, the FERC's administrative law judge issued his initial decision in the *CPUC* v. *El Paso* matter. This initial decision finds that El Paso and El Paso Merchant Energy violated the FERC's affiliate rules when El Paso Natural Gas awarded 1.2 bil-

lion cubic feet per day of pipeline capacity to California to its unregulated marketing affiliate, El Paso Merchant.

It also finds that El Paso Natural Gas and Merchant Energy, as a result of the contract, possessed market power in the market for delivered natural gas supplies to Southern California and that El Paso Merchant garnered, "tremendous profits," during the term of the contract. But the ALJ was unable to make a definitive finding based on the record in the case that El Paso Natural Gas or Merchant Energy actually used their market power to raise prices.

In my view, the judge's acknowledged inability to find clarification in the record on the market conduct evidence compels the full commission to look at the record evidence carefully when it reviews its initial decision. This is important, because it is clear to me that much of the future regulatory work of the FERC will involve similar evaluations of the behavior of market participants in partially deregulated markets, such as in California. If the regulator cannot come to grips with this kind of behavioral evidence based on actual transactions in the market, then it will be very difficult to perform the oversight function required to permit competition to substitute for regulation.

While gas markets are admittedly complex, electric power markets are even more so. If evidence of market power abuse cannot be discerned from the record in the CPUC-El Paso matter, then I have serious doubts as to whether it could ever be found in a matter involving electric power generation. For example, to give you a bit of a flavor for the kind of evidence introduced at the hearing and the kind of evaluation required, I included in my written statement today a few of the exhibits which are part of the overall picture in that record.

The evidence goes to the key question of whether El Paso withheld capacity from the market during the summer and fall of 2000 when prices began to rise significantly and when storage injections should have been occurring in anticipation of the coming winter. Did El Paso Merchant Energy fully utilize its capacity during the storage fill period of March 2000 through October 2000, as compared to the other large shippers on El Paso? The answer is clearly no, as evidenced by figure 5 in my presentation.

During this period, Merchant Energy's average utilization was 44 percent, although the three next largest shippers—Burlington, Williams and SoCalGas—achieved 87, 84 and 86 percent utilization rates respectively. Did El Paso Merchant Energy even attempt to fully utilize this capacity during this period as compared with other shippers? That answer is clearly no and is depicted in figures 6 and 7 of my submission, which compare nominations and flows between Merchant Energy and all other shippers on a monthly and daily basis respectively.

In his initial decision, Judge Wagner states that during this period, when El Paso Merchant did not nominate 100 percent of its capacity, the relevant question is whether other shippers had sufficient capacity to make up the slack. The evidence slows that if El Paso Merchant—and I'm quoting the judge—had attempted to exercise market power by restricting its nominations and flows of gas to California during the summer of 2000 and thereafter, other firm

shippers who were experiencing cuts in their own nominations could have flowed and would have every incentive to flow more gas.

In my view, that conclusion flies in the face of the evidence of actual conduct established at the hearing. The other shippers did nominate nearly all of their capacity during this period and achieved very high utilizations. Even if the evidence supported the conclusion, one must ask whether evidence of actual withholding conduct by a firm with market power can be dismissed simply because other smaller shippers could have flowed more gas but chose not to.

In conclusion, no matter what the eventual outcome, the *CPUC* v. *El Paso* matter will be a bellweather case, illustrating the kinds of economic evaluation of market conduct that will be required of future regulators. We will not be successful in promoting competition as a substitute for regulation if the regulatory oversight function cannot distinguish anticompetitive conduct from competitive conduct.

Thank you very much.

Mr. OSE. Thank you, Mr. Carpenter.

[The prepared statement of Mr. Carpenter follows:]

Statement of
Paul R. Carpenter, Ph.D.
Principal
The Brattle Group, Inc.

Before the Subcommittee on Energy Policy,
Natural Resources and Regulatory Affairs
U.S. House of Representatives

October 16, 2001

Mr. Chairman and Members of the Subcommittee, thank you for inviting me to speak to you today about some of the lessons we have learned for regulatory oversight of the interstate natural gas transportation industry from California's dramatic energy market experiences in 2000 and 2001. In particular, I intend to speak today about the issues and evidence relating to the disposition of inter- and intrastate pipeline capacity and storage in the state, some of the evidence concerning the exercise of market power by holders of interstate pipeline capacity to California during this period, and the effect of this conduct on California gas and electricity consumers. While we hope these effects will not occur again in the future, now is the time to evaluate that evidence and determine whether there is more that could have been done, and more to be done in the future, to ensure the efficient and competitive performance of these markets.

Mr. Chairman, by way of background, I am an economist and Principal of *The Brattle Group*, a consulting firm with offices in Cambridge, Massachusetts, Washington D.C. and London, England. I currently lead *Brattle's* energy and finance practice area. I have been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for twenty years. For about fifteen of those years, I have been actively involved in matters relating to the California natural gas market, its performance and its regulation. Earlier this year, my colleagues and I conducted a comprehensive study for Southern California Edison Company on the question of whether El Paso Merchant Energy, the largest holder of interstate pipeline capacity rights to California, possessed and exercised market

power so as to drive up the price of natural gas (and thus electricity) to California during the period March 2000 through March 2001.[1] This study was submitted to the Federal Energy Regulatory Commission (FERC) in the complaint proceeding brought by the California Public Utilities Commission (CPUC) against El Paso Natural Gas, the regulated pipeline, and El Paso Merchant, its unregulated marketing affiliate.[2] I testified in that proceeding this summer on the results of our study.

Natural Gas Prices During the California Crisis

On the grounds that 'a picture is worth a thousand words' I have prepared two graphs that depict the severity of the natural gas price problem that Californians experienced during 2000 and 2001. Figure 1 compares monthly natural gas prices at the southern California border with those experienced at the Henry Hub near the Gulf Coast of Louisiana (the Henry Hub price is the reference price for much natural gas trading in the U.S. and is considered a benchmark for gas prices in the Eastern U.S.) from January 1997 to the present. As you can see, prices at those two locations tracked very closely until the early summer of 2000, when a very sharp divergence begins to occur. During the 15 months of the term of the El Paso Merchant contract that began in March 2000, gas prices at the California border were $3.34 per MMBtu (or 69%) higher than prices at the Henry Hub, despite the fact that prices in the rest of the U.S. also experienced significant increases. Again, these are monthly prices. On a daily basis, prices at the California border peaked in December 2000 at $59.42 per MMBtu. After the expiration of the El Paso Merchant contract in June 2001, prices in California have declined to their pre-2000 parity with those in the eastern U.S.

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1 Exhibit SCE-4, "The Brattle Group Study of EPME's Exercise of Market Power March 2000 through March 2001," submitted May 8, 2001 in FERC Docket No. RP00-241-000.

2 FERC Docket No. RP00-241-000.

Figure 1

California Experienced Unprecedented Natural Gas Prices During Term of El Paso Contract

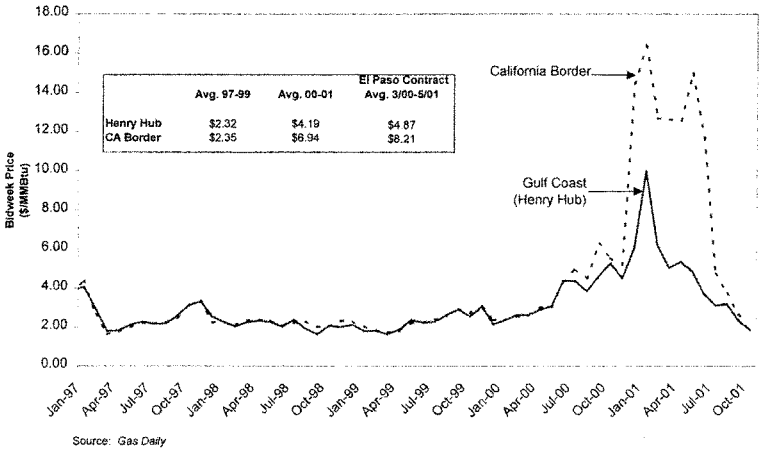
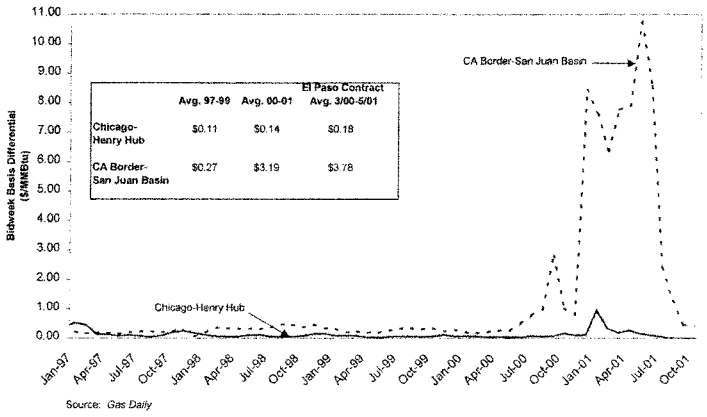


Figure 2 examines the pipeline situation more closely. It compares the monthly value of transportation capacity (sometimes called the "basis differential") on two significant pipeline corridors in the U.S., between the Henry Hub and Chicago, and between the San Juan Basin in the four corners area of Colorado and New Mexico and the southern California border. During the period of the El Paso Merchant contract, the California differential widened to an average of $3.78 per MMBtu while the Chicago-Henry Hub differential increased only slightly to $0.18 per MMBtu. Note that the regulated maximum cost-based tariff rate to transport gas on the El Paso system from the San Juan Basin to California was only $0.55 per MMBtu. The events in 2000 and 2001 in California were unique and unprecedented in the history of U.S. natural gas markets.

Figure 2

Implied Value of Transportation Capacity to California Increased Dramatically During Term of El Paso Contract



The Chief Judge's Initial Decision in *CPUC vs. El Paso*

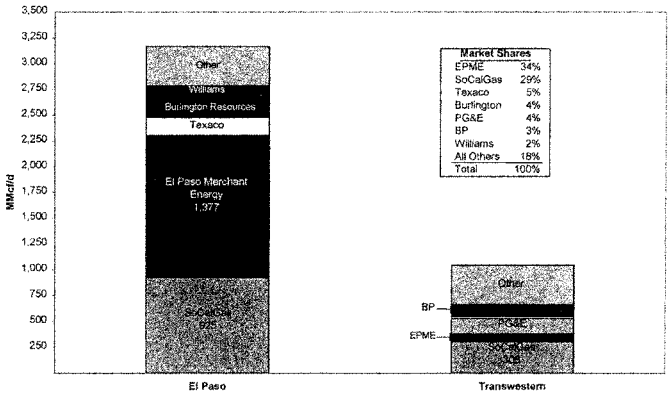
Last week, the FERC's Chief Administrative Law Judge (ALJ) issued his Initial Decision in the *CPUC vs. El Paso* matter. As the Judge indicated in his decision, the evidence collected in the case was massive, comprising 5,573 pages of transcript and 515 exhibits. Some have said to me that this was easily the most lengthy, complex, and publicly-followed case ever conducted before the FERC.

In his initial decision, Judge Wagner found that El Paso and El Paso Merchant Energy (its unregulated marketing subsidiary) had violated the FERC's affiliate rules when El Paso Natural Gas awarded 1.2 billion cubic feet a day of interstate pipeline capacity to California to Merchant Energy. The Judge also found that El Paso Natural Gas and Merhant Energy possessed market power in the market for delivered natural gas to Southern California, due to the high

concentration level among the holders of existing pipeline capacity, coupled with El Paso Merchant's high market share achieved by the abuse of its affiliate position. Figure 3 depicts the relative market shares of the holders of capacity to the southern California border. This means that the Judge found that El Paso Natural Gas and Merchant Energy were in an economic position to profitably raise natural gas prices to California by withholding capacity from the market, if they chose to do so. Further, the Judge found that despite the claim that El Paso had hedged-away its ability to profit from any anticompetitive behavior, "despite of the hedging (sic), El Paso Merchant made tremendous profits, $184 million, on the 50 percent of the capacity that was not hedged."[3]

Figure 3

Firm Capacity Holders to California from Southwest Supply Basins



Source: Table II-1 from SCE-4, which relied on El Paso and Transwestern January, 2001 Index of Customers Reports.
Note: El Paso capacity holdings adjusted for long-term releases from SoCalGas to El Paso Energy Marketing Company (EPME), Duke Energy Trading and Marketing, and ONEOK.

Even though the Judge found that El Paso Merchant possessed market power, that it made "tremendous profits," and despite the evidence that prices had risen substantially in California

[3] Initial Decision in FERC Docket No. RP00-241-000, issued October 9, 2001, page 20.

relative to anywhere else in the country, the Judge concluded that "while El Paso Pipeline and El Paso Merchant had the ability to exercise market power, *it is not at all clear from the record in this proceeding* that El Paso Merchant and El Paso Pipeline exercised market power."[4] While Judge Wagner was apparently unable to render a definitive finding on the question of whether El Paso actually exercised its market power, he nonetheless recommended to the FERC that the Complaint be dismissed with respect to all market power-related questions. Curiously, despite the fact that the vast majority of transcript pages and exhibits at the hearing and hours of detailed cross-examination were concerned with the evidence of market conduct and market power abuse, the Judge's consideration of that evidence in his Initial Decision consists of just a few brief pages of text, with little critical evaluation.

In my view, the record evidence in the case establishes clearly that El Paso withheld capacity from the market in the summer and fall of 2000, with the effect of raising prices substantially at the southern California border. (I will return to some of this evidence in a moment). This conduct led to a reduction in storage inventories going into the winter peak gas demand season, which had the direct effect of creating an artificial (but real) shortage of inter- and intrastate pipeline capacity in California during the winter of 2000-2001.

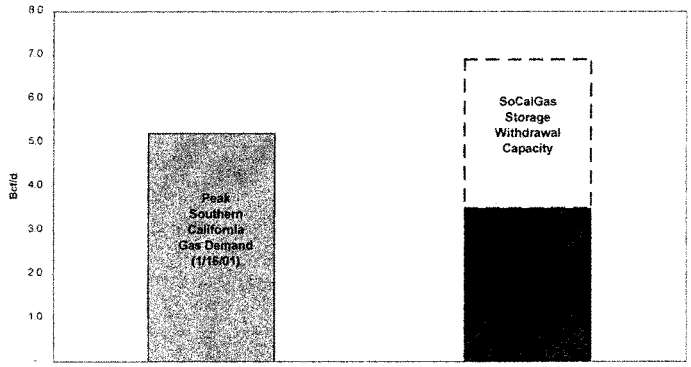
Turning to the pipeline capacity situation in California during this period, much has been claimed about the scarcity of pipeline capacity into and within the state in comparison to the increased demand for gas due to increased gas-fired power generation demands starting in the summer of 2000. While the demand for gas clearly increased during this period, our analysis indicates that the existing infrastructure would have been sufficient to fully meet the demands during the summer and early fall of 2000, if the capacity in the hands of El Paso Merchant had been fully nominated and utilized. But the summer and fall are not the typical peak periods for gas consumption in California. Peak demands occur during the winter. In the winter months, California relies on withdrawals from storage inventories to meet peak demands. The importance of storage in southern California cannot be overstated. In Figure 3 I have depicted the recent peak demand day on the Southern California Gas system as compared to supplies

[4] Initial Decision in FERC Docket No. RP00-241-000, issued October 9, 2001, page 14.

available from existing interstate pipelines and in-state storage withdrawals to meet the peak. As you can see, southern California relies heavily on storage to meet its peak demands. This has always been the case, even prior to the events of 2000-2001. Thus, if storage inventories are low due to lack of storage fill in the spring and summer months as a result of high border prices, it is possible that capacity constraints can be experienced. This is what happened in the winter of 2000-2001. We estimated that if El Paso Merchant had utilized its pipeline capacity at just a 70% rate during the summer storage fill months, instead of its actual 48% utilization, this extra gas if injected into storage would have avoided any significant capacity constraints in the winter of 2000-2001 on the SoCal Gas system.

Figure 4

Use of Storage Is Critical to Meet Peak Demand for Gas in Southern California



Note: Peak Southern California Gas Demand is SoCalGas' highest daily sendout over the period January 1997 to the present.

The overall effect of El Paso's capacity withholding in the summer and fall of 2000 and its follow-on effects via lack of Southern California storage inventories in the winter of 2000-2001 was to severely overcharge California natural gas and electricity consumers. Table 1 shows the results of our calculation of the size of those price effects (relative to the prices that would have been achieved with competitive pipeline transportation rate) for the 13 months covered in the

FERC proceeding, and the 15 months of the entire El Paso Merchant contract. The gas-related overcharges alone are in the range of $3.6 to $3.8 billion for the 13 month period and $4.9 to $5.1 billion for the 15 month period. We further estimate that these increased prices for natural gas in California drove up the cost of electricity for Edison's customers in southern California by an additional $1.0 to $1.1 billion over the period – the statewide impact, of course, was even greater.

Table 1

Overcharges to California Gas and Electricity Customers from March 2000 through May 2001

Overcharges to California Gas Customers
(Billions)

	March 2000 through March 2001	April 2001 through May 2001	Total
Southern California (SoCalGas)	$2.2 - $2.3	$0.9	$3.1 - $3.2
Northern California (PG&E)	$1.4 - $1.5	$0.4	$1.8 - $1.9
	$3.6 - $3.8	$1.3	$4.9 - $5.1

Overcharges to Electricity Customers Due to Excessive Gas Prices
(Billions)

	March 2000 through March 2001
Southern California (Edison)	$1.0 - $1.1

Source: March 2000 - March 2001 overpayments taken from SCE-4, Tables VI-1 and VII-1.

Market Power Conduct Evidence and Required Regulatory Oversight

In my view, the Judge's acknowledged inability to find clarity in the record on the market conduct evidence compels the full Commission to look at the record evidence carefully when it reviews his Initial Decision. This is important because it is clear that much of the future

regulatory work of the FERC will involve similar evaluations of the behavior of market participants in partially deregulated markets, such as in California. **If the regulator cannot come to grips with this kind of behavioral evidence based on actual transactions in the marketplace, then it will be very difficult to perform the oversight function required to permit competition to substitute for regulation where possible, and to make "lighter-handed" regulation possible in the future.**

As FERC Chairman Wood has acknowledged in his draft Strategic Plan for 2001-2005 entitled "Making Markets Work," the third of the four key challenges for the FERC is to *Protect customers and market participants through vigilant and fair oversight of the transitioning energy markets.* The objectives identified under this challenge are "to improve understanding of energy market operations;" "assure pro-competitive market structures;" and "remedy individual market participant behavior, as needed, to assure just and reasonable outcomes."[5]

While gas markets are admittedly complex, electric power markets are even more so. If evidence of market power abuse cannot be discerned from the record in the *CPUC vs. El Paso* matter, then I have serious doubts as to whether it could ever be found in a matter involving electric power generation, for example.

The Clarity of the Conduct Evidence

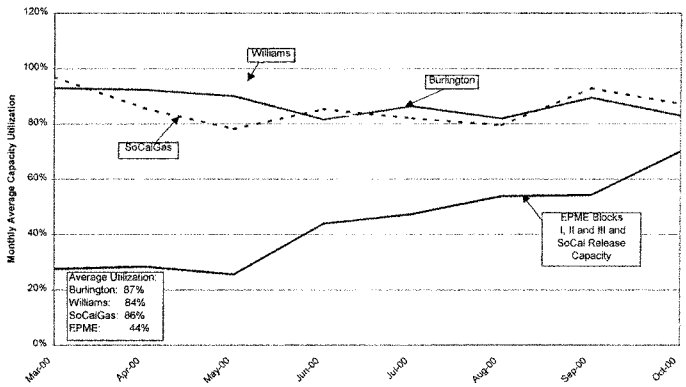
To give you a bit of a flavor for the kind of evidence adduced in the hearing, and the kind of regulatory evaluation required, I have brought with me today a few exhibits which are part of the overall picture in that record. This evidence goes to the key question of whether El Paso withheld capacity from the market during the summer and fall of 2000 when prices began to rise significantly and when storage injections should have been occurring in anticipation of the coming winter.

[5] Federal Energy Regulatory Commission Strategic Plan 2001-2005, *Making Markets Work*, September 25, 2001, Revision B.

Did El Paso Merchant Energy fully utilize its capacity during the storage fill period of March 2000 through October 2000 as compared to the other large shippers on El Paso? The answer is clearly no, as evidenced by Figure 5 (Exhibit SCE-107 from the hearing). During this period, Merchant Energy's average utilization was 44%, while the three next largest shippers, Burlington, Williams and SoCal Gas achieved 87%, 84% and 86% utilization rates, respectively.

Figure 5

EPME's Utilization of Its Capacity to California Was Significantly Less Than That of Other EPNG Shippers SCE-107

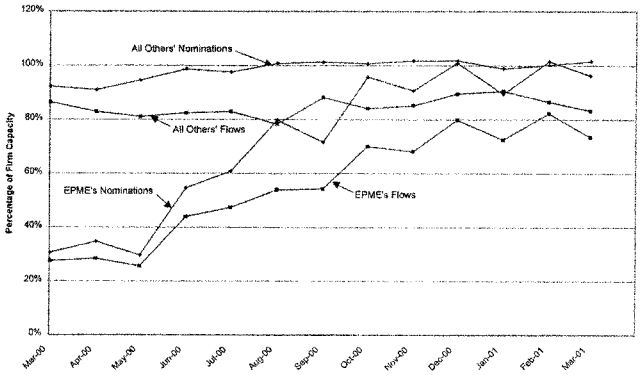


Note: Derived from Figures III-41 and V-25 in SCE-4
Source: EPNG's Response to SCE 1-1

Did El Paso Merchant Energy even attempt to fully utilize its capacity during this period as compared to other shippers? That answer is also clearly no, and is depicted in Figures 6 and 7 (Exhibits SCE-24 and SCE-109) which compare nominations and flows between Merchant Energy and all other shippers, on a monthly and daily basis, respectively.

Figure 6

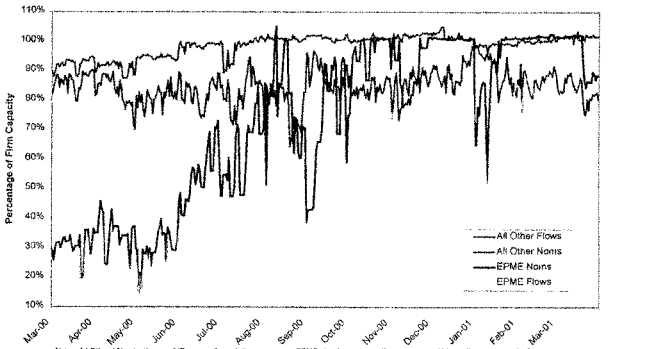
EPME Nominations and Flows Were Significantly Less Than Those of Other Shippers SCE-24



Note. All Others' Nominations and Flows are monthly averages from Kalt workpapers. EPME Nominations and Flows are monthly averages of data in EPNG's Responses to SCE 1-1, 1-10, and 1-11 and include nominations and flows for Blocks I, II, III and SoCal release capacity.

Figure 7

EPME Nominations and Flows Were Significantly Less Than Those of Other Shippers SCE-109



Note. All Others' Nominations and Flows are from Kalt workpapers. EPME Nominations and Flows are from EPNG's Responses to SCE 1-1, 1-10, and 1-11 and include nominations and flows for Blocks I, II, III and SoCal release capacity.

In his Initial Decision, Judge Wagner states that "during this period when El Paso Merchant did not nominate 100 percent of its capacity, the relevant question is whether other shippers had sufficient capacity to make up the slack. The evidence shows that if El Paso Merchant had attempted to exercise market power by restricting its nominations and flows of gas to California during the summer of 2000 and thereafter, other firm shippers who were experiencing cut in their own nominations could have flowed, and would have every incentive to flow, more gas."[6] But this conclusion flies in the face of the evidence of actual conduct established at the hearing. The other shippers *did* nominate nearly all of their capacity during this period and achieved very high utilizations. Even if the evidence supported the conclusion, one must ask whether evidence of actual withholding conduct by a firm with market power can be dismissed simply because other, smaller shippers could have flowed more gas, but chose not to.

In conclusion, no matter what the eventual outcome, the *CPUC vs. El Paso* matter will be a bellweather case illustrating the kinds of economic evaluation of market conduct that will be required of future regulators. We will not be successful in promoting competition as a substitute for regulation in natural gas or electricity markets if the regulatory oversight function cannot distinguish anticompetitive from competitive conduct.

Mr. Chairman, thank you again for the invitation to appear today, and I will be happy to answer any questions you may have.

[6] Initial Decision in FERC Docket No. RP00-241-000, issued October 9, 2001, page 16.

Mr. OSE. Professor Kalt for 5 minutes.

Mr. KALT. Thank you, Chairman Ose.

I appreciate the opportunity to appear here today. It's no secret that the question of what caused California natural gas prices to rise beginning in mid-2000 is a contentious one. I played a role in that debate by testifying on behalf of El Paso Merchant Energy in the recent FERC hearings. If nothing else, the intensity of that proceeding has given me the opportunity to examine tests and be tested on the data and evidence relating to recent natural gas prices, supplies and infrastructure in California. Based on this, the only other explanation that makes sense to me in the debate that the FERC has undertaken and heard is the supply/demand explanation.

I think it is evident that by the second half of 2000 an unprecedented and unfortunate confluence of events created a situation in which absolutely extraordinary levels of natural gas demand combined with the gas supply delivery system that was pushed to its practical limits. With demand booming and pipeline infrastructure effectively maxed out, the inevitable result was sharply higher prices.

Supply was restricted by infrastructure. I do not think that the evidence indicates that there was artificial withholding of supply through an exercise in market power. Let me briefly review what happened in California.

Going into the summer of 2000, storage inventories were essentially on a par with historic levels. The delivery system serving California consumers generally had additional capacity available to enable a response to a typical season's upswing in demand, but in the second half of 2000, things turned out to be anything but normal. On top of a growing California economy, the summer of 2000 turned out to be one of the hottest on record. At the same time, normal inputs into California of hydroelectric power from the Pacific Northwest were severely hampered by drought. June 2000 hydroelectric output in the Northwest, for example, was 23 percent lower than the June average for the previous 5 years.

The market's supply and demand forces played out in the context of a set of crucial State policies. Until very recently, the California Public Utilities Commission has found it expedient to support a nonexpansionist policy with respect to the natural gas transportation infrastructure serving California. Specifically, under policies designed to insulate so-called core residential and small commercial customers from upward pressure on gas prices, policymakers in California have been under pressure to implement a policy that limits the options of larger noncore industrial and other customers, keeping them tied to the transportation facilities of the State's incumbent regulated utilities.

To top things off, the passage of summer into fall and winter gave California no breaks. The winter of 2000–2001 developed as unusually cold, again spurring demand for electric power and the gas needed to produce such power.

It's hard to overstate just how dramatic the increase in demand for natural gas was in California in the second half of 2000. Energy economists have a rough rule of thumb. The growth rate in energy demand tends to be about the same or a little bit less than the

growth rate of the economy in general. So if the economy is growing 3 or 4 percent, we expect energy demand to grow maybe 2 to 3 percent.

In California, in the second half of 2000, statewide demand for natural gas was almost 20 percent higher than any previous year. In the case of the Southern California Gas system, for example, compared to the same months in 1994 through 1997, June 2000 demand for natural gas was 42 percent higher than the average of prior Junes. July 2000 demand was 39 percent higher. August 2000 demand was 34 percent higher. September 2000 demand was 28 percent higher. October 2000 demand was 30 percent higher.

These extreme increases in demand experienced in California in the second half of 2000 put the State in quite a bind. Beginning in the summer, the shippers who were trying to sell gas into California began to find their nominations to move more gas being cut due to infrastructure capacity limitations. They could not move all of the gas they wanted to California. The result was that instead of building storage inventories, as would normally happen in the summer, California utilities found themselves drawing down their storage of gas just to keep up with demand.

Under these conditions, no one, at least no economists, should be surprised that California would see sharp increases in the price of natural gas. Of course, these observations about the confluence of supply and demand factors is little solace to those who bore the brunt of higher pries, and it is natural to look for a scapegoat. However, based on a thorough review of the facts and the data, I conclude that the market power that has been alleged in California did not take place.

In order to exercise market power, there has to be an ability to withhold supply from the market. If supply in the aggregate cannot be restricted, prices cannot be raised. If the system serving California consumers is running full and the suppliers put essentially every molecule of gas that they can into that system, then those suppliers are not exercising market power; and this is precisely what happened in the case of California in the critical 2000–2001 period.

I think there are two major lessons that emerge from this. The first is that Federal rules aimed at counteracting any tendencies toward market power and making markets work in fact have worked well.

Second, the infrastructure inadequacies in California teach us that Federal and State policy must maintain proper incentives for the investment and development of our Nation's natural gas delivery infrastructure.

Thank you.

Mr. OSE. Thank you, Professor.

[The prepared statement of Mr. Kalt follows:]

Before the
Congress of the United States
House of Representatives
Committee on Government Reform
Subcommittee for Energy Policy,
Natural Resources and Regulatory Affairs

Hearings Regarding

Natural Gas Capacity, Infrastructure Constraints, and Promotion of Healthy Natural Gas Markets, Especially in California

107th Congress

Statement of

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John F. Kennedy School of Government
Harvard University

October 16, 2001

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October 16, 2001

Thank you for the opportunity to appear here today. My name is Joe Kalt. I am the Ford Foundation Professor of International Political Economy at Harvard University's John F. Kennedy School of Government. I hold B.A., M.A., and Ph.D. degrees in economics and am a specialist in the economics of competition, antitrust, and regulation, with particular emphasis on the transportation, energy, communications, and financial sectors. Throughout my professional career I have conducted research, published, taught, and testified extensively on the economics of market structure, competition, antitrust policy, regulation, pricing, and strategic performance in the energy industries (including natural gas transportation and marketing) and various other segments of the economy.

Obviously, we are here today because of the volatility natural gas prices exhibited in California during the second half of 2000 and early 2001. As Figure 1 shows, these prices became increasingly volatile

through the winter of 2000-01 and remained high by historical standards until near the end of the summer of 2001. Today, I would like to address the question of what has driven natural gas prices in California over the last year and a half. Why did prices reach the levels they did, and what can be done to prevent natural gas price shocks to California in the future?

It is no secret that the question of what caused California natural gas prices to rise beginning in mid-2000 is a contentious one. Indeed, I have played a role in this debate by testifying on behalf of El Paso Corporation's marketing company, El Paso Merchant Energy, in the recent hearings at the Federal Regulatory Energy Regulatory Commission (FERC).[1] If nothing else, the intensity of that proceeding has given me the opportunity to examine, test, and be tested on the data and evidence relating to recent natural gas prices, supplies, and infrastructure in California.

There are competing views on what caused California natural gas prices to rise beginning last year. After having thoroughly reviewed all the evidence, the only explanation that makes sense to me is the supply and demand explanation. Specifically, what might be called a "perfect storm" of meteorological and market conditions caused prices to climb to previously unheard of levels. Seen through the compelling lens of basic supply and demand forces, it is evident that, by the second half of 2000, an unprecedented and unfortunate confluence of events created a situation in which absolutely extraordinary levels of natural gas demand combined with a gas supply delivery system that was pushed to its

[1] The views expressed here are my own and are not presented as the views of any other party. I am not being compensated for my appearance here today.

practical limits.[2] With demand booming and pipeline infrastructure effectively maxed out, the inevitable result was sharply higher prices.

On the other hand, certain parties have claimed that the course of natural gas prices in California by mid-2000 was the result of an exercise of market power on the part of suppliers of gas to California customers. The administrative law judge in the FERC proceeding has recently rejected these claims regarding the exercise of market power.[3] Nevertheless, assertions of blame continue to be aimed particularly at El Paso as both a supplier of gas through its pipeline to California and a marketer through El Paso Merchant Energy. These claims maintain, at their heart, that supply was artificially withheld from the marketplace. In the extreme, such a purported restriction of supply is represented as the sole cause of elevated natural gas prices in California.

As mentioned, I believe that the economics and the evidence indicate that the path of natural gas prices in California over 2000-01 has been a legitimate reaction to supply and demand forces and was not the result of any exercise of market power. The combination of unprecedented demand and inadequate infrastructure to serve that demand caused prices to soar. The infrastructure of interstate and intrastate pipelines delivering gas to California consumers was pushed to

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[2] See, for example, Energy Information Administration, "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply," June 12, 2001. http://www/eia/doe.gov/emeu/steo/pub/special/california/june01article/canatgas.html. See also, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities: Part I of Staff Report on U.S. Bulk Power Markets,* November 1, 2000, at 5-2 to 5-7, and *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator and the California Power Exchange,* 95 FERC ¶ 61,115, at 61,351 (2001).

[3] In the initial decision, issued October 9, 2001, the Chief Judge of the Federal Energy Regulatory Commission concluded that the complaint concerning whether El Paso Pipeline and/or El Paso Merchant had and exercised market power should be dismissed as unsupported by the evidence.

its effective limits by mid-2000. All the gas that could get to California consumers did so. There was not an artificial withholding of supply through an exercise of market power.

Let us look more closely at the debate over the reasons for California's predicament. It is helpful to begin with an understanding of the market and policy environment that California has confronted. Going into the summer of 2000, natural gas storage inventories, needed to meet demand under peak (i.e., high demand) conditions, were essentially on par with historic levels. Natural gas pipelines serving California consumers and shippers holding contracts to ship on those pipelines generally had additional capacity available to enable them to respond to a typical season's upswing in demand. But the second half of 2000 turned out to be anything but normal. On top of ongoing growth in the overall California economy and its attendant energy needs, the summer of 2000 turned out to be one of the hottest on record. While this was pushing up demand for electricity, key non-gas-fired power generation assets serving the State were unavailable. To make matters even worse, normal imports into California of hydroelectric power from the Pacific Northwest were severely hampered by drought. June 2000 hydroelectric output in the Northwest, for example, was 23% lower than the June average for the previous five years.

These supply and demand basics were not the only contributing factors to the California story. The market's supply and demand forces played out in the context of a set of crucial State policy choices made over the course of a decade. Several key policies impacted, and continue to impact, the resilience of markets in the face of unexpected supply and demand fluctuations. Until very recently, the California Public Utilities

Commission (CPUC) has found it expedient to support a non-expansionist policy with respect to the natural gas transportation infrastructure serving California. Specifically, under policies designed to insulate "core" residential and small commercial customers from upward pressures on gas prices, policymakers in California have been under pressure to implement a policy that limits the options of large, non-core industrial (and other) customers and keeps them tied to the natural gas transportation facilities of the State's incumbent regulated utilities.

Electric power policy in California has also been a critical factor in the recent history of natural gas prices in the State. During the decade leading up to the California energy crisis, at least two important policy forces were impacting the ability of the electricity generators to respond to changes in supply and demand experienced in the market for power. First, investment in new electric generation facilities was inhibited by lengthy plant approval processes. Difficulties in getting approval resulted in the well-documented and oft-reported lack of new, efficient generation facilities in California. When demand for power soared in 2000, the State had to turn to older, less efficient gas-fired facilities. Second, the situation was exacerbated by certain aspects of the State's electricity deregulation strategy. This flawed strategy discouraged longer-term supply arrangements and employed electricity price caps that dampened electric power consumers' price-induced incentives to conserve. These and related factors left California susceptible to the full force of shorter-term and sharp upturns in demand and fuel prices. To top things off, the passage of summer into fall and winter gave California no breaks. The winter of 2000-01 developed as unusually cold – again spurring demand for electric power and the gas needed to produce such power.

It would be hard to overstate just how dramatic the increase in demand for natural gas was in California in the second half of 2000 as a net effect of these policy and marketplace forces. Energy economists have a rough rule of thumb: the growth rate in energy demand tends to be about the same as, or a little bit less than, the rate of growth in the economy in general. For example, if GDP is growing at 3-4% per year, energy demand might grow at 2-3% per year. In California in the second half of 2000, however, State-wide demand for natural gas was almost 20% higher than in any previous year. Demand in the State was high and stayed high (Figure 2). In the case of the Southern California Gas system, for example, compared to the same months in 1994-97, June 2000 demand for natural gas was 42% higher than the average of prior Junes; July 2000 demand was 39% higher than the average of prior Julys; August 2000 demand was 34% higher than the average of prior Augusts; September 2000 demand was 28% higher than the average of prior Septembers; and October 2000 demand was 30% higher than the average of prior Octobers.

The extreme increases in demand that California experienced in the second half of 2000 put the State in quite a bind. With demand so strong, the supply side of California's natural gas market never got the chance to regain its balance and get back to "normal." Beginning in the summer (normally a period in which utilities build their natural gas inventories), unexpectedly high demand began to strain the capacity of the delivery system by which gas ultimately gets to California consumers. Tellingly, the shippers who were trying to sell gas into California began to find their nominations to move gas on the multiple inter- and intrastate pipeline delivery systems which serve the State being cut due to those

systems' capacity limitations. They could not move all of the gas they wanted to California. The result was that, instead of building storage inventories during the summer of 2000, California's utilities found themselves drawing down their storage of gas just to keep up with demand (Figure 3).

The patterns of the summer did not abate as California went into the winter of 2000-01. The winter season started off with November being the coldest in 90 years. Storage build-up that might normally continue into December never took place as storage continued to be depleted (Figure 3). The infrastructure for delivering gas continued to be pushed to its effective limits. Under these conditions, no one – at least, no economist – should be surprised that California would see sharp increases in the price of natural gas.

It follows from the most basic of economic principles that, when demand explodes and meets a supply constraint such as the capacity of pipelines bringing natural gas molecules to California customers, prices are going to increase. This is how a properly functioning market operates. In fact, we have designed our economy in general and our natural gas policies in particular to function this way. Prices communicate information about the relationship between supply and demand: Are there weak demand and excess capacity in the system at prevailing prices? Are excess demand and a shortage of capacity causing high prices? Prices send signals to investors about when it is time to build more infrastructure; when higher prices are sustained over time, those prices indicate that it is time to add new capacity to the system. Similarly, high prices signal consumers to conserve until new supplies can be made available. Indeed, we should expect a well-functioning and

competitive marketplace to have periods of higher prices in order to communicate the most efficient allocation of resources.

Of course, these observations about the role of the marketplace are of little consolation to everyday citizens and businesses during periods of higher prices. And, it is natural to look for a scapegoat to blame for the disruption caused by higher prices in natural gas and other energy markets. The resulting political pressures, I believe, are the source of the alternative, so-called "market power" explanation of why California experienced high natural gas prices during the 2000-2001 period. Let's examine the market power theory.

Based on a thorough review of the facts and the data, I conclude that market power in natural gas supply has not been the source of California's natural gas crisis. Consider the economics of market power. In order to exercise market power in the supply of natural gas, there has to be an ability to withhold supply from the market for a sustained period of time. If supply in the aggregate cannot be restricted, prices cannot be elevated above competitive levels. If the pipelines serving California consumers are running full, and the suppliers put every molecule of natural gas they can into those pipelines, then those suppliers cannot be exercising market power by withholding supply.

Indeed, the evidence indicates that this was precisely the case in California in the critical 2000-2001 time period: The interstate and intrastate pipeline infrastructure needed to get natural gas to California consumers was running at its effective maximum. We know this most directly from the fact that shippers with firm contracts for capacity on the system were consistently faced with cuts to their attempted

shipments to the market because the system could not handle all of their nominations of supply. Then, too, shippers seeking to ship gas on an "interruptible" basis (i.e., using pipeline space available after higher priority firm contract shippers are served) attempted to serve California customers, but could not consistently find substantial space on the system.

The infrastructure constraints on the supply of gas that could reach California consumers have been real. California operates with a system in which the installed capacity within California that is needed to take gas from the interstate pipelines reaching the State is less than the capacity coming in from the outside.[4] This basic fact was exacerbated in the second half of 2000 by limitations on the effective capacity of the interstate pipeline system to serve California as, for example, deliveries from Canada were reduced by diversions of supplies to non-California customers and the El Paso system experienced a rupture.

The filling of the delivery system serving California to its practical limits and the fact that shippers were offering more supplies than the system could handle clearly tell us that market power was not being exercised. In fact, the system operated as FERC's rules intended. These rules govern the supply and marketing of natural gas and have been well-constructed to work against any exercise of market power in precisely the conditions that were observed in the California situation in 2000-01. If any particular shipper attempts to withhold capacity on pipelines serving a given market, such as California, other shippers with

[4] See, for example, California Energy Commission, *Natural Gas Infrastructure Issues: Committee Draft Final Report*, August 2001, at 69; *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange*, 95 FERC ¶ 61,418, at 62,561 (2001); and *San Diego Gas and Electric Co.*, 95 FERC ¶ 61,264, at 61,934 to 61,935 (2001).

capacity have every incentive to fill the space left empty as long as selling gas is profitable. In other words, if a shipper can earn revenue on its sales of gas that covers its transportation costs, that shipper will want to flow gas to the market. No profit-maximizing shipper will want to leave "money on the table." Even if shippers with firm contracts on a pipeline exhaust their contractual capacity so that they cannot automatically fill in a void artificially created by a shipper attempting to withhold capacity, the FERC rules assure that interruptible capacity, available at known and guaranteed rates, serves to counteract effectively any attempt to withhold pipeline supplies flowing to a given market. With these kinds of protections emanating from the FERC rules, those rules act to remove the ability and incentive that an individual shipper might otherwise have to exercise market power.

In short, the facts of the California experience combined with the market regulations enforced by the FERC leave claims of market power unsupported. Put plainly, what happened in California in 2000 and into 2001 was that dramatically higher demand met up with a supply system for natural gas that was pushed to its physical limits. The effect was sharply higher prices of natural gas for California.

The demand pressures for natural gas in California have moderated somewhat from the intense period of the second half of 2000 and early 2001. Since approximately April of this year, prices have been on a downward trend – although they remained high relative to historical levels until about the last month (Figure 1). The softening of prices has reflected, in part, the slowdown in the overall economy. It also reflects more favorable weather conditions and improved policies affecting electric power demand for gas as a fuel. With weakening demand,

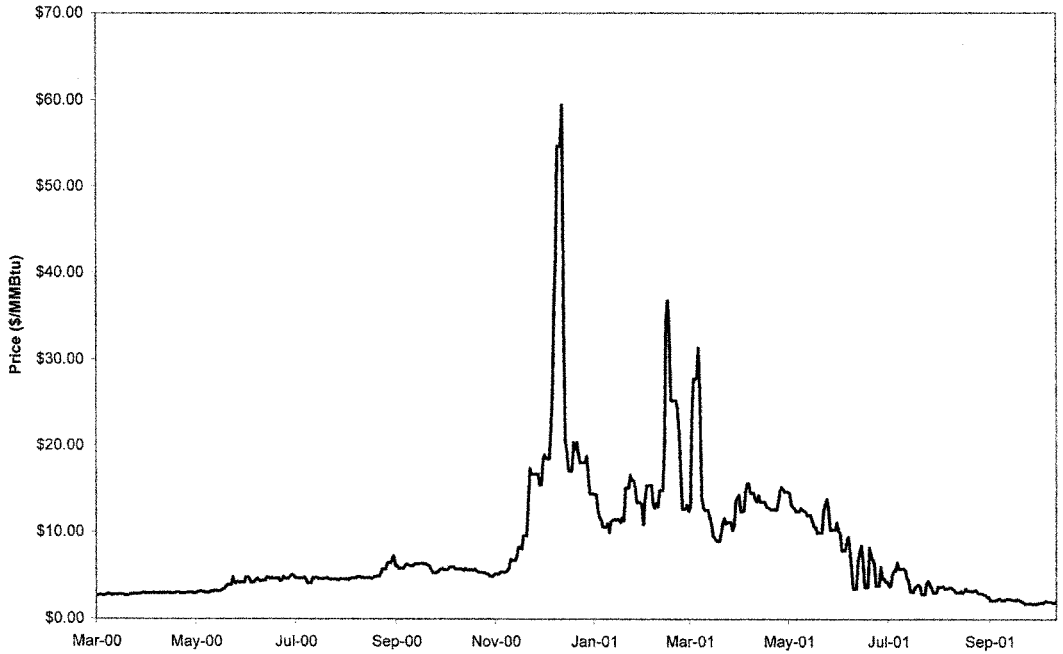
pressures on price are now not so great as they were even a few months ago, and prices have been following the course that supply and demand analysis would predict. Still, it is useful to ask what we can learn from the recent experience that will allow us to prevent such a sustained and painful situation in the future.

I see two major lessons for public policy emerging from the recent California experience in natural gas markets. First, the federal rules aimed at counteracting any tendencies toward market power that might be thought to exist in natural gas marketing and transportation have proven themselves to be quite effective. This lesson should not only be heartening to federal policymakers, but should be heeded by state officials as well.

Second, the infrastructure inadequacies in the California case teach us that federal and state policy should maintain proper incentives for the investment in and development of natural gas delivery infrastructure when and where it is needed. In particular, the direction of past policies in California that were developed to protect the status quo needs dramatic rethinking. In the past, policymakers in California have been under pressure to protect in-State utilities from capacity expansions by other shippers in an effort to facilitate a status quo in which "core" (essentially residential and small business) customers were protected from carrying the full burden of paying for investments in the utilities' infrastructures. Over the past decade, this policy direction resulted in virtually uniform opposition from incumbent in-State players to any major expansion of delivery capacity into their territories. If infrastructure is not expanded by the utilities and/or their competitors,

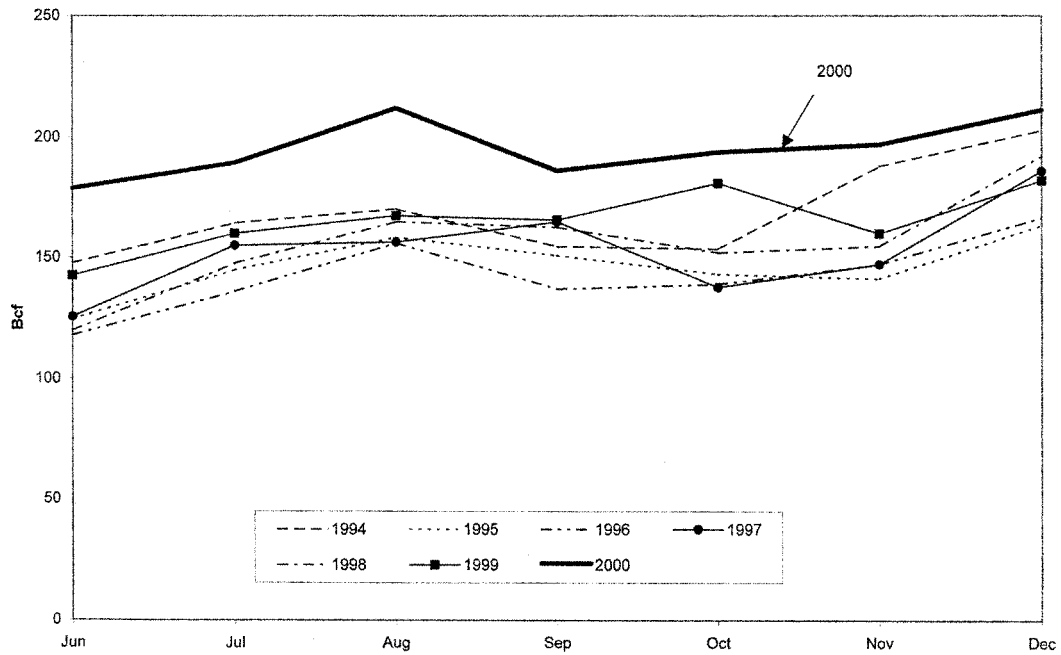
we can expect the next surge in demand to have the same impact as the last. This is not in California's interest.

Figure 1
SOCAL BORDER PRICE INDEX



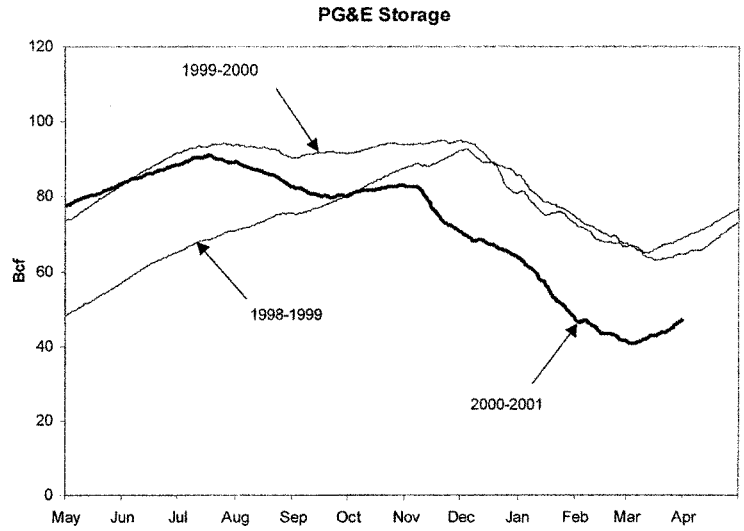
Source: Gas Daily

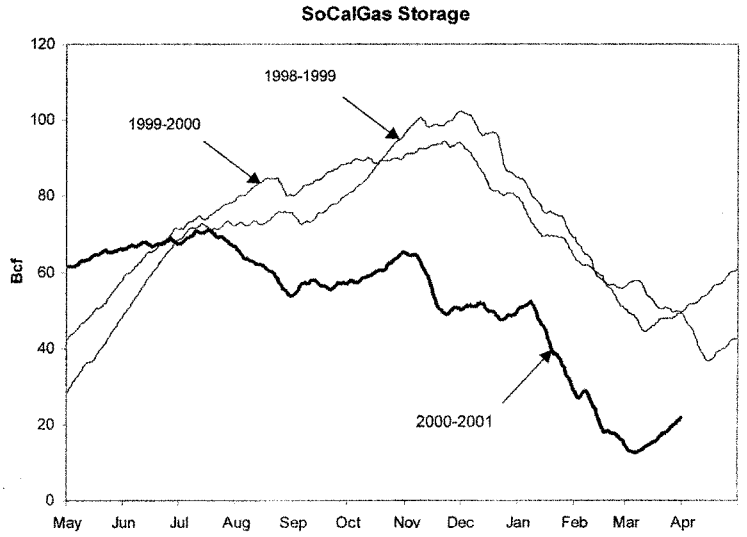
Figure 2
CALIFORNIA END-USE CONSUMPTION
June-December, 1994-2000



Source: Energy Information Administration

Figure 3
CALIFORNIA STORAGE INVENTORY





Source: Federal Energy Regulatory Commission, Docket No. RP00-241-000

Mr. OSE. Our next witness is Paul Amirault, for 5 minutes.

Mr. AMIRAULT. Thank you, Chairman Ose, and thank you for the opportunity to participate in this hearing today.

The natural gas market in North America is very volatile. Natural gas is one of the most volatile commodities there is. California being at the end of the pipeline system has that volatility amplified.

In California, the demand increases dramatically when it gets hot, but also when it gets cold; and it does get cold there, not as cold where I come from, but it does get cold. The demand also varies dramatically with the availability of hydropower.

Hydro, nuclear and, to a certain extent, coal provides the base load for power generation. Gas-fired generation takes all of the swings. Gas-fired generation, as other panelists have talked about, is increasing dramatically, but not just in California, also in the neighboring States, outside the State's borders and generally upstream on that pipeline grid. So that adds to the volatility of the gas market in California, because they have competing demands outside of their borders. So the infrastructure problem is one of a challenge to serve a very volatile and peaking market.

It doesn't make sense to build your infrastructure assuming that the demands will always look like last year. But it also doesn't make sense, and it's reassuring to see that this committee seems to recognize that demand won't always be like this year either. This is part of the cycle of demand, and this is a good opportunity to try and prevent the next crisis.

What storage can do for the infrastructure is create a more efficient infrastructure. For existing pipeline capacity, storage injections provide an opportunity to make use of pipeline capacity when it's otherwise unutilized or of low value. When new pipeline infrastructure is needed, when new supplies need to be brought to the marketplace because the average day's supply isn't sufficient, then integrating storage into the design can help make that design much more efficient and cost-effective.

Design your pipelines to meet average loads, not peak loads. Certainly storage can't always be found right at the very end of the pipeline system, but generally you can find a storage reservoir much closer to the market point than all the way back in the supply basin, so even if you have to build your pipeline from storage to the market to meet that peak withdrawal, it's generally going to be a lot less expensive than building your pipeline to meet the peak demands all the way from the supply basins. As a storage developer, we hope our customers get a lot of value out of storage, but storage value also accrues to the marketplace at large in significant measures.

The pipeline efficiencies that I've just talked about lead to lower tolls, but when customers using storage bring their gas out of storage under peak conditions, if they're consumers, they're avoiding buying gas on the spot market; if they're sellers, they're selling gas into the spot market out of storage, and that has the effect of dampening those price peaks. That can be extremely significant. It doesn't have to just be avoiding $50 kind of gas prices, like we saw last winter, but even saving 30 cents for 30 days would have the effect of saving the PG&E noncore market, who principally buy

their gas based on spot prices, $10 million: 30 cents, 30 days, $10 million.

Also, on abnormal peak days, most jurisdictions will curtail noncore markets to ensure that core markets like home heating loads have sufficient gas. That can have a big economic effect. In California, a lot of that noncore market is power generation.

Cutting off power supplies under cold conditions is also going to create its own crisis. Power plants used to have alternate fuel capability as a backup for such situations. Environmental considerations have all but eliminated alternate fuel capability in California. Storage should be thought of as the alternate, alternate fuel capability.

Finally, market power concerns have been raised in the marketplace over and over. In our view, the best way to prevent market power issues is just to ensure ample and diverse competition. Storage, in effect, competes with pipelines by making them more efficient and therefore you need less. It also competes with pipeline shippers by being an alternative source of supplies under those peak demand days.

To ensure the maximization of those benefits to the marketplace, it's important that storage transactions occur at the same marketplace as other trading transactions in that marketplace. Any toll design that separates storage from the market center will reduce the liquidity of the market trading point, and that will reduce the stability of prices.

What can be done to encourage more storage to fit in with the system? In California, we have to recognize that the utilities that connect storage to the marketplace are also the competition. It's important to push for unbundling of storage transmission and distribution to prevent cross-subsidies and to prevent any conflicts of interest.

Second, encourage interstate pipelines, encourage them to have efficient designs that factor in the load factor of how their markets will utilize their pipelines. Also to encourage or incentivize efficient utilization of those pipeline systems.

That concludes my remarks. Thank you.

Mr. OSE. Thank you, Mr. Amirault.

[The prepared statement of Mr. Amirault follows:]

United States Congressional Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

Hearing On Natural Gas Capacity, Infrastructure Constraints, And Promotion Of Healthy Natural Gas Markets, Especially In California.

Written testimony of Paul Amirault,

Vice-President, Marketing, Wild Goose Storage Inc.

October 16, 2001

Written testimony of Paul Amirault, of Wild Goose Storage Inc., to the October 16, 2001 hearing on natural gas capacity, infrastructure constraints, and promotion of healthy natural gas markets, especially in California, held by the Congressional Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

Background and Credentials:

Wild Goose Storage Inc. (WGSI) owns and operates an underground natural gas storage facility in Northern California, located just a little north-east of the load center of PG&E's market territory. In its third year of operation, Wild Goose is the only independent storage facility in California (although one other is under construction). Capacity at Wild Goose is 14 BCF of working gas, with peak deliverability of 200 mmcf/d. The majority of California gas storage is owned and operated by the large utilities (PG&E and SoCalGas), with the bulk of capacity reserved for core customers. Wild Goose represents less than 10% of California gas storage capacity.

WGSI is a wholly owned subsidiary of Alberta Energy Company Ltd. (AEC), a large independent energy company headquartered in Alberta, Canada. The Gas Storage business unit of AEC operates 125 BCF of capacity (about 4% of N. American storage capacity) at 4 different facilities (2 in Canada and 2 in the United States, including Wild Goose). We also utilize leased storage capacity at two other facilities in the United States.

As Vice-President, Marketing for Wild Goose Storage Inc., I am responsible for the commercial aspects of the facility, including marketing capacity to customers and servicing those contracts. I have over 20 years experience in the pipeline and gas marketing industries, including over 10 years of involvement with the California natural gas market.

Starting late last year, there was a significant increase in customer interest in the Wild Goose facility. In December 2000 an open season resulted in selling out existing capacity with 4 and 5-year contracts. A further open season this spring generated sufficient additional customer interest and commitments for us to submit an application to the California Public Utilities Commission (CPUC) for authorization to construct a major expansion. The proposed expansion would double working gas capacity (14 to 29 BCF) and increase injection capacity over 5-fold (80 to 450 mmcf/d) and withdrawal capacity 3.5 times (200 to 700 mmcf/d). We hope to commence expanded service in 2003, but that depends on getting relief from onerous state regulatory requirements. Legislative efforts to streamline the process are being considered.

Nature of the California Natural Gas Market

Gas demand in California is highly volatile. Demand increases dramatically when temperatures get cold, but also when temperatures get hot. Demand for gas-fired power

generation also varies dramatically with temperatures, and additionally with the availability of hydropower generation. The swing in annual average California gas demand between a 'wet' hydro year and a 'dry' hydro year, is as much as 1 BCF/d, or 15% of average total consumption in the state. There is also significant variance in demand as a result of economic activity levels. This is seen regularly in daytime vs. nighttime, and weekday vs. weekend demand fluctuations. More dramatically, this effect is seen in the difference between 2000, when a rapidly growing California and national economy was peaking, and 2001, when the slowing of the national economy and the substantial downturn in the technology sector, hit the California economy especially hard.

Events of both 2000 and 2001 established nearly opposite extremes of market conditions. The year 2000 had both hot and dry weather conditions, a major pipeline outage, nuclear power plant outages, aged (less efficient) gas-fired power generation infrastructure, lagging natural gas supply response, and a forward price curve for natural gas that encouraged market participants not to store gas in the summer because it would be cheaper later.

In 2001, dry conditions have continued, but temperatures have been much more moderate. There has been no pipeline outage, and nuclear plants are in the part of their cycle where little maintenance downtime has been required. New gas-fired power plants have come on-line, displacing older plants with much improved efficiency. Across North America, gas supply has responded to last year's price run-up. Similarly, there has been a demand response to higher energy prices, particularly in California. The forward price curve has consistently been in 'contango', where gas in near months is less expensive than gas in months farther out in the future. This encourages market participants to store gas now because it is expected to be worth more in the future. Through forward sales or financial hedges, storage users can lock-in that future value. In summary, there has been ample excess supply over demand, and the correct price incentive, so storage users are filling storage in California, and throughout N. America, to capacity this year.

The volatility experienced between the years 2000 and 2001 may be extreme, as so many factors came together at the same time. However each of the individual factors is an ever-present contributor to volatility in the natural gas supply/demand balance. The North American gas market is volatile enough. California's market characteristics, and the fact that it is located at the end of the pipeline grid, amplifies that volatility.

To an industry participant, it is encouraging that this Subcommittee seems intent on taking advantage of the current reprieve, to investigate market and infrastructure fundamentals. For certain, the current market conditions are laying the foundation for the next crises; Supply will begin to decline again, infrastructure projects may be postponed, and lower energy prices will encourage demand to return. When the economy also rebounds, we may quickly return to crises. We would encourage you, as policy-makers, to advance and support structural solutions that will mitigate against the re-emergence of the crisis. The time to stop the next crisis is today!

Gas Infrastructure Requirements:

The problem is a peak period problem. A review of the market characteristics, and the experience of the last two years, amply illustrates this. It would make no more sense to design the infrastructure as if extreme peak demand conditions like last year would always prevail, then it would to assume market conditions of this year will be the norm and nothing needs to be done.

The most significant growing market component in California and the west, is gas-fired power generation. Initially it is replacing older, less-efficient generation, dampening the overall impact on gas demand. But fundamentally, it is this most volatile sector of western gas demand that is, and will be, growing the most.

Thus the natural gas infrastructure needs to be used and designed in the most efficient way possible to respond to a volatile demand pattern. Delivering the gas to the marketplace as reliably and efficiently as possible, given that demand changes significantly from weekday to weekend, from season to season, and from one year to the next.

The availability of gas supply can also fluctuate significantly. Producers respond to price signals with the drill bit. There is significant lag time (6 months to a year or more), however, between a price signal, and when increased drilling will result in growing gas supply. Decline rates of existing production are rapid, such that production levels will quickly start to decline when drilling activity decreases.

California is in a particularly vulnerable situation, from a supply perspective. Not only is it subject to changes in the N. American supply/demand balance. Its position at the end of the pipeline grid makes it subject to having supply diverted away by upstream markets. Not to suggest that California customers who subscribe to firm service on interstate pipelines should fear capacity curtailments or diversion of their supply. However many of the new shippers on the expanding pipeline systems have all or part of their potential consumption upstream of California. Currently, there seems to be more gas-fired generation projects under development in the states bordering California, upstream on the pipeline grid, than being developed in California itself. About double. The reasons likely relate to siting difficulties, lengthy regulatory processes, and an uncertain business climate within the state. However, the same pipelines, existing and proposed, will serve both the demands in those bordering states, and the demand within California. To the extent that marketers, rather than end-users, hold pipeline capacity, they will naturally deliver supply to the highest value markets, which may be upstream if the demand is there. Of course producers will also naturally deliver their supply to shippers returning the highest value, who may be in pipelines going to entirely different markets.

It is evident that if even a few of the pipeline projects that have been proposed since last winter's crises to serve California, are built, the State of California may appear 'over-piped'. However, when it gets hot, or cold, in the west, much of that capacity will deliver gas to markets upstream of California (perhaps even to produce power for California).

California may receive less gas on those peak days, even through those expanded pipeline systems, than it does today. Industry, government and regulators can't just look at the gross capacity coming to the border to determine if the California market is balanced. We have to look at the supply/demand balance on the entire path. Storage in California may be necessary just to reliably meet current demand levels, even after a substantial expansion of interstate pipeline capacity.

So, within California, the infrastructure design shouldn't assume that the full capacity of interstate pipelines would be delivered to its border on peak days. Outside of California, the interstate pipelines should recognize that most of their new shippers are power generators and have substantially different load characteristics than the pipelines are used to. How can they deliver gas for those shippers efficiently, but still reliably?

The Role of Storage in Efficient Gas Infrastructure:

The utilization of natural gas storage at the market or downstream end of the gas infrastructure, can substantially increase its efficiency, and contribute significant additional benefits to the marketplace at large.

Storage helps improve the utilization of existing pipeline infrastructure, by attracting shipments for injection when pipeline capacity is at low value, or underutilized. This improves the load factor utilization of a pipeline system, directionally lowering the per-unit transportation tolls. Most of the pipelines serving the west do not operate at full capacity year round, even though at times they are full.

To the extent that new pipeline capacity for most of the distance between the supply basins (e.g. Rockies, Mid-continent, or W. Canada) and the market can be designed for average day, rather than peak day, demand, the capital cost savings can be huge.

Pipelines may argue that their tolls can be lower if they build more capacity and enter into shipper firm contracts for increased throughput. In some cases, the tolls will be lower because shippers are paying reservation charges for capacity that they don't need a good part of the time. They may do that to ensure they have capacity for their peak needs, particularly if they don't see an alternative. Tolls may be lower, but total dollars paid by industry are higher than they need to be.

Naturally, most pipelines will be economically advantaged if they can add rate-base supported by firm shipper contracts that ensure an adequate return, but that can be expected to be poorly utilized. Poor utilization of firm contracts allows marketing of incremental interruptible services, which can produce shareholder benefit under any toll design with an incentive component.

Policy-makers should encourage efficient pipeline use and design, not just incremental revenues.

An example of the type of design that should be encouraged, is the Ruby pipeline, under development by Colorado Interstate Gas, to bring gas from the Rockies basin in Wyoming to markets in northern California. Their proposal would have a smaller diameter pipe, designed for high utilization, between the supply basin and storage in N. California. The pipeline segment from storage to the customers' burner tips will be a larger diameter, designed to accommodate peak demands. Storage will buffer the difference. The overall cost savings of that design (including costs of storage) is in the order of 20%.

Storage can't always be located exactly at the market's load center. The reservoirs are where they are, and can't be moved. So pipelines still need to ensure sufficient capacity from storage to the load center, but that will still be a much shorter distance than building that peak capacity all the way from the supply basins.

General Market Benefits of Storage Utilization:

As a storage developer, we hope storage customers benefit sufficiently from using storage to pay fees that provide a reasonable return on investment to the owner. However, the general marketplace, the bulk of whom will not be direct users of storage, receive substantial benefits as well.

Firstly, all market participants receive the benefits of lower transportation tolls, through more efficient design and utilization of the pipeline systems, as described in the preceding section.

Secondly, when storage customers withdraw gas to sell into peaking markets (or to avoid buying gas at peak prices), the effect is to add supply (or reduce demand) to the market at that time. The effect is a dampening, or reduction, of peaking prices in the market. All consumers in the marketplace that are effected by the price set in the spot market, will see the benefit of the dampening of spot market price peaks.

Thirdly, under peak demand conditions, if there isn't enough gas supply available to serve all customers, the core (home heating) demand takes priority. California, like most jurisdictions, has procedures established to curtail non-core loads at such times, diverting the gas supply to core markets. The economic impact of curtailing industrial customers can be wide-ranging. However in California, a substantial and growing portion of the non-core market is gas-fired power generation. Curtailing power generation under extreme cold conditions facilitates a crisis of its own. Storage can provide additional supplies to the marketplace under peak conditions that will reduce or eliminate the need for non-core load curtailments.

The California power generation infrastructure used to include substantial alternate fuel capability, for just such situations. Over time, it became environmentally unacceptable to burn fuel oil in these locations, and alternate fuel capability has been all but eliminated.

Years of slack capacity and moderate weather hid this change until last year. Gas storage should be thought of as the alternative to alternate fuel capability.

Finally, there have been concerns expressed over the past year about possible market power abuses by participants in the western energy marketplace. In our view, the best way to ensure against the potential of market power abuse is to ensure ample and diverse competition. Natural gas storage is both a competitor to pipeline capacity (as storage improves the efficiency and reduces the overall demand for pipeline capacity), and an additional provider of gas supply under peak period conditions (that can compete with supplies provided by pipeline shippers).

The fact that the general marketplace, even those that are not direct customers of storage, receive such substantial benefits from the existence and utilization of natural gas storage in a marketplace, should justify in most cases the roll-in of any pipeline costs required to ensure the delivery of storage withdrawals the last few miles to the load centers.

A Healthy Gas Marketplace:

A few of the key contributions of storage to a healthy natural gas market have been described above. Competition to pipeline capacity and pipeline delivered supplies; and additional supply available at times of high demand to dampen spot price peaks.

To maximize those benefits, pipeline toll design should not separate market-area storage from the key market trading points. The additional liquidity provided to a trading point from storage and hub transactions occurring at the same point, can add substantial stability to prices at that point. If counterparties have to factor in an incremental cost of transportation between storage and the market trading point, that doesn't apply to other transactions occurring at that trading point, liquidity will be reduced to the detriment of price stability.

Barriers to Storage Infrastructure, and Recommendations:

In California, the utilities that provide the connections between supplies, independent storage, and consumers, also are natural competitors to new storage. As such, they may directly or indirectly resist or impede new storage development. Such resistance may result in less efficient gas transmission infrastructure, or in duplicative tariff structures that detract from a healthy marketplace. A more disastrous result for the marketplace would be to frustrate the development of incremental gas storage.

We would encourage regulators and policy-makers to push for full unbundling of intrastate transmission in California, in order to minimize cross-subsidies and conflicting interests. Secondly, to push for requirements for utilities to maintain their transmission systems to a standard that will be able to accept maximum storage withdrawals, at least under peak market demand conditions, from independent storage facilities that meet a

1 cost-benefits test. A cost-benefits test would compare the cost of the impacts on the
2 transmission system to accommodate new storage, with the benefits created for the broad
3 marketplace (transmission efficiency, peak-period price dampening, and avoidance of
4 non-core curtailments). The purpose of the benefits test would be to prevent uneconomic
5 proliferation of storage.
6
7 Finally, and this may currently be more directly under federal jurisdiction, we would
8 encourage support of pipeline proposals that represent the most efficient design. We
9 suggest that pipeline proponents be required to examine the expected load factor of their
10 shippers and describe in their applications how their design responds to load factor
11 considerations. In addition, we suggest that incentive mechanisms that reward pipelines
12 for more efficient design or utilization be developed and implemented by regulatory
13 authorities.
14
15
16 This concludes my testimony. I hope it has been helpful to your investigation.

Mr. OSE. Our next witness is Ms. Gay Friedmann. She's the senior vice president, legislative affairs, for the Interstate Natural Gas Association of America.

Welcome, Ms. Friedmann. You're recognized for 5 minutes.

Ms. FRIEDMANN. Thank you, Mr. Chairman.

I want to say that natural gas provides 25 percent of the energy consumed in the United States. Since the mid-1980's, the regulatory structure for interstate natural gas pipelines has changed. Interstate pipelines no longer own the gas moving through their system; instead, they market capacity on their pipelines in much the same way that airlines sell seats on their aircraft.

The cost-of-service rates charged by interstate pipelines, however, remain regulated by the Federal Energy Regulatory Commission. In the years since this restructuring has occurred, interstate pipelines have become more efficient, reduced their costs, and created and offered new services while significantly increasing the volumes of natural gas transported.

The EIA and others estimate that the use of natural gas will increase from 23 trillion cubic feet today to about 30 TCF sometime after 2010. The largest area of growth, as I believe has been mentioned earlier, is expected in electric generation. In light of this increase in demand, INGAA must stress the importance of building new interstate pipelines.

The natural gas pipeline industry will not support a 30 TCF market. There's simply not enough capacity. A study prepared for our INGAA Foundation estimated that our industry needs to invest about $34 billion in interstate pipeline structure between now and 2010. In 1999, $2.2 billion was expended to bid new interstate pipelines, and in 2000, $2.5 billion. We brought three brand-new pipelines into the marketplace.

Moving to California, everyone has already talked about all the things that happened last year—the hotter weather, the colder weather, the lack of hydro in the Northwest, the lower storage. And this has all increased demand for natural gas by California electric generators, severely straining the natural gas infrastructure.

Most interstate pipelines delivering natural gas to California end at the State line. Currently, these interstate pipelines have the capacity to deliver more natural gas to the border of California than can be taken away by the intrastate pipelines. While interstate natural gas pipeline facilities are regulated by FERC, as has been mentioned earlier, the intrastate pipelines are regulated by the CPUC. They are not required to be open access like FERC jurisdictional pipelines, and the CPUC has exclusive authority for approving new intrastate lines.

A mismatch between capacity at the Southern California border and the capacity within the SoCal system is a significant problem in California. Unfortunately, the State of California has a long history of discouraging the construction of interstate natural gas pipelines into the State. As you have mentioned earlier, the only two pipelines going in right now are Mojave and Kern. These facilities were built in the late 1980's and early 1990's, mainly to provide natural gas to serve the heavy gravity crude fields up around Bakersfield.

The California Energy Commission has affirmed that higher demand, coupled with an inadequate natural gas infrastructure on the SoCal system, limited the ability of California to receive natural gas, contributing to higher prices for natural gas experienced in California. These higher prices reflected at the border were mainly the result of a premium being paid by nonfirm capacity customers to obtain transportation on the intrastate systems. When demand for capacity exceeds supply, price is the means to rationalize the market. SoCal is now increasing its intrastate capacity, as has been mentioned earlier, and this capacity should come on by the end of this year.

INGAA wants to commend the FERC for the quick actions that it has taken earlier this year on a number of our member company proposals to build or expand capacity to and into California. Some of this added capacity is already completed and serving the California market. There are numerous proposals, either pending or proposed to be pending at FERC in the near future.

The CEC believes that the current assumptions and requirements for natural gas in California need to be reevaluated. These include a current CPUC requirement that, during peaks of high demand—periods of high demand conditions, only the natural gas core market needs are to be met. Noncore markets include many large users, including electric generators.

A key point made by the CEC, and INGAA agrees, is that from a public interest standpoint, it is better to put slack, or as we say, "excess capacity" and to pay a few cents more for transportation than to pay dimes or dollars more for natural gas supplies. While the CEC does not say it directly, they seem to support new interstate pipelines coming into California by saying a mixture of utility and privates, or so-called "bypass infrastructure investments" will help to provide the necessary intrastate and interstate pipeline capacity to meet California's future demand for natural gas.

INGAA believes that natural gas pipeline capacity in California is critical. This goal can only be achieved through the construction and expansion of both interstate and intrastate pipelines in the State. Absent this additional pipeline capacity, California customers will never get to a truly competitive market and the choice in lower prices that such a market can provide.

Thank you.

Mr. OSE. Thank you, Ms. Friedmann.

[The prepared statement of Ms. Friedmann follows:]

TESTIMONY OF GAY FRIEDMANN,
SENIOR VICE PRESIDENT, LEGISLATIVE AFFAIRS,
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA (INGAA)
BEFORE
THE HOUSE GOVERNMENT REFORM SUBCOMMITTEE ON ENERGY POLICY,
NATURAL RESOURCES AND REGULATORY AFFAIRS
OCTOBER 16, 2001

My name is Gay Friedmann. I am Senior Vice President, Legislative Affairs for the Interstate Natural Gas Association of America (INGAA). INGAA is the trade association that represents interstate natural gas pipelines in the United States, the inter-provincial pipelines in Canada and PEMEX in Mexico. These pipeline systems transport 90 percent of the natural gas consumed in the United States.

Natural gas provides 25 percent of the energy consumed in the United States. Because of the significant role natural gas is playing in improving air quality, many experts have called it the preferred fuel.

Before discussing the issues regarding increased natural gas demand throughout the country and particularly in California, I would like to give you some background on the natural gas industry. Wellhead natural gas prices were regulated for many years. The history of wellhead price regulation in the U.S. was a dismal one where prices were held artificially low, causing a significant natural gas shortage in the mid 70s. Congress responded by enacting the Natural Gas Policy Act in 1978. This law began the process of decontrolling these wellhead prices. Ten years ago, Congress saw fit to repeal all remaining federal economic regulation of natural gas production. The Federal Energy Regulatory Commission (FERC) followed up shortly thereafter with its Order No. 636, which unbundled pipeline transportation services from the natural gas commodity, and removed pipelines from the gas merchant function. Interstate pipelines no longer own the natural gas moving through their systems; rather, they market capacity on their pipelines in much the same way that airlines sell seats on their aircraft. The rates charged by interstate pipelines, however, remain regulated by the FERC. In the years since this restructuring has occurred, interstate pipelines have become more efficient, reduced their costs and created and offered new services while significantly increasing the volume of natural gas transported. On average, the transportation segment represents approximately 19 percent of the price consumers pay for natural gas.

FURTURE GAS DEMAND

The Energy Information Administration (EIA) estimates that use of natural gas will increase from 23 Tcf today to 30 Tcf shortly after 2010 (a 32 percent increase in gas demand). Other experts forecast a similar growth in gas use.

The largest area of growth is expected in electric generation, which currently uses natural gas to fuel 16 percent of electric generation, followed by the industrial sector. The primary reasons for the large growth in the gas segment of the power generation market are the relatively low cost of gas-fired generation, the low air emission characteristics of those facilities, and the reduced timeframe it takes to permit and build those facilities.

In light of this increase in demand, INGAA must stress the importance of building new interstate pipelines. The current natural gas pipeline infrastructure will not support a 30 Tcf market. There simply is not enough capacity. Energy and Environmental Analysis, Inc. completed a study in 1999 for the INGAA Foundation. This study, *Pipeline and Storage Infrastructure Requirements for a 30 Tcf U.S. Gas Market,* estimated that our industry needs to invest about $34 billion in interstate pipeline and storage infrastructure development between 1999 and 2010 just to keep up with where the market is going. Expenditures for new pipelines and pipeline expansions were $2.2 billion in 1999 and $2.5 billion in 2000. Three new pipelines were brought on line last year—the Alliance Pipeline bringing natural gas and natural gas liquids to the Chicago area from Alberta, Canada, the Maritimes Northeast Pipeline bringing natural gas from Sable Island, off the East Coast of Canada, through Maine and into the Boston area and Vector pipeline bringing natural gas from Chicago through Michigan into Canada. All of INGAA's member companies continue to work aggressively to build the necessary infrastructure to meet this increase in demand.

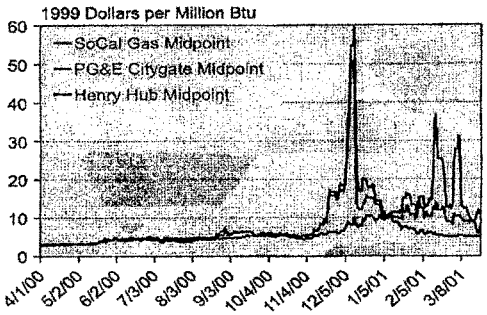
THE CALIFORNIA MARKET

A number of things happened in the California marketplace that affected natural gas demand and, therefore, price beginning last year. Economic growth throughout the west and in California was particularly strong in the late 1990s. In addition, weather impacts were significant: On the heels of a cooler than normal summer in 1999, the weather that California experienced the summer of 2000 was hotter and drier than normal. A colder and earlier winter followed, leading into 2001. In the Pacific Northwest, drier weather also resulted in lower hydropower capacity pushing in-state demand for natural gas for electric generation to unprecedented levels. An incident on the El Paso system in the summer of 2000 shut down some natural gas deliverability to California for a period of time. Natural gas storage in California was used to offset this loss of delivered natural gas. As this natural gas was not replaced in storage when there were opportunities to do so, the storage levels were below normal. EIA reported that these storage levels were 152 Bcf in

November of 2000, 34 Bcf less than the five-year average. The demand for natural gas by California electric generators severely strained the natural gas infrastructure.

The Energy Information Administration study of "U.S. Natural Gas Markets: Recent Trends and Prospects for the Future" (May 2001) states, "Throughout 1998-99 spot prices for natural gas at the Henry Hub, on SoCal for large packages, and at the PG&E city gate tracked fairly closely. Beginning in June 2000, however, California prices began to diverge from Henry Hub prices." As the chart below depicts, these spot prices did not diverge significantly until mid-November, the beginning of the winter heating season, even though the electric price in California had increased significantly starting in the previous summer.

Natural Gas Spot Market Prices, April 2000-March 2001



Source: *Gas Daily, Financial Times Energy* (various issues).

Most interstate pipelines delivering natural gas to California end at the state line. Currently, these interstate pipelines have the capacity to deliver more natural gas to the border of California than can be taken away by *intra*state pipelines in the State. While interstate natural gas pipeline facilities are regulated by the Federal Energy Regulatory Commission, these intrastate pipelines are not regulated by FERC but rather by the California Public Utility Commission (CPUC). They are not required to be "open access" like FERC-jurisdictional pipelines and the CPUC has the exclusive authority for approving new intrastate capacity expansions.

This mismatch between capacity at the Southern California border and the capacity within the SoCal Gas system is the fundamental problem in California. Unfortunately, the State of California has a long history of discouraging the construction of interstate natural gas pipelines in the State. The only interstate pipelines currently operating in California are Mohave and Kern River. These facilities were built in the late 1980s and early '90s mainly to serve oil fields in Southern California. These pipelines were vigorously opposed at that time by the CPUC and the California utilities. (See the attached chart.)

As the California Energy Commission has reported, the higher demand, coupled with an inadequate natural gas infrastructure on the SoCal Gas systems, limited the ability of California to receive natural gas. This was a factor that contributed to high prices for natural gas experienced in California in late 2000 and early 2001. This insufficient receipt capacity in California limited the flow of natural gas on interstate pipelines serving California. The resulting high prices reflected at the California border were mainly the result of a premium being paid by non-firm capacity customers to obtain transportation on the intrastate systems. When demand (for capacity) exceeds supply, price is the means to rationalize the market.

WHERE DO WE GO FROM HERE

SoCal Gas is now increasing its intrastate pipeline capacity by 375 MMcf/d. This additional capacity is expected to come on line about the end of this year. In response to the electric crisis, California has also had an aggressive program to construct new electric generation facilities.

INGAA wants to commend the FERC for quick action that it took earlier this year to approve an expansion of Kern River facilities to increase capacity to California. In late spring FERC approved a proposal to add an additional 135 MMcf/d capacity. With the quickest review and approval by FERC and other federal agencies that INGAA can recall, this new capacity was brought on line before the end of July. FERC also expedited a 210 MMcf/d expansion of the PG&E Gas Transmission-Northwest system that will begin service in November. In addition, FERC has approved other expansions of capacity by other interstate pipelines as well as a new Southern Trails pipeline. There currently are as many as 15 proposals to bring additional interstate capacity to or into California.

However, the CPUC has, in the past, approved rates on the SoCal Gas system that have discouraged construction of interstate natural gas pipelines into Southern California. SoCal Gas recently replaced this controversial back-up residual load service (RLS) with a new peaking service. The RLS service has been challenged as an "anti-bypass" mechanism, meaning

it would be uneconomical for a customer to leave the SoCal Gas service to obtain natural gas from a different pipeline. This limits customer choice and, therefore, competition. INGAA is concerned that the new peaking service, approved by the CPUC in August, while better than the RLS service, still does not level the playing field. Under the peaking service, if an electric generator, for example, wants to take natural gas from SoCal Gas and also from a competing pipeline, the generator will have to pay a higher rate for SoCal's service than captive customers taking service entirely from SoCal.
Additionally, just last week, San Diego Gas and Electric filed a request for authorization of a peaking service in response to potential competition from the proposed North Baja Pipeline Project. These two peaking services discourage the development of interstate pipelines that can directly serve California end-users.

The CEC believes that current assumptions and requirements for natural gas in California need to be reevaluated. These include a current CPUC requirement that, during periods of high demand conditions, only the natural gas "core" market needs are to be met. Non-core markets include many large users including electric utility generators. A key point made by the CEC that INGAA agrees with is that "(f)rom a public interest standpoint, it is better to put in slack (excess) capacity and to pay a few cents more for transportation than to pay dimes or dollars more for gas supplies." One of our member companies responded to the CEC staff draft report by stating that expanding and upgrading of the gas transportation system is far preferable to fine-tuning of any curtailment or diversion rules in anticipation of more frequent curtailments.

While the CEC's does not say it directly, they seem to support new interstate pipelines coming into California by saying "a mixture of utility and privates, or so-called 'bypass', infrastructure investments will help to provide the necessary intrastate and interstate pipeline capacity to meet California's future demand for natural gas." INGAA believes that additional pipeline capacity in California is critical. This goal can only be achieved through the construction and expansion of both interstate and intrastate pipelines. Absent this additional pipeline capacity, California customers will never get to a truly competitive market and the choice and lower prices that such a market can provide.

I thank the Subcommittee for inviting me to testify and hope this information is helpful to the Subcommittee.

Complaints and Protest on Pipeline Expansions in California

	Filing Date	CPUC	Sempra (SDG&E, SoCal Gas)	PG&E
Kern River 2001 Emergency Expansion Doe 9: CPOI-106	3/15/01		3/30/01 SoCal Gas Protest	3/30/01 PG&E
			SoCal Gas protests degradation or service because it will not expand Wheeler Ridge capacity.	PC&E contend that Wheeler Ridge is currently constrained by take away capacity. Further increases into Wheeler Ridge could negatively impact existing, firm upstream shippers at Wheeler Ridge.
Kern River (2002 California Expansion) Doc #: CPOI-31	11/15/00		12/15/00 Sempra	
			Sempra contends that delivery rapacity exceeding SoCal takeaway rapacity at Wheeler ridge would result in pro rate cuts detrimental to existing shippers on Kern River.	
Southern Trails Doe #: CP99-163	1/19/1999 and Amended on 3/5/99	4/5/99 CPUC Protest	4/5/99 SoCal Gas Protest	
		Without the FERC's help through its conditioning authority wider Section 7(e) of the Natural Gas Act, ARCO Refiner (and potentially any other California end-user) can circumvent the intent of the California Legislature by not paying for these public purpose programs as of the data it switches to service from Questar's West Zone.	Without the FERC's help through its conditioning authority wider Section 7(e) of the Natural Gas Act, ARCO Refiner (and potentially any other California end-user) can circumvent the intent of the California Legislature by not paying for these public purpose programs as of the data it switches to service from Questar's West Zone.	
			If the Southern Trails pipeline is constructed, the surcharges will undoubtedly be reallocated to the remaining customer base thus driving up costs to all other customers, or alternatively, providing a potential wider-collection of state-mandated social program coats. They also contend that the project is not needed because there is no existing or foreseeable market to support the project.	
Transwestern (Gallup Expansion) Doe N: C P99-522	5/13/99		Sempra Protest 1/13/2000	
			Sempra contends that TW should not be allowed to sell more capacity on a primary basis than downstream systems are able to accommodate. It would degrade service for all upstream and downstream shippers. Sempra believes that there is no market need for this project.	

Proposal	Filing Data	CPUC	Sempra (SDG&E, SoCal Gas)	PG&E
Mojave II (Northwest Expansion) Doc #: CP93-258-000, CP93-258-001, CP93-258-003)	3/17/93	2/15/94 CPUC Protest		2/15/94 PG&E Protest
		CPUC argues that Mojave will bypass PG&E non-core customers and, to a lesser extent, SoCal customers, resulting in a significant economic loss. CPUC requests that Mojave pay PG&E's stranded cost and repay PG&E's reservation cost for unused capacity on EPNG.		PG&E claims that Mojave will bypass PG&E's non-core customers, resulting in a significant economic loss, which would be passed on to remaining PG&E customers. PG&E request that Mojave pay PG&E's stranded cost and repay PG&E's reservation cost for unused capacity on EPNG.
Mojave I Kern River and Mojave Entry (including Common Facilities) Doc #: CP89-2047, CP89- 2048, and CP89-1-002	8/31/89	Contends the application violates the optional certificate regulations with respect to cost shifting. And so, they will result in LDC bypass which will impermissible shift costs to existing CA LDC customers.		
		They argue that the applications should be dismissed because they prejudice other pending proposals.		PG&E contend that project is related to Altamont Project Group's proposal. They contend that the two should be considered together, and that the Commission must prepare supplemental EIS examining the two proposals.

Expansion Information

*Kern River 2001 Emergency Expansion: Construction of emergency facilities to provide up to 135,000 Mcf/d of limited-term, incremental capacity from Wyoming to California. This project will be phased into the 2002 California Expansion which will add 124,500 dth/d.

*Kern River (11/15/2000 filed with FERC): 2002 California Expansion Project-would add 124,500 dth per day (in Service date: 5/1/02) Another request will by filed mid-2001 (2003 expansion of 380 MMcf/d)

*Questar Pipeline (Southern Trails) received approval to convert an oil pipeline to gas for transmissions of 120,000 Dth/d to California. (San Juan to Long Beech)

*Transwestern (Gallup expansion): Allows TW to once again operate Mainline west of Thoreau certificate capacity of 1,090,000 Dth/d.

Mojave II (Northwest Expansion) proposes to increase system capacity from 400MMcf/d to 875MMcf/d through compression and looping they would also add 290 miles of pipeline running from Bakersfield to Martinez, CA and a further 59 miles to Sacramento, CA.

*Kern River and Mojave Entry (Mojave I): Kern proposed to construct 676.2 miles of 36-Inch pipeline from Opal, WY and into CA that transports 700 MMcf/d. Mojave proposed to construct 159 miles of 24 and 30-inch from Topock, AZ to CA that transports 400 MMcf/d. Their combines facilities consist of 222.5 miles of 30, 36, and 42 Inch pipe with a design capacity or 1.1 Bcf running from the interconnection point to Bakersfield, CA.

Mr. OSE. We have some questions we want to go through, but before I get to the prepared questions, I have a couple other issues that I want to examine.

Mr. Carpenter, you've got a figure 6 here in your testimony that talks about the flowage in the various pipelines in terms of percentage. But I don't see a correlative—it's not on the same chart, the pricing of natural gas, and as near as I can get it reconciled, it appears to me, if I look at figure 1 and try and transpose the pricing—and I guess this is the spot market in figure 1?

Mr. CARPENTER. That's correct.

Mr. OSE. If I transpose the graph in figure 1 to figure 6 to try and correlate rates of increase and percentages of firm capacity, I'm trying to see how close of a connection there is for, say, April 2000 on figure 1. It looks to be that the price on the spot market is around 250, and the utilization in El Paso is somewhere around 30 percent. Am I reading that correctly?

Mr. CARPENTER. Somewhat.

Actually, I think it's a little more helpful to look at figure 2, because figure 2 shows the critical basis differential, the value of the transportation capacity, which is sort of the component of the delivered price that explains why the border price was so much higher than elsewhere in the country; and if you look at that figure, you see—in roughly April 2000 and moving into June, you started to see an increase in the differential from what had been a very low differential for easily 5 to 10 years prior to that.

So this was the first time we ever really saw in the California market context, which always at least since 1988, had the view that they had too much pipeline, interstate pipeline capacity to California. And we start to diverge in roughly May and June, and if you look at figure 6, which shows the nominations and flows on the El Paso system, it's—while clearly, you know, El Paso was not fully utilizing or nominating their capacity in the March-to-May time period, admittedly prices were low during that period. But prices started to rise, and at the same time, El Paso was still not fully nominating, whereas every other shipper on the El Paso system was fully nominating.

So our view is that the price increase experienced in California in the summer—in the early summer of 2000, which was the critical time period for filling of storage, that that problem was exacerbated by the fact that the capacity holder that has market power in Southern California was not fully nominating or utilizing its capacity.

Mr. OSE. If I understand your point, then, it's that the groundwork for the spike in the fall of 2000 was laid in the spring of 2000?

Mr. CARPENTER. Exactly.

Mr. OSE. All right.

Now, educate me a little bit. How frequently do transmission lines of this nature run at 100 percent of capacity?

Mr. CARPENTER. Actually, most transmission lines in the United States run at very high, greater than 80 to 90 percent of load factors. All of the other transmission lines into California, Kern River, PGT line, Transwestern, during this entire period were running at a greater than 95 percent load factor.

Now, that is affected by whether you have storage which allows you to maintain a high load factor on other pipelines in the country, but basically pipelines try to maintain very high load factors.

Mr. OSE. So if we're sitting there monitoring flows on the five main lines into California, you're saying four of them were effectively running at 100 percent?

Mr. CARPENTER. Yes, during this time period.

Mr. OSE. And is that the historical norm, I mean, that they just run flat out?

It would seem to me that it would be if they could fill it, they would.

Mr. CARPENTER. Historically, El Paso has been the swing pipeline, and that is because it serves the most expensive supply basin. So naturally——

Mr. OSE. Which would be Southern California?

Mr. CARPENTER. From the southwest producing basins in Texas, it's typically been the most expensive supply into California. So El Paso's pipeline would be the last one to fill up.

Mr. OSE. So what is the historical norm for El Paso, then?

Mr. CARPENTER. Oh, if I remember correctly, sort of prior to the PGT expansion into California, El Paso was running at a fairly high load factor. Once the Kern River system and the PGT system were expanded, then El Paso's load factor dropped rather significantly.

Mr. OSE. To what? Dropped to what?

Mr. CARPENTER. I'd have to look back at the figures. I want to say, on average, 60, 70 percent on an average across the year, but I'd have to look.

Mr. OSE. Are there any transmission problems in any of these lines that you know of that would account for less than full utilization? For instance, did Kern River or Mojave, did they have a breakdown in their pumping equipment or what have you? Was there some other rationale that is looked at or explored or answered in that respect?

Mr. CARPENTER. That would explain why they had such a high load factor?

Mr. OSE. As to why El Paso may have been only at 44, or somebody else may have been only at 80 or 92 or less than 100?

Mr. CARPENTER. OK. Well, just to be clear on figure 6, when we refer to EPME's nominations, we're talking about the Merchant Energy contract, not the load factor on El Paso as a whole. All other nominations up above are talking about all of their nominations and flows on the El Paso system. So figure 6 just deals with El Paso.

Mr. OSE. Was the demand on the El Paso line met by the flows that were on the El Paso line?

Mr. CARPENTER. Yes, but if more gas had been nominated and flowed, there would have been either additional demand or additional storage injection at lower prices during this period. So people were making decisions in the summer of 2000, do I inject into storage or do I sell gas at the California border?

Mr. OSE. And yet I heard testimony from Mr. Lorenz in the last panel about the pricing curve, saying that people had anticipated

further decline in prices, so they were not buying even though the price curve actually went the other way and it turned up.

Mr. CARPENTER. That's correct, and I believe that was a result of the withholding of capacity in the market during that period.

Mr. OSE. That turn-up was?

Mr. CARPENTER. No. That it raised prices in the short term, yet the forward curves were still showing declines.

Actually, if you look at the basin prices during exactly that same period, you didn't see the decline. You only saw the decline at the California border; and I believe that is a direct result of the withholding of capacity at the border that induced people to sell gas at the border at the high price, instead of injecting it into storage.

Mr. OSE. If I have capacity in pipeline, how long in advance do I go through the nomination process?

Mr. CARPENTER. On the El Paso system, there's four cycles of nominations. Two of them occur the day before the gas flows, and there are two that occur on the day that the gas flows.

Mr. OSE. So it is almost contemporaneous?

Mr. CARPENTER. It is.

Mr. OSE. All right. So there's no time lag in that respect? And there are no transmission problems on the line that would otherwise result in a reduction of its capacity, that you're aware of?

Mr. CARPENTER. Well, in August, we did have the Carlsbad explosion, which did reduce capacity.

Mr. OSE. By how much?

Mr. CARPENTER. For a 2-week period, it was roughly 700 million a day, I believe. And then there was a longer-term, permanent—or longer-term reduction of 250 million a day for safety reasons that continued through the year. But again our evidence indicates that there was still available capacity on the El Paso system that could have been utilized if Merchant Energy had chosen to nominate and flow its gas.

Mr. OSE. What I'm trying to get at—I mean, 44 percent kind of just jumps off the page at you. I'm trying to watch out for all of the adverse occurrences to get to what it would have been under an optimal scenario.

Now, the reduction in flowage from August forward would have accounted for something. Did El Paso Merchant accept the entire burden of that reduction, or was it apportioned amongst all of the people conveying gas through the pipeline? Do you know the answer to that?

Mr. CARPENTER. Well, if you look at figure 6, for example, you'll see that in the August time period, if you look at all others' flow, there was a reduction in other people's flows, as well, during that period. And those people were nominating at 100 percent all across the board.

The curious question in my mind that has never been fully explained is why El Paso Merchant was not nominating 100 percent. Why were they not even trying to get as much of their gas into the market as they could?

And the explanation during this summertime period can't be that, oh, there wasn't a market for it. Relative to historical standards, prices were extremely high, so there would be a market for people willing to take the gas at a slightly lower price, believe me.

That is the case.

Mr. OSE. If the total capacity of the pipe is 100, El Paso Merchant's share of that 100 is how much?

Mr. CARPENTER. About 35 percent.

Mr. OSE. So if it's 35 percent, and they're only running 44 percent of that, they're at somewhere around 15 percent of the overall capacity?

Mr. CARPENTER. Right. It's about, on average, I think about 400 to 500 million a day of unutilized capacity during this summertime period, which is almost equivalent—if you think of the Kern River pipeline, that is a 700-million-a-day pipeline, so it's like that much—you know, two-thirds of that capacity being pulled out of the market.

Mr. OSE. All right. So if they're running at 15 percent of the pipeline capacity and they have basically idle 20 percent of their share, and everybody else is running flat out, that means 80 percent of the pipe is being used?

Mr. CARPENTER. Yes. Although even on the El Paso system, even everybody else when they nominate 100, they—they're lucky if they're able to get, you know, 85 to 90 percent flows. You can see that if you look in the winter of 2001, where everybody acknowledges that the system was maxed out. People are nominating 100 percent, but they're getting, you know, 80 to 90 percent flow rate.

Mr. OSE. So, in any case, the pipe is not running at 100 percent anyway? I mean, nobody is using—other than, say, let's see, here in December 2000 and February 2001, those are the only 2 months people are running at 100 percent. Again, I'm trying to understand, is the amount of gas that was going in the pipeline that El Paso Merchant was part of combined with the amount of gas coming through the other pipelines going into the State, was that adequate to meet demand; and if it was, I'm trying to understand why El Paso Merchant would only run at 44 percent? I just——

Mr. CARPENTER. And the reason why they would do that is because, by doing so they would be able to raise the price at the border and be able to sell gas at the border at a higher price.

Mr. OSE. And it's your contention, if I read your testimony correctly, that they did it for the purpose of raising the price at the border and that there was collusion amongst everybody on the line?

Mr. CARPENTER. No. There doesn't need to be collusion. The issue that I address there is the question of whether or not everybody else was fully utilizing their capacity, which was something that the judge theorized was the case. And, again looking at figure 6, pretty much during this entire period of the El Paso contract, all other shippers were nominating—were attempting to use all of their capacity.

So to say that during this period, say, if you look at July when El Paso was nominating about half of its capacity and flowing about 40, 45 percent of its capacity, during that period to say, oh, well, all others could have nominated and shipped more, is just incorrect.

Mr. OSE. Because according to this chart, they're nominating at 100 percent, even though they're flowing at, say, 83 or 84 percent.

Mr. CARPENTER. Right. The flowing aspect of the El Paso system is a feature of the fact that there's—it serves a couple of supply ba-

sins, and there's some complicated allocation questions, so that nobody ever seems to be able to get 100 percent of their nominations, except in some months.

Mr. OSE. Now, Professor Kalt, your testimony on page 8 says that basically this market power that might be embedded in El Paso Merchant does not exist, or more accurately, has not been the source of the natural gas crisis in California. So you have a wholly different view.

Mr. KALT. Well, my colleague and I did testify on opposite sides in this matter, and I think the data do indicate otherwise, yes.

Mr. OSE. How do you reconcile the issue of an increase in price versus 80 percent basically of the pipeline capacity being utilized?

Mr. KALT. Well, in the discussion you just had, I think there are at least two additional critical facts that would be helpful to your understanding.

One is that El Paso Merchant Energy, the marketing arm, held this capacity in a number of different blocks; and without going into all the details, with respect to El Paso pipeline capacity, the marketing company had three critical blocks. One of those blocks was equivalent in its security, its firmness, to what other parties held. But two of the blocks were not as secure; they could be bumped off the line.

Mr. OSE. You're talking about the other parties who were nominating for capacity?

Mr. KALT. Yes, yes. And two of the blocks that El Paso Merchant Energy held were lower priority service, and when we look at the nomination strategy as the demand in California picked up, as I detailed in my testimony, and the pipeline began to fill what you saw was, not surprisingly, the parties with the best quality were able to get into the market first.

When El Paso Merchant Energy had capacity of equivalent quality with the other shippers, what we see is behavior that mirrors those other shippers. They tend to nominate quite comparably.

Mr. OSE. You've looked at the empirical data that says when you have apples and apples in terms of transmission capacity, everybody was behaving the same?

Mr. KALT. In terms of firm transportation capacity.

Mr. OSE. Apples and apples?

Mr. KALT. Apples to apples, yes.

Mr. OSE. Everybody was behaving the same.

Mr. KALT. Well, there are differences, but you do not find this 44 percent difference. What you find is that El Paso Merchant Energy, for example, on its most secure capacity, it nominates 100 percent, and it tries to nominate and push gas through the system just like everyone else, when you look at it on an apples-to-apples basis.

Mr. OSE. It was in the other blocks or the other—the inferior tranches of capacity that they did not meet or did not utilize their entire allocation, so to speak?

Mr. KALT. When you look at the empirical data, if you look at those other tranches or blocks, the less secure quality capacity that El Paso Merchant Energy had, that's what generates these kinds of numbers that have been thrown around like 44 percent.

I mentioned that there were two critical factors. A second critical factor is important to get on the table. Beginning in the summer of 2000, the shipments that were being nominated on the El Paso system, the nominations began to be cut as the capacity of the system was strained. In other words, parties, all parties attempting to push gas through the system found themselves being cut, I think you earlier asked Dr. Moore if the capacity was actually they found themselves trying to push more than X in the system and the nominations began to be cut, what that tells us is that it's not an artificial restriction in supply by one of the shippers, but rather the system itself is having trouble getting that gas through to California customers.

So I think when you add in those—at least those two critical facts, I think a very different story emerges, and it tells you that you faced infrastructure constraints in the summer of 2000 and on into the winter.

Mr. OSE. How much of these inferior tranches, or how much of the demand represented by the inferior tranches of allocation represent noncore customers in California?

Mr. KALT. I don't know if we have that data, sir.

Mr. OSE. It would seem to me that would be a highly variable demand, if it's noncore and it's nonfirm.

Mr. KALT. Sure, you would think that it would. I don't know if we have the data exactly. The utilities themselves who serve their core customers, PG&E and SoCalGas, are essentially large shippers on the system, both on their own account and in some cases they have purchased capacity from others. But they are shippers, as well, on the system.

Mr. OSE. I'm going to get to you. Be patient.

I want to go back then, Mr. Carpenter, in terms of the capacity on that line that El Paso Merchant was participating in, that line was delivering gas to the border and that gas, at the border, was then put into an intrastate pipeline based on a nomination process that favored certain customers, core customers over noncore customers. I mean, that was the testimony from Mr. Lorenz; I think also Ms. Lynch.

Are you familiar with the nominating process of the gas going into the intrastate lines?

Mr. CARPENTER. Yes.

Mr. OSE. Is there any connection between the manner in which the nomination process is made on the intrastate line to the capacity utilization on the interstate line?

Mr. CARPENTER. I think, in answering that question, you need to distinguish between northern and southern California.

Mr. OSE. It does so happen I have right here in my notes to ask about that distinction.

Mr. CARPENTER. In northern California, PG&E has unbundled its high pressure transmission system, which they call the backbone, and the way that they have done that and the way that they conduct nominations and scheduling on the backbone is very much like an interstate pipeline, in the sense that if you're a shipper, you can hold firm capacity on the PG&E backbone, and you can trade it just like you can hold interstate capacity, and you can trade it. So

it makes for a relatively seamless set of transactions into the heart of the demand centers in San Francisco.

Mr. OSE. So far, greater certainty on that side?

Mr. CARPENTER. Yes. And with respect to the SoCalGas system, they have not as yet unbundled. They treat their transmission system as part of their local distribution network, and so when you nominate into the SoCalGas system, essentially you're not utilizing a transportation right that you have on the high pressure part of their lines; you're nominating for the ability to get into the system and have your gas delivered via local distribution service or all the way to the burner tip.

And because there are some points on the SoCalGas system that are more valuable than others from a market point of view. There has been this tendency historically to load up nominations on the relatively more valuable points. One of them is called Topock, or Wheeler Ridge, which is the connection between PG&E and SoCalGas's system. That is where Kern River comes in, and SoCalGas then allocates in a prorationing form approach, which they call "windowing." They allocate those rights into the system, and it's been my sort of firm conviction for a number of years now that process in southern California creates some inefficiency that could be rectified if the system was unbundled in the way that PG&E, for example, had unbundled its system, and that you'd have a more consistent statewide network.

And, in fact, there was a proceeding, which I participated in at the California commission, which investigated exactly that question, and a settlement had been reached which would have done partly that. And that all got caught up in the electricity crisis and basically hasn't moved forward as yet. But I think you heard Commissioner Lynch mention that those issues are still on their docket.

Mr. OSE. Was there enough capacity at the border? If El Paso Merchant had run at something in excess of 44 percent, was there enough take-away capacity at the border to take the gas?

Mr. CARPENTER. Yes, during the summer period, in my judgment. And if storage had been filled as a result, our calculations indicate there would have been enough capacity in the winter to meet even the winter peak.

You have to remember that in southern California, gas is still winter-peaking; the highest demand is in the winter. So the system was fully—should have been capable of taking that additional gas in the summertime. And I believe Mr. Lorenz has so testified. And if storage had been filled, the system would have been able to meet the winter demands, as well, without reaching capacity constraints. Unfortunately, we didn't have that situation.

Mr. OSE. But that gets to the pricing curve that Mr. Lorenz related.

Mr. CARPENTER. And whether the withholding of capacity directly influenced that border price curve, which I believe it did.

Mr. OSE. Professor Kalt, you don't agree?

Mr. KALT. No, I don't think that is accurate on two counts.

And the FERC has been presented with an analysis of this. Both of the conditions that Dr. Carpenter just mentioned, filling the storage and servicing the growing demand and booming demand that was going on in California, they both couldn't be satisfied.

When you look at the data, the data indicate that you could not fill the storage and satisfy the demand and keep the prices at the historic levels that were talked about earlier.

The binding and constraint in that analysis turns out to be inside the State system. It can't get enough gas in. The simple reality is that California found itself in a situation in which summer, normally a storage-fill period, demand boomed. And then winter came on, and then November 2000 was the coldest winter in 90 years. It started out that way. California never got a breather to go fill that storage, and so it hit the winter with a situation in which demand remained very high in the winter and storage had never been filled.

Second, I think that the analysis of the price curve is wrong. That price curve is a statement of people's expectations. El Paso Merchant Energy was known by the marketplace to have this capacity. It was going to have that capacity through the storage-fill season on into the winter. If it thought that there was market power going to be exercised, there was no reason not to exercise that. And El Paso Merchant Energy wasn't going to give up its capacity in the middle of the summer of 2000. It was known it would have that capacity.

But I think the basic reality is that California found itself in the situation—it was described earlier as "the perfect storm"—where it never got a breather to go fill that storage, and the demand simply outstripped the capability of the system to fill storage and service demand.

Mr. OSE. Mr. Amirault, on page 4, in the second-to-the-last paragraph, you talk about the economic advantage that both pipelines get from adding rate base and that poor utilization of the firm contracts basically helps the shareholder. In other words, you do a bad job, your shareholder's benefit, I think, is the connection.

I'm asking something that is almost implicit here, and if I'm wrong, you need to correct me, but are you saying that the structure of the contracts, that being the core versus noncore, or the manner in which they're nominated for, are you saying that structure is one of the root causes of the pricing structure?

Mr. AMIRAULT. It's not the core versus noncore aspect; it's the contract capacity aspect of it and the fact that pipelines get the bulk of their revenue through demand charges that are reservation charges paid by the shipper, whether they use that capacity or not. So a pipeline in its business is getting a return on rate base.

To the extent it can make a proposal to shippers, get shippers to sign up for long-term contracts where they're going to pay reservation charges for that full term whether they use the capacity or not, that assures the pipeline of a reasonable return on its investment. Then the company says, OK, that base return is covered. The pipeline says, I'm good for 10 years, I've got a return on my investment; how do I go and generate incremental revenue?

And toll designs have encouraged looking for incremental revenue with mechanisms that share that incremental revenue with the shippers. It will reduce the tolls for the shippers if they can generate some incremental revenue, but to encourage that, they also give some of it to the pipeline shareholder in an incentive ratemaking scheme. So the net result is that the system is set up so

that a pipeline is advantaged by encouraging a design that becomes inefficient, where the people that are paying the basic return aren't going to effectively utilize that capacity so that, in turn, they can generate some more revenue and get an extra return for the shareholder.

It may appear that the tools, the base tools, are lower than they would be otherwise, because the pipeline will say, the more I can get, the lower average toll I can charge. That's because they're charging that average toll over some capacity that is not being very effectively utilized by the firm shippers paying for it. The industry as a whole is paying more money to the pipeline company than they might need to if there was a more effective design.

Mr. OSE. I'm thinking about what you just said.

So in effect, you basically have, if you will, an annuity, which is the standby charge, and then you're trying to add little bits and pieces over time to that annuity to increase your returns, and the pipeline owner, in effect, is willing to split that with the gas purveyor to their mutual benefit?

Mr. AMIRAULT. That's right. It's as if a hotel sold a block of rooms to a corporation for 10 years, and knew that the corporation would only use it 75 percent of the time. So they go and resell some of those rooms to other parties.

Mr. OSE. Statistically, they're going to be OK on that 25 percent?

Mr. AMIRAULT. That's right.

Mr. OSE. All right. Now, your storage facility, you buy gas for storage, and then you basically wheel it back into the system on demand. You're buying gas on long-term contract?

Mr. AMIRAULT. No. Essentially we're a service provider. We're a warehouse. We sell space in our warehouse to third parties.

Mr. OSE. Third parties who own the gas. They come to you and they say, Mr. Amirault, we want one-third of your tank?

Mr. AMIRAULT. Right.

Mr. OSE. OK. And then depending on their demand, they will wheel that one-third out to meet whatever vagaries they have in their demand?

Mr. AMIRAULT. That's right. If they're a consumer, they will store gas when they can buy it more cheaply than they expect to have to pay at times when their demand peaks. If they're a seller, they will store gas when prices are low so that they can try and sell it and withdraw it and sell it into markets when prices are higher.

Mr. OSE. The gas that you have in storage, does it come from a single source or a single pipeline, or do you get it from multiple sources?

Mr. AMIRAULT. We're connected to the PG&E pipeline system, and so any gas that our customers put into our storage facility has been transported over the PG&E pipeline system, and when it's withdrawn, it is withdrawn onto the PG&E system.

Mr. OSE. All right. Do you know—in terms of the intrastate practices on pricing, educate us a lit bit about northern versus southern California. I mean, I can look at electricity prices and there is a constant differential of some 50 to 60 cents per megawatt between NP–15 and SP–15. Does that same kind of differential exist for natural gas?

Mr. AMIRAULT. There has been a similar differential between the northern California and the southern California marketplaces. What that can be ascribed to may be a number of factors. I suspect part of it is the unbundling of transportation on the PG&E system that hasn't occurred yet on the SoCal system. So that there is a city gate market on PG&E, and the city gate is after the transmission from the California border to the load center near San Francisco. There is an effective marketplace there. People pay their transportation toll to get to that city gate market center, and then they can transact business with end-use customers.

Mr. OSE. You're suggesting there's a competitive advantage to coming across the PG&E line versus going into southern California.

Mr. AMIRAULT. The end-use customer, I think, has benefited marginally in northern California, yes.

Mr. OSE. Is that competitive advantage that goes to the retail customer a function of the manner in which SoCalGas handles its nomination process, or its contracts, for use of its pipeline?

Mr. AMIRAULT. Well, it's a function of the different market structure in SoCalGas territory. I believe that's so because they don't have unbundled transportation from the border to a city gate; customers can't contract for transportation and be assured that their volumes will move on their capacity without a potential prorationing and this windowing effect.

In northern California, customers can contract for firm capacity from the State's borders to the city gate. And when they nominate it, they can be assured it will flow; it won't be prorationed. There is a difference.

Mr. OSE. Mr. Lorenz was talking about the lack of construction of generating facilities in southern California. Is this the root cause of it? Is this a differential of firm capacity?

Mr. AMIRAULT. I could only speculate on various causes for that. It may be, as you described it, a power value difference.

There's a constraint across this path 15, which can make power more valuable north of that path, as I understand it. It may be siting considerations, environmental considerations, making it difficult to site. It may be the general business and regulatory climate in the State has encouraged parties to locate sites outside of the city.

Mr. OSE. Just a moment, please.

Mr. Carpenter, one of the things we've struggled with is quantifying natural gas demand in northern California, natural gas demand in southern California versus interstate capacity for transmission of gas into northern California, interstate capacity of natural gas into southern California and then intrastate capacity north and south for distribution.

Do you have any data indicating how that dynamic plays out? How does demand compare to supply in northern and southern California?

Mr. CARPENTER. Yes. We have that kind of information. It's a difficult question to generalize about and a difficult question to analyze, because you need to decide whether you're going to talk about averages, annual averages or whether you're going to talk about system peaks, because they're different in the different parts of

California. So it's a multifaceted question, you're asking me, and there's not a simple answer.

Mr. OSE. Would you like to do it in writing instead? I mean, that might be easier.

Mr. CARPENTER. I'd be happy to, and it also gets to this question of whether there's a mismatch between inter- and intrastate capacity. I actually don't believe there is a significant mismatch, and many of the comparisons you see don't adequately take into account the pipelines that cross the border, Kern River and Mojave, and when they make those calculations——

Mr. OSE. We're going to ask the same question of Professor Kalt, too, so we're going to get both perspectives here.

Mr. CARPENTER. OK.

Mr. OSE. Now, if I might go on, Mr. Waxman, I thought, brought up an excellent observation regarding the June 2001 expiration of the El Paso Merchant contract; and he ascribed the decline in prices to the relinquishment of the contract.

The question I have is—and maybe it's purely coincidental, but FERC's market mitigation plan actually kicked in on May 29th, a couple of days prior to the expiration of the El Paso Merchant's contracts. I'm trying to get a better feel for whether or not, given the relationship between natural gas and electricity, whether the decline in prices at the end of May or the first of June was a function of FERC's market mitigation plan or the relinquishment by El Paso Merchant of their contract; and I'd appreciate any input from any of you on that.

Mr. CARPENTER. I would venture to say that it's some of both, for the following reason: With respect to the Merchant capacity, the fact that you went from one seller holding a billion-and-a-half cubic feet a day to 25 sellers holding that capacity and competing to provide it had to have an impact.

The reference to the mitigation plan I think is important, too, in the sense that one of the problems that we had in California that resulted in the ability to exercise market power in the way that was done, in my view, is that demand for gas was very inelastic by power generators, in part because there wasn't a mitigation plan in place. Once the mitigation plan is in place, in my view, the elasticity of demand—in other words, the responsiveness of the buyer to price, increases. And so I think you could also ascribe some of the effect to that happening at that time. But I think it is very important to recognize that—we all went into the summer expecting the prices to continue to be high.

In fact, Professor Kalt was making the argument at the time that the forward price for gas, which continued to show high prices through the summer, that was an affirmative indication that El Paso didn't have market power. When he will, the reality was that when the contract was actually relinquished, the prices fell. So I don't think you can overstate the importance of that as well.

Mr. KALT. I think the discussion here got off on the wrong foot, in that Mr. Waxman was provided with incorrect information. He said a couple of times—he's not here, but he said a couple of times that prices began to decline in June. If you look at figure 1 that I attached to my testimony, you'll see that, in fact, as demand began to soften in California when you got into the springtime,

there's been a downward trend in California prices since about April, and that downward trend continued on out into sometime, it looks like in September.

And so that downward trend, if you look at June where you see a bunch of spikes there, I think it's just bad science, if you will, to try to pick out a single spike and say that is the end of some market power. I think what you see is a market that is going through a lot of turmoil. Demand is softening, but prices did not return to the level predicted by the market power theory.

On a consistent basis, it's really out in September, sometime within about the last month when prices have really come down to their historic levels, and that downward trend is—just as I said, it's sort of bad science to pick out May 29th or June 1st. We were in a situation, as I detail in my testimony, where demand was gradually softening in California, and I think prices reflect the supply/demand forces in that trend.

Mr. AMIRAULT. If I could just add a few other comments, I think that there were many other factors that also contributed to the time of that price decline.

A similar-shaped curve happened to North American prices, as Professor Kalt shows in his testimony he just referred to, so the North American price curve was falling in the same pattern. As I described, the volatility is amplified in California for various reasons, but it was driven by a lot of North American supply/demand factors.

Supply was increasing in the North American supply basins in response to the price run-up that had occurred the previous fall and winter; that supply was coming on. Demand was decreasing across North America. Many industrial consumers decreased their consumption of natural gas because it had gotten too high-priced. That was accentuated in California's economy with the downturn in the technology sector. To use the "perfect storm" analogy again, it was almost a perfect storm of market events in the opposite direction that occurred in 2001, as occurred in 2000 in many factors.

Mr. OSE. I mean, it's almost pure Adam Smith response, invisible hand reaction.

Mr. AMIRAULT. The market was working.

Mr. OSE. Mr. Carpenter, I'm confused by something in your testimony. You say that the pipeline capacity in southern California, along with the SoCalGas storage withdrawn capacity, exceeds that of the peak southern California gas demand in January 2001.

I mean, am I correct on that?

Mr. CARPENTER. Yes. The system's capability substantially exceeds the peak demand that was experienced in January 2001. Again, conditional on the gas actually being in the storage inventory to be available to be withdrawn, this is the capacity if it had been full.

Mr. OSE. The aggregate capacity between interstate deliveries and storage?

Mr. CARPENTER. That's correct.

Mr. OSE. Now, on that day, interstate deliveries at the border may have been some amount, and draw and storage may have been a different amount. It's your testimony that the take-away capacity at the border was sufficient to handle whatever came in and that

the intrastate system was sufficient to handle whatever was drawn out of storage, if it had been there?

Mr. CARPENTER. Yes. That system was sized to handle roughly a 7-BCF-a-day peak, or 6.5-BCF-a-day peak. This is what figure 4 shows. And the peak on the SoCalGas system was about 5.2 BCF a day.

Mr. OSE. All right. Let me just take a moment here.

Mr. Amirault, there's something we've just been struggling to figure out, how this gets quantified, gas flows into a storage facility.

You guys hold it. A third party owns it. Then demand rises, and the retail purveyor draws that—I mean, that gas is drawn out for demand. There is a cost of moving it from the storage facility back into the distribution system for the end-user.

What is that added cost of transportation, and how is it factored in? That is a CPUC decision, I presume.

Mr. AMIRAULT. It is, and in PG&E's toll design, where we're situated, the effect is that storage customers pay the transportation toll on the way into storage, and they don't pay that transportation toll again to come out of storage. So the storage——

Mr. OSE. You pay to divert, but you don't pay to put back on, so to speak?

Mr. AMIRAULT. You pay that transmission toll once, even though you're dropping off partway between. You pay it on the way in; you don't pay it on—you don't pay it again on the way out. You effectively paid for the whole path on your injection leg.

Mr. OSE. And that's a tariff set by PUC?

Mr. AMIRAULT. Yes.

Mr. OSE. All right.

Mr. AMIRAULT. And that is a good design in my view, because it makes those storage transactions not differentiated by a toll from the city gate trading point. So they're adding to the liquidity at that city gate market trading point.

Mr. OSE. From your experience—well, you had to locate wherever you located because that is where the geologic structure was. But the manner in which PG&E handles its transmission into your facility relative to how transmission into a storage facility might be handled by SoCalGas, besides the geologic or the geographic difference that you have, do you have a preference or any insights you might offer us as to which is a better way of doing it?

In other words, is the "unbundled" manner in which PG&E handles it preferable to the manner which SoCalGas handles theirs; or is it vice versa?

Mr. AMIRAULT. You can't move the reservoirs. They are where they are, and this was the best reservoir we could find in California.

But the CPUC's storage decision of 1993 said that there wouldn't be duplicate tolling for storage. They encouraged the utilities to design their toll structure so that you wouldn't pay a duplicative toll. You wouldn't pay coming out what you already paid coming into storage. So even though SoCal's toll structure is different in that they haven't unbundled their transmission, presumably if somebody developed an independent storage facility on their system, somehow that same effect would be accomplished. You won't pay twice.

The advantage to the PG&E system, in my view, is the unbundling, the clear separation of transmission from the other bundled storage services provided by the utility and the distribution service provided by the utility. That is much more clearly separated in PG&E's structure than it is in SoCal's structure.

Mr. OSE. Ms. Friedmann, I hate to put you on the spot, but I'd be curious about what INGAA thinks. Is there a preference amongst your members for the manner in which capacity is nominated?

Ms. FRIEDMANN. I don't know.

Where did she go? I was just looking for our general counsel.

Mr. OSE. I mean, if you don't have a position, just tell me.

Ms. FRIEDMANN. I think you know, we have a process that we use on the interstate system. The way our process works, when we want to build new pipeline, what we do is we go out into the marketplace, and we ask—we have what we call an "open season."

Mr. OSE. Right.

Ms. FRIEDMANN. And what we're trying to do is ascertain whether there are customers out there to build—who would want this capacity, and once we find that we have enough of that, then we will go off and build whatever there is that we think we need.

Mr. OSE. Well, I mean, you're begging this question. I'm going to ask it. It would seem to me that some of these generating facilities that rely on natural gas——

Ms. FRIEDMANN. A great many.

Mr. OSE [continuing]. To fire their turbines, from a technological standpoint are far more efficient, say, than some of the existing infrastructure. In other words, new is better than old in terms of converting BTUs to electricity, and for the benefit of the consumer, that conversion ratio, the higher we can make that conversion ratio, the lower the price of the end-user.

The question you beg is, why wouldn't we set it up so that someone who is using huge amounts of natural gas as their base fuel to run a highly efficient technologically advanced generating facility relative to, say, some of the existing or older facilities, why wouldn't we make it possible for them to directly contract for interstate delivery?

Ms. FRIEDMANN. Now you're talking about California. We basically, elsewhere in the country, are doing that right now. We have numerous pipelines out there. A lot of this 30 TCF that I mentioned in my testimony is new electric generation throughout the country; and as you have seen, there are a number of instances where we have even had mergers of interstate pipelines with electric utilities, and part of that value is because the electric utilities then want to build along the interstate pipeline system these new highly efficient plants.

All of our member companies are out there right now seeking those kinds of customers and saying who is willing to, who is not; there are a lot of people out there right now looking at building electric plants. Not every one of those plants is going to be built. We want to find the people who are willing to sign those contracts, and we are eager to then build the capacity to help serve them; and we have worked for the last few years to acquire the flexibility in our system in order to accommodate that service.

Mr. OSE. Now, does the matrix under which you're operating, or the dynamic under which you're operating, account for the decline in deliveries to the end of the pipeline off of existing infrastructure if you locate that generating facility someplace outside California?

In other words, whatever the pipeline is, currently it's delivering X to California. If you put another straw in the pipeline, say, in Arizona, the pipeline still only has X capacity. I mean, does your matrix account for that——

Ms. FRIEDMANN. That basically is something that each pipeline looks at. But, for example, I know Kern River is now proposing to build a significant expansion into California.

One of the reasons they are doing that is because they are not able, I believe—and I want to be careful that I'm saying this as Gay Friedmann and not as Kern River—but they have had that circumstance where they have a number of electric generating facilities in Nevada, and, therefore without new capacity, they are not able to serve—fulfill all their capacity to California. Therefore, they are going to increase their capacity in order to meet new anticipated demand out there, as well as serve their customers between California and Wyoming.

Mr. OSE. Is the process working now, today, to expeditiously accomplish that goal? Is FERC working——

Ms. FRIEDMANN. FERC, I would say, is doing very well. I really commend the Commission. They have been working very hard to try to expedite the building of interstate transmission facilities. And we have a lot of applications; I have a number of them just here that are pending right now before FERC.

Mr. OSE. Would you like to enter those in the record?

Ms. FRIEDMANN. Sure.

Mr. OSE. OK. We'll do that.

Ms. FRIEDMANN. Sure. OK. Pardon my writing. We'll get you cleaner copies, but——

Mr. OSE. That's all right.

Ms. FRIEDMANN. Then you can show Mr. Shays that indeed there are a number of pipeline proposals up in the New England area.

[The information referred to follows:]

MAJOR PROJECTS PENDING

Company/Project	Capacity	Miles	Compression	Cost (Millions)	States	Docket	Filing Date(s)
ONSHORE							
Columbia Gas Transmission Corporation (Millennium Pipeline)	700.0	417.3	0	$683.6	NY	CP98-150	12/22/97 05/09/00
Iroquois Gas Transmission (Eastchester Extension)	230.0	32.8	54,300	$173.9	NY	CP00-232	04/28/00 12/15/00
Cross Bay Pipeline Company, L.L.C.	125.0	37.0	16,000	$59.5	NJ, NY	CP00-412	07/21/00
Maritimes & Northeast Pipeline, L.L.C. (Phase III Project)	360.0	25.0	0	$134.0	MA	CP01-4	10/10/00
Algonquin Gas Transmission Company (HubLine Project)	230.0	35.0	0	$159.0	MA	CP01-5	10/10/00
North Baja Pipeline, LLC	500.0	79.8	7,200	$146.0	AZ, CA	CP01-22	10/31/00 9/06/01
Colorado Interstate Gas Company	272.0	119.1	4,450	$72.1	CO	CP01-45	12/04/00
Petal Gas Storage LLC	700.0	59.0	9,000	$94.3	MS	CP01-69	01/23/01
ANR Pipeline Company	210.0	22.0	0	$19.5	WI	CP01-79	02/01/01
Tuscarora Gas Transmission Company	95.9	14.2	24,000	$57.8	CA, NV	CP01-153	04/12/01
Georgia Straits Crossing Pipeline, LP	94.0	47.0	10,302	$90.7	WA, CANADA	CP01-176	04/24/01

Pipe signal to build — customers willing to sign contracts

MAJOR PROJECTS PENDING

Company/Project	Capacity	Miles	Compression	Cost (Millions)	States	Docket	Filing Date(s)
Tennessee Gas Pipeline Company (Dracut Expansion)	200.0	12.0	0	$36.5	MA	CP01-360	05/07/01
Northwest Pipeline Corporation (Gray's Harbor Lateral Project)	161.5	48.9	4,700	$75.2	WA	CP01-361	05/11/01
East Tennessee Natural Gas Company (TVA Project)	86.0	26.5	9,525	$44.4	TN	CP01-375	05/25/01
Islander East Pipeline Company, L.L.C.	285.0	50.4	0	$149.6	NY, CT	CP01-384	06/15/01
Algonquin Gas Transmission Company (Islander East Project)	285.0	0.0	10,310	$32.3	MA	CP01-387	06/15/01
Transcontinental Gas Pipe Line Corporation (Momentum Expansion Project)	359.0	64.1	45,000	$197.0	AL, GA, MS, NC	CP01-388	06/18/01 09/25/01
Transcontinental Gas Pipe Line Corp. (Leidy East Project)	130.0	30.6	3,400	$98.1	PA, NJ	CP01-389	06/19/01
Kern River Gas Transmission Company (High Desert Lateral Project)	282.0	31.6	0	$29.0	CA	CP01-405	07/18/01
East Tennessee Natural Gas Company (Patriot Project)	510.0	210.3	35,820	$289.1	TN, VA, NC	CP01-415	07/26/01
Kern River Gas Transmission Company	885.6	716.7	163,700	$1,260.3	WY, UT, NV, CA	CP01-422	08/01/01

MAJOR PROJECTS PENDING

Company/Project	Capacity	Miles	Compression	Cost (Millions)	States	Docket	Filing Date(s)
Northwest Pipeline Corporation (Rockies Displacement Project)	175.0	91.1	24,924	$154.3	ID, WY	CP01-438	08/30/01
Southern Natural Gas Company South System Expansion Project	360.0	123.3	76,930	$245.5	AL, GA, LA, MS	CP02-1	10/01/01
Northwest Pipeline Corporation (Evergreen Expansion Project)	223.5	27.8	107,930	$239.8	WA	CP02-4	10/03/01
TOTAL ONSHORE	**7,459.5**	**2,321.4**	**607,491**	**$4,541.5**			

MAJOR PROJECTS PENDING

Company/Project	Capacity	Miles	Compression	Cost (Millions)	States	Docket	Filing Date(s)
OFFSHORE							
Calypso Pipeline, LLC (Calypso Pipeline Project)	832.0	41.8	0	$132.0	FL	CP01-409	07/20/01
TOTAL OFFSHORE	**832.0**	**41.8**	**0**	**$132.0**			

MAJOR PROJECTS PENDING

Company/Project	Capacity	Miles	Compression	Cost (Millions)	States	Docket	Filing Date(s)
TOTAL ONSHORE AND ONSHORE	8,291.5	2,363.2	607,491	$4,673.5			

CALIFORNIA PROJECTS PENDING

Company/Project	Capacity	Miles	Compression	Cost (Millions)	States	Docket	Filing Date(s)
North Baja Pipeline, LLC	500.0	79.8	7,200	$146.0	AZ, CA	CP01-22	10/31/00 9/06/01
Tuscarora Gas Transmission Company	95.9	14.2	24,000	$57.8	CA, NV	CP01-153	04/12/01
Kern River Gas Transmission Company (High Desert Lateral Project)	282.0	31.6	0	$29.0	CA	CP01-405	07/18/01
Kern River Gas Transmission Company	885.6	716.7	163,700	$1,260.3	WY, UT, NV, CA	CP01-422	08/01/01
TOTAL	**1,763.5**	**842.3**	**194,900**	**$1,493.1**			

Mr. OSE. All right. I want to finish on one particular question, very similar to what I asked the last panel; and we'll just go right across the panel.

Notwithstanding the differences to the capacity issues and all that, Congress has a charge. Obviously we want gas delivered where there's demand. We want the people who deliver the gas to be able to survive. We want the end-users to have the product they need.

What, if anything, should Congress be doing to address the issue of infrastructure, whether it be pipelines or storage, to meet the demand for natural gas in this country?

Mr. Carpenter.

Mr. CARPENTER. Yes. I think the watchword I would suggest is market monitoring, and the reason I say that is because we have a regulatory regime in place at the Federal level that relies to a great extent on competition between the holders of pipeline capacity to ensure that it's efficiently utilized and to send the price signals to the market for when pipeline capacity should be expanded.

That regulatory regime, to be effective, has to have in place a mechanism whereby it can monitor for the potential presence and exercise of market power. It didn't need to do that under the old regulatory regimes, cost-of-service-based regimes. You do need to do it now in natural gas markets.

I think Commissioner Wood—and I commend him for his approach with respect to the strategic plan that he's put forward that emphasizes market monitoring, and I think the situation in California perhaps, we hope it's unique, that it will never happen again, but I think it was a classic case where the prior regulators didn't see the signals that were in the market. As far back as when Dynegy held that block of capacity on the El Paso system, and the regulator was apprised of the fact that there was a market power problem that could potentially create the situation that occurred.

So the watchword, from my point of view, would be market monitoring, and the kinds of hearings that you're having here which emphasize that, I think are important.

Mr. OSE. Before we go to Professor Kalt I want to followup on one thing, would you support or oppose—let me phrase it the other way. As it relates to the different State's PUCs, in terms of the tools to be given to utilities to address their power needs, do you support or oppose giving utilities the ability to forward contract at their own economic risk?

Mr. CARPENTER. Oh, I support it wholeheartedly. I think that's a very important tool to have in place. But it has to be watched. If the utility is in a position where it could—it has an information advantage or some advantage that another market player doesn't have, that could create a potential for market manipulation.

Mr. OSE. Which gets to that monitoring issue.

Mr. CARPENTER. Exactly. Exactly.

Mr. OSE. What percentage of an overall utility's power production portfolio do you think should be dependent upon the spot market? Or I could do it the other way. What percentage do you think should be dependent upon either in-house production or forward contracting?

Mr. CARPENTER. That is a difficult question to answer in the generic sense, because I think it depends on the kind of generating equipment they have, how much they're relying on their own generation versus buying from merchant generators. In other words, how exposed are they to the fuel price risk that your question implies some need to mitigate, so——

Mr. OSE. Why don't we give you that question in writing and you can respond accordingly.

Mr. CARPENTER. And we may have to refer to some specific circumstances to be more precise about that. We can at least talk about how you would analyze that question.

Mr. OSE. The reason I ask it is, in California, the direction given to the utilities was they wanted to increase their reliance on the spot market while at the same time removing their ability to forward contract to cover their exposure. So, I mean, it's something very near and dear to my interest.

Mr. CARPENTER. Yes.

Mr. OSE. Professor Kalt, same question. What should Congress be doing?

Mr. KALT. Let me address that from the Congress's perspective.

I think—first, I'm sort of surprised in this hearing. Actually, you hear a fairly unanimous view that FERC is on the right course, and I agree with that. I think that hearings like this are important. As Dr. Moore said, these kinds of oversight hearings allow for an airing of the issues; but just as importantly, they give muscle to the policy and send signals throughout the system as to the interest of Congress.

Third, I would echo something that Dr. Moore said in the first panel. And that is, in terms of infrastructure investment, it remains the case that the NIMBY problem, not in my backyard, continues to sit there and cause delays, expense, risk, all of those things discourage investment.

That is not to say in any way, shape or form we should put the environment at risk. But we continue to need to work on it in this country. And it occurs at the State level, it occurs at the local level, and it occurs at the national level. We have to try to find mechanisms that streamline these processes, that stabilize the rules of the game, that cut down on the litigation expense and that cut the risk, while at the same time protecting the environment and the other legitimate interests.

But that remains a huge problem out there, and it discourages investment in infrastructure.

Mr. OSE. I asked Mr. Carpenter this same question. In terms of the forward contracting tool for utilities, do you support different State's PUCs giving that to utilities?

Mr. KALT. Actually, I've written quite a bit on that and published a fair amount on that issue, and I think it's absolutely essential to an efficient natural gas system and ultimately the feeding of the gas to industrial users, the residential users and the power plants.

Mr. OSE. Your analyses, have they included a discussion as to what percentage of a production portfolio should be exposed to the spot market?

Mr. KALT. Not in quite that way, and it's—let me give you a slightly different perspective. That's why Paul here has difficulty answering it in the generic.

The way I look at that question is slightly differently. I've been a proponent of so-called incentive-based regulation which says, give the utility the flexibility to adjust to—if it sees softness in the spot market, go buy spot gas. If it thinks it's going to face a future where it needs to lock in prices, go get lock-term contracts or use other derivatives.

But by using incentive-based regulation rather than a strict sort of rules like 23 percent of your portfolio should be spot, I think therein lies a better way to go about this question because, after all, you're trying to get people to adjust to the changes in their systems, the changes in the forecasts and so forth, and you've got to leave that flexibility within the system.

Mr. OSE. So you give them a range, basically?

Mr. KALT. Or a range, or a range based on their performance, the rates of return and so forth.

Mr. OSE. Mr. Amirault, same question. What should Congress be doing?

Mr. AMIRAULT. I agree with the other panelists——

Mr. OSE. Of all the panelists, I have to tell you, these guys are a lot smarter than me, and Gay knows a lot more of the people, but you and I are business people, so, you know, you have a unique perspective here.

Mr. AMIRAULT. Thank you. The coordination of the issue is essential, and that is, hearings like this help with that, so that is important. It's not just an in-State problem; it's not just a problem coming up to the State borders. There's a regional supply/demand challenge here that has to be managed and coordinated.

It's not good enough to simply look at the balance of pipeline capacity coming to the State's borders and coming away from the State border and see if that matched. That doesn't tell you if the situation is in hand or not. We have to look at the supply/demand balance across the region, because even if there is capacity coming to the border and the ability to take it away, just like depending on what customers do, there might not be gas in storage to meet peak demands.

If customers didn't fill it, there might not be gas in the pipelines to serve the California market if they've decided to deliver that gas to a different market upstream. You've got to assess the whole balance, and that coordination is something that hearings like this can really help assist with.

I'd also encourage, where you can, the State to complete the unbundling task. To the extent that they can push the SoCal system to look a little bit more like PG&E's. PG&E's isn't completely unbundled either, but it goes a lot further than SoCal's. If PG&E's gas transmission system comes under Federal jurisdiction, as proposed in their bankruptcy solution, then I would encourage FERC, and to the extent you can influence that, not to mess up what they've done. Just complete the job.

Finally, I would encourage the development of incentives to promote efficiency on the interstate pipeline system. Efficiencies in their design and in their utilization.

Mr. OSE. Could you be a little more specific on those efficiencies?

Mr. AMIRAULT. As I've discussed in my testimony, if a pipeline can be designed to move the average day load from the supply basin to a market area storage and then the peak day from storage on to the end-use customer, that's a lot less costly than moving the peak day supply all the way from the supply basin.

Mr. OSE. Your point being that then you only have to capitalize the big pipe from the storage back into the distribution rather than from the source to the storage.

Mr. AMIRAULT. Exactly.

Mr. OSE. OK.

Ms. Friedmann.

Ms. FRIEDMANN. Well, first of all, I want to commend Congress, at least the House, for passing H.R. 4, because I think the first thing we need is, we need to continue to make sure we have a supply of natural gas, and that was one of the problems that faced the entire country last winter.

Second, I do want to say then on the NIMBY problem, we can use the support of Congress individually—not as a body, but as individual Members—when interstate pipelines are applying to FERC, to support it. When you think that there is a market out there and you know that there's a market out there for us to help respond to some of the, "Hell, no, we don't want to build in our backyard" types of people.

And I also would encourage, particularly the Californians, to look at encouraging the State to be more receptive to opening up their system and to permitting more interstate pipelines into California. I think you'll end up with a healthier economy.

Mr. OSE. OK. We're going to go ahead and wrap up here. I want to advise everybody we're going to leave the record open for 10 days, during which time we hope to communicate such questions that we'll have to each of you in writing, such as the two that I asked the two of you in particular. The other Members of Congress will be able to submit some more questions, and they will be forwarded to the appropriate parties.

I want to thank you all for coming, as well as the first panel. This is, to me, something that is very long-range, because as you look out over the coming 20 or 30 or 50 years, in California you see us going toward the fuel that has been very gentle, on a relative basis, to the environment. And I suspect that the rest of the country is going to have to go that way.

Accordingly, the way we deal with that is we put in place now the policies that allow us to create the solutions 10, 15, 20 years hence. And to the extent that you've participated today to help us learn what we need to do, you have Congress's appreciation, as well as the country's.

This is not an easy task. There are lots of competing interests. There are clearly differences of opinion on some things. But the education that you impart to us will help us with our policy decisions, and we thank you for that.

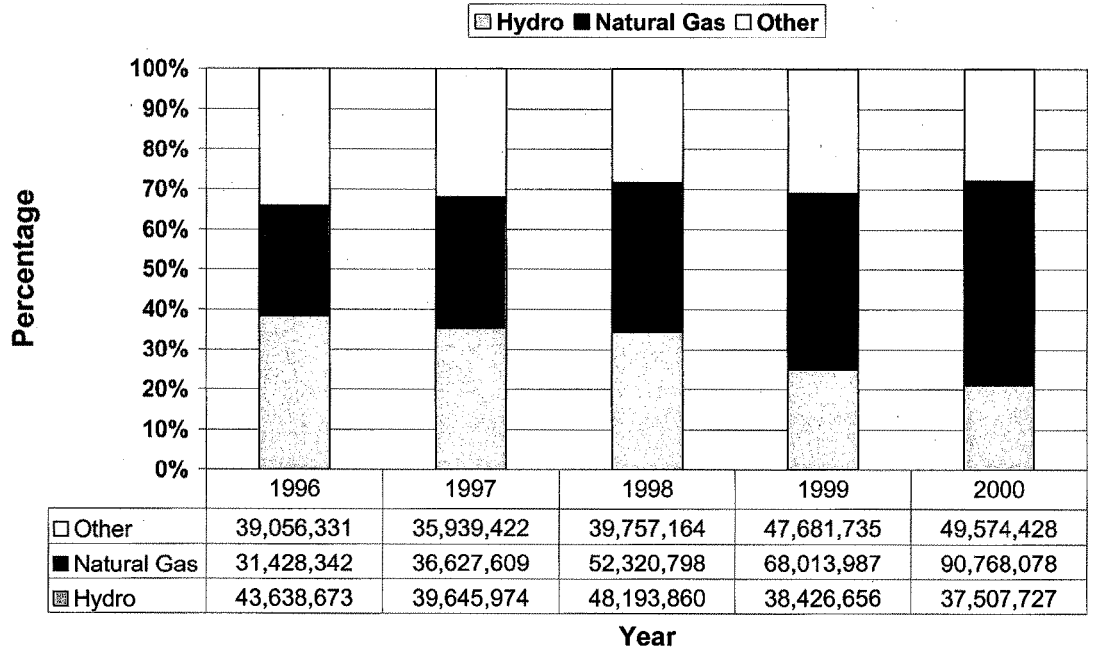
We are adjourned.

[Whereupon, at 3:26 p.m., the subcommittee was adjourned.]

[Additional information submitted for the hearing record follows:]

California Net Generation for 1996 - 2000

Percentage of Generation Provided by Hydro, Natural Gas & Other Fuels



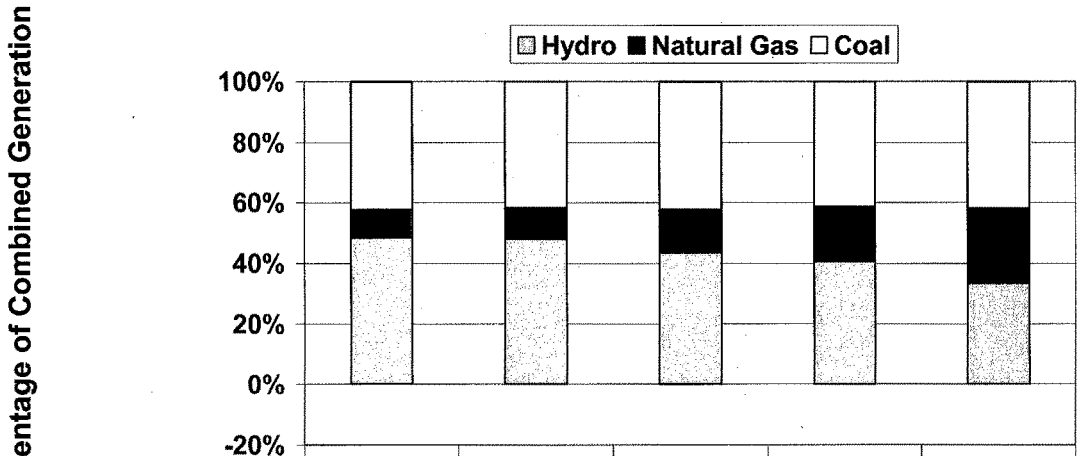
	1996	1997	1998	1999	2000
Other	39,056,331	35,939,422	39,757,164	47,681,735	49,574,428
Natural Gas	31,428,342	36,627,609	52,320,798	68,013,987	90,768,078
Hydro	43,638,673	39,645,974	48,193,860	38,426,656	37,507,727

SOURCE: Resource Data International, Inc.
POWERdat, Data Version P3.1, Data Set July 01
RDI Modeled Production Cost–Ownership Based

U.S. West (WSCC)

Interrelationship of Hydro, Natural Gas & Coal

As Percentages of Their Combined Generation



Year	1996	1997	1998	1999	2000
NW Precip % of Avg	35%	9%	22%	1%	-16%
W Precip % of Avg	33%	-10%	56%	-26%	-6%
Coal	197	204	220	224	234
Natural Gas	43	50	74	98	138
Hydro	226	234	227	220	186

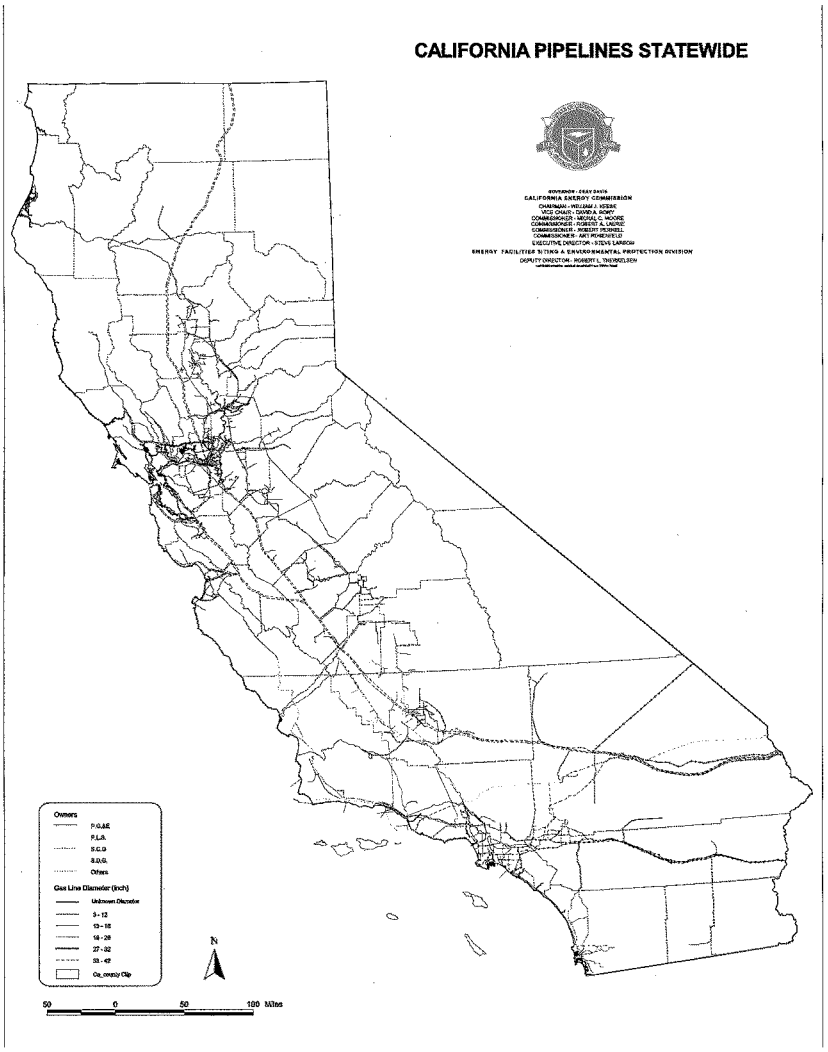
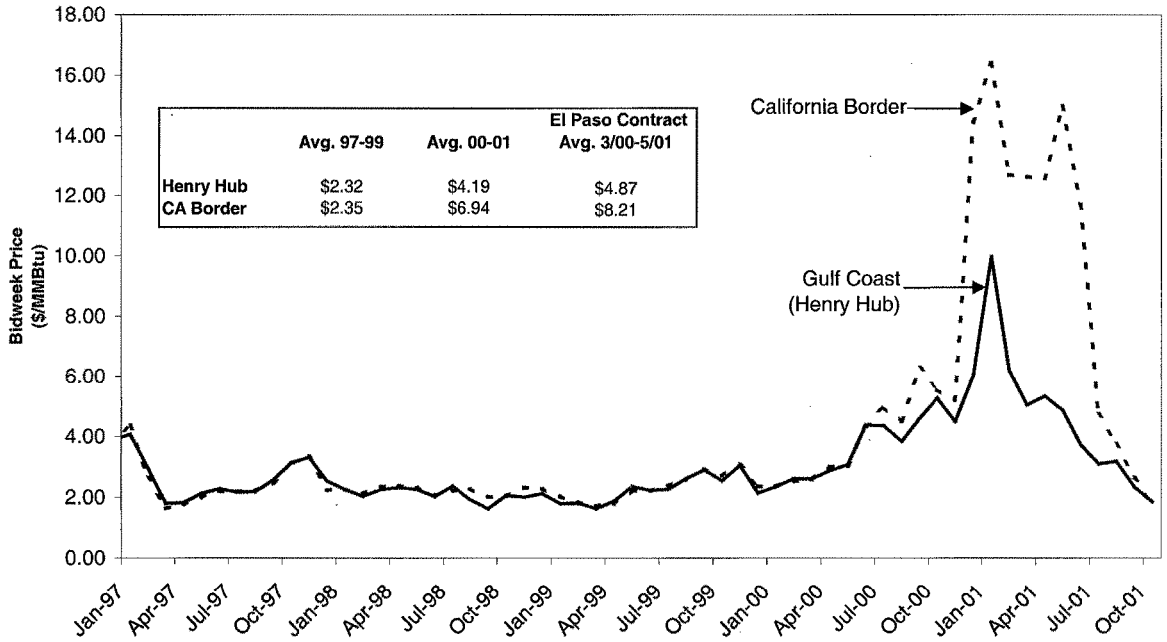

CALIFORNIA PIPELINES STATEWIDE
GOVERNOR - GRAY DAVIS
CALIFORNIA ENERGY COMMISSION
CHAIRMAN - WILLIAM J. KEESE
VICE CHAIR - SANDRA BOHY
COMMISSIONER - MICHAEL C. MOORE
COMMISSIONER - JAMES D. BOYD
COMMISSIONER - ROBERT PERNOSKE
COMMISSIONER - ART ROSENFELD
EXECUTIVE DIRECTOR - STEVE LARSON
ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION
DEPUTY DIRECTOR - ROBERT L. THERKELSEN
Owners
P.G.&E.
P.L.S.
S.C.G
S.D.G.
Others
Gas Line Diameter (inch)
Unknown Diameter
9 - 12
13 - 18
19 - 26
27 - 32
33 - 42
Ca_county Clip
N
50
0
50
100 Miles

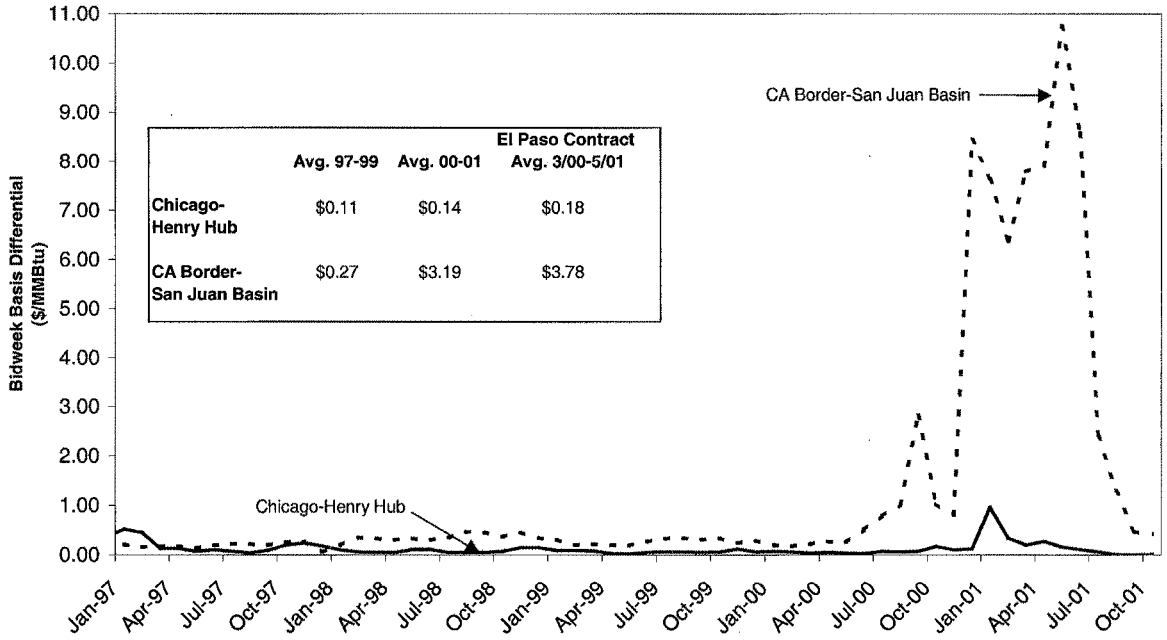
Figure 1
California Experienced Unprecedented Natural Gas Prices During Term of El Paso Contract



	Avg. 97-99	Avg. 00-01	El Paso Contract Avg. 3/00-5/01
Henry Hub	$2.32	$4.19	$4.87
CA Border	$2.35	$6.94	$8.21

Source: *Gas Daily*

Figure 2
Implied Value of Transportation Capacity to California Increased Dramatically During Term of El Paso Contract

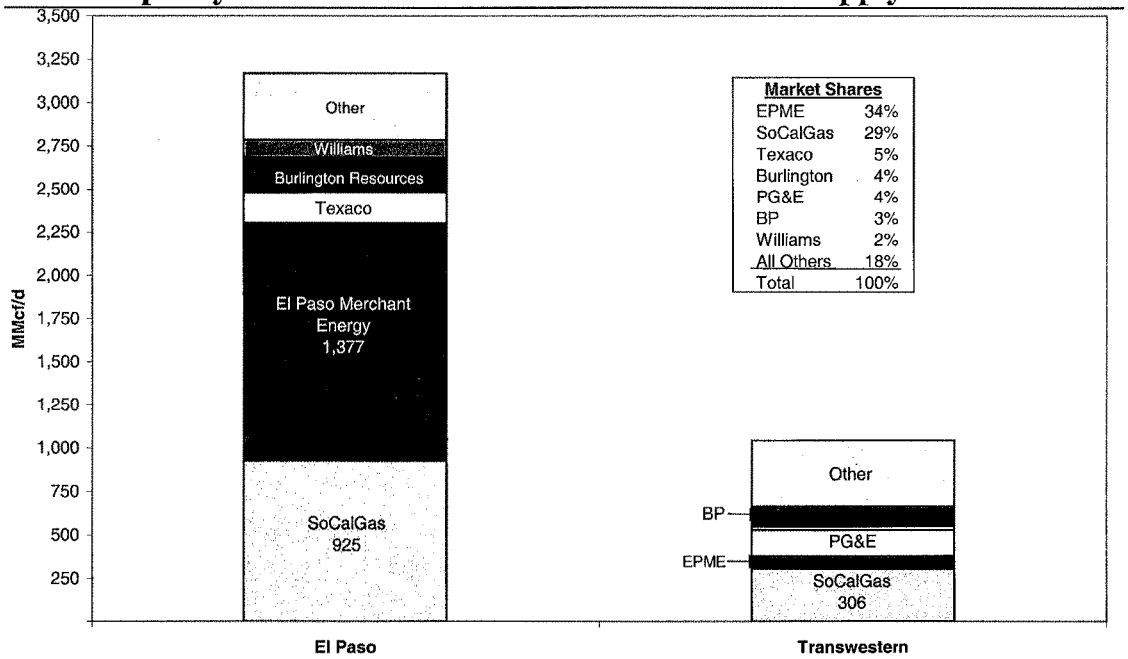


	Avg. 97-99	Avg. 00-01	El Paso Contract Avg. 3/00-5/01
Chicago-Henry Hub	$0.11	$0.14	$0.18
CA Border-San Juan Basin	$0.27	$3.19	$3.78

Source: *Gas Daily*

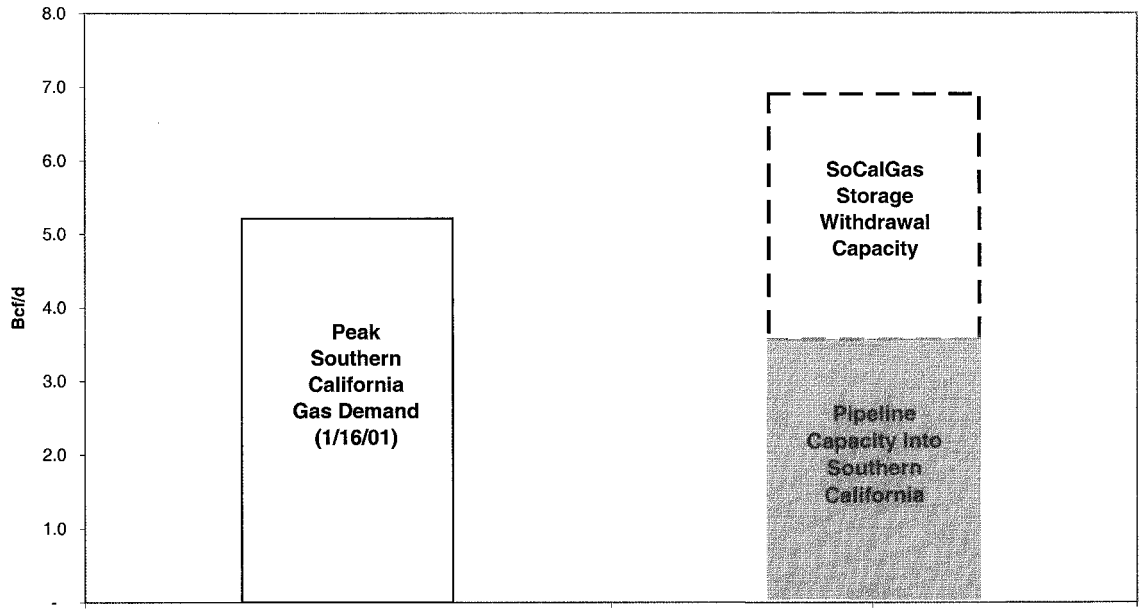
Figure 3

Firm Capacity Holders to California from Southwest Supply Basins



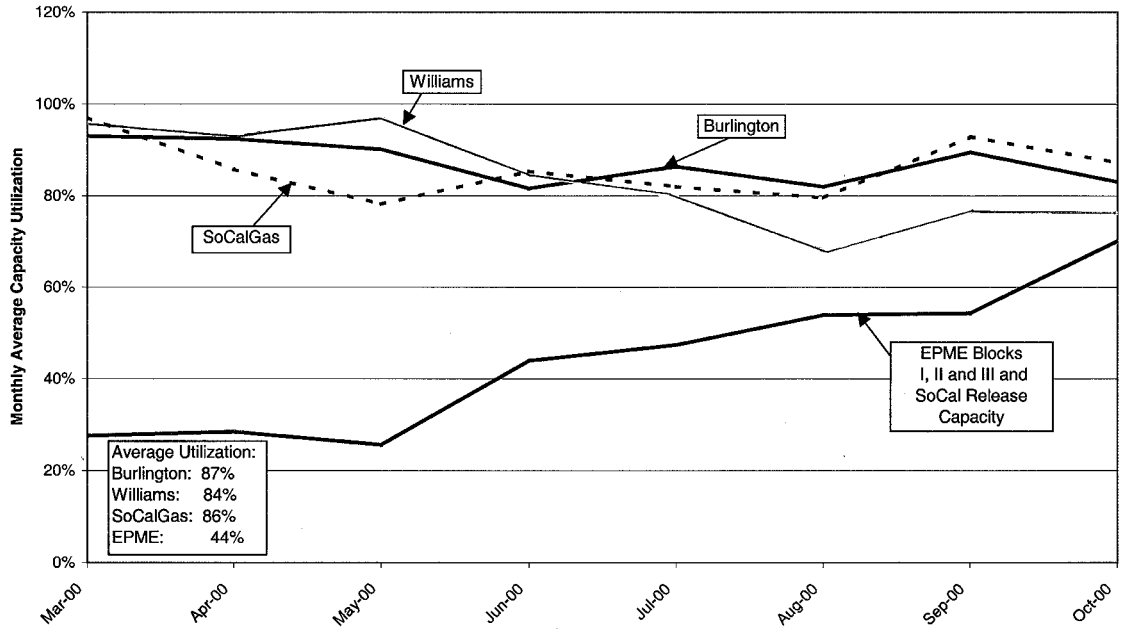
Source: Table II-1 from SCE-4, which relied on El Paso and Transwestern January, 2001 Index of Customers Reports.
Note: El Paso capacity holdings adjusted for long-term releases from SoCalGas to El Paso Energy Marketing Company (EPME), Duke Energy Trading and Marketing, and ONEOK.

Figure 4
Use of Storage Is Critical to Meet Peak Demand for Gas in Southern California



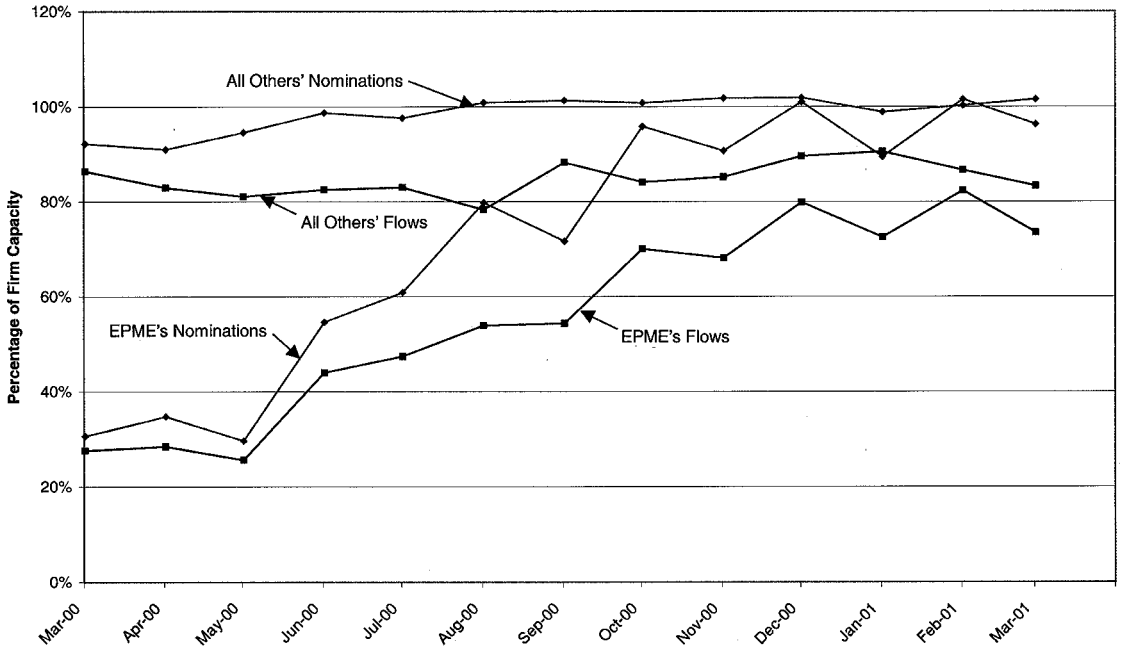
Note: Peak Southern California Gas Demand is SoCalGas' highest daily sendout over the period January 1997 to the present.

Figure 5
EPME's Utilization of Its Capacity to California Was Significantly Less Than That of Other EPNG Shippers



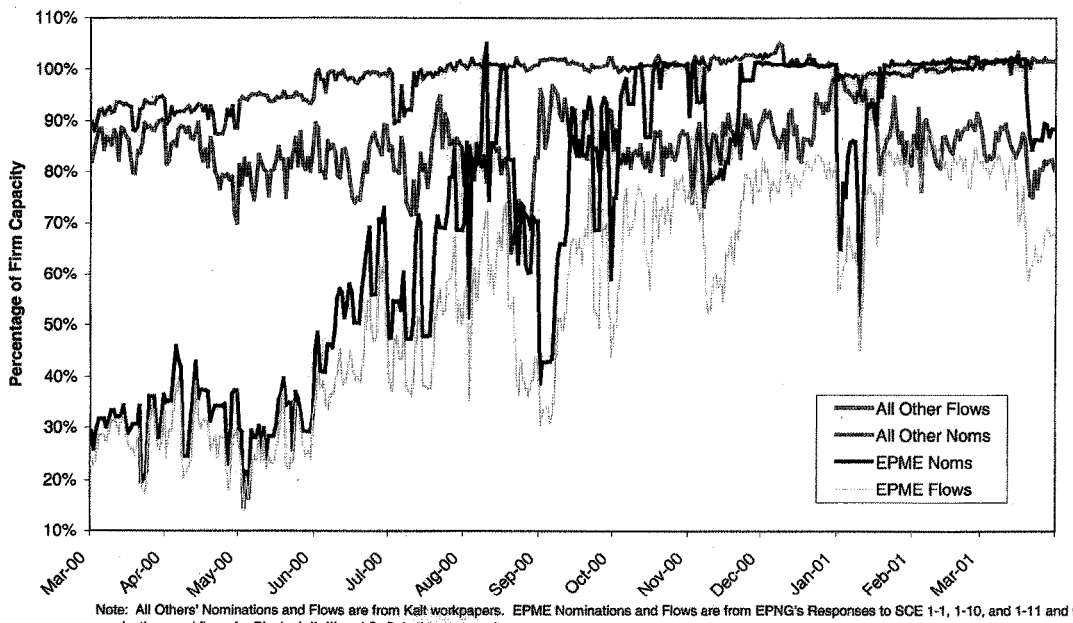
Note: Derived from Figures III-41 and V-25 in SCE-4.
Source: EPNG's Response to SCE 1-1.

Figure 6
EPME Nominations and Flows Were Significantly Less Than Those of Other Shippers



Note: All Others' Nominations and Flows are monthly averages from Kalt workpapers. EPME Nominations and Flows are monthly averages of data in EPNG's Responses to SCE 1-1, 1-10, and 1-11 and include nominations and flows for Blocks I, II, III and SoCal release capacity.

Figure 7
EPME Nominations and Flows Were Significantly Less Than Those of Other Shippers



Note: All Others' Nominations and Flows are from Kalt workpapers. EPME Nominations and Flows are from EPNG's Responses to SCE 1-1, 1-10, and 1-11 and include nominations and flows for Blocks I, II, III and SoCal release capacity.

Table 1
Overcharges to California Gas and Electricity Customers from March 2000 through May 2001

Overcharges to California Gas Customers
(Billions)

	March 2000 through March 2001	April 2001 through May 2001	Total
Southern California (SoCalGas)	$2.2 - $2.3	$0.9	$3.1 - $3.2
Northern California (PG&E)	$1.4 - $1.5	$0.4	$1.8 - $1.9
	$3.6 - $3.8	$1.3	$4.9 - $5.1

Overcharges to Electricity Customers Due to Excessive Gas Prices
(Billions)

	March 2000 through March 2001
Southern California (Edison)	$1.0 - $1.1

Source: March 2000 - March 2001 overpayments taken from SCE-4, Tables VI-1 and VII-1.

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INDEPENDENT

October 30, 2001

The Honorable Patrick Wood III
Chairman
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dear Chairman Wood:

I am writing to follow up on October 16, 2001 hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas. Thank you again for your testimony at that hearing. As discussed at the hearing, I request that you respond to a series of follow-up questions, which are attached to this letter.

Please provide the requested information to the majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building not later than November 13, 2001. If you have any questions about this request, please call Professional Staff member Connie Lausten at (202) 226-2067. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

Attachment

cc: The Honorable Dan Burton
The Honorable John Tierney

Questions for FERC Chairman Wood

Q1. Witnesses testified that, since California is downstream of the interstate natural gas pipelines, natural gas pipeline capacity holders do not always have natural gas available for California customers.

a. Does the Federal Energy Regulatory Commission (FERC) presently require pipeline applicants to examine the load factor of their shippers?

b. Does FERC require pipeline applicants to describe in their applications how their pipeline design responds to load factor considerations?

c. How does FERC determine whether a pipeline design is adequate to meet shippers' load requirements?

d. During FERC's approval of natural gas electricity generation projects, does its analysis include assessing the capabilities of the natural gas pipeline serving the power plant to deliver natural gas for its upstream and downstream client demands as well?

Q2. Is an interstate natural gas pipeline, that sells firm transmission service to a customer that it cannot later provide, subject to any penalties at FERC or elsewhere? If so, what are they?

Q3. Are California natural gas shippers able to use all of the interstate pipeline capacity for which they have contracted and paid?

Q4. How can FERC ensure that electric generation customers, or any other non-core California natural gas customers, can get firm interstate pipeline transportation upstream of their local distribution companies?

Q5. For natural-gas-based electricity generators operating in the interstate market, has FERC determined an appropriate level of exposure to the spot market for fuel and, if so, please provide this information?

Q6. What is the ideal natural gas contract mix for an industrial gas user or electricity generator?

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

November 20, 2001

The Honorable Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs
Committee on Government Reform
U.S. House of Representatives
Washington, D.C. 20515

Re: Responses to Follow-up Questions on October 16, 2001 Natural Gas Hearing

Dear Chairman Ose:

Thank you for your letter of October 30, 2001, forwarding several questions related to the Subcommittee's hearing on October 16, 2001. Below are my responses to those questions.

Q1. Witnesses testified that, since California is downstream of the interstate natural gas pipelines, natural gas pipeline capacity holders do not always have natural gas available for California customers.

a. Does the Federal Energy Regulatory Commission (FERC) presently require pipeline applicants to examine the load factors of their shippers?

Shippers' load factors should not, in and of themselves, affect whether customers receive contracted-for natural gas. As stated in answer 1(b) below, FERC requires that a pipeline be capable of providing service to satisfy firm contracts, and that means that a pipeline should be able to provide 100 percent of its contracted-for firm service whenever called upon. Many pipelines run at very high overall load factors, with no loss of service to customers.

That said, the FERC does not require pipeline applicants in certificate proceedings to conduct an examination of their shippers' load factors. For greenfield (brand new) pipelines, the applicants typically measure the amount of interest in the expansion or greenfield project by conducting an open season in which bids from potential shippers are received. At that time, shippers may not

know what their load factors will be. In evaluating whether a pipeline's proposed expansion project is needed or correctly sized, or whether a new, or greenfield, project is needed, the Commission largely relies on market forces and conditions. The Commission recently enunciated its policy on assessing certificate applications in Docket Nos. PL99-03-000 and PL99-03-001.[1] Under the Policy Statement, the starting point for the Commission's assessment is to ensure each project is designed to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas. Our threshold requirement is that pipeline expansions should not be subsidized by existing customers. The absence of subsidization is the prerequisite for a determination of market need and approval of each proposed project. The Commission believes that this process provides the appropriate incentives for the optimal level of construction and leads to efficient customer choices. Commission policy also encourages another critical step with regard to the appropriate sizing of pipeline projects. This step occurs prior to the certificate application. The Commission's current policy encourages all pipeline applicants to conduct an open season in which existing customers are given an opportunity to permanently relinquish their capacity.[2] This step ensures that a pipeline will not expand capacity if the demand for capacity can be filled by existing shippers relinquishing their capacity. The Commission's approach strives to advance development of a sustainable energy infrastructure that supports economic growth, environmental protection and other social benefits over the life of the projects.

b. Does FERC require pipeline applicants to describe in their applications how their pipeline design responds to load factor considerations?

Section 157.14(a)(7) requires that an applicant for a pipeline certificate provide flow diagrams showing the daily design capacity and reflecting operation of its pipeline system with and without the proposed facilities. Further, Section 157.14(a)(9)(i) requires that an applicant provide all assumptions, bases, formulae, and methods used in the development and preparation of the flow

---

[1]Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61,227 (1999), order clarifying statement of policy, 90 FERC ¶ 61,128 (2000) (Policy Statement).

[2]Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines, 71 FERC ¶ 61,241, at 61,917 (1995), reh'g denied, 75 FERC ¶ 61,105 (1996).

diagrams and accompanying data. As a practical matter, the pipeline must be designed so it meets 100% of its firm contractual commitments, i.e., a 100% load factor.

c. How does FERC determine whether a pipeline design is adequate to meet shippers' load requirements?

FERC staff reviews and analyzes the flow diagrams and assumptions provided by the applicant in its application along with any pipeline flow simulation computer models submitted by the applicant either with the application or provided in response to staff data requests. In addition, FERC staff will construct its own computer models based upon information provided by the pipeline company. Through its analysis, FERC confirms whether the applicant's design will meet 100% of its firm contractual commitments.

d. During FERC's approval of natural gas electricity generation projects, does its analysis include assessing the capability of the natural gas pipeline serving the power plant to deliver natural gas for its upstream and downstream client demands as well?

The Commission does not have the authority to approve the siting or construction of electric generation projects. Under the Federal Power Act, the Commission's jurisdiction generally is limited to establishing just and reasonable rates, terms and conditions of service pertaining to the sale of electric energy for resale in interstate commerce and the transmission of electric energy in interstate commerce.

If the question refers to Commission authorization of an interstate natural gas pipeline's service to electric generators, the matter could be raised in a number of different ways. For example, a pipeline with existing firm capacity can begin providing transportation service to any customer that requests it, including an electric generator, without Commission pre-approval. However, if the pipeline seeks to provide a service that is different from its standard tariff-based services, it must file the non-conforming agreement with the Commission, a filing that is subject to protest and Commission review. If that service affects other customers' services, they may file a complaint with the Commission. If the Commission received such complaints, or its monitoring activities showed that a certain type of service was degrading other customers' services, the Commission could undertake action either individually or in a rulemaking proceeding to rectify any problems.

If an interstate natural gas pipeline needs to construct or expand its firm transportation capacity to serve an electric generator, such a project should likewise not affect other firm customers of the pipeline. The construction project will provide incremental capacity to serve the generator, but will not reduce or limit the amount of firm capacity reserved by upstream or downstream pipeline customers on the interstate pipeline. The pipeline will still be able to transport gas on its facilities up to the firm contract level of existing shippers.

Q2. Is an interstate natural gas pipeline, that sells firm transmission service to a customer that it cannot later provide, subject to any penalties at FERC or elsewhere? If so, what are they?

A2. The Commission has various means of addressing such circumstances, including penalty authority in certain cases. Under Commission regulations, an interstate pipeline with available firm transportation service must sell that service to shippers. The sale of firm service means that, under planned operating conditions, the pipeline can ensure the transportation of natural gas from the receipt point(s) to the delivery point(s) in the shipper's contract. Holding firm transportation on an interstate pipeline only ensures a shipper that it can transport natural gas on the interstate pipeline's facilities between the receipt and delivery point(s) in its contract; it does not guarantee that a shipper can receive gas from an upstream pipeline or gas supply source or have that gas delivered to a downstream LDC or pipeline. Whether gas can be received from an upstream pipeline or supply source or delivered to a downstream LDC or pipeline may depend upon the shipper's contractual rights on the upstream pipeline or supply source and the downstream LDC or pipeline. For example, a shipper with firm capacity on a pipeline may not be able to deliver gas if it does not have firm capacity on the downstream LDC or interconnecting pipeline and the downstream LDC or pipeline is unable to accept the shipper's gas.

If force majeure or unexpected operational reasons (such as unexpected maintenance) prevent a pipeline from meeting its commitment to transport gas from the receipt point(s) to the delivery point(s) in a shipper's contract, the pipeline's tariff generally provides for a credit to the shipper of the rates paid for firm service during the period of service interruption.

If, however, the pipeline has contracted to provide firm service that it is regularly unable to deliver, the Commission has the authority under the Natural Gas Act to remedy the situation. The type of remedy will depend on the factual circumstances of the violation, and can include requiring the pipeline to increase its capacity to its certificated level of service as well as monetary awards to

compensate for extra costs incurred as a result of the failure to deliver service or to prevent unjust enrichment. In addition, in some cases, the Commission could have penalty authority under the Natural Gas Policy Act and, in cases of willful and knowing violations, the Commission can seek penalties in District Court under the Natural Gas Act.

Q3. Are California natural gas shippers able to use all of the interstate pipeline capacity for which they have contracted and paid?

A3. Yes, subject to two conditions: (1) the shipper must have a firm contract and primary rights at its nominated receipt or delivery points; and (2) adequate take-away capacity must be available within California, as discussed in the answer to Q2.

In general, shippers are entitled to use their full contract quantity under a firm transportation service as long as they nominate shipment between their primary receipt and delivery points. Nominations at alternate receipt or delivery points are subject to available capacity at those points.

In the case of El Paso Natural Gas Company (El Paso), however, there are ongoing disputes regarding mainline capacity availability and receipt point rights. In Docket No. RP99-507, the Commission implemented a one-time allocation of firm delivery point rights among existing shippers on the El Paso system to address complaints by shippers that they could not schedule all of the capacity under their contracts to desired delivery points on the El Paso system (primarily the SoCal Topock delivery point). The Commission is currently evaluating El Paso's mainline capacity allocation procedures in Docket No. RP00-366, particularly with regard to how El Paso intends to handle allocation of mainline capacity between its full requirements customers east of California and its other mainline customers. Shippers' receipt point rights on the El Paso system are also being evaluated in that docket. Further, in Texas, New Mexico and Arizona Shippers, v. El Paso Natural Gas Company (Docket No. RP01-486-000), the complainants allege that El Paso has over-sold its mainline capacity.

While shippers are entitled to full use of interstate firm capacity, subject to the above described alternate point availability, actual gas flows depend on confirmation that gas delivered by the interstate pipeline will be accepted and delivered by the downstream LDC system (except for those end users served directly by the interstate pipeline). To the extent there is insufficient take-away capacity on the downstream LDC system, shippers may not be able to use their full

interstate capacity. In its October 2001 report, the California Energy Commission on Natural Gas Infrastructure Issues stated:

> Gas utilities' intrastate pipelines, especially in Southern California, were running at nearly full capacity at times during 2000-2001. This created bottlenecks in delivering supplies from interstate pipelines to gas consumers, including electric generators, in 2000 and early 2001.

Q4. How can FERC ensure that electric generation customers, or any other non-core California natural gas customers, get firm interstate pipeline transportation upstream of their local distribution companies?

A4. FERC actively regulates the process by which capacity is allocated on existing pipelines, through open-access tariff requirements, and on proposed pipeline projects, through open-season procedures. Any interested shipper, including electric generation customers, can bid on available pipeline capacity as it becomes available under tariff administration rules controlled by part 284 of the Commission's regulations. FERC certification policy for new pipeline projects requires that proponents of such projects allow potential shippers to contract for new capacity on a nondiscriminatory basis. Firm service by definition can be sold by the pipeline only if it has firm capacity. To ensure firm transportation to California, any shipper may initially designate points at or within California (depending on the physical location of the individual pipeline system) as their primary delivery points.

However, firm interstate capacity may not be economically or practically feasible for a natural gas user that cannot get corresponding intrastate firm capacity, at a reasonable price. Generally, intrastate pipeline (including LDCs) rates and services are regulated by the states.

Q5. For natural-gas-based electricity generators operating in the interstate market, has FERC determined an appropriate level of exposure to the spot market for fuel and, if so, please provide this information.

A5. No. Generators must make such determinations in the first instance based on their evaluation of the needs of their business and market risk. As an example, some peaking generators may place more reliance on the spot market than baseload generators, since the peaking generator runs only infrequently. Generators that do rely on the spot market can minimize risk through different

techniques, such as maintaining a portfolio of gas and capacity contracts, and using financial instruments, as well as contracts for physical delivery of natural gas–a strategy commonly known as "hedging." Each company must determine the most economic strategy by evaluating its own business requirements and the relative costs and benefits of various options.

It also should be noted that while the question asks about natural-gas generators buying gas "on the spot market," the "spot market" for natural gas can have a variety of meanings. The spot market generally refers to buying gas based on daily gas prices. But spot markets exist at both upstream gas production areas and downstream delivery markets. For example, shippers with firm pipeline contracts may buy natural gas at receipt points or at receipt hubs, such as the Henry Hub. Shippers without pipeline firm capacity may buy gas at the spot market at a delivery point. Spot gas prices often differ substantially between supply area hubs and market area hubs, particularly when, due to weather, there is increased demand at the delivery hub. In addition, there are a number of different scenarios that may apply to spot market purchases. For example, a generator may buy physical deliveries of natural gas on a daily basis at a delivery point. But that scenario is very different from a generator that holds long-term firm interstate pipeline capacity, and holds a long-term supply contract with an individual producer under which the generator pays an average of 5 major market hubs for that gas on any given day. All of these generators could be considered to be buying "on the spot market" but their risk profiles could vary enormously. Finally, while buying on the spot market might seem risky when prices are high, entering into a long-term contract during a time of higher than normal prices might also be a risky proposition over the life of the contract.

Q6. What is the ideal natural gas contract mix for an industrial gas user or electricity generator?

As discussed in the answer to Question 5, there is no ideal contractual portfolio applicable to any category of business. The contract portfolio selected by any company will reflect the needs of its business, an evaluation of the transportation market (including the company's perception of whether non-firm transportation service will be available, or whether it should purchase firm transportation or storage services), the supply market (i.e., how natural gas prices are likely to change over the near, mid and long-term horizon) and its tolerance for risk. For example, industrial customers that use a relatively constant amount of natural gas throughout the year may opt for holding a large portfolio of firm contracts–both for transportation and commodity, or through so-called "bundled" contracts–guaranteeing delivery at a delivery point at a certain price, and

combining the commodity with the transportation. An industrial customer with uneven demand or a peaking generator, however, may find that contracting for firm transportation service is too expensive and risky since it may not be using that service for much of the year. Finally, in addition to contracts for physical deliveries of natural gas (i.e., the commodity and the transportation components), there are a variety of ways that gas users can protect themselves from price volatility through financial instruments. No particular purchasing strategy is necessarily lower-cost or less risky than another.

Thank you for the opportunity to share my thoughts and ideas on these issues. If I may be of further assistance, please let me know.

Best regards,

Pat Wood, III
Chairman

cc: The Honorable Dan Burton
The Honorable John Tierney

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INDEPENDENT

October 30, 2001

The Honorable Loretta Lynch
President
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Dear President Lynch:

I am writing to follow up on the October 16, 2001 hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas. Thank you again for your testimony at that hearing. As discussed at the hearing, I request that you respond to a series of follow-up questions, which are attached to this letter.

Please provide the requested information to the majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building not later than November 13, 2001. If you have any questions about this request, please call Professional Staff member Connie Lausten at (202) 226-2067. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

Attachment

cc: The Honorable Dan Burton
The Honorable John Tierney

Questions for CPUC Chairman Lynch

In-State Natural Gas Production

Q1. Due to the Pacific Gas and Electric Company's (PG&E) requirement for small in-State natural gas producers to produce at least 10,000 cubic feet per day (cfd) to have their gas collected, there are between 60 to 200 million cfd of natural gas not available to the California market. In July 1997, the California Public Utility Commission (CPUC) approved the "Gas Accord Settlement," which included divestiture of PG&E's gas gathering system.

a. Why has the CPUC not followed through in requiring PG&E to divest its gathering lines?

b. What is the status of this divestiture order and when will it be completed?

Interstate Capacity

Q2. You stated that there is not a deficit of natural gas interstate capacity in California. CPUC's March 28, 2001 complaint filed against El Paso Merchant and El Paso Natural Gas for exercising market power indicates that there is not enough competition or capacity of interstate lines. Please provide the natural gas infrastructure and demand data that support your argument that California does have enough interstate natural gas pipeline capacity.

Q3. According to the CPUC, what is the actual natural gas demand in Northern and Southern California?

Q4. What is the interstate natural gas capacity in Northern and Southern California, respectively?

Q5. What do you believe is the appropriate slack capacity of interstate capacity? Has that level been met in Northern and Southern California?

Q6. Given the unprecedented increase in natural gas demand in California between 1996 and 2001, what is the natural gas demand forecast in five, ten and 20 years?

Q7. During the hearing, you stated that the CPUC would decide upon the Southern California Gas proposal to modify the nomination process, the residual load service, and the windowing process on October 25, 2001. On October 25th, the CPUC announced a delay in this decision until November 8th. Are there any reasons whatsoever that this decision will not be completed on November 8th?

Q8. Given that California non-core customers frequently indicated that they are not able to access their interstate capacity, what aspects of the CPUC Southern California

Gas Proposal will assist industrial natural gas users? Please explain how the CPUC proposal will provide them with accessibility to their interstate firm capacity.

Intrastate Capacity

Q9. You indicated that California needs neither more intrastate capacity nor more take-away capacity. Federal Energy Regulatory Commission Chairman Patrick Wood III and California Energy Commission Commissioner Michal Moore testified that California needs more intrastate natural gas capacity. In light of this information, please provide the Subcommittee with information supporting your assertion that in-State capacity can meet the enormous increase in demand now and in the future.

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BERNARD SANDERS, VERMONT,
INDEPENDENT

October 30, 2001

Mr. Paul R. Carpenter
Principal
Brattle Group
44 Brattle Street –3rd Floor
Cambridge, MA 02138-3736

Dear Mr. Carpenter:

I am writing to follow up on the October 16, 2001 hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas. Thank you again for your testimony at that hearing. As discussed at the hearing, I request that you respond to a series of follow-up questions, which are attached to this letter.

Please provide the requested information to the majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building not later than November 13, 2001. If you have any questions about this request, please call Professional Staff member Connie Lausten at (202) 226-2067. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

Attachment

cc: The Honorable Dan Burton
The Honorable John Tierney

Questions for the Brattle Group

Natural Gas Demand and Supply

Q1. What was the demand for natural gas from Northern and Southern California, respectively, during 1999, 2000, and 2001?

Q2. What was the actual interstate supply and capacity available to Northern and Southern California, respectively, during 1999, 2000 and 2001?

Slack Capacity

Q3. Given the available interstate natural gas capacity and the actual volumes delivered to the State, was there sufficient slack capacity or supply to Northern and Southern California?

Q4. From an economic perspective, what slack capacity do you recommend for capacity margins?

Q5. What policies do you recommend to promote the ideal slack capacity in the market?

Natural Gas Demand Projections

Q6. What are the Brattle Group's natural gas demand projections for both Northern and Southern California, respectively, for the next five, ten and 20 years?

Q7. Is there sufficient interstate and intrastate capacity and planned capacity to meet these projections?

California utilities were directed by the policies of the California Public Utilities Commission (CPUC) to purchase natural gas, as well as electricity, on the spot market. This situation left these entities vulnerable to the high natural gas prices. Given the Brattle Group's economic expertise:

Q8. Is CPUC's direction on this subject the correct policy decision?

Q9. What is the optimum mix of long-term, mid-term and short-term (spot) market natural gas contracts for an industrial entity or electricity generator to have?

Q10. What are the important criteria in determining the optimum mix of contracts?

Q11. What policy suggestions do you have to encourage industrial natural gas users to settle at an optimum contract mix?

The Brattle Group *Economic, Environmental & Management Counsel*

CAMBRIDGE
WASHINGTON
LONDON

November 13, 2001

Doug Ose, Chairman
Subcommittee on Energy Policy,
Natural Resources and Regulatory Affairs
2157 Rayburn House Office Building
Washington, D.C. 20515-6143

Dear Mr. Ose:

Attached you will find answers to the questions you asked in a letter dated October 30, 2001. I would be happy to provide answers to any follow-up questions the Subcommittee may have. Feel free to call me at 617-864-7900 if I can be of any further assistance.

Sincerely,

Paul R. Carpenter
Principal

44 Brattle Street Cambridge, MA 02138-3736
Voice 617.864.7900 Facsimile 617.864.1576 email office@brattle.com

Responses from *The Brattle Group*

Natural Gas Demand and Supply

Q1. What was the demand for natural gas from Northern and Southern California, respectively, during 1999, 2000, and 2001?

A1. See Exhibit 1 for demand for natural gas in northern and southern California in the 1999-2001 period.

Q2. What was the actual interstate supply and capacity available to Northern and Southern California, respectively , during 1999, 2000 and 2001

A2. See Exhibit 2 attached for interstate capacity to Northern and Southern California. Interstate pipelines in total have delivery capability of roughly 7.0 Bcf/d to the state. Intrastate take-away capacity at California delivery points is roughly 6.5 Bcf/d (as shown in Exhibit 2). In addition, California receives gas produced within state boundaries (roughly 0.5 Bcf/d).

Slack Capacity

Q3. Given the available interstate natural gas capacity and the actual volumes delivered to the State, was there sufficient slack capacity or supply to Northern and Southern California?

A3. Yes, there should have been sufficient pipeline capacity to meet peak demands in 2000-2001 in both northern and southern California, had storage been adequately filled in the April-October 2000 period. It was the failure to fill storage (in part resulting from El Paso Merchant Energy's withholding behavior) that created constraints on the interstate system serving California in the winter of 2000-2001.[1]

Q4. From an economic perspective, what slack capacity do you recommend for capacity margins?

A4. In considering the issue of slack capacity, it is useful to distinguish between three types: interstate capacity (to California), intrastate capacity (within California), and storage capacity. Slack capacity in these intrastate markets in the 10-20% range would not be an unreasonable target. An efficient alternative to building slack intrastate pipeline capacity is to encourage the development of new storage facilities in California. (See recently-passed California Assembly Bill 1233.) New storage (owned or operated by non-utility third parties) is the most efficient way to meet peak demand requirements, in part because it increases the average utilization of the existing transmission system.

Q5. What policies do you recommend to promote the ideal slack capacity in the market?

A5. To the extent feasible, market-place decisions of private parties should determine the appropriate level of slack capacity. (In California, this has been referred to as a "let the market decide" policy.) For example, interstate pipelines typically make expansion decisions through the use of "open seasons," in which shippers make commitments to

[1] The Market Oversight and Enforcement Section (MOE) of the Office of the General Counsel of the Federal Energy Regulatory Commission (FERC) recently recommended a more complete investigation of the reasons capacity went unused during the winter 2000-2001. This recommendation was made following MOE's review of the record in RP00-241-000, which MOE believed suggested potential violations of FERC open access regulations, but insufficient evidence to conclude a violation had occurred.

subscribe to firm capacity. This policy has been broadly successful. For intrastate transmission capacity expansion, a "let the market decide" policy may not be feasible in light of the dominant (monopoly) positions of SoCalGas and PG&E. Policies encouraging the development of storage within California (especially by non-utility third parties) should also be pursued as an alternative to building slack pipeline capacity.

Natural Gas Demand Projections

Q6. What are the Brattle Group's natural gas demand projections for both Northern and Southern California, respectively, for the next five, ten and 20 years?

A6. *The Brattle Group* has not prepared any forecasts of natural gas demand for California. See Exhibit 3 for a forecast for both northern and southern California, prepared by the California utilities and published in the 2000 California Gas Report. It should be noted that there is enormous uncertainty in forecasting gas demand. The projections made in the 2000 California Gas Report were made in a different economic environment than currently exists. Furthermore, a lot of the long-term gas demand uncertainty is driven by questions surrounding the development of new gas-fired power generation in the region, while a lot of short-term uncertainty is due to weather (including temperature, hydro conditions, etc.). The forecasts will be affected by how much power generation is built, where it is built, and to what extent it displaces inefficient gas-fired power plants.

Q7. Is there sufficient interstate and intrastate capacity and planned capacity to meet these projections?

A7. See attached Exhibits 4, 5 and 6, showing the sufficiency of pipeline capacity to California relative to average forecasted daily demand. Although daily demand is higher in winter periods, capacity is sufficient to meet winter daily demands provided storage is adequately filled (see response to Question 3 above).

California utilities were directed by the policies of the California Public Utilities Commission (CPUC) to purchase natural gas, as well as electricity, on the spot market. This situation left these entities vulnerable to the high natural gas prices. Given the Brattle Group's economic expertise:

Q8. Is CPUC's direction on this subject the correct policy decision?

A8. *The Brattle Group* believes the circumstances surrounding procurement of gas and electricity by California utilities have been quite different. While electric utilities were required to buy power on a spot basis from the California Power Exchange, gas procurement has been undertaken pursuant to procurement incentive mechanisms approved by the California Public Utilities Commission for PG&E and SoCalGas. While the procurement incentive mechanisms compare actual gas costs to benchmark gas costs (determined by spot prices), *The Brattle Group* is not aware of specific mandates requiring the California gas utilities to purchase gas at spot prices.

Nonetheless, most U.S. gas distribution utilities (including the California gas utilities) do in fact purchase gas on a monthly spot or daily spot basis, or under long-term contracts that are indexed to spot prices. In the period following Federal Energy Regulatory Commission Orders 500 and 636, it is our impression that most gas utilities generally

have not bought gas under long-term fixed price contracts for fear of prudence challenges should fixed price commitments exceed spot prices.

However, many state regulatory commissions (including the CPUC) have allowed utilities to use financial instruments (futures, forwards, options, and swaps) to "hedge" their gas costs. These instruments can be used for price stability. That is, they reduce the variance of gas costs, but do not reduce the level of gas costs on average over the long term. In some years, the use of these instruments will lead to higher gas costs relative to spot prices, while in other years they will lead to lower gas costs relative to spot prices.

The Brattle Group believes the use of these hedging instruments can be beneficial for utility customers so long as the programs are well-designed and systematic (e.g., do not lead to speculation). Furthermore, appropriate regulatory rules must be in place regarding the use of these instruments (including cost recovery guidelines for the cost of purchasing such instruments). *The Brattle Group* takes no position on the CPUC's specific hedging rules in place for California gas utilities. However, *The Brattle Group* recently filed testimony before the CPUC explaining the perverse incentives potentially provided under SoCalGas' Gas Cost Incentive Mechanism, under which SoCalGas is allowed to use financial/hedging instruments. In the winter of 2000-2001, SoCalGas' hedging program resulted in significant profits that served to reduce its cost of gas relative to spot prices.

Q9. What is the optimum mix of long-term, mid-term and short-term (spot) market natural gas contracts for an industrial entity or electricity generator to have?

A9. As explained in the response to Question 8, the mix of long-term, medium-term, and short-term gas contracts is not likely to have a dramatic effect on prices paid since long-term contracts are generally indexed to spot prices. Furthermore, there is no single optimal level that we can provide for the amount of hedging that should be done by industrial entities or electricity generators. The level of hedging depends on many factors that are not constant across gas purchasers. For example, for an electric generator, the appropriate level of hedging may depend on the type of power sales contracts that are in place, whether the generating unit is a baseload, intermediate, or peaking plant, the financial structure of the owning entity, etc. For industrial customers, the optimal amount of hedging also is likely to be different across purchasers and across industries.

Q10. What are the important criteria in determining the optimum mix of contracts?

A10. See response to Question 9.

Q11. What policy suggestions do you have to encourage industrial natural gas users to settle at an optimum contract mix?

A11. Since the optimum mix may vary by gas user, *The Brattle Group* cannot offer a policy suggestion that would be suitable for all users. Various publications provide principles and/or guidance on financial risk issues. See, for example:

S.C. Myers and R.A. Brealey, *Principles of Corporate Finance*, 6th edition, McGraw-Hill, 2000 (especially Chapter 26).

C.W. Smith and C.H. Smithson, *Managing Financial Risk: A Guide to Derivative Products, Financial Engineering, and Value Maximization*, 3rd edition, McGraw-Hill, 1998.

Exhibit 1

Gas Demand In California

(MMcf/d)

	1999	2000	2001 YTD*
PG&E[1]	2,475	2,718	2,713
SoCalGas[1]	2,749	3,120	3,223
SoCalGas Bypass[2]	395	398	NA
SoCalGas Total	**3,144**	**3,518**	**3,223**

[1]PG&E and SoCalGas Daily Operating Records.
[2]SoCalGas Bypass volumes from 2001 California Gas Report.
*January through October.

Exhibit 2
Delivery Capacity to California
1999-2001
(MMcf/d)

Northern California		
	PG&E Gas Transmission Northwest	1,803
	El Paso, Transwestern and Kern River	1,140
	California Production	200
	Total delivery capacity to Northern California	3,143
Southern California		
	El Paso	1,750
	Transwestern	750
	Kern River/Mojave	1,100
	California Production	300
	Total delivery capacity to Southern California	3,900
	Total delivery capacity to California	7,043

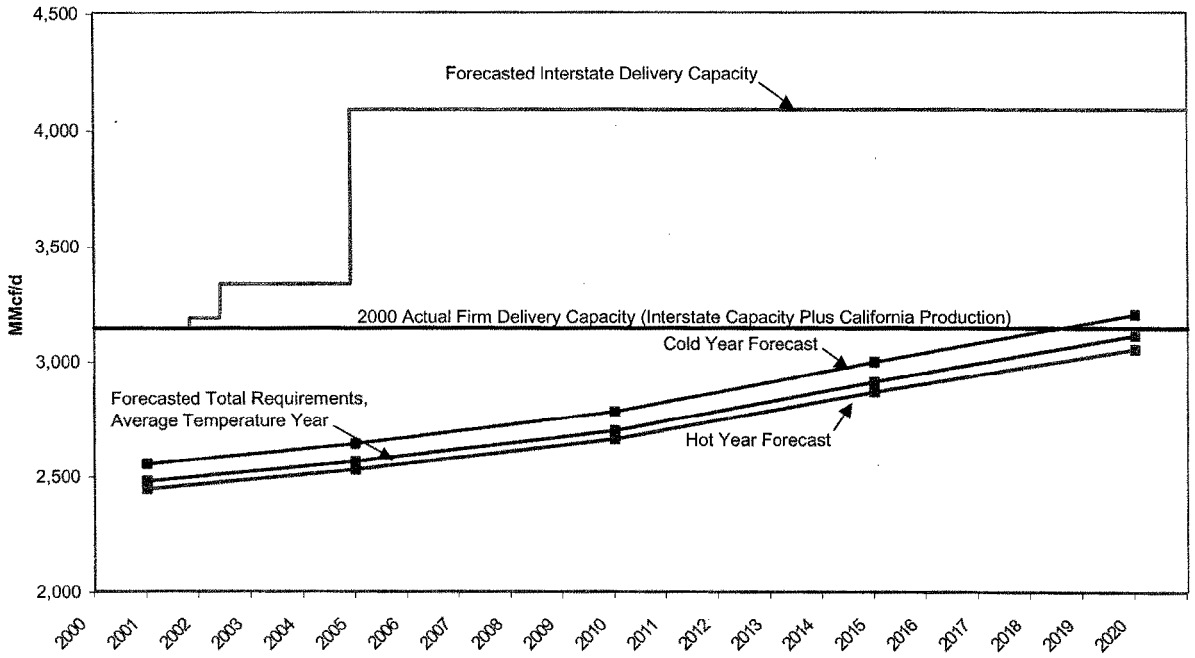
Notes:
(1) Total Kern River/Mojave delivery capacity to California is 1,100 MMcf/d. Kern River/Mojave can deliver the full 1,100 MMcf/d to SoCalGas and direct connections to end-users in Southern California, or Kern River can divert 175 MMcf/d to Northern California (PG&E).
(2) El Paso, Transwestern and Kern River deliveries to Northern California are limited to 1,140 MMcf/d, the capacity of PG&E's Baja Path.
(3) El Paso and Transwestern have the capacity to deliver 2,020 MMcf/d to Northern and Southern California at Topock, but intrastate takeaway capacity limits deliveries at Topock to 1,680 MMcf/d, decreasing interstate delivery capacity to California by 340 MMcf/d.

Exhibit 3
Forecasted California Requirements
(MMcf/d)

	2001	2005	2010	2015	2020
Average Temperature Year:					
Northern California	2,477	2,562	2,696	2,909	3,109
Southern California	3,188	2,896	2,995	3,089	3,181
Total:	**5,665**	**5,458**	**5,691**	**5,998**	**6,290**
Cold Temperature Year:					
Northern California	2,551	2,639	2,779	2,995	3,201
Southern California	3,317	3,029	3,134	3,237	3,338
Total:	**5,868**	**5,668**	**5,913**	**6,232**	**6,539**
Hot Temperature Year:					
Northern California	2,443	2,526	2,660	2,865	3,050
Southern California	3,065	2,766	2,858	2,945	3,029
Total:	**5,508**	**5,292**	**5,518**	**5,810**	**6,079**

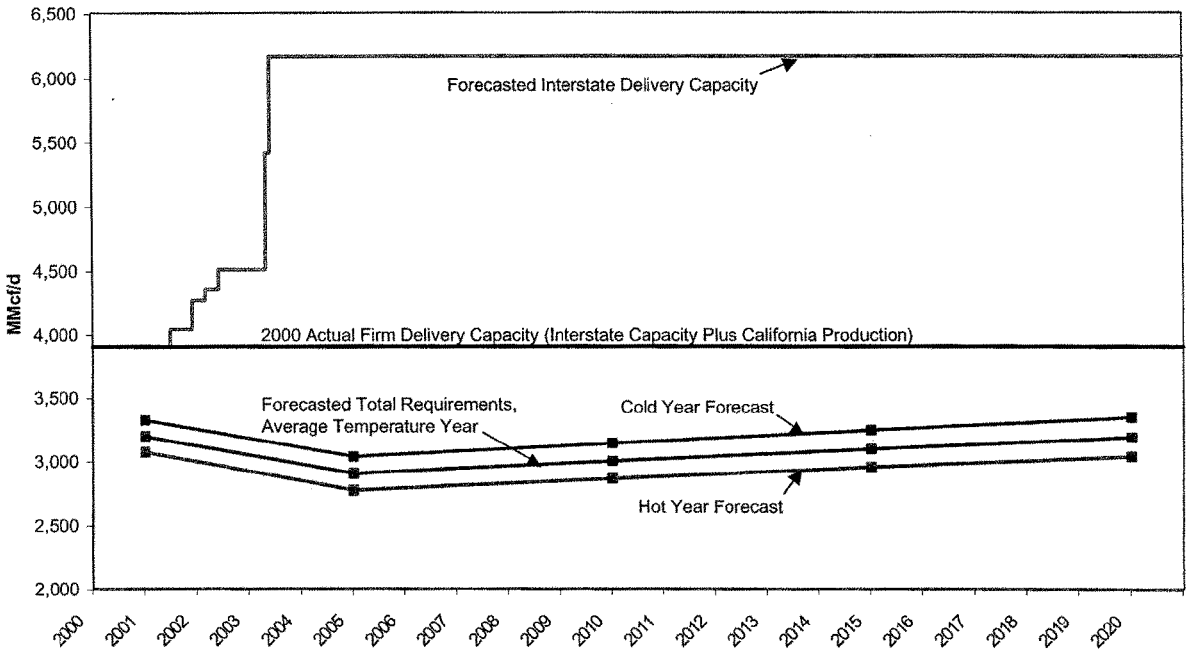
Source: 2000 California Gas Report.

Exhibit 4
Forecasted Northern California Interstate Delivery Capacity vs. Total Requirements



Source: Northern California requirements forecast from 2000 California Gas Report. California interstate pipeline delivery capacity forecast from *Natural Gas Infrastructure Issues - Commission Final Report*, California Energy Commission, October 2001. The following expansions are identified by the California Energy Commission to increase capacity to northern California: PG&E-GTN (2001, 2002) and Ruby Pipeline (2004). All others are assumed to increase capacity to southern California.

Exhibit 5
Forecasted Southern California Interstate Delivery Capacity vs. Total Requirements



Source: Southern California requirements forecast from 2000 California Gas Report. California interstate pipeline delivery capacity forecast from *Natural Gas Infrastructure Issues - Commission Final Report*, California Energy Commission, October 2001. The following expansions are identified by the California Energy Commission to increase capacity to southern California: Kern River (2001, 2003), El Paso Plains-All American (2001), Questar (2002), Transwestern (2002), and Sonoran Pipeline Phase I (2003). All others are assumed to increase capacity to northern California.

Exhibit 6

Interstate Pipeline Projects

Pipeline Project	*Capacity (MMcf/d)*	*Start Date*	*Assumed Start Date*
Kern River Pipeline Expansion	135	July 2001	7/1/01
PG&E-GTN Pipeline Expansion	44	November 2001	11/1/01
El Paso Plains-All American Pipeline	230	Winter 2001	12/1/01
Questar Southern Trails Pipeline	90	Spring 2002	3/1/02
PG&E-GTN Pipeline Expansion	149	Summer 2002	6/1/02
Transwestern Pipeline	150	June 2002	6/1/02
Kern River Pipeline Expansion	906	May 2003	5/1/03
Sonoran Pipeline, Phase I to CA Border	750	Summer 2003	6/1/03
Ruby Pipeline	750	December 2004	12/1/04

Source: *Natural Gas Infrastructure Issues - Commission Final Report,* California Energy Commission, October 2001.

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DIANE E. WATSON, CALIFORNIA

BERNARD SANDERS, VERMONT,
INDEPENDENT

October 30, 2001

Ms. Gay Friedmann
Senior Vice President, Legislative Affairs
Interstate Natural Gas Association of America
10 G Street, N.E. – Suite 700
Washington, DC 20001

Dear Ms. Friedmann:

I am writing to follow up on the October 16, 2001 hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas. Thank you again for your testimony at that hearing. As discussed at the hearing, I request that you respond to a series of follow-up questions, which are attached.

Please provide the requested information to the majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building not later than November 13, 2001. If you have any questions about this request, please call Professional Staff member Connie Lausten at (202) 226-2067. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

Attachment

cc: The Honorable Dan Burton
The Honorable John Tierney

Questions for INGAA

Q1. How important is it to interstate pipeline owners that the capacity on their lines has firm capacity contract holders?

Q2. Do some States have significantly different policies with respect to bundled and unbundled intrastate lines compared to the majority of other States? If so, which States are they? Also, describe how those State policies significantly differ from those of most other States. Are these differences helpful to the process of delivering natural gas through the interstate transmission system?

Q3. How do bundled intrastate natural gas transmission lines negatively impact pipeline owners?

Q4. Are California natural gas shippers able to use all of the interstate pipeline capacity for which they have contracted and paid? If not, why not?

Q5. What policies does the Interstate Natural Gas Association of America (INGAA) suggest to ensure that non-core California natural gas customers can get firm interstate pipeline transportation upstream of their local distribution companies?

GAY H. FRIEDMANN
VICE PRESIDENT, LEGISLATIVE AFFAIRS

November 13, 2001

The Honorable Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs
B-377 Rayburn Office Building
Washington, D.C. 20515

Dear Mr. Chairman:

Following are my responses to your follow-up questions to the hearing your subcommittee held on October 16, 2001.

1. How important is it to interstate pipeline owners that the capacity on their lines has firm capacity contract holders?

   As a regulatory matter, in order for new pipeline construction or pipeline expansions to take place, the applicant must show the Federal Energy Regulatory Commission ("FERC") that there is a need for additional capacity. Among other factors, FERC considers long term firm contracts evidence of such need.

   Firm contracts are essential to the economic well being of the interstate pipeline industry. Firm contract holders provide the revenue stability necessary for interstate pipelines to maintain and operate their systems in a safe and reliable manner and to generate the funds in the capital market on reasonable terms necessary to expand their systems to meet market growth and to compete with others for market share. Thus, INGAA has long promoted and supported regulatory policies that encourage long-term firm contracts.

2. Do some States have significantly different policies with respect to bundled and unbundled intrastate lines compared to the majority of other States? If so, which States are they? Also, describe how those State policies significantly differ from those of most other States. Are these differences helpful to the process of delivering natural gas through the interstate transmission system?

   INGAA does not have the information necessary to answer this question. But I would assume that there are differing state policies governing the provision of service by intrastate pipelines, which are subject to state jurisdiction. The National Association of Regulatory Commissions may have access to this type of information.

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However, INGAA's position has been that unbundled services at the intrastate pipeline/local distribution company level–with costs properly assigned to such services–are preferable to bundled services because they result in a more competitive balance between all service–intrastate and interstate-and lower costs in the market place.

3. How do bundled intrastate natural gas transmission lines negatively impact pipeline owners?

   As with question 2, as this question involves intrastate pipelines, INGAA does not have the information necessary to answer this question. The arguments relative to the benefits and/or burdens of bundled services at the state level and their impact on intrastate pipeline owners is properly addressed by the intrastate pipelines and their respective state regulators. However, as noted above, if the question is directed to interstate pipeline owners, INGAA prefers the unbundling of downstream services for the reasons set forth above.

4. Are California natural gas shippers able to use all of the interstate pipeline capacity for which they have contracted and paid? If not, why not?

   Shippers enter into freely negotiated contracts with interstate pipelines. Those contracts are subject to the terms and provisions of pipeline tariffs on file with FERC and also are subject to the regulations and policies of the FERC. Therefore, when shippers enter into such contracts, they do so with full knowledge of the ground rules governing their services and receive services for which they have contracted and paid.

   However, shippers also are responsible for securing gas supplies in the gas supply basins in which the pipelines are located, for locating and serving markets downstream of such basins and for taking the steps necessary to match their supplies with their markets through the pipeline nomination and confirmation process which the FERC has mandated. Thus, from time to time shippers may not be able to use all of the capacity for which they have contracted because they have not been able to confirm supplies or markets.

5. What policies does the Interstate Natural Gas Association of America (INGAA) suggest to ensure that non-core California natural gas customers can get firm interstate pipeline transportation upstream of their local distribution companies?

   There are several methods by which non-core California natural gas customers can get firm interstate natural gas transportation service. First, when existing pipeline capacity becomes available, the pipeline posts that capacity on its bulletin board and non-core customers can bid for it just as any other shipper. Likewise, when pipelines serving California seek to expand their systems, non-core customers can bid for capacity on those pipeline expansions. Finally, non-core customers can participate in the FERC's capacity release program and secure firm

interstate pipeline capacity in that manner through existing shippers on the pipeline who wish to release their capacity to others.

However, as FERC and others have recognized, there are some delivery points in California where the intrastate pipeline capacity does not match the interstate pipeline's capacity to deliver gas at that point. In this case, it would appear that non-core customers have at least two options. They can lobby their public utility commission to expand the intrastate capacity to relieve the bottleneck. In some cases, depending on their proximity to an interstate pipeline, they can build a pipeline to connect directly to the interstate pipeline in order to secure service.

I hope that the above information is helpful to you. Please let me know if you have other questions.

Sincerely,

Gay H. Friedmann

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BERNARD SANDERS, VERMONT,
INDEPENDENT

October 30, 2001

The Honorable Michal C. Moore
Commissioner
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5512

Dear Commissioner Moore:

I am writing to follow up on the October 16, 2001 hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas. Thank you for your testimony at that hearing. As discussed at the hearing, I request that you respond to a series of follow-up questions, which are attached to this letter.

Please provide the requested information requested to the majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building not later than November 13, 2001. If you have any questions about this request, please call Professional Staff member Connie Lausten at (202) 226-2067. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs

Attachment

cc: The Honorable Dan Burton
The Honorable John Tierney

Questions for CEC Commissioner Moore

Interstate Capacity

Q1. What is the actual natural gas demand in Northern and Southern California?

Q2. What is the interstate natural gas delivery capacity in both Northern and Southern California, respectively?

Q3. What do you believe is the appropriate slack capacity of interstate capacity? Has that level been met in Northern and Southern California?

Q4. Given the unprecedented increase in natural gas demand in California between 1996 and 2001, what is the natural gas demand forecast in five, ten and 20 years?

Q5. You stated that California shippers are not currently able to use all of their firm interstate pipeline capacity for which they have contracted and paid. From a regulatory or policy perspective and from an infrastructure perspective, what are the reasons for this inability?

Intrastate Capacity

Q6. In contrast to California Public Utilities Commission President Loretta Lynch's comment that California has enough intrastate capacity, you indicated in your testimony and in the California Energy Commission (CEC) "Natural Gas Infrastructure" report that it does not. What reasons did the CEC find to explain why California is short on intrastate natural gas pipeline capacity?

Q7. What is the ideal slack capacity for the intrastate natural gas pipeline and for the take-away capacity?

Q8. Do you think that take-away capacity must meet all of the delivery interstate capacity? What are your reasons for or against matching these capacities?

DAN BURTON, INDIANA,
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BERNARD SANDERS, VERMONT,
INDEPENDENT

October 30, 2001

Professor Joseph Kalt
John F. Kennedy School of Government
Harvard University
124 Mt. Auburn - Suite 100-120
Cambridge, MA 02138

Dear Professor Kalt:

I am writing to follow up on the October 16, 2001 hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas. Thank you again for your testimony at that hearing. As discussed at the hearing, I request that you respond to a series of follow-up questions, which are attached to this letter.

Please provide the requested information to the majority staff in B-377 Rayburn House Office Building and the minority staff in B-350A Rayburn House Office Building not later than November 13, 2001. If you have any questions about this request, please call Professional Staff member Connie Lausten at (202) 226-2067. Thank you for your attention to this request.

Sincerely,

Doug Ose
Chairman
Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs

Attachment

cc: The Honorable Dan Burton
The Honorable John Tierney

Questions for Professor Kalt

Natural Gas Demand and Supply

Q1. What was the demand for natural gas from Northern and Southern California respectively, during 1999, 2000, and 2001?

Q2. What was the actual interstate supply and capacity available to Northern and Southern California, respectively, during 1999, 2000 and 2001?

Slack Capacity

Q3. Given the available interstate natural gas capacity and the actual volumes delivered to the State, was there sufficient slack capacity or supply for Northern and Southern California?

Q4. From an economic perspective, what slack capacity do you recommend for capacity margins?

Q5. What policies do you recommend to promote the ideal slack capacity in the market?

Natural Gas Demand Projections

Q6. What are your natural gas demand projections for both Northern and Southern California, respectively, for the next five, ten and 20 years?

Q7. Is there sufficient interstate and intrastate capacity and planned capacity to meet these projections?

California utilities were directed by policies of the California Public Utilities Commission (CPUC) to purchase natural gas, as well as electricity, on the spot market. This situation left these entities vulnerable to the high natural gas prices. Given your economic expertise:

Q8. Is CPUC's direction on this subject the correct policy decision?

Q9. What is the optimum mix of long-term, mid-term and short-term (spot) market natural gas contracts for an industrial entity or electricity generator to have?

Q10. What are the important criteria in determining the optimum mix of contracts?

Q11. What policy suggestions do you have to encourage industrial natural gas users to settle at an optimum contract mix?

Joseph P. Kalt
Ford Foundation Professor
of International Political Economy

November 13, 2001

The Honorable Doug Ose
Congress of the United States
House of Representatives
Committee on Government Reform
2157 Rayburn House Office Building
Washington, DC 20515-6143

Dear Congressman Ose:

As you requested in your letter of October 30, 2001, I am responding to your follow-up questions to my testimony at the October 16, 2001, hearing of the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs on natural gas.

Q1. *What was the demand for natural gas from Northern and Southern California, respectively, during 1999, 2000, and 2001?*

A1. Attached, as Figure 1, is a chart depicting monthly consumption data available from the Energy Information Administration (EIA) for 1999, 2000, and 2001. The EIA data is available on a statewide basis only. Two consumption quantities are graphed in Figure 1: end-use consumption and end-use consumption plus net storage additions. When the "end-use consumption plus net storage additions" is higher than the "end-use consumption," California was utilizing natural gas not only to serve consumers' contemporaneous needs, but to build storage inventories as well. Of course, the level of actual demand in California is dependent on the price of natural gas. In well-functioning markets, as capacity becomes constrained, price will rise until demand is consistent with available capacity.

Q2. *What was the actual interstate supply and capacity available to Northern and Southern California, respectively, during 1999, 2000, and 2001?*

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A2. California can access gas supplies from in-state oil and gas fields, Canada, New Mexico, Oklahoma, Texas, the Rocky Mountain states, and elsewhere. In general, the supply of natural gas available in production regions exceeds the amount of capacity available to move those supplies to consumers in California. Figure 2 summarizes the design capacity of interstate natural gas pipelines that serve California. Effective capacity, however, is often significantly less than design capacity and can vary from day to day as a result of numerous factors. These factors include maintenance on a system, service outages due to other disruptions, changes in weather, constraints on receipt and/or delivery at specific points, etc.

Q3. *Given the available interstate natural gas capacity and the actual volumes delivered to the State, was there sufficient slack capacity or supply for Northern and Southern California?*

A3. As the summer of 2000 developed, California effectively ran out of "slack" capacity. As I noted in my prepared remarks to the Committee (at pp. 6-7): "Beginning in the summer (normally a period in which utilities build their natural gas inventories), unexpectedly high demand began to strain the capacity of the delivery system by which gas ultimately gets to California consumers. Tellingly, the shippers who were trying to sell gas into California began to find their nominations to move gas on the multiple inter- and intrastate pipeline delivery systems which serve the State being cut due to those systems' capacity limitations. They could not move all of the gas they wanted to California. ... The patterns of the summer did not abate as California went into the winter of 2000-01. The winter season started off with November being the coldest in 90 years. ... The infrastructure for delivering gas continued to be pushed to its effective limits."

Q4. *From an economic perspective, what slack capacity do you recommend for capacity margins?*

A4. Many systems are designed to meet forecasted peak day requirements. However, such systems can find themselves with no "slack" capacity if unexpectedly high peaks occur or if demand remains strong such that peak levels persist day after day. Economically, capacity planning requires a delicate balancing of competing objectives. On the one hand, building more capacity can prevent periods of high prices when

capacity would otherwise become scarce. On the other hand, building more capacity requires the investment of significant and largely "sunk" capital that goes unutilized except at particular peak times. The proper amount of "slack" capacity is appropriately determined by a cost-benefit calculation that weighs the capital costs of incremental expansions of system capacity against the consumers' willingness to pay to avoid periods of tight capacity. Because such a calculation varies from system to system, no simple, general answer to the question is feasible.

Q5. *What policies do you recommend to promote the ideal slack capacity in the market?*

A5. Policies aimed at encouraging optimal investment in the natural gas infrastructure serving California should ease barriers to entry into the provision of both storage and pipeline services. In this case, easing barriers would mean, in part, not opposing entry on economic grounds so long as proponents of a proposed project are willing to put their own capital at risk. In addition, streamlining or eliminating unnecessary FERC and State government permitting requirements can also work to ease entry into the marketplace. Finally, prices of access to infrastructure assets must be allowed to respond to marketplace forces of supply and demand, particularly when supply is tight due to infrastructure constraints. This sends proper signals to both the suppliers of infrastructure and consumers and signals where and under what conditions additional infrastructure is needed.

Q6 & Q7

Q6. *What are your natural gas demand projections for both Northern and Southern California, respectively, for the next five, ten, and 20 years?*

Q7. *Is there sufficient interstate and intrastate capacity and planned capacity to meet these projections?*

A6 & A7

I am not personally engaged in forecasting natural gas demand or infrastructure needs. Nevertheless, there are a number of publicly available studies and investigations that address these issues directly.

While the data and analyses in the sources below do not always agree with each other, they may be useful as references.

- California Energy Commission, *Natural Gas Infrastructure Issues: Committee Revised Final Report*, September 2001.
- California Energy Commission, *California Energy Outlook: Electricity and Natural Gas Trends Report*, Staff Draft, September 2001.
- Energy Information Administration, *Annual Energy Outlook 2001 With Projections to 2020* (and Supplemental Tables), December 2000 (www.eia.doe.gov/oiaf/aeo).
- FERC, with input from the CPUC, has been investigating in-state California energy infrastructure and is monitoring developments. The relevant dockets include PL01-4-000, AD01-2-000, and AD01-3-000. Transcripts and pleadings from these dockets are available from the RIMS system on the FERC's web site (www.ferc.gov).

Q8 – Q11

Q8. *Is CPUC's direction on this subject the correct policy decision?*

Q9. *What is the optimum mix of long-term, mid-term, and short-term (spot) market natural gas contracts for an industrial entity or electricity generator to have?*

Q10. *What are the important criteria in determining the optimum mix of contracts?*

Q11. *What policy suggestions do you have to encourage industrial natural gas users to settle at an optimum contract mix?*

A8 – A11

I have written extensively on these matters in the past and have attached two articles that address the complex issues raised by your questions. The articles are:

- Jaffe, Adam B., and Joseph P. Kalt, *Oversight of Regulated Utilities' Fuel Supply Contracts: Achieving Maximum Benefit from*

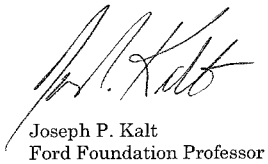
Competitive Natural Gas and Emission Allowance Markets, The Economics Resource Group, April, 1993.

- Jaffe, Adam B., and Joseph P. Kalt, "Insight on Oversight," *Public Utilities Fortnightly*, April 15, 1994.

I hope that you will find the foregoing sufficient for your purposes. If there is any further information or clarification that would be useful, do not hesitate to contact me.

Once again, thank you for the opportunity to express my views on the important issues under consideration by your subcommittee.

Sincerely,

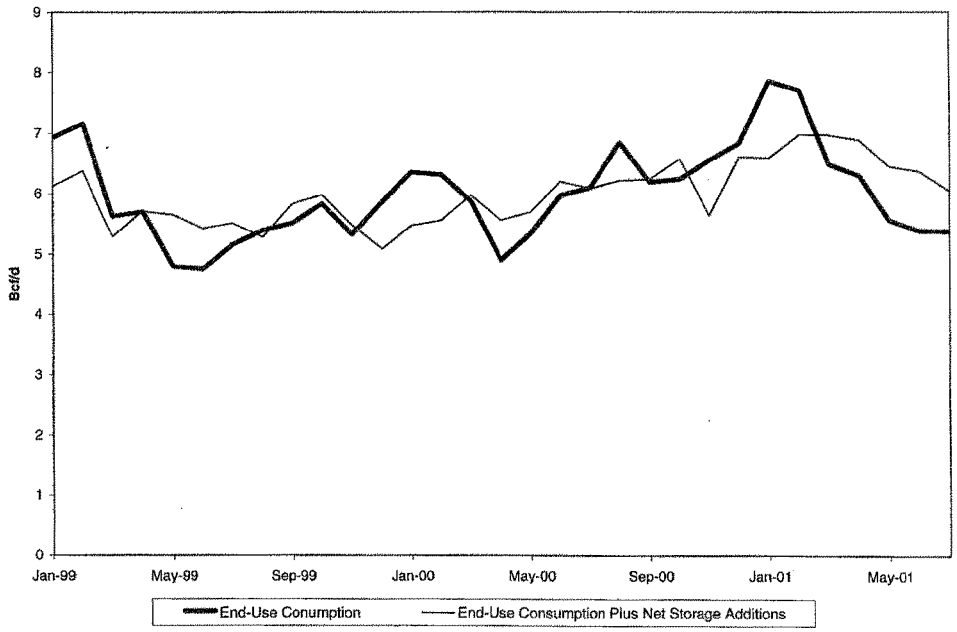


Joseph P. Kalt
Ford Foundation Professor of International Political Economy

Encl.

Figure 1

CALIFORNIA NATURAL GAS CONSUMPTION



Source: Energy Information Adminstration.

Figure 1:
TABULAR DATA

Month	End-Use Conumption (Bcf/d)	End-Use Consumption Plus Net Storage Additions (Bcf/d)
Aug-98	5.3	5.5
Sep-98	5.4	5.6
Oct-98	4.9	5.7
Nov-98	5.2	5.6
Dec-98	6.2	5.2
Jan-99	6.9	6.1
Feb-99	7.2	6.4
Mar-99	5.6	5.3
Apr-99	5.7	5.7
May-99	4.8	5.7
Jun-99	4.8	5.4
Jul-99	5.2	5.5
Aug-99	5.4	5.3
Sep-99	5.5	5.8
Oct-99	5.8	6.0
Nov-99	5.3	5.5
Dec-99	5.9	5.1
Jan-00	6.4	5.5
Feb-00	6.3	5.6
Mar-00	5.9	6.0
Apr-00	4.9	5.6
May-00	5.4	5.7
Jun-00	6.0	6.2
Jul-00	6.1	6.1
Aug-00	6.8	6.2
Sep-00	6.2	6.2
Oct-00	6.2	6.6
Nov-00	6.6	5.7
Dec-00	6.8	6.6
Jan-01	7.9	6.6
Feb-01	7.7	7.0
Mar-01	6.5	7.0
Apr-01	6.3	6.9
May-01	5.6	6.5
Jun-01	5.4	6.4
Jul-01	5.4	6.1

Source: Energy Information Administration.

Figure 2

CALIFORNIA INTERSTATE PIPELINE DELIVERY CAPACITY

Pipeline	Interstate Delivery Capacity (MMcf/d)
PG&E GT-NW (at Malin)	1,950
Kern River (at Daggett)	200
EPNG (at Topock)	1,680
EPNG (at Ehrenberg)	1,210
Transwestern (at Topock)	340
Transwestern (at Needles)	750
Mojave (at Hector)	50
Kern/Mojave (at Wheeler Ridge)	850
Total Delivery Capacity	**7,030**

Source: EPM-30, Federal Energy Regulatory Commission, Docket No. RP00-241-000.

ADAM B. JAFFE AND JOSEPH P. KALT

INSIGHT ON OVERSIGHT

A trio of tenets state regulators can use to maximize benefits from natural gas and emission allowance markets.

A DRAMATIC CHANGE HAS OCCURRED IN RECENT YEARS IN THE ROLE MARKETS AND COMPETITION PLAY IN ACHIEVING THE NATION'S ECONOMIC POLICY OBJECTIVES. In regulating sectors as diverse as telecommunications and natural gas pipelines, change has taken the form of deregulation, service unbundling, and increased reliance on markets and competition to determine prices and industry structure. In environmental regulation, passage of the Clean Air Act Amendments of 1990 was a major step toward implementing economic incentive-based approaches to control environmental externalities through a system of tradable emission allowances.

Public utility commissions governing local utilities are finding that unleashed markets are remarkably fluid and complicated. With so many new options and players to contend with, state policymakers are struggling with big questions: How do they fulfill their mandated obligations to ensure that local utilities are behaving prudently and providing gas and electricity under just and reasonable terms? How do they ensure that utilities buying major inputs in newly created, or at least newly freed, markets act in the best interests of ratepayers?

Some propose a deceptively "easy" solution: Simply require utilities to purchase commodities such as natural gas and pollution emission "allowances" in the public "spot" market. Or, alternatively, let them purchase as they choose, but allow them to recover in rates only the current spot prices. Such proposals are based on a fundamental misunderstanding of how competitive markets operate, and of the potential they hold for improving the performance of the gas and electric industries.

The simplistic view that all commodity acquisition transactions should be evaluated relative to the spot price ignores the importance of risk management. Among industries where investments are made in capital assets with long useful lives, risk is a real social cost that can be managed but not eliminated. After all, risk raises the cost of capital and discourages productive investment.

One important source of risk associated with these investments is price volatility. Efficient risk management, including risk due to price volatility, is one of the functions that competitive markets perform well. In a highly evolved commodity market, a diversity of contractual forms and options will exist, permitting the risk of price volatility to be transferred to parties who can bear the risk most efficiently. This diversity is absolutely necessary for market participants to hold portfolios of supply options that yield a better combination of risks and prices than can be achieved solely through reliance on spot pricing.

This has long been understood by

The simplistic view that evaluates commodity acquisition transactions relative to the spot price ignores the importance of risk management.

unregulated, competitive firms. Those that make long-lived investments requiring a continuous, reliable supply of inputs do not rely exclusively on spot markets to supply those inputs. Such firms typically use some combination of vertical integration, long-term contracts with a degree of price-fixity, and price-hedging, along with spot-market input purchases, to meet their needs. There is no valid economic or public policy reason for preventing regulated firms from adopting this same sort of portfolio strategy. Indeed, public policy should create incentives and mechanisms that actively encourage and facilitate the development of acquisition strategies that involve diverse portfolios.

That being said, how should public utility commissions proceed? The essence of the problem lies in the unavoidable need to make decisions in an *ex ante* environment of uncertainty, while the payoffs of decisions can only be known *ex post*. In such a context, public policy must be particularly concerned with the incentives it presents to economic agents and with maximizing the opportunity for the forces of competition to operate. Standards and procedures that use competition and economic incentives provide commissions with the most viable approach to ensuring the prudence of gas, electricity, and allowance market participants' decisions —keeping in mind, of course, that it is impossible to guarantee that no mistakes will be made.

What are the elements of an approach to state regulatory oversight of the performance of local distribution companies (LDCs) and electric utilities that will rely on competition and appropriate incentives? At least three stand out.

UNBUNDLING AND DEREGULATION

Where markets are workably competitive, competition rather than regulation should be used to govern *ex ante* and *ex post* performance. As a working presumption, this means that many of the functions traditionally bundled with the physical delivery provided by LDCs may be more efficiently provided under state-level policies of unbundling and deregulation that parallel those implemented at the federal level.

Unbundled open access to transportation on local systems could result in a proliferation of market competitors like those that operate on interstate pipelines. Brokers, marketers, producers, risk intermediaries, supply aggregators, storage arrangers, and so on are all potential competitors for the business of local gas customers. This is perhaps most evident in the case of large industrial gas users, who have been clamoring for bypass of, or open access to, local distribution systems. Even among smaller industrial, commercial, and residential customers, so-called "core aggregators" could be expected to compete for sales traditionally made by LDCs. Evidence indicates that consumer prices are lower under such conditions than they would be under traditional LDC ratesetting.

In the long run, fostering the emergence of a competitive retail-gas merchant industry offers commissions the possibility of allowing the competitive market to take over the burden of monitoring the prudence of utility supply decisions. In the short run, even the development of limited competition would greatly facilitate regulating the merchant function, because the prices charged by competitive entrants would provide the best possible yardstick against which to compare utility prices.

PREAPPROVING CONTRACT PORTFOLIOS

To the extent commissions perceive that LDCs and electric utilities continue to have market power in their gas and electricity sales functions, preapproval should be given to broadly outlined portfolio strategies for gas (and, as the market develops, emission allowance procurement). This is the second element in our proposed approach.

By pursuing a portfolio of contractual terms, a utility can take advantage of market opportunities in many different forms of transactions as they arise, while diversifying its mix of price and supply

reliability. As applied to acquisition and pollution abatement, such strategies would be natural extensions of the portfolio-based integrated resource planning (IRP) systems now used to determine utilities' capital investment portfolios.

A key component is preapproval of the composition of acquisition portfolios. Preapproval policies would require a gas- or allowance-purchasing utility to justify the composition of its acquisition portfolio to its commission. An effective preapproval process would establish parameters on the relative shares of purchases of different types—for example, spot purchases, contracts with prices indexed to the spot market, fixed-price contracts of various durations, and hybrid contracts such as a variable price with a floor and ceiling.

Portfolio structure preapproval can enhance the sustainability of the regulatory bargain by publicly and procedurally committing the commission. In this way utilities could acquire the inputs they need, with commitments designed to minimize price risk, and without unduly exacerbating regulatory risk.

COMPETITION AND INCENTIVES

As for the third element, competitive-bidding requirements within preapproved portfolio categories of gas and allowance acquisition terms should be used to promote utility performance. A commission that has established appropriate parameters for a utility's acquisition portfolio also should be concerned about the utility's efforts to acquire individual portfolio components at least cost. The simplest mechanism, and the one that fits most directly into evolving IRP frameworks, is to rely on competitive bidding to supply the different portfolio components.

How might this work? Once the quantities to be secured have been determined, utilities would seek bids for supplies meeting the parameters specified for that category. Parameters specified would include contract attributes such as term and reliability, and also seller qualifications such as minimum assets and other financial indications necessary to ensure contract performance. Utilities choosing to acquire gas or make allowance purchases (or sales) would be obligated to select the supply options that offer the best combination of price, nonprice terms, and noncontract conditions. Commissions could appropriately monitor the competitiveness of this process, and are generally familiar with doing so.

The regulatory burden of portfolio preapproval and monitoring of least-cost bidding are only necessary to the extent that unbundling and direct competition for retail customers are not implemented. In effect, portfolio preapproval and least-cost bidding requirements are imperfect methods of replicating the price discipline that competition would otherwise create. These are imprecise and cumbersome procedures—a strong argument for the transition to competition as the best way to ensure efficient acquisition behavior.

HIGH STAKES

The new era of relying on competitive markets to achieve public policy objectives makes the jobs of commissions much harder. To realize the maximum social benefit from these policy innovations, regulated firms must be given incentives to participate in these complicated, evolving markets. Commission policies can either enhance or inhibit the evolution of efficient and innovative markets. A grave danger exists that adopting simplistic rules for evaluating the actions of regulated firms in these markets will stifle their development and thereby reduce the social benefits potentially available from deregulation and the use of market-based approaches to environmental protection.

Avoiding simplistic approaches begins with the recognition that risk is a real cost that can be minimized but not eliminated. Competitive markets have shown that managing risk is one of the functions they perform well.

The stakes in establishing appropriate policy are large. Because the cost of financing capital investments is

A competitive retail-gas merchant industry offers commissions the possibility of letting the market monitor the prudence of utility supply decisions.

A simple mechanism is to rely on competitive bidding to supply the different portfolio components.

adversely affected by increases in risk, commission policies that increase risk by stifling development of the needed diversity of contractual forms will raise costs throughout the affected industries. Increases in producers' capital costs will reduce the supply of gas and thereby raise its price. Increases in gas and electric utility risks will further raise costs to ratepayers. And increases in risks associated with the use of emission allowance markets and natural gas will bias pollution-compliance decisions in favor of capital-intensive solutions such as scrubbers. This will raise the cost of pollution control and undermine the success of the emissions trading system itself.

A rough estimate of the cost of these effects suggests the following: To the extent that "spot only" commission oversight policies choke off efficient risk-reducing and risk-shedding contractual opportunities in the natural gas and emission allowance markets, the debt-carrying capacities of affected firms are reduced. This causes a shift toward more expensive equity forms of financing. In the case of gas supply investments, decreased access to debt finance can raise the capital costs of gas development and delivery by as much as $0.80 a thousand cubic feet.

On the electric generation side, we estimate that each 5-percent reduction in the debt share of new units' financing corresponds to a 1.6-percent increase in the revenues needed to cover the units' costs; pushing the financing firm from a debt/equity ratio of 75/25 to a ratio of 25/75 would raise the costs of new gas-fired electric generation units by more than 16 percent. Finally, if commission policies impede development of an efficient emission allowance market and block a shift toward natural gas as an antipollution strategy, each forgone thousand cubic feet of gas use will cost the nation $0.16 to $0.45 in the form of higher pollution-control expenditures.

Regulatory reform and the evolution of new policy inevitably move with a "two steps forward, one step back" pattern. The unwinding of the old system of regulated fixed-price contracts governing fuel acquisition in favor of markets, and the development of an active and visible spot market for gas, are important and have benefited consumers greatly. It would be unfortunate indeed if these market processes in gas procurement and emission allowances were cut down in their infancy because of inadequate understanding of what competitive markets are all about. ▼

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Oversight of Regulated Utilities' Fuel Supply Contracts:

Achieving Maximum Benefit From Competitive Natural Gas and Emission Allowance Markets

By Adam B. Jaffe and Joseph P. Kalt

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TABLE OF CONTENTS

Executive Summary		Page i
Section I:	Introduction	Page 1
Section II	The Recent Evolution of Gas Policy and Markets	Page 2
Section III:	Long-Term Contracts, Transactions Cost Minimization, and Optimal Allocation of Risk	Page 6
Section IV:	Implications for Utility Natural Gas and Emission Allowance Contracts	Page 13
Section V:	Standards for Prudence Review	Page 20
Section VI:	Conclusion	Page 24
Endnotes		Page 26
Appendix I	Major Federal Regulatory reforms Leading To Unbundling of Transportation by Interstate Pipelines	Page 29
Appendix II	U.S. Clean Air Act Amendments of 1990	Page 31

OVERSIGHT OF REGULATED UTILITIES' FUEL SUPPLY CONTRACTS:

ACHIEVING MAXIMUM BENEFIT FROM COMPETITIVE NATURAL GAS AND EMISSION ALLOWANCE MARKETS

By Adam B. Jaffe and Joseph P. Kalt

Executive Summary

An ongoing trend toward deregulation and reliance on competitive markets is challenging and changing the traditional roles of the Public Utility Commissions (PUCs) that regulate the nation's local gas and electric utilities. When regulated utilities under PUCs' jurisdiction purchase major inputs in newly created, or at least newly freed, markets, how can regulators ensure that the utilities do so in a way that is in the best interests of the ratepayers? It has been argued by some that the existence or potential existence of public "spot" markets for commodities such as natural gas and pollution emission "allowances" offers an easy solution to this problem: simply require utilities to purchase these commodities in the spot market, or, alternatively, permit them to purchase as they choose but allow them to recover in rates only the current spot price.

Proposals of this type are based on a fundamental misunderstanding of how competitive markets operate, and of the potential they hold for improving the performance of the gas and electric industries. The implementation of such "spot only" standards with respect to gas purchase decisions by Local Distribution Companies (LDCs) and electric utilities, as well as utility trades governing emission allowances under the 1990 Clean Air Act Amendments, will stunt the healthy development of gas and emission allowance markets, raise costs to ratepayers, discourage the expansion of the nation's use of natural gas, and undermine the important national experiment with the use of emissions trading to minimize the cost of air pollution control.

The simplistic view that all commodity acquisition transactions should be evaluated relative to the spot price ignores the importance of *risk management*. In industries in which investments must be made in capital assets with long useful lives, risk is a real social cost that can be managed but not eliminated. Risk raises the cost of capital and discourages productive investment. An important source of risk associated with these investments is price volatility. Efficient management of risk, including risk due to price volatility, is one of the functions that competitive markets perform well. In a highly evolved commodity market, there will exist a diversity of contractual forms and options, which permit the risk of price volatility to be transferred to those parties who can bear the risk most efficiently. This diversity of contractual forms is absolutely necessary for market participants to be able to hold *portfolios* of supply options that yield a better combination of risks and prices than can be achieved through sole reliance on spot pricing.

Unregulated, competitive firms that make long-lived investments

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that require a continuous, reliable supply of inputs do not rely exclusively on spot markets for the supply of those inputs. Such firms typically utilize some combination of vertical integration, long-term contracts with some degree of price fixity, and price hedging, along with spot-market input purchases, to meet their needs. There is no valid economic or public policy reason for preventing regulated firms from adopting this sort of portfolio strategy. Indeed, public policy should create incentives and mechanisms that actively encourage and facilitate the development of acquisition strategies that involve diverse portfolios.

The stakes in this debate are large. Because the cost of financing capital investments is adversely affected by increases in risk, PUC policies that increase risk by stifling the development of the needed diversity of contractual forms will raise costs throughout the affected industries. Increases in producers' capital costs will lessen the supply of gas and thereby raise its price. Increases in gas and electric utility risks will further raise costs to ratepayers. Increases in risks associated with the use of emission allowance markets and natural gas will bias pollution compliance decisions in favor of capital intensive solutions such as scrubbers, raising the cost of pollution control and undermining the success of the emissions trading system itself.

This study finds that, to the extent that "spot only" PUC oversight policies choke off efficient risk-reducing and risk-shedding contractual opportunities in the natural gas and emission allowance markets, the debt-carrying capacities of affected firms are reduced. This causes a shift toward more expensive equity forms of financing. In the case of gas supply investments, the capital costs of gas development and delivery can be raised as a result by as much as $0.80 per thousand cubic feet (mcf). Gas-using electric companies can be similarly affected. We find that each 5% reduction in the debt share of new units' financing corresponds to a 1.6% increase in the revenues needed to cover the units' costs; and pushing the financing from a debt/equity ratio of 75/25 to a ratio of 25/75 would raise the costs of new gas-fired electric generation units by more than 16%. If PUC policies impede the development of an efficient emission allowance market and thereby block a shift toward natural gas as an anti-pollution strategy, each foregone mcf of gas use will cost the nation on the order of $0.16-$0.45 — with aggregate stakes in the hundreds of millions of dollars.

The design of efficient policies for regulatory oversight of LDC and electric utility decision making is inherently difficult. The essence of the problem lies in the unavoidable need to make decisions in an *ex ante* environment of uncertainty, while revelation of the payoffs to decisions can only be known *ex post*. In such a context, public policy must be particularly concerned with the *incentives* that it presents to economic agents, and with maximizing the opportunity for the forces of *competition* to operate. Absolutely guaranteeing "right" decisions and no mistakes is impossible. Standards and procedures that use competition and economic incentives provide PUCs with the most viable approach to ensuring the prudence of gas, electricity, and allowance market participants' decisions.

What are the elements of an approach to state regulatory oversight of the performance of LDCs and electric utilities that will rely on competition and appropriate incentives? At least three principles stand out.

1. Unbundling and Deregulation: Where markets are workably competitive, competition rather than regulation should be utilized to govern *ex ante* and *ex post* performance.

As a working presumption, this means that many of the functions that have traditionally been bundled with the physical delivery service provided by LDCs may be more efficiently provided under state-level policies of unbundling and deregulation that parallel those that have been implemented at

the federal level. Unbundled open access to transportation on local systems could be expected to result in the proliferation of market competitors that we have seen operating on interstate pipelines. Brokers, marketers, producers, risk intermediaries, supply aggregators, storage arrangers, and so on are all potential competitors for the business of local gas customers. This is perhaps most evident in the case of large industrial gas users, who have already been clamoring for bypass of, or open access on, local distribution systems. Even in the case of smaller industrial, commercial, and residential customers, so-called "core aggregators" could be expected to compete for sales traditionally made by LDCs. In fact, available evidence indicates that consumer prices are lower under such conditions than they would be under traditional LDC rate setting.

In the long run, fostering the emergence of a competitive retail gas merchant industry offers PUCs the potential to allow the competitive market to take over the burden of monitoring the prudence of utility supply decisions. In the short run, even the development of limited competition would greatly facilitate regulation of the merchant function, because the prices charged by competitive entrants would provide the best possible yardstick against which to compare utility prices.

2. Pre-Approval of Contract Portfolio Structure in the Context of Integrated Resource Planning: To the extent that PUCs perceive that LDCs and electric utilities continue to have market power in their gas and electricity sales functions, pre-approval should be given to broadly outlined *portfolio* strategies for gas (and, as the market develops, emission allowance) procurement.

By pursuing a portfolio of contractual terms in its gas acquisitions, for example, a utility can take advantage of market opportunities in many different forms of transactions as they arise, while diversifying its mix of price and supply reliability. In fact, the value of portfolio strategies is widely recognized by market participants and their regulators. As applied to acquisition and pollution abatement, such strategies would be natural extensions of the portfolio-based Integrated Resource Planning (IRP) systems that are now widely used in determining utilities' capital investment portfolios.

A key component of an effective portfolio approach to PUC oversight of utilities' natural gas and emission allowance contracting is pre-approval of the composition of acquisition portfolios. Pre-approval policies would require a gas- or allowance-purchasing utility to justify the composition of its acquisition portfolio before the PUC, much the same way that IRP policies now require utilities to justify the extent of their reliance on Demand-Side Management (DSM), base-load capacity (either utility-owned or purchased), peaking capacity, short-term purchase commitments, and so forth. An effective pre-approval process would thereby establish parameters on the relative shares of purchases of different types, e.g., spot purchases, contracts with prices indexed to the spot market, fixed price contracts of various durations, and hybrid contracts such as variable-price with a floor and ceiling. Pre-approval of portfolio structures can enhance the sustainability of the regulatory bargain by publicly and procedurally committing the PUC. In this way utilities could acquire the inputs they need with commitments designed to minimize price risk, and could do so without unduly exacerbating regulatory risk.

3. Use of Competition and Incentives to Minimize the Cost of Portfolio Components: Competitive bidding requirements within pre-approved portfolio categories of gas and allowance acquisition terms should be used to promote utility performance.

A PUC that has established appropriate parameters for the composition of a utility's acquisition portfolio should also be concerned about the utility's efforts to acquire the individual

portfolio components at least cost (with appropriate consideration for non-contract circumstances, such as the creditworthiness of the seller). The simplest mechanism for achieving cost efficiency, and the one that fits most directly into evolving IRP frameworks, is to rely on competitive bidding for supply of the different portfolio components. That is, once the quantities that are to be secured in various contracting categories have been determined, utilities would seek bids for supplies meeting the parameters specified for that category. Parameters specified would include contract attributes such as term and reliability, and also seller qualifications such as minimum assets and other financial indications necessary to ensure contract performance. Utilities choosing to acquire gas or make allowance purchases (or sales) would be obligated to select the supply options that offer the best combination of price, non-price terms, and non-contract conditions. PUCs could appropriately monitor the competitiveness of this process, and are generally familiar with doing so.

It is important to emphasize that the regulatory burden of portfolio pre-approval and monitoring of least-cost bidding are only necessary to the extent that unbundling and direct competition for retail customers are not implemented. In effect, portfolio pre-approval and least-cost bidding requirements are imperfect methods for replicating the price discipline that competition would otherwise create. The imprecision and cumbersome nature of these procedures are strong arguments in favor of the transition to competition as the solution to the problem of ensuring that acquisition behavior is efficient.

The new era of relying on competitive markets to achieve public policy objectives with respect to public utilities and environmental protection makes the jobs of PUCs much harder. To get the maximum social benefit from these policy innovations, regulated firms must be given incentives to participate in these complicated, evolving markets. There is a grave danger that the adoption of simplistic rules for evaluating the actions of regulated firms in these markets will stifle their development and thereby reduce the social benefits that are potentially available from deregulation and the use of market-based approaches to environmental protection.

Regulatory reform and the evolution of new policy inevitably move with a "two steps forward, one step back" pattern. The unwinding of the old system of regulated fixed-price contracts governing fuel acquisition in favor of markets, and the development of an active and visible spot market for gas, are extremely important and have benefitted consumers greatly. We are now on the threshold of the next major step forward, in which the structure of these gas markets will widen and deepen, again to the benefit of the ultimate consumer. The same potential for gain exists in environmental policy. The innovative regulatory regime created by the 1990 Clean Air Act Amendments offers the potential to achieve significant pollution reductions at a cost far less than would be possible with traditional regulatory tools. It would be unfortunate indeed if these market processes in gas procurement and emission allowances were stifled in their infancy because of inadequate understanding of what competitive markets are all about.

OVERSIGHT OF REGULATED UTILITIES' FUEL SUPPLY CONTRACTS:

ACHIEVING MAXIMUM BENEFIT FROM COMPETITIVE NATURAL GAS AND EMISSION ALLOWANCE MARKETS

By Adam B. Jaffe and Joseph P. Kalt

I. INTRODUCTION

There has been a dramatic change in recent years in the role of markets and competition in achieving the nation's economic policy objectives. In public utility regulation of sectors as diverse as telecommunications and natural gas pipelines, this has taken the form of a wave of deregulation, unbundling of regulated and unregulated services, and increased reliance on markets and competition to determine prices and industry structure. In environmental regulation, the passage of the Clean Air Act Amendments of 1990 took a major step in implementing the use of economic incentive-based approaches to controlling environmental externalities through a system of tradeable emission allowances for the control of sulphur dioxide (SO_2) emissions. It is probably not a coincidence that the same time period also saw the collapse of "command and control" economic systems in the former Soviet bloc. It is a heady time for economists and other advocates of competitive market systems.

In the case of natural gas, the industry has been rocked — for the better — by an emphatic turn in federal policy over the last fifteen years. After decades of well-intentioned but ultimately infeasible policies of government planning and direction, the watchwords are now "competition", "market forces", and "incentive-based regulation". Gas producers are now free to price and market as they see fit, constrained by intense competition to serve the public's interest in an efficient industry. Long-distance pipelines face regulation that is designed to mimic competition in those transportation functions where natural monopoly remains a concern, but are compelled to compete on equal footing with a multitude of other shippers when they want to ship on their systems in their role as merchants of gas. With the new-found ability to "rent" space on pipelines, a full array of shippers, marketers, brokers, hedgers, and speculators has been created by the marketplace to serve the role of directing gas supplies to the uses that are most highly valued by the nation's economy.

It is fair to say that most state-level policies and public utility commissions (PUCs) governing local gas distribution and gas-using electric utilities have lagged behind, and in some cases are out of sync with, the recent reforms of federal policy. Just as non-market economies around the world have been learning, PUCs are finding that unleashed markets are remarkably fluid and complicated. Yet, regulated firms' participation in these markets raises a host of new regulatory issues. With so many new options and players to contend with, state policy makers are struggling with how to fulfill their mandated obligations to ensure the consuming public that local utilities are behaving prudently, and that they are providing gas and electricity under just and reasonable terms.

The policies that PUCs follow with respect to their oversight of utilities' gas procurement decisions will play a preeminent role from here forward in determining the performance of the nation's gas industry. PUC policies have the ability to enhance or inhibit the evolution of efficient and innovative gas markets — and the stakes are large. By all accounts, domestically produced natural gas is a relatively abundant and environmentally appealing energy source for the future. The development, movement and use of natural gas, however, will require *investment* — from the well in the ground and the pipeline that taps that well to the residential furnace and the electricity-generating turbine.

Similarly, PUCs have only begun to struggle with the regulatory issues raised for them by the creation of the SO_2 emission allowance market. As with gas, participation in these markets will involve a set of options and players with which PUCs are not familiar. The efficient functioning of this market will depend on the kinds of incentives created by PUCs' treatment of allowance sales and purchases. Because allowance trading raises many of the same issues of PUC approval of actions taken in competitive markets, it is likely that PUC decisions regarding regulatory treatment of gas purchase decisions will have a significant influence on the evolution of the allowance market as well.

Of central concern in the regulatory oversight of utilities' gas procurement and environmental compliance decisions is whether that oversight will distort or enhance investment incentives. The range of possible outcomes is broad because state policy makers have so many possible approaches. Should PUCs second-guess utilities' procurement decisions? Should they try to plan such decisions with or for utilities? Should utilities' recovery of gas and allowance purchase costs be pre-approved? Should recovery be determined after-the-fact by reference to some *ex post* benchmark such as spot prices or other utilities' procurement costs? The states' answers to these questions will affect the procurement and contracting incentives and options of gas distribution and electric utilities. In so doing, the states will directly impact utilities' investment decisions, and indirectly affect the investment decisions of other market participants who are linked to utilities' fuel and pollution abatement choices.

This study addresses the appropriate structure and function of gas contracts and, to a lesser extent, the efficient evolution of emission allowance trading. We also examine the concomitant implications for PUC prudence standards in gas procurement and allowance purchases and sales. There has been considerable recent interest among policy makers and policy analysts in the possibility that the gas spot market can reveal a single "true" market value for natural gas. Indeed, the loosening of the bonds of regulation and the spread of competition to heretofore tightly-controlled market structures has engendered contractual arrangements with increased degrees of price flexibility.[1] The implication has been drawn that utilities ought to be compelled to procure gas only on spot market terms or, at least, be subjected to *ex post* gas cost recovery capped by spot market prices.[2] Moving from the observation that there has been a movement toward greater price flexibility in natural gas contracts to the conclusion that only perfectly spot-responsive contracts should be allowed to prevail is poor public policy.

We find that competitive, efficient gas markets with deregulated sales and unbundled transportation support a rich array of contractual forms in terms of both price flexibility and duration. Indeed, this variety is one of the most desirable aspects of a well-functioning gas procurement marketplace. It represents the matching of multiple products to the heterogenous needs, desires and risk-bearing capacities of gas customers. Outguessing the complexity of the marketplace through implementation of "spot market pricing only" prudence standards would be likely to reduce the viability of long-term contracts with varying forms of price guarantees and risk allocation terms. In so doing, "spot only" PUC policies for gas and emission allowance procurement would increase investment risks for producers, gas-distributing and gas-using utilities, and gas-using pollution abatement strategies — ultimately to the detriment of the consuming public.

The compelling matter confronting public utility commissions is not whether the spot market is *the* competitive market for gas. Rather, the real issue is the derivation of prudence standards and policies that provide undistorted incentives for utilities to use markets efficiently. Such policies must recognize and promote the complexity and fluidity produced by market forces. We investigate a number of possible approaches below and find particular strength in prudence policies that commit regulators to pre-approval of portfolio strategies for contractual mix and require utilities to live by the results of competitive bidding for the various components of their portfolios.

Section II below reviews the recent history of natural gas markets and policies, with emphasis on the implications for the choices being created for gas buyers. In Section III, we investigate the basic economic forces underlying contracts, investment, and risk. Section IV applies this economic reasoning to the acquisition strategies of gas distribution companies, with attention to the implications of alternative contractual options, and to the interrelated decisions of electricity generators regarding fuel purchase, investment, and Clean Air Act compliance. In Section V, we examine alternative prudence policies that state regulators might adopt, and Section VI provides a summary.

II. THE RECENT EVOLUTION OF GAS POLICY AND MARKETS

II.A The Driving Role of Federal Policy. The nation's natural gas industry has undergone revolutionary change since the late 1970s. In earlier days, virtually every stage and facet of the industry was subject to intensive federal or state oversight. Wellhead prices received by producers in their interstate sales were capped by federal authority at well below market levels. Interstate pipelines had their construction, terms and areas of service, rates of return, and resale prices for the natural gas they bought, shipped and resold meticulously controlled by a national level "public utility commission". At the retail level, local distribution companies (LDCs) operated as franchise monopolies, with state public utility regulators governing their rates of return, territories of operation, price and service offerings, and the prudence of their decisions.[3]

In this environment, prices at each stage of the natural gas industry served primarily as cost-recovery devices, as prescribed by traditional fair rate of return principles applicable to regulated public utility firms.[4] The price mechanism of the marketplace was stripped of much of its role of channeling available supplies to willing buyers. With prices, entry, terms and conditions of service, and geographic markets relegated to the courtroom and the rate hearing, little scope was left for competition by which sellers might otherwise try to attract and hold customers and by which gas buyers might otherwise search for gas supplies, transportation, storage, and reliability of price and volume.

Such pervasive subjugation of the forces of the marketplace eventually yielded the lessons that we have recently seen demonstrated so vividly in non-market economies around the world: shortages, sharply reduced choices for buyers, and stark disincentives for sellers to be innovative and cost efficient. In the 1970s, rapidly rising oil prices encouraged consumers to try to switch toward other fuels and, thereby, jacked up gas demand dramatically. This increase in demand could not be satisfied, however. Prices capped from wellhead to burner tip at below market-clearing levels did nothing to either discourage the gas consumption levels consumers desired or encourage the supply expansions that could have satisfied those desires. By the middle of the decade, shortages, involuntary curtailments and supply emergencies were widespread; and the rationing of gas became overwhelmingly a *political* process at both the federal and state levels. The country's natural gas industry was being pulled further and further down the path toward a system of government planning and bureaucratic management.

The beginnings of a permanent solution to the abysmal performance of natural gas policy can be marked by the passage of the Natural Gas Policy Act of 1978 (NGPA). The NGPA launched the necessary process of wellhead price decontrol — a process that was finally completed on January 1, 1993. As wellhead markets began to clear, competition began to emerge and buyers could find the supplies they desired if they were willing to pay market prices. A sharp downturn in natural gas prices in the early 1980s (accompanying recession and softening oil prices) gave a powerful charge to gas buyers' interests in being able to shop around for their fuel supplies. These were thwarted, however, by regulatory rationing rules originally adopted to deal with shortages. Pipelines, for example, had been required to back up their sales commitments to LDCs with very long-term and inflexible (typically ceiling) price contracts with producers. LDCs and other intermediate gas buyers were restricted from dealing with marketers other than the one (or few) pipeline(s) licensed ("certificated") to serve them. End-use customers were prevented from bypassing their LDCs in order to arrange for their own supplies.

What the marketplace needed to operate effectively was the capability for buyers to shop around. To do this, buyers needed flexible access to long-distance and local transportation alternatives so that delivery could be arranged for gas from a wide array of emerging decontrolled upstream supply options. In particular, if gas-buying LDCs, industrial users, and marketers were to reach producers directly, they would have to be able to buy transportation service as an unbundled separate product from the merchant pipelines that had traditionally sold them gas.[5] The impetus for fundamental change came from the Federal Government.

The unbundling of pipeline transportation began in earnest with Special Marketing Programs (SMPs) authorized by the Federal Energy Regulatory Commission (FERC) in 1983. (A summary of major federal regulatory developments is provided in Appendix 1.) SMPs enabled "non-core" (primarily large industrial) pipeline customers to arrange their own gas supplies, albeit to be delivered on their certificated pipeline carriers. The federal courts, however, ruled in 1985 that SMPs were illegally discriminatory against pipelines' core customers, who also might wish to benefit from competition in upstream markets. This spurred the FERC in October 1985 to adopt Order 436 (later modified by court rulings and FERC Order 500). Order 436 allowed pipelines to convert "contract demand" (i.e., their gas sales volume commitments) to commitments of guaranteed ("firm") transportation capacity; transportation capacity could be sold by pipelines on an "interruptible" basis when contract demand customers were not using it. Downstream gas buyers, including LDCs, industrial users, electric utilities, and independent marketers now had access to unbundled transportation.

The unbundling of pipeline transportation from pipelines' sales as gas merchants has not meant that pipelines can charge anything they want for their transportation services. Rather, these services have remained subject to cost-of-service regulation under public utility principles of just and reasonable rate making. Unfortunately, on pipelines with relatively strong demand and aging embedded costs, this has meant prices (rates) for firm transportation service that have been below the levels at which supplies and demands for such service can be brought into balance. Pipelines offering firm capacity under such circumstances find themselves oversubscribed, with traditional contract demand customers (primarily LDCs) having *de jure* and *de facto* first call. As a result, the first call customers acquire a valuable rent-bearing right —a right to guaranteed transportation that is worth more than they pay for it. Not surprisingly, these customers are reluctant to relinquish capacity claims; and the development of a market in firm pipeline transportation capacity has been slow.[6]

After investigating a number of alternatives, ranging from "market-based" rate design to auctions of capacity claims,[7] the FERC weakened the "grandfathering" of traditional customers' priorities to firm service. This was done under Order 490 in 1988, which allowed abandonment of service obligations upon expiration or renegotiation of firm sales contracts. The FERC then followed with its Order 636 in 1992, allowing capacity claims to be released by their holders into a capacity brokering market. It appears that a firm transportation market is now becoming well established; gas carried under firm transportation totaled more than 40% of total shipments in 1992, up from less than 10% in 1988.[8] This is providing shippers with reliable transportation options that can be coupled with the gas supplies they arrange. At least in federal policy, the primary pieces are now in

place for LDCs, electricity generators, industrial and commercial users, gas marketing companies, and risk-taking brokers and speculators to operate across a wide spectrum of gas customers and services.

II.B The Scope and Theory of Remaining Regulation. The unbundling of transportation from pipelines' gas sales has placed parties with claims on pipeline capacity and interruptible shippers in competition with pipelines' merchant (gas resales) business. This has compelled policy makers to confront the issues of the conditions of service and prices at which firm and interruptible shippers should be able to buy transportation from pipelines. Obviously, completely unregulated pipelines could have incentives to tilt the playing field in their favor. Pipelines, however, remain heavily regulated.

The underlying push of federal pipeline regulation in this era of open access and unbundling is to expand the scope and force of marketplace discipline into each facet of the business. The objectives are to foster an industry in which prices reflect true scarcity and value, to spur cost efficiency, to encourage innovation, to open up producers' alternatives for selling their gas, and to expand customers' options for tailoring their acquisition choices over price, reliability, location, and timing to their needs. The expansion of marketplace discipline, in turn, means substituting competition for regulation into each segment of the market from wellhead to burner tip so long as conditions of natural monopoly (or oligopoly) are absent.

"Natural" monopoly arises when unregulated markets allow a single firm to dominate a market by virtue of economies of large scale (size) or wide scope (across functions or products) which can give that firm a cost advantage over any combination of multiple, smaller firms. In the natural gas industry, the most compelling evidence of potential natural monopoly arises in the transportation functions (both long-distance and local distribution), where the technology of pipelines and networks often makes costs rise less than proportionately when the volumetric capacity of a tubular system is expanded.[9] As a result, unit costs of providing service decline as firms get larger, and a single large firm in competition with smaller rivals may "naturally" be able to underprice them and leave itself the sole survivor.[10]

Notwithstanding prospects for natural monopoly in pipeline systems, many other aspects of getting gas from the wellhead to the ultimate customer are generally subject to competition — at least when market participants have access to transportation on terms comparable to those confronted by pipelines-as-merchants. These include such functions as gas exploration and development, the arranging of supplies with producers, the arranging of transportation and storage, the agglomeration of supply portfolios, the marketing of supplies to customers, the buying and selling of risks through contractual options, the arbitraging of price and sales-term differences, and the aggregation of multiple customers into buying agents. For activities such as these, competition can serve as the regulator of performance.

The benefits of competition are founded in its ability to serve consumers and avoid waste. Competition tends to push revenues toward costs (where costs include a rate of return sufficient to attract and hold capital). Competition also leads to prices that are based on marginal costs, i.e.,

Figure1

PARTICPANTS AND THEIR ROLES IN THE NATURAL GAS MARKETPLACE

Participant	Role	Regulator
Producer	Seller/Producer	None
Pipeline	Transporter	FERC
	Gas Reseller	FERC
	Local Distribution Company Supplier	FERC
	Main Line Industrial Supplier	FERC Certificate/State PUC Tariffs
	Electric Utility Supplier	FERC Certificate/State PUC Tariffs
	Storage Operator	FERC /State
Local Distribution Company	Local Distribution	State PUC
	Transporter	State PUC
	Gas Reseller	State PUC
	Storage Operator	State PUC
Marketer/Broker/ Agent	Buyer	None
	Broker	None
	Transport Arranger	None
	Pipeline Capacity Buyer	FERC
	Supply/Customer Aggregator	None
New York Merchantile Exchange	Futures Market	CFTC
Financial Institutions/ Commodity Traders	Risk Intermediation	None (Banks' Capital regulated by Fed)
	Arbitrage	None

Source: Energy Information Administration, Growth in Unbundled Natural Gas Transportation Services

the costs of bringing incremental output into an industry. As a result, if prices are not sufficient to cover an industry's cost of attracting needed inputs away from other sectors, where revenues from buyers are also being used to compete for inputs, the industry stops expanding. In this way, the tendency for price to equal marginal cost in competitive industries strikes an appropriate balance between consumers' alternative desires. Finally, competition also tends to weed out the inefficient. The customers of companies that cannot keep their costs at or below market-wide prices have elsewhere to go. This discipline on firms also spurs innovation as sellers seek out at least temporary advantage by finding otherwise unfulfilled desires or lower-cost strategies.

In accord with the benefits of competition, federal policy now generally seeks to leave competitively supplied services unregulated (or subject to only light-handed regulation).[11] The result has been a burst of new players and new products that have arisen to seek out previously unmet marketplace demands in the gas industry. This change in industry structure is suggested by the rise in unbundled transportation service noted above and summarized by the description of market participants contained in Figure 1.

II.C The Predicament of State Regulatory Authorities. The regulatory ball is now in the court of the state PUCs. Still armed for the most part with the regulatory apparatus of an earlier era, the PUCs confront an environment in which the companies under their jurisdiction operate in a drastically changed environment. LDCs now face: (1) a hugely expanded array of options for securing gas supplies; (2) an equally expansive set of gas transportation choices; (3) increased head-to-head competition on both the sellers' and buyers' sides of their procurement efforts; (4) increased head-to-head competition among transportation providers; (5) demands and opportunities for the release or other brokering of both gas and interstate pipeline capacity claims; (6) federal policies to increase head-to-head competition between electricity generators; and (7) federal moves designed to increase head-to-head competition between gas-selling LDCs and (often unregulated) "bypassing" alternatives for traditionally LDC-served customers. Gone are the days when the franchise monopoly utility seeking gas supplies could simply count on 20- to 30-year, regulated-below-market, fixed-price (or inflexible-price) contracts with one or a few dedicated interstate pipelines. And gone are the days when the franchise monopoly electric utility could count on periodic installation of utility-owned mega-units for which operational reliability received more attention than fuel choice, cost volatility and environmental acceptability.

Faced with vastly increased complexity in the marketplace and limited administrative resources, it is perhaps not surprising that state regulators would be tempted to adopt reactive and conservative responses. Indeed, to date, progress on reform has been meager. Unbundled open access to the portion of transportation service under PUC jurisdiction — i.e., the local gas distribution system — is typically available only on an interruptible basis. Most states protect their LDCs from competitive entry, and rate structures often are designed to protect favored classes of customers.[12] "Vanilla" service offerings dominated by simple guaranteed firm service for residential customers and non-price-determined interruptible priorities for less-favored classes are the norm.[13]

The notion of a local regulated utility "playing the market" for fuel, transportation, storage, pollution abatement allowances or electricity itself as buyer, seller, broker, arbitrageur, investor and/or risk hedger can be anathema to regulatory concepts of long-range planning and stable procedure. Nevertheless, learning to "play" in these ways is important to the promotion of fuel and power sectors that are efficient, responsive to changing local and global supply and demand forces, and able to yield (or at least mimic) the results of competitive forces.

Natural gas is a major and environmentally attractive domestic energy source, with the potential to remain so well into the next century. For example, as shown in

Figure 2

PROJECTED SHARES OF GENERATION BY FUEL TYPE: 1990 AND 2010

	1990	2010
COAL	52%	53%
OIL	4%	4%
GAS	12%	17%
NUCLEAR	19%	14%
RENEWABLE/OTHER	12%	12%

SOURCE: Energy Information Administration, Annual Energy Outlook 1992

Figure 2, the Department of Energy (DOE) projects that natural gas could account for 17% of electricity generated in the U.S. by 2010, up from only 12% in 1990.[14] Total gas consumption in all uses is projected to increase by 21% by 2010, according to DOE.[15] These prospects are driven in large part by the relative abundance of gas reserves, estimated at over 60 years' capacity at current rates of consumption out of currently recoverable reserves, and approximately double that amount out of future additions to recoverable reserves.[16] The development of cost-effective gas-using technologies over the last two decades is also spurring gas demand. As shown in Figure 3, the capital costs of gas-fired electric generating units now make such units competitive options for both utilities and non-utility generators. In addition, an increasing

common feature of any well-functioning modern economy.[20] Of course, contracts in a competitive gas market are likely to take considerably different forms from those under regulation, precisely because they serve different functions. Thus, " long-term gas contracts" are not necessarily limited to the 15-year or longer, fixed- or regulated-price, take-or-pay contracts that were common under regulation. Instead, one of the most important features of a competitive market, and one of its most important advantages over regulated markets, is diversity of contractual forms and relationships. Different buyers and sellers have different needs and different abilities to control the costs of engaging in gas-acquisition transactions and to mitigate risks in those transactions. As a result, a wide variety of contractual relationships evolve in competitive markets. This process has only recently begun for gas, and it is likely to continue for some time to come. It is barely beginning to operate for emission allowances.

Economic analysis identifies two broad categories of benefits created by long-term contracts: transactions cost reduction and optimal risk allocation. In the present context, reduction of transactions costs revolves primarily around the issues of contract negotiation, monitoring and enforcement and the problem of ensuring adequate reliability of physical supplies. These matters are discussed in the next subsection. Risk allocation in gas contracting is affected primarily by pricing and price volatility. This is taken up in the subsequent subsection.

III.B Contracts and Transactions Cost Minimization. The most widespread function of contractual relationships in a market economy is to minimize transactions costs. In the simplest economic theory, there are no costs associated with using the market. But this does not apply to real markets. Even the most efficient markets, such as organized commodity and financial exchanges, have associated costs. There are many sources of such costs, including: information acquisition; transaction making, recording and verification; and dispute resolution. These costs may not be large for any single transaction, but for many repeated transactions they can accumulate to consume significant resources. Indeed, a great deal of what is often referred to as "company overhead" —management, analysts, accountants, attorneys, consultants and even office space and expenses —is associated with the costs of initiating, striking and carrying out transactions.

A party that transacts as a buyer or a seller repeatedly in the same commodity frequently can reduce transactions costs through the use of contracting. On the simplest level, contracting exploits the fact that many transactions costs need be incurred only once. By contracting for purchases over a period of time, cumulative transactions costs can be reduced. On a deeper level, contracting allows parties to develop a long-term relationship with one another. If this relationship has value to both parties, then the very existence of the relationship reduces transactions costs by giving the parties incentives not to be opportunistic at the other's expense. In addition, the creation of a long-term relationship makes it cost-effective to invest legal, managerial and other resources in negotiating special arrangements to deal with issues of non-performance, dispute resolution, and renegotiation. This allows the parties to long-term contracts to deal with each other more flexibly than is possible in standardized arm's-length transactions.

Another aspect of transactions cost minimization relates to the combining of related products and services. Spot market gas transactions, for example, require the arrangement of the gas purchase and the necessary gas transportation such that both are in approximate synchronization. This creates a coordination problem, the solution to which incurs transactions costs. In the context of a long-term contract, durable purchase and transportation arrangements may be more easily made in tandem, replacing a repeated coordination problem with a one-time one.

Contracting also permits the diversification of supply risks. A gas purchaser that depends on the spot market will be highly exposed to fluctuations in spot market conditions. The buyer may find its suppliers in danger of non-performance precisely when circumstances which tend to make spot markets tight occur, including periods of extreme weather or breakdown of physical delivery systems. Contracting allows the creation of a portfolio of supplies with different kinds of reliability and different forms of guarantees and options in the event of problems. In this way it is less likely that all suppliers will be creating problems at the same time.

Our discussion so far has assumed implicitly that the buyer of a commodity like natural gas would itself hold contracts of varying forms, thereby diversifying risk and reducing transactions costs. But the logic of transactions cost minimization can drive the process even further. Depending on transactions costs, a buyer may choose to hire or deal with specialists, such as brokers and marketers, to arrange all its supplies. This strategy can permit a multiplicity of supply contracts to be replaced by one or a few contracts with specialists. Such specialists, by arranging and managing supplies for many buyers, can economize further on the investment in understanding many different contracting options, monitoring market conditions, working out disputes, and so forth. Of course, specialist marketers and brokers can be expected to charge a price for "gas", which differs from the "spot" price, in order to compensate themselves for their efforts. Buyers may readily find that they are better off paying this price than arranging all of their own supplies and paying the full complement of salaries, benefits, travel expenses, legal fees and other costs of a purchasing department, analytic staff, in-house law department, etc.

The advantages of specialists are not limited only to small companies. The stock market, for example, is an extremely thick and well-developed "spot" market in which even the very smallest can participate. Yet, an institution such as Harvard University chooses to hire outside managers to oversee its multi-billion dollar endowment; and most

large companies, unions and public entities handle their pension funds similarly. Despite the size of the investment and the magnitude of the transactions involved, these institutions have concluded that it is cheaper for them to pay a management fee than to acquire the necessary expertise for internal management of these transactions.

The extreme of a gas-using utility holding a single contract with a specialist "transactions manager" for all its gas is not likely to be efficient for most buyers. Instead, what can be expected to emerge in a competitive market is a variety of contractual forms, each of which carries embedded within it varying degrees of "transactions management" services. Needless to say, the prices of these different bundles of "gas"and "transactions management" will not all be identical. If the market for "gas transaction management services" is sufficiently competitive, however, all of these different prices should be considered competitive market prices.

This last conclusion belies the use of solely spot-price-based prudency standards by PUC's concerned about the efficacy of LDC procurement strategies. One of the most desirable characteristics of a competitive and efficient gas market is a multiplicity of contracts. Contract variety permits buyers and sellers, perhaps with the aid of specialist intermediaries, to tailor their relationship to fit their specific circumstances. The existence of more complicated market interactions than arm's-length spot transactions makes it difficult to identify "the" market price: there is no single, "standard" commodity that is being routinely traded.

III.C Management of Price Risk. The discussion thus far has considered transactions costs and risks associated with the physical delivery of a commodity. Substantial risks are also associated with uncertainty about prices of commodities such as natural gas. These risks arise with the greatest force when buyers and sellers must make long-lived investments whose ultimate profitability is a function of future prices. If individuals (stockholders, managers, workers, consumers) are risk averse, then price risk is a real cost to society: the economic agents who bear risk are worse off as a result. To get a risk averse investor to voluntarily bear risk generally requires compensation. This is another way of saying that risk raises the cost of capital; and this is the source of the social costs of risk — it discourages investment.

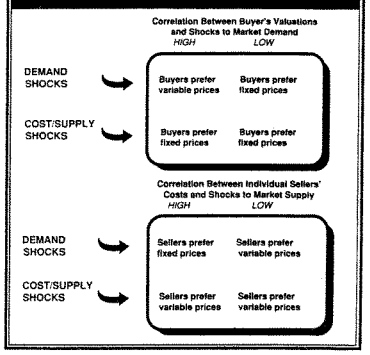
The impact of risk on the cost of capital is the reason that raising capital through the issuance of equity is more expensive than issuing debt. Stockholders stand in line behind bondholders in the event of a bankruptcy or liquidation and, hence, they face a higher probability of going home empty handed. In fact, the cost of debt is itself a function of the riskiness of the debt.[21] A major factor in judging the riskiness of debt is volatility in a firm's net flows because such volatility raises the probability of there being inadequate funds available to make debt payments. To the extent that commodity prices affect cash flows, uncertainty about future prices increases risk and raises the costs of acquiring capital from investors.

Risk can never be completely eliminated. The cost to society that the risk represents will depend, however, on where and how it is borne. An important function of long-term contracts, beyond the transactions cost minimization described above, is to reduce the cost to the parties of the risks associated with the underlying transactions. Contracts do this in two ways. First, appropriate structuring of the terms of a contract can minimize risk. Second, a contract can allocate risk to those parties who can bear it most efficiently — i.e., at least cost. As with the discussion of reliability and transactions cost management above, these risk management functions of contracts provide an additional dimension along which the "product" contained in particular contracts can differ. A contract for "gas", for example, may also provide for varying amounts of risk management services and will be priced accordingly.

To the extent that a buyer agrees to contract terms that reduce the risks borne by the seller, the price of "gas" in a contract can be lower than the analogous spot market price. For example, a contract with a price indexed to the spot market price, but which contains a minimum price that will be paid even if the spot price goes lower, could be expected to contain a discount to compensate the buyers for the "insurance" against low gas prices that this contract provides the seller. Conversely, gas prices under a contract in which a seller takes on risks otherwise borne by the buyer can be expected to exceed the analogous spot prices.

Figure 4

WHEN DO BUYERS AND SELLERS WANT FIXED PRICES



One way to use long-term contracts to mitigate risk is to use them to agree on pricing rules that have the effect of reducing price volatility relative to what occurs in related spot markets. Economists have analyzed the

factors that determine whether contractual price fixity reduces overall risk.[22] These factors include the relative risk aversion of buyers and sellers, the sources of uncertainty about spot prices, and the degree of correlation between individuals' supply (cost)/demand (willingness-to-pay) schedules and those of the market. Figure 4 summarizes key combinations of these factors.

Suppose, for example, buyers are more risk averse than sellers, the main source of uncertainty is fluctuations in demand, and fluctuations in individual demands are highly correlated with those of overall market demand. These conditions mean that prices are uncertain because buyers' future valuations of the commodity are uncertain; if those valuations are high, then prices will be high, and vice versa. Further, since individual demands of market participants are highly correlated, then when buyers' valuations are generally high, each individual buyer's valuation is high. Under these assumptions, allowing contract prices to vary with contemporaneous spot prices actually minimizes risk: prices are high exactly when buyers' valuations of the commodity are high and the buyers are willing to pay dearly for a product. Because of the assumption that buyers are more risk averse than sellers, it is the relationship between the price and the buyers' valuations that carries the greatest cost of risk. Under these assumptions, contractual price fixity would not be desirable; it creates the possibility of the (fixed) price being high at a time when the buyer's valuation is low.

Similarly, if it is sellers who are most risk averse, uncertainty comes from the supply side, and individual sellers' costs (supply curves) are highly correlated with each other, then spot-pricing is risk-minimizing. The reason is that spot prices are most likely to change when costs change throughout an industry, rather than when only one or a few firms' costs change. With high correlation between all sellers' cost changes, individual sellers will be able to count on prices being high when their costs are high. To a risk averse seller, this is preferred to risking the chance that a fixed sales price under a contract could leave it with losses when production costs are high and rising.

Alternatively, suppose it is sellers who are most risk averse, but the primary source of uncertainty is on the demand side. In that case, fixed prices mitigate the cost of risk. The reason is that demand-side uncertainty causes variations in spot prices that are unrelated to the sellers' costs. Thus, spot pricing will create large fluctuations in net cash flows and subject sellers to the possibility that prices will be soft when costs are high. The prospect of such a threat of losses means that risk averse producers will be worse off with spot pricing. By contracting at prices that vary less than spot, producers can reduce threatening fluctuations in net cash flows. The same result follows when the main source of uncertainty is on the supply side, but individual producers' cost curves are not well correlated with the market supply curve.[23] Such circumstances, again, imply that contractual price fixity would mitigate risk, by reducing fluctuations in risk averse producers' net cash flows.[24]

Application of the analysis underlying Figure 4 is particularly complicated in the context of emission allowance markets because there is not a clear delineation between buyers and sellers: any polluting or potentially polluting firm could be either a buyer or a seller, depending on its control costs relative to the control costs of the marginal polluter (whose costs of abatement will determine the spot price for allowances). Nevertheless, a key factor will be the extent of correlation of individual firms' valuations of allowances. For example, once a firm makes a decision to install a scrubber or build a gas-fired facility (and sell the allowances thereby generated), its "production costs" for the associated allowance sales have been largely sunk. If the cost of compliance (and hence the price of allowances) falls in the future, that fall will not benefit the firm whose compliance decisions have already been made. On the buyer side, if a firm has made the decision to forego construction of a scrubber and rely instead on allowance purchases, a decline in control costs (and hence the price of allowances) may not translate into a decline in the buyer's willingness to pay for allowances, since the lead times necessary for scrubber construction may make that option infeasible anyway.[25] Hence, it would appear that, like the situation in which an individual gas producer's costs are not highly correlated with the market's supply schedule, sellers and buyers of allowances are likely to demand relatively fixed prices over spot prices.

In natural gas markets, the analysis underlying Figure 4 can be seen through simple, albeit hypothetical, examples. Gas buyers who are risk averse and use gas in industrial processes, for instance, are likely to prefer fuel supply contracts with relatively fixed prices. Their willingness to pay for gas is largely derived from the strength of the manufactured goods markets in which they sell. Their valuation of gas is unlikely to fluctuate with many of the forces that drive gas prices (such as the seasons of the year). Hence, reliance solely on spot market gas can subject them to fluctuations in net cash flow and periods in which their gas costs are high but their output market revenues are weak. Gas users in such settings can be expected to be willing to pay premiums for price fixity as insurance against cash flow changes driven by volatility in the gas market.

A typical gas producer might also desire price fixity in its sales. Most of the costs of producing wells are sunk costs; they do not fluctuate with gas prices. Thus, dependence on fluctuating spot prices could be expected to subject a producer's net cash flows to relatively high volatility. A risk averse producer in such circumstances would prefer to operate under contracts with some degree of price fixity. In fact, if such a producer meets the industrial gas user (as described above) in the marketplace, they can be expected to strike a contract embodying price fixity.

Whether or not the resulting contract prices in this example would be at levels that are higher, lower, or equal to the spot prices the parties would otherwise face cannot be determined *a priori*. Even if they agree on their forecasts of spot prices, contract prices will be determined by the relative strength of the parties' respective susceptibilities to the volatility of net cash flows that is attributable to spot gas price fluctuations, as well as their respective aversions to risk. If, for example, the gas user is strongly risk averse compared to the producer, it could reasonably turn out that the contract would set prices with little or no flexibility at a level higher than expected spot prices and for an extended period of time. The premium would compensate the gas producer for providing relatively more gas under fixed prices than the producer might have preferred as the less risk averse party and in light of the options that commitment to a long-term contract would cut off.[26]

The discussion to this point has not addressed how long is "long term." If the risk preferences of the buyer and the seller favor price stability, one might expect them to "lock in" a price for the life of their agreement, which may be as long as the life of the underlying "sunk" investments; in the case of pipeline or electricity generation capital this can be 20 or 30 years or more. Contracts with prices fixed for such long durations appear to be relatively uncommon in most commodity markets.[27] Apparently, there are incentives that act to limit the desirability of permanently and completely fixing prices. Most significantly, as we look farther into the future, uncertainty about prices increases. This has two effects. First, as the time horizon of price fixity expands, it becomes increasingly unlikely that parties will be able to agree on the expected prices against which to assess their future options. Indeed, they may not even trust their own ability to forecast it with any reliability. Second, this rise in uncertainty as contract length increases raises the chances that any agreed-upon fixed price will diverge greatly from the realized spot price at some time in the future. While this possibility is exactly what the parties would like to be able to protect themselves from, large divergences create incentives for the parties to breach the contract, either voluntarily or because of binding financial constraints. Such contractual difficulties are expensive for both parties. At some point, the cost associated with higher probabilities of contractual disagreement outweigh the benefits of reduced price volatility. Therefore, the optimal contract may fix the price for some period of time, but not necessarily for the life of the contract, or may reduce the amount of price fluctuation (relative to a spot price) without completely fixing the price by tying price changes under the contract to agreed-upon formulas.

How the tradeoff between price stability and costs associated with long-term price fixity is resolved depends to some extent on legal and marketplace institutions and conventions. It can therefore evolve over time. One institutional solution to the conflict between price stability and contractual difficulties is vertical integration of buyer and seller. Vertical integration internalizes price risk to a single company and essentially eliminates contracting costs (although the vertically-joined divisions of the company still have to work out their relationship and accounting procedures). Conditions that would make extremely long fixed-price commodity contracts attractive can make vertical integration even more desirable.[28] In the absence of past and present regulatory constraints (such as the Public Utility Holding Company Act), it is quite likely that there would be more vertical integration in the gas industry, obviating some of the need for long-term contracts. Since vertical integration is, in a sense, the most extreme form of long-term contract, an industry in which vertical integration is desirable but not achievable is likely to be an industry in which long-term contracts are particularly desirable.

The costs and risks associated with contractual difficulties in long-term fixed price contracts can also be mitigated by the development of more extensive market institutions. In particular, the existence of "secondary" markets for commodity contracts (discussed below) can reduce contractual strains. If contracts can be freely traded to other parties on a "thick" secondary market, then contracts with prices that diverge from spot simply will be marked down (or up, accordingly) on a more or less continuous basis. This allows the "pressure" created by deviations between spot and contract prices to be dissipated gradually rather than continuing to build.[29] Further, the market-makers in these secondary markets are typically large, sophisticated financial and commodity trading firms, making the risk of default because of credit problems quite remote.

III.D Financial Markets and the Management of Risk. In a sense, management of risk is the key function of financial markets. In our context, we can think of financial markets as permitting the separation of the price risk inherent in a commodity contract from the other attributes of the transaction. This is extremely important. As noted above, parties to a contract can try to structure it to allocate the risk between themselves in the lowest-cost way. But in many commercial situations, the direct parties to a transaction will have only limited ability to bear and manage the risk. By separating the risk from the rest of the transaction and passing it on to other parties, the chances of finding someone who can bear it at low cost are increased. With well-developed financial markets, the set of possible risk bearers is essentially unlimited, and hence, the efficiency of risk bearing is greatly increased.

The simplest example of this sort of "risk shedding" is the hedging of a supply contract through an organized futures exchange. In an organized futures exchange, parties exchange commitments to deliver a standardized form of a physical commodity (e.g. natural gas at a particular pipeline interconnection in Louisiana) on

particular dates. For example, the New York Mercantile Exchange (NYMEX) can be used today to buy the right to receive a given quantity of gas up to 18 months in the future. Similarly, commitments to deliver up to 18 months hence can be "sold" on NYMEX. The key feature of an organized futures exchange is that the prices for these future commitments change continuously, just like the price of a share of stock. Much of the participation in these markets is so-called "paper" trading: many of the buyers and sellers never actually make delivery (or take possession) of the commodity that they have sold (or bought). Rather, they close out their position on the exchange before the delivery date arrives.

The existence of an organized exchange allows either party to a commodity supply contract to convert a fixed-price contract into a flexible one and vice versa. For example, consider a producer who has agreed to sell gas over the next year at a price tied to the spot price at the time of delivery. Suppose the producer desires to lock-in a known cash flow, rather than face the risk that spot prices may fall significantly. The producer can use the futures exchange to sell gas for delivery in the future at the known futures prices (as specified on the exchange) at the times and in the quantities that it has agreed to with the contractual customer. The gas producer does not expect to make delivery on these futures contracts. Rather, when the delivery date approaches, the right to deliver gas to someone else is sold. If spot prices have fallen, then the value of the futures position will have risen. In this way, the producer locks in a known revenue stream, despite the spot pricing in the actual delivery contract.

It is conceivable that the contractual buyer may be willing to buy on the same fixed terms, in which case the producer does not need the futures exchange. The exchange, however, makes it unnecessary for each buyer and seller to find counterparts who desire the same degree of price fixity as themselves. The exchange, by permitting separation of the price risk from the other contractual attributes, greatly facilitates efficient contracting and risk management. The existence of this exchange is, in fact, further evidence of aversion to price risk by at least some market participants and of differences across participants in their willingness and ability to bear price risk.

The virtues of an organized exchange are high liquidity, absence of credit risk, and maximum price revelation. High liquidity is achieved because of a relatively large number of potential traders. Absence of credit risk results because the organized exchange itself stands behind each transaction, so participants need not worry about the credit or reliability of other parties. Maximum price revelation is achieved because trades are public and prices are reported continuously.

The organized futures exchange is, however, only one example of a mechanism for shedding risk. Because exchanges are expensive to organize and maintain, they exist only for certain commodities and certain future dates, and the contracts take only a small number of highly standardized forms. Commodities and trade dates that extend farther into the future than the exchange's horizon and more sophisticated kinds of price risk management are traded "over-the-counter"(OTC).[30] Trading in these off-exchange markets is not as thick, transactions tend to be more individually tailored, and the discovery of market prices is not as complete as on organized exchanges. But, in the gas industry they, generally, are highly competitive, rapidly growing markets: it is estimated that over 2500 OTC transactions in natural gas contracts took place in 1992.[31]

The OTC market has a number of advantages for buyers and sellers. First, the low credit risk offered by the futures exchange is achieved at the price of a requirement that exchange participants maintain margin accounts. This is costly and creates complex regulatory problems for utilities that participate directly in the futures market. More importantly, the limited variety of contracts offered on the futures exchange simply does not meet the needs of many participants; the OTC market offers a much wider range of options that satisfy buyers' and sellers' particular needs. Examples of arrangements that are possible through off-exchange transactions include: (1) hedging for longer time periods than are possible on the exchange; (2) different hedging approaches, such as prices that vary with spot but not beyond some pre-specified price range; (3) "one-stop-shopping" in which physical gas delivery, price risk management and pipeline transportation can all be arranged in a single transaction; and (4) hedging of so-called "basis risk," or variations in the price differential between the Henry (Louisiana) Hub (where futures contracts are tied) and the buyer's actual gas purchase points.

The importance of basis risk can be seen in Figure 5, which shows just how variable prices for gas in particular regions can be, relative to prices at the Henry Hub. For each region, the figure shows the differential between spot prices in that region and the spot prices at Henry Hub during 1992. In the Permian Basin, for example, the differential relative to Henry Hub varied from a low of -$0.34 per Mcf (in November) to a high of +$0.02 per Mcf (in September). Given Permian Basin gas prices in this period on the order of $1.70 per Mcf, this is a very large price fluctuation. A gas purchaser purchasing gas at spot in the Permian Basin and seeking to hedge against spot price variations using the NYMEX futures contract tied to the Henry Hub would not have been able to hedge against this $0.36 price fluctuation. A gas buyer bypassing the NYMEX and dealing with an OTC trading firm, however, could hedge directly against the price in the Permian Basin, thereby fully insuring against price volatility. Similar conditions confronted risk averse buyers in the Rocky Mountain region, where spot price differentials relative to the Henry Hub ranged from -$0.09 to -$0.67 per Mcf; and in Canada, where differentials ranged from -$0.09 to a huge -$1.36 per Mcf (Figure 5).

This diversity leads to the expectation that mature markets will be characterized by a wide diversity of contractual forms. There may be contracts indexed completely to spot prices; contracts with spot pricing bounded by floors or ceilings; contracts indexed to the prices of other commodities; contracts with prices that are fixed or tied to cost indices; and contracts with fixed prices but with various "market out" provisions that allow for renegotiation if the contract price gets too far out of line with spot prices.

Diversity of contractual forms is one of the notable strengths of competitive markets; and an increase in the diversity of contract offerings is likely to be one of the most significant benefits of moving from a world of regulated supply contracts to one governed by competitive markets. Besides the obvious advantage of allowing buyers and sellers in different situations to make arrangements best suited to them, this diversity enhances the efficiency of the market by improving the opportunities for transferring risk from parties who find it expensive to bear to those who can bear it most cheaply. Not only can supply contracts themselves be structured to allocate the risk between the contracting parties efficiently, but also in a well-developed market either party can transfer all or part of the risk associated with the transaction to third parties. In this way, the overall social cost of bearing risk is reduced.

The presence of heterogeneity in receptivity to risk, and the evolution (and simultaneous coexistence) of a wide variety of contractual forms, can be seen in numerous unregulated or recently-deregulated markets. A recent study of coal, ocean shipping, intrastate gas and a number of metals markets found that the typical pattern was one in which participants use mixtures of spot and various forms of longer-term pricing, depending on their attitudes toward risk and the inter-relationships among risks associated with supply reliability and those associated with price.[34] In some markets, spot prices appear to be higher, on average, than longer-term prices; in some markets they are lower. The recent spread of deregulation and competition to a number of historically regulated markets now appears to be creating less reliance on rigidly fixed price contracts, as new market institutions and contractual forms arise, although the ability and incentive to strike contracts with some degree of price fixity is highly dependent on PUC policies toward cost recovery. In gas procurement, greater flexibility in prices is clearly emerging, yet it is not the case that contracts now uniformly provide perfect spot flexibility. Particularly among unregulated independent electric power producers who rely on gas-firing, there is a wide range of long-term contractual forms providing intermediate degrees of price fixity (see further discussion below).[35]

The markets for fixed-rate and adjustable-rate mortgages offer another example of markets in which spot and longer-term prices coexist and among which buyers and sellers choose based on their own characteristics. An adjustable-rate mortgage (ARM) is analogous to a long-term commodity supply contract with a price indexed to "spot". That is, the homeowner is receiving a long-term (typically 15- to 30-year) commitment for the supply of credit, but the price to be paid (the interest rate) fluctuates according to a published index. In contrast, a fixed-rate mortgage sets the price of credit for the life of the contract. Just as with commodities, a large number of variations on these two polar extremes has emerged, including shared appreciation and growing equity, as well as hybrids with fixed rates for an initial period followed by floating rates.[36]

Figure 6 shows how the popularity of adjustable rate mortgages has changed over time, varying between 20% and 65% of the market, depending largely on the relative prices of fixed and adjustable rates, as well as the overall level of interest rates. Economic research also confirms that the choice between fixed and variable rates is governed by many of the risk characteristics discussed above.[37] For example, households whose incomes rise and fall with inflation (just as interest rates tend to do) tend to prefer ARMs, while those with fixed nominal incomes prefer fixed rates. This is just what the analysis underlying Figure 4 above predicted.

Figure 7
TERM AND PRICING OPTIONS IN NATURAL GAS PROCUREMENT CONTRACTS

	Fixed Price (FP)	*Variable Price (VP)*
Long Term (LT)	*LTFP*	*LTVP*
Short Term (ST)	*STFP*	*STVP*

IV. IMPLICATIONS FOR UTILITY NATURAL GAS AND EMISSION ALLOWANCE CONTRACTS

IV.A Contractual Characteristics in Natural Gas Markets. Applying the above analysis to LDC gas acquisition requires consideration of a number of questions. First, what are the major characteristics of gas supply contracts? Second, what are the risk preferences of the LDC's customers, of the LDC itself, and of gas transporters and producers, and how do these interact with the likely sources of marketplace uncertainty? Finally, what is the magnitude of potential costs that may be imposed if mature gas markets are not permitted to evolve?

In the deregulated world, gas supply contracts differ along many dimensions. These include: term of the contract; degree of price fixity; price level; degree of supply reliability; nature of required takes or other buyer obligations; provisions for *force majeure*; provisions for renegotiation and/or dispute resolution; and remedies for failures to perform. It is important to distinguish among these different contractual provisions. For example, as we have implicitly assumed throughout, it is perfectly possible to have contracts with a very long contract term that do not have fixed prices. The simplest conceptual possibilities for combinations of price fixity and contract term are shown in Figure 7. The traditional regulated gas supply contract falls in the upper left-hand box: long-term, fixed-price (LTFP). The spot market falls in the lower left-hand box: short-term, fixed-price (STFP).[38] Spot-indexed and other forms of contracts with variable pricing would fall in the upper right-hand box: long-term, variable-price (LTVP). Figure 7 is, of course, a stylized simplification of the variety of pricing terms that can and do appear in long-term contracts. As with mortgages, prices can be fixed for part of the contract term and then made variable, or be variable within a floor and ceiling, and so forth. We will return to these possibilities below.

Major considerations to be faced by LDCs and their regulators when fuel supplies are being arranged include the appropriate degree of price fixity in acquisition contracts and the interaction between the degree of price fixity and the price level. Pricing in gas contracts is commonly described in the gas industry in terms of premia or discounts relative to the spot-market price. While this is a convenient shorthand for communication purposes, it can obscure the fact that any particular contract will differ from a spot-market transaction in multiple ways. As discussed above, the product "gas", when bundled with a particular package of reliability characteristics, risk management services and transaction services, is not the same "product" as the gas sold in the spot market. Hence, prices in these different kinds of transactions cannot be compared to each other without careful attention to other, non-price contract attributes.

We are particularly interested in the relationship between pricing levels and the degree of price fixity and, to a lesser extent, in the relationship between pricing and supply reliability. Conceptually, the latter is represented by the average premium (relative to a chosen spot index) that is charged in a spot-indexed contract with a high degree of supply reliability. This premium can take the form, for example, of a simple ¢/Mcf add-on or an up-front reservation ("demand") fee in a two-part pricing formula.[39] In contrast, the relationship between price levels and price fixity cannot be determined by comparing fixed-price contracts with spot prices; it can only be discerned by comparing the average, over a long period of time, of prices in fixed-price contracts with those in spot-indexed contracts with the same degree of supply reliability and comparability in other contract terms. To put it another way, the price effect (positive or negative) associated with any particular contractual term can only be determined by looking at it "all else equal", or, in economists' jargon, *ceteris paribus*.

IV.B Risk Preferences of Market Participants. The LDC purchases gas on behalf of its residential, commercial, and industrial customers. These customers are likely to be somewhat risk averse, preferring a constant stream of gas payments to one that is highly volatile. This is likely to be particularly true for low-income customers. For many of these customers, however, gas purchases are a relatively small fraction of their overall budgets, suggesting that fluctuations in gas prices may not create significant risk. Therefore, it is unclear to what extent the LDC's customers have a strong demand for price fixity.

What of the LDC itself? Suppose first that the LDC is subject to "perfect" cost of service regulation, by which we mean that it always recovers all of its incurred costs in its prices, but no more. There is no reason for this hypothetical, perfectly-regulated utility to be risk averse: its net cash flow is *not* affected at all by fluctuations in its gas costs because, by assumption, the prices that it charges move in sync with its costs and thereby stabilize cash flow. Under this idealized assumption, then, the LDC would also be risk neutral with respect to volatility in gas purchase prices.

This assumption does not, however, seem to correspond to the real world. Real cost-of-service regulation does not correspond to perfect cost passthrough. There are, for example, lags between cost changes and cost recovery.[40] More importantly, regulated utilities perceive generally increased regulatory and political scrutiny associated with high and/or rising prices, particularly when prices rise rapidly and discontinuously. As a result, the probability of a failure to recover costs is an increasing function of price volatility.[41] Failure to recover costs will, of course, lead to volatility in net cash flows. As for any other company, volatility in net cash flows raises the cost of capital. Thus, under this more realistic description, LDCs perceive their cost of capital to increase with gas price volatility, and hence, enter the gas market as risk averse buyers trying to hold down their capital costs by shedding risk. The effect of volatile gas prices on utility capital costs is demonstrably present in financial evaluations by investment banks and bond rating agencies. Dependence on gas with uncertain future prices is a noted source of uncertainty about the ability to make debt payments, thereby contributing to the cost of capital utilities face when raising investment funds.[42]

Gas producers are likely to be risk averse as well because variations in their net cash flows raise their financing costs in the ways noted above. Gas exploration and production investments are commonly financed by a mixture of internally generated funds, externally raised equity, debt and various forms of non-recourse financing.[43] All of these create incentives to

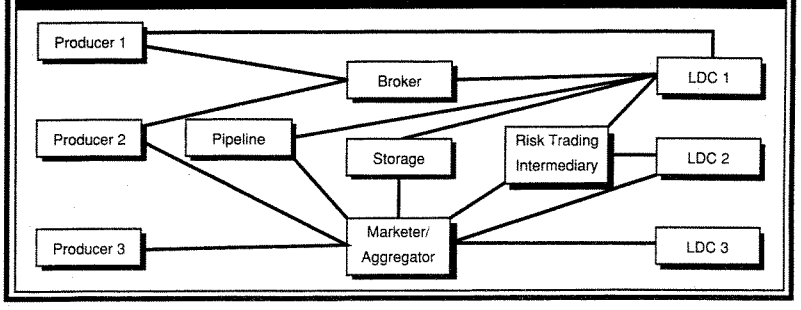
stabilize net cash flow. Internally-generated funds are usually the cheapest source of finance, but they are limited in quantity; variation in net cash flow means variation in the availability of this cheap source of investment capital and hence, disruption of any ongoing investment program. Unless gas prices are uncorrelated with the stock market as a whole, volatility in prices will also raise the cost of equity finance. Finally, all forms of debt increase in cost with the probability of non-payment, which in turn depends on volatility in net cash flow.

Thus, gas markets are characterized by risk averse producers and regulated buyers whose degree of risk aversion depends on the nature of the regulation they face. As discussed above, however, the desire for price fixity also depends on the sources of price uncertainty and the extent to which buyers' valuations and sellers' costs are correlated across buyers and sellers. Two major sources of uncertainty about future gas prices appear to be: (1) the world price of oil as it is affected by the actions of OPEC and other supply and demand factors, and (2) future technological change in gas discovery and recovery technology.[44] Hence, at least to some extent, uncertainty comes from both the demand side and the supply side of the gas market. Importantly, however, it does not appear that these sources of uncertainty are likely to be highly correlated across buyers and sellers. On the demand side, the price of oil affects the price of gas primarily through the demands of fuel-switchable industrial customers. An unexpected increase in the price of oil may increase the demand of these customers for gas, possibly increasing the price of gas, but it does not increase the value of that gas to customers for whom oil is not an option. Thus, LDCs' valuations of gas are not likely to be highly correlated with this demand-side uncertainty, particularly when customers' loads are dominated by residential and commercial customers. On the supply side, a given producer negotiating a supply contract from a given set of producing or soon-to-be producing wells would typically not expect that new discoveries, or new technologies that permit heretofore uneconomic gas to be produced, will affect the cost of production from its own wells. Therefore, supply-side uncertainty is also likely to be relatively uncorrelated across different producers.[45]

If the above analysis is correct, then we would expect relatively fixed prices to be a desirable contract form in the gas industry. Fixed prices would reduce producers' cash flow volatility, thereby reducing their cost of capital and their overall cost of production. If cost-of-service regulation makes LDCs approximately risk neutral, this lowering of producers' costs, combined with competition among producers to make sales, would yield equilibrium prices in LTFP contracts that are lower, on average, than those in LTVP contracts. To the extent that cost-of-service regulation is not perfect, however, risk averse LDCs would also prefer fixed prices, which would lower *their* cost of capital. This effect, combined with competition on the buyers' side, would create a market force offsetting the pressure from producers' competition and tend to drive LTFP prices above LTVP prices. Where these forces would balance cannot be determined *a priori*. Thus, whether we would expect fixed-price contracts to be more or less expensive, on average, than LTVP contracts (or STFP contracts) would depend on the relative magnitude of buyers' and sellers' risk aversion, the fraction of the market represented by LDCs, and the impact of price volatility on LDC and producer investment costs.

One common method of reducing risk is diversification. Of particular relevance here is the diversification that can be achieved by holding a portfolio of contractual forms on the principle that if one contract is performing poorly, others in the portfolio can be expected to be performing well at any particular time.

Figure 8
POSSIBLE TRANSACTION PATHS FOR ARRANGING GAS SUPPLY, TRANSPORTATION, STORAGE AND RISK MANAGEMENT



Indeed, we could not expect all contracts to be fully LTFP in a well-functioning gas market. Rather, we would expect that some amount of LTFP contracts would be a significant component of LDCs' acquisition portfolios and sellers' supply portfolios.

Note also that, as discussed above, price fixity would not necessarily be achieved solely, or even primarily, via the mechanism of price fixity in supply contracts themselves. Rather, the existence of futures exchanges and informal markets for trading of price risk permit the separation of the trading of the different aspects of gas supply, much as unbundling on the interstate pipelines permits the separation of gas supply and gas transportation transactions. This leads to a much more complicated structure of the industry. Depending on the benefits of specialization, the magnitude of transactions costs and other factors, a purchasing LDC may deal with only a producer and a transporter; or an aggregator and a transporter; or a producer, a broker and a transporter; or a pipeline that combines all the previous functions; or any combination of the previous with a risk-trading intermediary.

Figure 8 sketches some of the possibilities: LDC 1 deals directly with producers and arranges its own transportation and storage, using a broker only to identify producer contacts. It also engages in swap transactions with a risk-trading intermediary to reduce price risk. LDC 2 chooses to deal with a marketer/aggregator who also arranges transportation and storage; like LDC 1, LDC 2 chooses to engage in transactions with a risk-trading intermediary as part of its price risk management. LDC 3 deals only with a marketer/aggregator, who arranges supplies, transportation and storage, and provides long-term supplies with price terms that LDC 3 feels provide it with adequate price risk management. Note that the marketer/aggregator may itself be using a risk-trading intermediary to manage the price risk that it bears by virtue of its mix of purchase and sales contracts; LDC 3 may be benefitting indirectly from the use of financial markets to manage risk without even knowing it.

Obviously, all this complexity makes the regulators' oversight role much more complicated than in earlier eras. In Section V of this paper, we return to the question of how PUCs can appropriately carry out their oversight functions in this complicated world without inhibiting the evolution of institutions that reduce the overall cost of gas supply.

On a conceptual level, the social benefits created by the option of price fixity do not depend on whether prices in LTFP contracts are, on average, above or below those in LTVP contracts. The cost savings to producers are real savings in the cost of capital, which translate into a reduction in society's resources consumed in the production of gas and an increase in the amount of gas that can ultimately be produced. From the perspective of LDCs and their customers, these benefits accrue either in the form of lower prices for wellhead gas or lower capital costs in the distribution sector itself. Either way, they permit burner-tip prices that are lower, on average, than would otherwise obtain.[46]

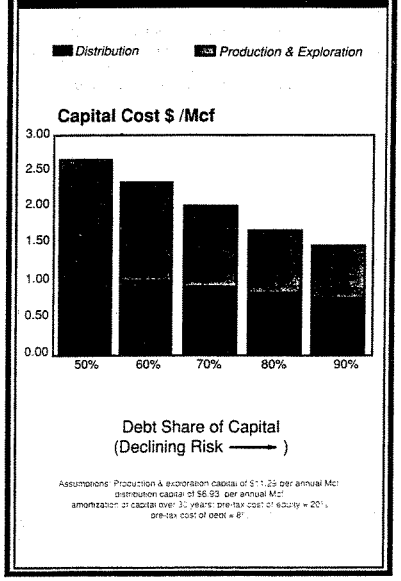
IV.C The Magnitude of the Stakes in Gas Development. If PUCs adopt inappropriate policies that stifle the evolution of the rich market structure described here by inducing LDCs to rely excessively on the spot market, a number of undesirable consequences would ensue. To the extent LDCs are prevented from recovering any gas costs above the current spot price, for example, the inclusion in supply portfolios of some contracts (either LTFP or LTVP) with a high degree of supply reliability would be discouraged. This, in turn, would degrade supply reliability, to the detriment of both core and non-core customers. It is one thing to rely on the spot market for a significant fraction of supply in the context of a portfolio of contracts with varying degrees of supply guarantees. It is quite another to rely exclusively on the spot market. In no industry where a continuous stream of inputs must be relied on do companies typically rely exclusively on the spot market to guarantee supply.[47] As noted above, the question of whether LTVP contracts with desirable supply guarantee characteristics will have prices significantly above the spot price is a matter for the competitive market to determine. If the market requires such pricing for some types of desirable contracts, then preventing the recovery of such gas costs will eliminate that type of contract from utility portfolios.

Disallowing recovery of fixed-price contract costs whenever those prices exceed spot would have more complicated and insidious effects. As noted above, even if LTFP contracts bear a market price that is lower, on average, than spot prices, there will still be times when spot prices fall below LTFP contract prices. If the LDC is denied cost recovery whenever this occurs, then LTFP contracts would become much more risky and would be eliminated from the marketplace. Even sketching the general outlines of the effects of such a development requires making an assumption about the extent to which LDCs and their financiers perceive themselves to be subject to imperfect cost-of-service regulation, and hence, vulnerable to price volatility. Consider, first, the hypothetical extreme in which they perceive effectively "perfect" regulation, so that LDCs are not risk averse (see above). In that case, the main effect of discouraging LTFP contracts, which producers would still desire, would be to raise the cost of finding and producing gas. This increase in gas producers' costs would translate into a disincentive to develop and produce new gas, lower gas supply, an increase in wellhead prices, an increase in burner-tip prices, and a corresponding decrease in the incentive to use gas.

If the LDCs do perceive benefits to the risk reduction associated with price fixity —because cost-of-service regulation is not "perfect" — then it might seem that the cost of eliminating them is less because we cannot be sure that LTFP contracts are priced on average lower than LTVP contracts. But this is a fallacy. First, even if buyer

competition keeps LTFP contract prices approximately equal to LTVP prices, producers will benefit from real cost reductions. These cost reductions, particularly in the context of LTFP contract prices that are not forced to reflect the cost savings, will encourage the development of new gas production. This additional production will exert downward pressure on all gas prices — downward pressure that would be lost if risk-reducing LTFP contracts went away. Second, even if wellhead gas prices were not affected, the LDCs' own greater cash flow volatility would increase their cost of capital, and hence, increase prices to consumers via distribution costs.

Figure 9
CAPITAL COST COMPONENT OF GAS PRICES AS A FUNCTION OF RISKINESS



We can summarize the possible consequences of eliminating LTFP contracts as follows. Regardless of LDCs' risk preferences, a cost would be imposed on the producing sector, which would discourage the development of new gas resources and which would be borne at least partially by consumers in the form of higher gas prices. To the extent that capital markets perceive LDCs to face cash flow volatility if gas prices are uncertain and volatile, then there would be an additional cost associated with a higher cost of financing LDC capital.

An illustration of the potential magnitude of these effects is presented in Figure 9. One way to capture the effect of cash flow volatility on the cost of capital is by varying the mix of debt and equity in the capital base, holding constant the cost of debt and equity finance. Firms with extremely predictable net cash flows — such as those with long-term contracts guaranteeing prices that cover costs — can be financed with extremely high debt/equity ratios, such as 90% debt to 10% equity.[48] At the other extreme, firms with extremely volatile cash flows must utilize much higher equity components. For example, equity fractions as high as 50% are not at all unusual for gas producers. Because debt is much cheaper than equity, the cost of capital is a strictly declining function of the debt fraction in the capital base: as the debt capacity of a firm rises, the cost of capital falls.

In Figure 9, we proxy the possible effect of reduced cash flow volatility on the cost of capital by looking at how capital costs per Mcf of gas vary as the debt/equity ratio is increased from 50% to 90%, using reasonable assumptions about the cost of debt and equity and the amount of capital needed in the production, exploration, and distribution stages to deliver 1 Mcf of gas. The figure shows that increasing the proportion of debt over this range reduces the cost of gas by about $0.50 per Mcf in the exploration and production stage, and by about $0.30 per Mcf in the distribution stage. Overall, moving debt capacity from 50% to 90% can cut the capital costs of bringing gas from development to delivery by about $0.80 per Mcf — or about 30%.

It is important to emphasize that the debt/equity ratio with constant costs of debt and equity is intended only as a proxy for the effect of risk on financing costs. In reality, increased cash flow stability could permit greater leverage, but it would also *reduce* the cost of both equity and debt finance for any given leverage level.[49] Of course, we cannot say with any certainty the degree of "equivalent leverage increase" that LTFP contracts would permit, but Figure 9 illustrates that even small changes in the cost of capital translate into significant effects on prices. The effective elimination of LTFP contracts by untoward LDC oversight policies would harm LDC customers.

IV.D The Magnitude of the Stakes in Gas-Using Electricity Generation. As noted in Section II, the gas-firing of electricity-generating units holds promise as a major source of increase in the future demand for gas. Yet, to the extent that utilities are risk averse and LTFP contracts run the regulatory risk that fuel cost recovery for gas-fired units will be limited by the PUC to no more than spot prices, reliance on risk-reducing LTFP contracts will be cut off. Those who finance investments in new generating units can be expected to respond by imposing higher capital costs on those investments. Just as in the case of gas supply development examined in Section IV.C, higher capital costs, in turn, can be expected to discourage utilities from buying gas-fired electricity generation units. In addition, the higher capital costs of units which are built imply higher revenue requirements and electricity prices.

the NUG's cost of fuel, the buyer is insulated from price volatility by such contractual mechanisms as the sharing of deviations from a benchmark (e.g., spot prices) and requirements that NUGs enter into LTFP contracts with substantial price fixity and/or bonus premiums for long-term supply acquisition.[52] In addition, the financial markets find that natural gas is subject to "price volatility and questionable reliability. Over-reliance on natural gas is therefore viewed as a risk by [investment analysts]."[53] PUC policies disapproving of LTFP utility contracts with NUGs would inhibit utilities' abilities to shed demonstrable price risk, discourage their reliance on gas-fired NUGs, and encourage their turning to otherwise more costly alternatives.

With pressure to either reduce price risk or face higher capital costs, NUGs themselves have demands for a portfolio of fuel supply sources that include long-term contracts with some degree of price fixity.[54] A representative list of contractual forms actually observed in NUGs' fuel acquisition choices is provided in Figure 11.[55] The lesson again is the diversity of options produced in unregulated markets, rather than the honing in on one contractual type.

IV.E The Magnitude of the Stakes in Clean Air Policy. PUC policies that raise the risks and associated capital costs of gas-fired electric power units are not only likely to raise the costs of electric power (per Figure 10); but also are likely to raise the cost the nation bears to meet its clean air objectives. The studies of the NAPAP indicate that if natural gas is not utilized as a strategic response to the new Clean Air Act Amendments, the primary least-cost strategy for meeting the Amendment's targets will involve substitution of low-sulfur coal for high-sulfur coal, with the higher prices of more expensive low-sulfur coal offset by their ability to produce tradable SO^2 allowances. It is estimated that allowances will have a value in the range of \$125-\$350 per ton of SO_2 emitted.[56]

The price of allowances reflects the incremental costs the nation bears for pollution control, since a utility for whom the costs of control exceed this price will choose to buy an allowance rather than reduce its pollution.[57] By the same token, a utility for which incremental abatement costs are less than the price of allowances will find it cheaper to invest in reducing its pollution rather than purchasing a permit to pollute. A direct implication of this reasoning is that the cost savings to the nation of using natural gas can be measured by the allowances it produces — i.e., by the incremental pollution control expenditures that can be avoided.

New natural gas-fired electric power combustion and combined-cycle units are virtually free of SO_2 emissions.[58] Compared to coal with an emission rate of 2 lbs/MMbtu and a heat rate of 9800 Btu/kwh,[59] each kilowatt-hour of electricity for which gas-firing can be substituted for coal-firing can reduce emissions by approximately 0.02 lbs. Translating this into dollars, at a gas-firing heat rate of approximately 7500 Btu/kwh and allowance values of \$250-\$350 per ton of SO_2, each MMbtu of gas that can substitute for coal reduces emissions of SO_2 and thereby earns allowances worth somewhere in the range of \$0.16-\$0.45. With delivered gas costs on the order of \$2.50/MMbtu, the payoff from SO_2 reduction upon substitution of gas for coal represents on the order of 10% of the cost of the gas. The value of these allowances is a direct measure of the national savings on pollution control that the use of gas provides. But will the allowance market function effectively?

IV.F Implications for the Emission Allowance Market. The attention in this analysis to the stakes attendant to PUC oversight of LDC contracting has been directed primarily to the natural gas market. The emerging market in SO_2 allowances, however, deserves special attention. Completely apart from the place of natural gas procurement by LDCs, allowances themselves constitute a product over which utilities are, and will be, facing purchase and sale decisions. The same issues regarding prudence standards and the same questions as to how PUCs will treat market transactions that arise with respect to gas arise with respect to emission allowances and their prices.

If the emergence of a fluid and complicated natural gas market has troubled state utility regulators, the idea of the emission allowance market must be doubly disconcerting. Indeed, there is already concern that state regulators will thwart the development of an efficient market in SO_2 allowances. One midwestern state, for example, has adopted policies to protect in-state coal mines by limiting utilities' abilities to substitute towards cleaner fuels that could produce allowances. In addition, industry observers report concern that after-the-fact prudence review of allowance trades has little precedent and presents utilities with high risks from participation in an allowance market. Regulators, risk averse themselves and unfamiliar with assessing performance in an emission allowance market, may be biased towards pre-approval of less flexible, more capital-intensive strategies for satisfying the Clean Air Act.[60]

Consider, for example, a utility that is contemplating building a combined-cycle gas plant in order to permit the early retirement of an existing coal facility. As discussed above, this gas-for-coal substitution generates a stream of allowances that can be sold; the revenues from the allowance sales should be viewed as reducing the net cost of the gas facility. But at the time of the investment decision, the future price of allowances is uncertain. Therefore, compared to installing a scrubber on the coal plant, the use of the gas plant can involve a more risky revenue stream; and as above, this risk raises the cost of that option. If the full scope of LTFP, LTVP, and STFP markets is allowed to evolve, we could imagine that the

utility could sell its stream of allowances to another utility under a LTFP contract, or protect itself from revenue fluctuations, by engaging in a transaction with a market intermediary that, in effect, guarantees its future allowance sales prices. In this way, a fully developed allowance market would reduce the cost to the utility sector of bearing the risks associated with compliance investment decisions.

If, however, PUCs do not permit the full scope of risk-shedding and risk-reducing transactions, or insist on always evaluating allowance trades for revenue purposes at then-current spot prices, the ability to mitigate allowance price risk will be destroyed, and the cost of achieving the policy objectives of the Clean Air Act will be increased. Thus, getting the full social benefit from the development of allowance markets creates the same problems and imposes the same burden on PUCs as the evolving complexity of the gas market. Ironically, pre-approving a multi-million dollar scrubber may be more palatable to the regulator than trusting the nascent emission allowance market. Regulator discouragement of LTFP contracts for allowances or fuel-intensive, allowance-producing abatement strategies (e.g., gas-firing) could have the effect of tilting utility decisions toward fixed investments in scrubbers—which are, of course, much more fixed and irreversible than a long-term contract.

The Clean Air Act Amendments of 1990 represent a potential turning point in the vexing problems the nation has faced in coming to grips with the costs of protecting the environment. It is a much more fundamental reform than the policy changes introduced into the natural gas industry. It portends the harnessing of the forces of the marketplace to the task of pollution abatement — but only if the major players in the market are not turned back by their regulators.[61] The challenge of good public policy vis-à-vis the SO_2 allowance market is to lay in place incentives for utilities to aggressively participate in the buying and selling of allowances so as to minimize their costs of compliance with the Clean Air Act Amendments of 1990. If this historic experiment with market incentives is undercut by PUC actions, the results will include not only higher electricity costs, but the dimming of prospects for innovative approaches to pollution abatement generally.

V. STANDARDS FOR PRUDENCE REVIEW

The analysis of this study emphasizes that a recognition of the complex structure of competitive gas and emission allowance markets must underlie PUC review of utility purchase and sale decisions in these arenas. It might have been hoped that simple rules, such as "spot only" or "no fixed-price contracts", would suffice to serve the public's interest in efficient LDC management. The search for such optimistic simplicity, however, is symptomatic of the difficulty that governmental planning processes face in trying to mimic the complexity of real world market forces. Nevertheless, there are principles and procedures that can be used by regulators to carry out their regulatory responsibilities in a way that maximizes the benefits of gas and allowance markets.

V.A Inappropriateness of a Spot Standard. The optimal use of gas and allowance markets requires utilities to carry *portfolios* of supply options including spot purchases, LTVP contracts, LTFP contracts, and the use of futures trades and swaps. For the reasons set forth above, there is no reason to believe that each of the many pieces of a well-designed portfolio of gas or allowance options would or should have the same price associated with it. Still, it has been argued by some that recovery of gas costs (and by implication allowance costs) should be allowed only to the extent that such costs do not exceed the current spot price.[62]

The case in favor of a spot-only standard seems to have a number of components.[63] First, it relies on a simple textbook notion of *the* market to argue that the existence of a publicly-reported, flexible price market gives some unique significance to the prices reported in that market. Second, it is argued that any desire by participants for hedging of price risk inherent in the spot market can be satisfied using the futures market. Third, it is argued that the economic theory of natural resource pricing suggests that the spot price contains all relevant information that market participants might need about the future path of prices. Fourth, it is asserted that LTFP contracts are creatures of the earlier eras of "heavy-handed" regulation described above in Section II and that regulated utilities' desires to sign such contracts is an undesirable effect of cost-of-service regulation. Finally, it is sometimes argued that even if other prices have just as much validity as the spot price, using the spot standard to reward utility decisions is a form of "incentive regulation" that will create the proper incentives for utilities to minimize costs.

It is hard to know what to say about the view that the spot market is somehow the "only" true indicator of market value. As we have discussed above, this view is simply wrong. The futures market, swaps transactions, and the universe of LTFP contracts are all markets. The prices determined in the various markets in which gas (and, potentially, emission allowances) is traded are all "market" prices, and they are generally competitive market prices. The public reporting of spot (and some futures) prices is a distinction without relevance to the matter at hand.[64] At any moment in time, the prices in these different markets will generally and justifiably differ to some degree. Once it is recognized (for the reasons described above) that it is desirable for utilities to hold portfolios of supply options with different price characteristics, it makes no policy sense to evaluate all options relative to the price of only one of those options. To do so would be analytically equivalent to requiring a rural utility to base recovery of its labor costs solely on the basis of wages in urban areas because there is better data on urban wages and despite the fact that wages in rural areas are systematically lower.

The appeal to the futures market to justify a spot standard is internally inconsistent. Suppose, for example, that an LDC does use the gas futures market to hedge against fluctuations of the price of gas over the next 12 months, thereby ensuring that its actual acquisition costs (contract costs plus net futures costs) will not be volatile. If the PUC then allows it to recover only the actual spot price that is later realized in each of these months, acquisition costs will be stable, but revenues will have been made volatile. Regulation will have re-introduced exactly the uncertainty and revenue volatility that the hedging was designed to prevent. To avoid this anomaly, PUCs might dictate that LDCs can recover spot prices, or futures prices if they are used, but not LTFP contract prices or swaps prices. But this lacks any conceptual justification. Other than the availability of data, there is no consequential difference between hedging price risk on the futures market, through a swaps contract, or through a LTFP supply contract. LTFP contacts, swaps, and other arrangements provide for risk reduction and shedding that spot and futures markets cannot handle (see above). Indeed, the supplier in a LTFP contract may, itself, be using the futures market to hedge the contract.

The noted assertion that economic theory implies that the spot price for a natural resource contains all available information about its future prices is an example of a little knowledge being a dangerous thing. It is true that many elementary expositions of the theory of natural resource pricing begin with a simple "Hotelling" model dating back to 1931.[65] In this model it is assumed that there are no production costs, there are no constraints on the rate of resource extraction, storage is costless, extraction rates have no effect on future production costs, and the total natural recoverable stock is known with certainty. Under these assumptions, the price of the resource must rise over time at the rate of interest in the economy. This implies that, if the spot price is observable today, *and* the complete future path of interest rates is known, then the spot price at any date in the future can be calculated. Thus, in this model, there is no price uncertainty and no reason for buyers and sellers to concern themselves with risk. Clearly, however, this model is inapposite to the policy problems confronted by PUCs and gas market participants. More realistic models of natural resource pricing, incorporating costs of production, uncertainty, and technological change, do not produce the simple "Hotelling"result.[66] Price risk in natural resource markets is very real, indeed.

In the real world, it is easy to see that there is no clear relationship between current spot prices and future prices. One need only glance at actual spot and futures prices. For example, on October 12, 1992, the spot price was $2.39; the futures price for October 1993, based on trades during the first week of October 1992, ranged between $1.66 and $1.90. By December 28, 1992, the spot price had fallen to $1.94, while the October 1993 futures price had stabilized in the range of $1.74-1.78.[67] On each date, the futures price embodies the available (albeit uncertain) information regarding what the price will be on that future date. In October 1992, supplies were known to be relatively "tight", so market participants expected prices one year hence to be below $2.00, despite the then-current spot price of $2.39.[68] By December, short-term conditions had eased, allowing the spot price to fall (despite the onset of winter) to $1.94. This $0.35 fall was not associated with significant movement in the futures price for October 1993.

This pattern cannot be reconciled with the view that current spot prices tell everything there is to know about future prices. Moreover, it is not possible to retreat to an argument that current spot prices, *combined with* published futures prices, tell everything there is to know about future gas prices. This merely creates an arbitrary and economically unsupportable distinction between the "futures" market and off-exchange markets including swaps, OTC, and other transactions. The correct statement is that all market prices contain some information about prices in the future. As one moves further into the future and away from thicker, publicly-traded exchanges toward thinner, privately-traded transactions, uncertainty increases, and information becomes less abundant. But there is no sharp discontinuity in validity, either between spot and futures prices, or between futures prices and other forms of forward pricing.

It is true that prior regulatory regimes created incentives for long-term contracts of particular forms. This does not imply, however, that unregulated firms do not desire LTFP contracts or other mechanisms for reducing price volatility. Further, cost-of-service regulation of LDCs can mitigate their incentives for cost-efficiency, but it does not follow that incentives are distorted particularly in favor of long-term contracts. Indeed, as discussed above, "perfect" cost-of-service regulation makes utilities indifferent to variations in input prices, creating, if anything, an incentive to choose price paths that are too variable relative to what their customers would prefer.[69] Thus, the fact that utilities are subject to cost-of-service regulation does create a reason why PUCs should be concerned with their purchase choices, but it does not imply that PUCs should be concerned about overcoming some innate bias in favor of long-term contracts.

Finally, it is sometimes argued that, even if the objective is to induce utilities to hold an optimal portfolio of acquisition options, evaluating that portfolio against a standard of current spot prices is a form of "yardstick competition" that will give the utility the optimal incentives to keep costs down on average. The problem with using the spot price as a "yardstick" is that it must inevitably have one of two effects. One possibility is that the regulated firm will pursue something like the optimal portfolio of supply options, including a mix of spot, LTFP, and other transactions. On average, this strategy will do well for consumers, but the utility will have a very volatile

net cash flow as it sometimes exceeds and sometimes falls behind the spot standard. This volatility will raise its cost of capital, and this cost will ultimately be borne by consumers. The second possibility is that faced with increased risk, the firm will respond to the spot standard by simply always buying at spot. As discussed above, this result will also raise costs to consumers and result in substantial social inefficiencies as the costs of capital are raised by the lack of access to risk-reducing and risk-shedding contractual forms in gas and emission allowance markets.

We have argued elsewhere that "yardstick competition" and other forms of "incentive regulation" are desirable regulatory innovations that can be used to mitigate the adverse incentives for cost-reduction and innovation created by cost-of-service regulation.[70] Incentive regulation is not, however, an end in itself; it is simply one possible means toward achieving the objective of minimizing costs and maximizing value to consumers. Further, it is a "second-best" solution that is appropriate only when it is not possible to rely on the direct discipline of competition as the main source of incentives. In the cases of acquisition decisions for gas and emission allowances, there may be some role for forms of incentive regulation, but the more important and effective regulatory policies are likely to be unbundling and enhanced competition, pre-approval of acquisition portfolio composition, and least-cost bidding. The role of each of these is discussed in the following section.

V.B A Framework for Improving Regulatory Oversight of Utility Contracting. It is easy to understand the attractiveness to state regulators of simplistic prudence standards such as "no more than spot". Reducing prudence review to a simple test based on widely published data suggests an alternative to investigations of complicated matters of *ex ante* diligence and *ex post* performance. Even more compelling is the fact that PUCs have lived through memorable episodes in which long-term commitments have turned out to be mistakes — notably the nuclear power cost overruns of the 1970s and early 1980s and the natural gas take-or-pay problems of the 1980s.

These kinds of events, in which commitments turn out to be more expensive than contemporaneous options, subject regulators to political pressures that are largely beyond their control. Regulators find themselves trapped between trying to live by the regulatory rules and conditions in force at the time binding commitments were made by the utility (e.g., to purchase a nuclear unit), on the one hand, and current ratepayer outrage, on the other hand. In breaking the "regulatory bargain" through *post hoc* disallowance of costs incurred prudently under *ex ante* policies, short-term relief is provided to ratepayers, but the implied insecurity for investors raises the capital costs of future investments.[71] In any particular instance the question of whether a cost disallowance constitutes a "breaking of the bargain" or, in fact, appropriate application of pre-existing prudence criteria can be debated (and litigated). One executive's imprudence may be another's due diligence. Nevertheless, there certainly is widespread perception in the capital market and among utility investors that the difficulties associated with the unwillingness or inability of PUCs to bind themselves and their successors to knowable, pre-committed criteria increases the cost of capital to the regulated LDC and electric utility sectors.[72]

Painful experiences with long-term commitments in the past create incentives for capital to flee the regulated sector (e.g., into NUGs) and for regulators to adopt excessively shortsighted tendencies in which commitments are never long-term. These are, however, the wrong lessons to learn from the past. When efficient capital is long-lived and risk allocations through LTVP and LTFP contractual dealings for fuel, power and pollution allowances are cost-reducing in the ways we have discussed here, it is appropriate that both market participants and regulators be able to adopt a longer-term view. It is true that mistakes can be made in making partially-or wholly-fixed commitments into the future; no matter how diligent decisionmakers are, we live in an uncertain world. But there are also favorable "mistakes" when decisions turn out to be better than expected. Consider, for example, the relatively happy fate of electric utilities who went ahead with oil-fired units on the basis of pre-1983/86 economic projections and now find themselves facing real oil prices that are no higher than those prior to the energy shocks of the 1970s. In fact, it is inevitable that excessive reliance on spot and LTVP contracts will eventually lead to the day when another shock to energy markets will cause a price spike that will generate furious political debate as to why utilities had not done more to "lock in" lower prices in the past.

The design of efficient policies for regulatory oversight of LDC and electric utility decision making is inherently difficult. The essence of the problem lies in the unavoidable need to make decisions in an *ex ante* environment of uncertainty, while revelation of the payoffs to decisions will only be known *ex post*. In such a context, public policy must be particularly concerned with the *incentives* that it presents to economic agents and with maximizing the opportunity for the forces of *competition* to operate. Absolutely guaranteeing "right" decisions and no mistakes is impossible. Regulatory authorities, experts, and processes are unlikely to be able to consistently outperform the decisions of economic agents, if those agents have their own profits and income at stake and are disciplined by competition. Standards and procedures that use competition and incentives provide PUCs with the most viable approach to ensuring the prudence of gas, electricity, and allowance market participants' decisions. This is particularly true in the highly complex and fluid marketplace that federal policy has wrought in natural gas and that is emerging in pollution control.

What are the elements of an approach to state regulatory oversight of the performance of LDCs and electric utilities that will rely on competition and appropriate incentives? At least three elements stand out.

1. *Unbundling and Deregulation*: Where markets are workably competitive, competition rather than regulation should be utilized to govern *ex ante* and *ex post* performance. As a working presumption, this means that many of the functions that have traditionally been bundled with the physical delivery service provided by local distribution companies may be more efficiently provided under state-level policies of unbundling and deregulation that parallel those that have been implemented at the federal level. Unbundled open access to transportation on local systems could be expected to result in the proliferation of market competitors that we have seen operating on interstate pipelines. Brokers, marketers, producers, risk intermediaries, supply aggregators, storage arrangers, and so on are all potential competitors for the business of local gas buyers.[73] This is perhaps most evident in the case of large industrial gas users, who have already been clamoring for bypass of, or open access on, local distribution systems. Even in the case of smaller industrial, commercial, and residential customers, however, so-called "core aggregators" could be expected to compete for sales traditionally made by LDCs. This has certainly been the case in telephone service where PUC policy has allowed versions of open access on local line systems. In fact, available evidence indicates that consumer prices are lower under such conditions than they would be under traditional LDC rate setting procedures.[74]

In the long run, fostering the emergence of a competitive retail gas merchant industry offers PUCs the potential to allow the competitive market to take over the burden of monitoring the prudence of utility supply acquisition decisions. In the short run, even the development of limited competition would greatly facilitate regulation of the merchant function because the prices charged by competitive entrants would provide the best possible yardstick against which to compare utility prices.

2. *Pre-Approval of Contract Portfolio Structure in the Context of Integrated Resource Planning*: To the extent that PUCs perceive that LDCs and electric utilities continue to have market power in their gas and electricity sales functions, pre-approval should be given to broadly outlined *portfolio* strategies for gas (and, as the market develops, emission allowance) procurement. By pursuing a portfolio of contractual terms in its gas acquisitions, for example, a utility can take advantage of market opportunities in LTFP, LTVP, and STFP transactions as they arise, while diversifying its mix of price and supply reliability. In fact, the value of portfolio strategies is widely recognized by market participants and their regulators.[75]

PUC approval of the composition of acquisition portfolios would be a natural extension of the framework of Integrated Resource Planning (IRP) that is developing in many states for both electricity and gas. A gas-or allowance-purchasing utility would be expected to justify the composition of its acquisition portfolio before the PUC, much the same way that an electric utility is required to justify the extent of its reliance on Demand-Side Management (DSM), base-load capacity (either utility-owned or purchased), peaking capacity, short-term purchase commitments, and so forth. An effective pre-approval process would establish parameters on the relative shares of purchases of different types, including spot, LTVP, fixed-price contracts of various durations, and hybrid contracts such as variable-price with a floor and ceiling. These parameters would reasonably be based on such factors as the competitiveness of the acquisition process (e.g., as revealed in a solicitation and bidding process), data availability, and reasonable and common industry practice.[76] Finally, pre-approval of portfolio structures improves the regulatory bargain and cuts regulatory risks by publicly and procedurally committing the PUC.

3. *Use of Competition and Incentives to Minimize the Cost of Portfolio Components*: A PUC that has established appropriate parameters for the composition of a utility's acquisition portfolio will also be concerned about the utility's efforts to acquire the individual portfolio components at least cost. There are two basic mechanisms for doing this. The simplest, and the one that fits most directly into evolving IRP frameworks, is to rely on competitive bidding for supply of the different portfolio components. That is, once the quantities that are to be secured in various contracting categories have been determined, utilities would seek bids for supplies meeting the parameters specified for that category. A utility deciding to acquire gas supplies or make a purchase (or sale) of emission allowances would be obligated to choose the suppliers who offered the best combination of price and non-price contract terms, with due consideration of non-contract conditions (such as the creditworthiness of the supplier). PUCs would appropriately monitor the competitiveness of this process.

Competitive bidding processes are, in fact, quite common across PUC jurisdictions. They are used to varying degrees by more than forty state PUCs and are applied to procurement ranging from stock underwriting services to equipment purchases (Figure 12). While bidding systems differ from state to state, they have generally proven effective in promoting prudence on the part of LDCs. In the case of electric utilities, they have been widely used to link IRP decisions on the composition of utilities' pre-approved generation portfolios (coal, gas, oil, etc.) to least-cost acquisition principles.

In theory, there is a second family of mechanisms for promoting cost efficiency than might be applied to utility gas and allowance transactions. These are known as "yardstick" or incentive regulation approaches. Under a yardstick policy, if it has been determined that, for example, 10 to 20 percent of a utility's gas purchases should be in contracts with prices fixed for a three- to five-year period, the PUC could create incentives for cost-minimization by pegging cost recovery for that portfolio component to the average price paid by other utilities under contracts of that duration. With this basis for cost recovery, rather than the utility's own contract costs, the utility is induced to be prudent and efficient: it benefits to the extent that it can beat this average yardstick, and it is penalized if it falls short.

Such a mechanism does not suffer from the problems enumerated above for the "spot only" standard because it conceptually entails "apples to apples" comparisons within portfolio categories. The risks it creates for the utility would be mitigated because each of its portfolio components would be tied to different benchmarks. We note, however, that implementing this kind of incentive mechanism would be somewhat complicated and not likely to outperform competitive bidding. It would not be appropriate, for example, to peg current cost recovery on a five-year contract struck three years ago to the prices *currently* being charged for five-year contracts. Thus, it would be necessary to collect and keep track of price and non-price contract information for each contract vintage. At present, such information is not systematically collected and compiled across PUC jurisdictions. Given these impediments and the likelihood that well-managed competitive bidding will yield competitively priced acquisitions, it is unlikely that additional incentive mechanisms are worth the trouble.

Figure 12

THE NUMBER OF STATES UTILIZING COMPETITIVE BIDDING FOR UTILITY PROCUREMENT

Category	*Number of States*
ANY COST ITEM	41
DEBT INSTRUMENTS	37
PREFERRED STOCK	38
STOCK UNDERWRITING	38
INSURANCE COVERAGE	27
MAJOR PROPERTY	28
EQUIPMENT PURCHASES	28
MATERIALS AND SUPPLIES	27
MANAGEMENT/CONSTRUCTION	26

SOURCE:
NATIONAL ASSOCIATION OF REGULATORY COMMISSIONERS.
UTILITY REGULATORY POLICY IN THE UNITED STATES AND CANADA, 1991-92

It is important to emphasize that the regulatory burden of portfolio pre-approval and monitoring of least-cost bidding are only necessary to the extent that unbundling and direct competition for retail customers are not implemented. In effect, these processes are imperfect methods for replicating the price discipline that competition would otherwise create. The imprecision and cumbersome nature of these procedures are strong arguments in favor of the transition to competition as the ultimate solution to the problem of ensuring that acquisition behavior is efficient.

VI. CONCLUSION

The new era of relying on competitive markets to achieve public policy objectives with respect to public utilities and environmental protection has complicated the tasks of PUCs. To get the maximum benefit from these policy innovations, regulated firms must be given incentives to participate in complicated, evolving markets. There is a grave danger that the adoption of simplistic rules for evaluating the actions of regulated firms in these markets will stifle their development and thereby reduce the social benefits that are potentially available from deregulation and the use of market-based approaches to environmental protection.

Avoiding simplistic approaches begins with the recognition that risk is a real social cost that can be minimized but not eliminated. Efficient management of risk is one of the functions that competitive markets perform well. For markets to perform this function, however, regulated firms need the flexibility to utilize a wide variety of contractual forms and deal with a diverse set of market participants. For both gas procurement and trading of emission allowances, this means that LDCs and electric utilities must have the ability and incentive to include long-term contracts with forward pricing provisions and financial market transactions, such as futures and swaps, in their portfolios. Elimination of these options through reliance on explicit or implicit "spot only" standards will raise the cost of gas and electricity in the long run, discourage the expansion of reliance on gas, and undermine the historic experiment in emission allowance trading.

With respect to gas purchases by local distribution companies, both the need for and the difficulty of PUC prudence review can be reduced by accelerating the movement toward competitive gas sales markets. If the unbundling of gas sales and transportation/storage were extended to the local level, the entry of competitive

suppliers would provide consumers with a direct choice in gas sales options, provide competition to discipline the market decisions of LDCs, and provide a competitive benchmark against which the PUC could evaluate effectively the gas purchase decisions of LDCs.

We recognize that the transition to a competitive environment will not occur overnight and that PUC oversight of acquisition decisions will continue to be appropriate for as long as competition is bottled up. Appropriate PUC review of regulated firms' decisions regarding gas acquisition and allowance trading should follow at least three key principles. First, review procedures must recognize the complexity of competitive markets and encourage regulated firms to use a portfolio of options rather than relying exclusively on a single form of transaction in acquiring their gas supplies and purchasing or selling emission allowances. Second, any review of the prudence of utilities' decisions should be conducted on an *ex ante* rather than an *ex post* basis. Otherwise, firms are placed in a "heads I win, tails you lose" situation that raises costs by creating unnecessary risks and discourages actions that are in the best interests of ratepayers but which create regulatory risk for the utility. This argues for pre-approval of utilities' portfolio structures. Finally, PUCs should exploit the competitive nature of supply markets by relying on least-cost bidding to ensure that utilities do not pay above-market prices for the various components of their acquisition portfolios.

Regulatory reform and the evolution of new policy inevitably move with a "two steps forward, one step back" pattern. The unwinding of the old system of regulated fixed-price contracts governing fuel acquisition in favor of markets and the development of an active and visible spot market for gas were extremely important and have benefitted consumers greatly. We are now on the threshold of the next major step forward, in which the structure of gas markets will widen and deepen, again to the benefit of the ultimate consumer. The innovative regulatory regime created by the 1990 Clean Air Act Amendments also offers the potential of substantial benefits — significant pollution reductions at a cost far less than would be possible with traditional regulatory tools. It would be unfortunate indeed if these market processes were stifled in their infancy because of inadequate understanding of what competitive markets are all about.

ENDNOTES

1 See, for example, Palmer, Karen, Peter Fox-Penner, David Simpson and Michael Toman, *Power Plant Fuel Supply Contracts: The Changing Nature of Long-Term Relationships* (Arlington, VA: Public Utilities Reports, Inc., 1992). Also published as "Contracting Incentives in Electricity Generation Fuel Markets," Discussion Paper No. 92-07, (Washington, D.C.: Resources for the Future, 1992).

2 See, for example, the recent *En Banc* and related proceedings before the California Public Utilities Commission (*En Banc on Gas Procurement*, February 1992; *Application of Southern California Gas Company...*, Decision 92-04-027, April 8, 1992); National Regulatory Research Institute, "State Regulatory Challenges for the Natural Gas Industry in the 1990s and Beyond," Occasional Paper #15, June 1992; Sutherland, Ronald J., "Natural Gas Contracts in an Emerging Competitive Market," in International Association of Energy Economics, *Planning for the Year 2000 and Beyond: Energy Markets and the Economy* (New Orleans: IAEE Proceedings, 1992).

3 For a summary, see MacAvoy, Paul W., "The Regulation-Induced Shortage of Natural Gas," *Journal of Law and Economics*, April 1971, pp. 167-99.

4 For a useful summary, see Kahn, Alfred E., *The Economics of Regulation* (New York: John Wiley and Sons, 1970).

5 Broadman, Harry G., "Deregulating Entry and Access to Pipelines," in Kalt, Joseph P. and Frank C. Schuller, *Drawing the Line on Natural Gas Regulation* (New York: Quorum Books, 1987).

6 Kalt, Joseph P., "The Redesign of Rate Structures and Capacity Auctioning in the Natural Gas Pipeline Industry," EEPC Discussion Paper Series, John F. Kennedy School of Government, Harvard University, July 1988.

7 Interview of Chairwoman Martha Hesse, Federal Energy Regulatory Commission, *Oil and Gas Journal*, April 20, 1987; Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation and Office of Economic Policy, "Gas Transportation Rate Design and the Use of Auctions to Allocate Capacity," July 1987; Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation and Office of Economic Policy, "A New Approach to Rate Design for Interstate Gas Pipelines," May 1987.

8 Interstate Natural Gas Association of America, "Carriage through the First Half of 1992," August 1992.

9 Kalt, Joseph P., "Market Power and the Possibilities for Competition," in Kalt and Schuller, *op. cit.*

10 This condition (declining unit costs) is not sufficient to provide the large firm with market power unless the market is also "uncontestable": if new entrants can credibly threaten to enter at efficient scale, the would-be natural monopolist will lack market power. In natural gas pipelines and distribution systems, contestability is limited by the fact that capital is (literally) sunk into a specific service. This deters entrants who risk getting stuck in a market with an incumbent who has also sunk its capital. See Baumol, William. J., John C. Panzar and Robert D. Willig, *Contestable Markets and the Theory of Industry Structure* (New York: Harcourt, Brace and Jovanovich, 1982).

11 None of this is to imply that antitrust protections for competition do not still apply.

12 See Broadman, Harry G. and Joseph P. Kalt, "How Natural is Monopoly? The Case of Bypass in Natural Gas Distribution Markets," *Yale Journal of Regulation*, Vol. 6, 1989, pp. 181-208.

13 For an LDC view, see Boswell, William. P. (The People's Natural Gas Co., PA), "The New Competitive Monopoly: A Thundering Silence," *Public Utilities Fortnightly*, October 1, 1992.

14 These estimates do not include the additional gas usage that could be spurred by a gas-intensive strategy for meeting the requirements of the Clean Air Act Amendments of 1990 — as described below.

15 United States Department of Energy, Energy Information Administration, "Annual Energy Outlook 1992," June 1992.

16 Estimate of the National Petroleum Council. See Madison Public Affairs Group, "The Role of Natural Gas in Electricity Generation: Issues and Potential Solutions," report prepared for the Interstate Natural Gas Association of America (INGAA), October 1992.

17 Madison Public Affairs Group, *op. cit.*

18 ICF Resources/Enron Corp., *The Natural Gas Advantage: Strategies for Electric Utilities in the 1990s* (Houston: Enron, 1992).

19 National Acid Precipitation Assessment Program (NAPAP), "Methods of Modelling Future Emissions and Control Costs," Report 26, December 1990, Section 7.

20 Indeed, one of the major obstacles to the creation of western economic systems in the former Communist countries is that they do not have an evolved body of contract law and contract practice, making it difficult to write and enforce contracts.

21 See, for example, Brealey, Richard A. and Stewart C. Myers, *Principles of Corporate Finance*, fourth edition (New York: McGraw Hill, 1991), Chapter 23; Copeland, Thomas E. and J. Fred Weston, *Financial Theory and Corporate Policy*, third edition (Reading, MA: Addison-Wesley, 1992), Chapter 13.

22 See particularly Polinsky, A. Mitchell, "Fixed Price Versus Spot Price Contracts: A Study in Risk Allocation," *Journal of Law, Economics and Organization*, Spring 1987, pp. 27-46; and Hubbard, R. Glenn and Robert J. Weiner, "Long-Term Contracting and Multiple-Price Systems," *Journal of Business*, April 1992, pp. 177-197.

23 For example, suppose that the major source of price uncertainty in natural gas is whether or not a major new field will be discovered somewhere in the U.S. in the next 15 years. The discovery of that field will not affect the supply curves of the owners of existing proven reserves, but could affect the price of gas.

24 It is sometimes argued (or assumed) that firms are always risk neutral, because of the ability of the investors to diversify firm-specific risks in the overall market. If this were true, then cash-flow volatility would not impose any costs. We do observe, however, firms paying money to financial intermediaries to reduce cash-flow volatility (see below), so they act as if they are risk averse.

25 This analysis would not apply to firms who plan to be net buyers, but who could switch to pollution reduction quickly if the cost of doing so fell. There, valuation of allowances would be highly correlated with the price, and hence spot pricing might be preferred.

26 Note that one cannot infer the long-term average relationship between fixed and spot prices on the basis of their difference at any point in time: spot prices will be above (below) longer-term prices in times of relatively tight (ample) supply, regardless of their overall average long-term relationship. We return to this issue below.

27 See Palmer, *et al.*, *op. cit.*

28 See Palmer, *et al.*, *op. cit.*

29 By analogy, firms issue fixed-interest rate bonds; if interest rates rise, the price of the bonds fall such that their holders are indifferent between receiving the "coupon" rate specified in the bond or the higher coupon rate now available on new bonds. When this price fall occurs, the holders of the bonds suffer a capital loss. Bondholders who are particularly concerned about further losses can sell, taking a small loss but preventing a larger one. As a result, old bonds that have significantly appreciated or depreciated pose no serious problems for policy or the marketplace.

30 The OTC market is also referred to as the off-exchange market, the secondary market and the derivatives market.

31 In fact, the growth in secondary market trading of gas contracts has been paralleled in other commodity markets. See, e.g., "Commodity Derivates: Primary Colours." *Risk*, February 1993, pp. 33-39.

32 See Kapner, Kenneth R. and John F. Marshall, *The Swaps Handbook: Swaps and Related Risk Management Instruments, Supplement 1991-92* (New York: New York Institute of Finance, 1991).

33 If both buyers and sellers desire price fixity, competitive market forces will determine whether discounts are or premia are actually sustained in the market.

34 Charles River Associates, "Natural Gas Procurement: Experience with Spot vs. Contract Pricing in Analogous Commodity Markets," prepared for El Paso Natural Gas Company, December 1986.

35 Palmer, *et al.*, *op. cit.*

36 Though beyond the scope of this paper, it is interesting to note that a wide diversity of mortgage forms has evolved following substantial deregulation of the banking sector, paralleling in both time and scope the evolution of the gas market.

37 See Dhillon, Upinder S., James D. Shilling and C.F. Stirmans, "Choosing Between Fixed and Adjustable Rate Mortgages," *Journal of Money, Credit and Banking*, February 1987, pp. 260-267; Brueckner, Jan K. and James R. Follain, "The Rise and Fall of the ARM: An Econometric Analysis of Mortgage Choice," *Review of Economics and Statistics*, February 1988, pp. 93-102.

38 The standard spot contract is for 30 days at a fixed price. Obviously, as the contract term becomes shorter, the difference between fixed and variable prices diminishes.

39 See "Short-Term Purchases and Supply Reliability," *Public Utilities Fortnightly*, October 1, 1987, pp. 81-89.

40 Joskow, Paul, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation," *Journal of Law and Economics*, October 1974, pp. 291-328.

41 Indeed, at least some utilities seem to believe that, during a period of high, volatile spot prices, gas costs resulting from spot purchases might be disallowed precisely because PUCs would deem the reliance on the volatile spot market to have been imprudent. See Madison Public Affairs Group, *op. cit.*

42 See, for example, "Utilities' Risks in Purchasing Power," Credit Comment in *Standard and Poor's Credit Week*, March 26, 1990, pp. 1-5, at 2.

43 Haines, Leslie, "Financing Backstops," *Oil and Gas Investor*, May 1992, pp. 52-54.

44 Policies of state regulators will, as discussed herein, also have significant impacts on future gas prices. Since, however, such policies are the subject of this paper, we ignore for current purposes their effect on price uncertainty.

45 Prices are not, of course, the only source of uncertainty faced by producers. A major risk affecting the cost of financing production is the uncertainty about the quantities ultimately producible from given reserves. Contractual provisions could also mitigate this risk, but such issues are beyond the scope of this paper.

46 This discussion assumes that the availability of some LTFP contracting does not affect the spot price itself, relative to what would occur in a world in which LTFP contracts were not possible. This is most likely incorrect: by raising the cost of capital to producers, elimination of LTFP contracts would tend to raise spot prices as well.

47 See Charles River Association, *op. cit.*; and Palmer, *et al.*, *op. cit.*

48 Such financing has been used, for example, by independent power producers who hold fixed-price requirements sales contracts and fixed-price gas supply contracts.

49 The costs of debt and equity themselves are also functions of the degree of leverage. See, for example, Copeland and Weston, *op. cit.*, pp. 464-71.

50 Standard & Poor's, *op. cit.*

51 National Independent Energy Producers (NIEP), *Negotiating Risk: Efficiency and Risk Sharing in Electric Power Markets* (Washington, D.C.: NIEP, October 1992).

52 NIEP, *op. cit.*

53 Standard & Poor's, *op. cit.*, at 2.

54 Standard & Poor's, *op. cit.*, at 2.

55 The length of contract in this sample varies from eight to twenty-three years.

56 To date, the allowance "market" has produced only a handful of trades, with prices generally in this range. See Bernstein, Mark, Alex Farrell and James Winebrake, "No Sale! What If States Restrict the Allowance Trading Market?", *Public Utilities Fortnightly*, November 1, 1992. The first EPA-sponsored auction of allowances took place on March 29, 1993, and yielded prices that ranged from $122 to $310. See "Sold: $21 Million Worth of Pollution," *The New York Times*, March 30, 1993, p. D1.

57 Of course, by buying an allowance, the utility selling the allowance must undertake pollution abatement.

58 NAPAP, *op. cit.*, at 26-76.

59 ENRON, *op. cit.*

60 For a discussion of the state of the allowance market and concomitant state policy concerns, see Bernstein, Farrell and Winebrake, *op. cit.*

61 Hahn, Robert W. and Robert N. Stavins, "Incentive-Based Environmental Regulation: A New Era from an Old Idea," *Ecology Law Quarterly*, Vol. 18, No. 1, 1991, pp. 1-42.

62 See note 3, *supra*.

63 See note 3, *supra*, for an example of the arguments being made in this context.

64 In the following subsection we will discuss PUC policies that would generate information about prices prevailing in these markets.

65 Hotelling, Harold, "The Economics of Exhaustible Resources," *Journal of Political Economy*, April 1931, pp. 137-175.

66 See, for example, Howe, Charles W., *Natural Resource Economics: Issues, Analysis and Policy*, (New York: John Wiley and Sons, 1979).

67 *Natural Gas Week*, October 12, 1992, and December 28, 1992. Spot price quotes are for the Henry Hub; futures quotes are the "Week's High/Low."

68 A situation in which the future price is below the current spot price is described in the financial literature as a "backwardated" market. This condition has prevailed in gas for the latter half of 1992. During much of this period, one could use the futures market to lock in gas prices for a year at an average below the then-current spot price. Of course, there would be no way of assuring that the price paid would be below the spot price during the month when delivery is actually taken. Conversely, buyers who locked in a year's worth of prices beginning in 1991 would have generally paid an average price above the then-current spot price, but would have found that their costs were far below the spot price that actually prevailed in the delivery month.

69 See Palmer, *et al*, *op. cit.*, p. 81.

70 Jaffe, Adam B. and Joseph P. Kalt, "Incentive Regulation for Natural Gas Pipelines," *New Horizons in Natural Gas Deregulation*, Conference of the Cato Institute and the Institute for Energy Research, Washington, D.C., March 4, 1993.

71 Kalt, Joseph P., Henry Lee, and Herman B. Leonard, "Re-Establishing the Regulatory Bargain in the Electric Utility Industry," EEPC Discussion Paper Series, John F. Kennedy School of Government, Harvard University, March 1987.

72 See, for example, Standard & Poor's, *op. cit.*; Axel, Farrell and Winebrake, *op. cit.*; INGAA, *op. cit.*; Madison Public Affairs Group, *op. cit.*

73 Unbundling of electric power from power transmission may also be feasible to a significant degree. See Joskow, Paul and Richard Schmalensee, *Markets for Power* (Cambridge, MA: MIT Press, 1983).

74 Mathios, Alan D. and Robert P. Rogers, "The Impact of Alternative Forms of State Regulation of AT&T on Direct-Dial, Long-Distance Telephone Rates," Rand Journal of Economics, August 1989.

75 See, for example, National Association of Regulatory Commissioners (NARUC), Staff Gas Subcommittee, *Considerations for Evaluating Local Distribution Company Gas Purchasing Choices* (Washington, D.C. : NARUC, November 1990); California Public Utility Commission, *En Banc*, *op. cit.*; Standard & Poor's, *op. cit.*; Charles River Associates, *op. cit.*; *Public Utilities Fortnightly*, "Supply Purchases and Supply Reliability," October 1987.

76 NARUC, *op. cit.*, offers a fairly detailed plan for pre-approval.

Appendix 1

MAJOR FEDERAL REGULATORY REFORMS LEADING TO UNBUNDLING OF TRANSPORTATION BY INTERSTATE PIPELINES

12/1/78	FERC Order 46	Allowed FERC to authorize the transportation of natural gas by interstate pipelines on behalf of intrastate pipelines, and vice versa.
4/27/79	FERC Order 27	Allowed essential agricultural users, schools, and hospitals to develop gas themselves or buy directly from producers. Term for purchases up to 5 years; for user-developed gas, term not to exceed 10 years. Interstate producers. Term for purchases up to 5 years; for user-developed gas, term not to exceed 10 years. Interstate pipeline companies authorized to transport such gas.
5/13/79	FERC Order 30	Authorized direct sale of gas from producers to end users that would otherwise have burned fuel oil and transportation of such gas by interstate pipeline companies. Program to run for duration of fuel oil emergency. Allowed gas usage in boilers formerly discouraged under Powerplant and Industrial Fuel Use Act of 1978: Immediate oil shortage seen as more pressing than long-term gas supply. (Order 30 sales ended 11/3/83 under Order 234-B. Sales to low priority end users continued under blanket certificates in order to alleviate gas glut.)
11/79	Off-System Sales	Allowed interstate pipeline companies to sell gas directly to end users not normally served. Service to existing customers could not be impaired. Gas price must be higher than seller's average cost for Section 102 gas and seller's average load factor rate. Seller must demonstrate potential take-or-pay liability. Purchaser could not be part of another pipeline company's core market.
Special Marketing Programs (SMPs) -Transco 4/83 -Columbia 11/10/83 -Tenneco 11/20/83 -Panhandle/Trunkline 3/19/84 -Texas Eastern 6/29/84 -El Paso 8/24/84 -Various Producers 1983-85		Transco established first SMP as part of rate settlement. Under Industrial Sales Program, Transco purchased and set prices for gas. Producer-suppliers and eligible end users who wished to participate could then sell gas to or buy gas from the program. Transco's SMP expanded in June 1983 to include Contract Carriage Program (CCP). CCP allowed producers and end users to enter into direct sales agreements with the pipeline company acting as transporter. Transco's two programs were models for all later SMP's. As of April 1985 more than 30 SMP's had been approved. The programs were aimed primarily (at first exclusively) at fuel-switchers, so captive customers could not purchase this market-priced gas.
8/83	Blanket Certificates to Transport Gas for High Priority Users FERC Order 319	Allowed interstate pipeline companies to use blanket certificates to transport gas for high priority end users (process, feedstock, commercial, essential agricultural users, schools, hospitals). Transporter does not need to obtain separate authorization for each transaction.
8/83	Blanket Certificates to Transport Gas for Non-Priority Users FERC Order 234-B	Allowed interstate pipeline companies to use blanket certificates to transport gas for users covered by Order 30, in effect creating a spot market of direct sales from producers and other intrastate suppliers to industrial boiler fuel users. Gas could be sold and transported for up to 120 days without prior approval. Longer agreement required prior notice and allowed for protest, but could be in effect for 120 days before process was complete.

Britton White Jr
Executive Vice President
General Counsel

October 8, 2001

The Honorable Doug Ose
Chairman
Energy Policy, Natural Resources and
Regulatory Affairs Subcommittee
House Government Reform Committee
B-377 Rayburn House Office Building
US House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

As General Counsel of El Paso Corporation, I am responding to your recent letter addressed to John Somerhalder, President of the El Paso Pipeline Group. Mr. Somerhalder is appreciative of the invitation to testify "from the perspective of the El Paso Pipeline Group" at the subcommittee's upcoming hearing "on natural gas capacity, infrastructure constraints, and promotion of healthy natural gas markets, especially in California." The Company looks forward to discussing with you and the other members of the subcommittee, at an appropriate time, the many factors that have had an impact on the natural gas market in California and throughout the nation over the last several years. Unfortunately, the present status and immediate timing of adjudicator proceedings now pending before the Federal Energy Regulatory Commission makes this an inappropriate time for the company to participate in the upcoming hearing.

As the Subcommittee knows, there are presently pending before FERC several proceedings directly related to the subject matter of the subcommittee hearing. In an adjudicatory proceeding filed by the California Public Utilities Commission under the provisions of Section 5 of the Natural Gas Act, the FERC is in the very final stages of determining the validity of the CPUC's claims against the company. We have disputed these claims, and in accordance with the procedures mandated by the Congress and FERC, these claims will shortly be decided. In addition, claims related to capacity on the El Paso Natural Gas pipeline system are currently pending before the FERC in several proceedings. The current critical stage of the CPUC adjudication makes this an inappropriate time to participate in a congressional hearing on the identical issues pending before FERC for decision.

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Under these circumstances we cannot help but conclude that it would not be appropriate for Mr. Somerhalder to accept your invitation to participate in a hearing to be held on October 16th. We would look forward to meeting with, or appearing before, the Subcommittee to discuss these important issues at a time and in a manner that does not present such a clear conflict with the resolution of the matter presently awaiting decision by the Commission.

We appreciate your consideration of this matter.

Very truly yours,

Burton White Jr.

L.P. Lorenz
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November 5, 2001

The Honorable Doug Ose
Chairman,
Subcommittee on Energy Policy, Natural Resources
And Regulatory Affairs
House Committee on Government Reform
B-377 Rayburn House Office Building
Washington, D. C. 20515

Dear Chairman Ose:

On behalf of Sempra Energy and Southern California Gas Company (SoCalGas), thank you for convening the October 16, 2001 hearing into Natural Gas Infrastructure and Capacity Constraints. This is a vital area of interest, and we appreciate your constructive engagement in this issue. The hearing was a very helpful beginning in clearing away the rhetoric and focusing on the real infrastructure situation in the west, and we were grateful for the opportunity to testify.

We were disappointed to see that the testimony on behalf of the Interstate Natural Gas Association of America (INGAA) appended a chart alleging that the utilities in California and the CPUC have consistently opposed interstate pipeline expansions. The exhibit lists six interstate pipeline proposals, dating back to 1989, and purportedly demonstrates SoCalGas opposition to these expansions. I would like to set the record straight.

First, I would like to state our company's general position on interstate pipeline expansions:

- SoCalGas supports construction of interstate and intrastate pipelines when necessary to meet the needs of our customers; and

- SoCalGas believes that construction should be coordinated to ensure regulators, both state and federal, that proposed expansion facilities will benefit consumers.

Inaccuracies in INGAA chart

SoCalGas has indeed opposed some of the projects, but it is critically important to understand the reason for our opposition, which fall into two basic areas:

Reduced reliability of existing services. SoCalGas has objected to pipeline construction or expansion projects that reduced the reliability of existing services. For example, the Mojave pipeline necessitated expansion of the upstream pipeline system of El Paso Natural Gas Company, on which SoCalGas had secured significant levels of transportation rights to serve customers in southern California. SoCalGas requested that shippers on the El Paso expansion be granted rights to deliver gas into the Mojave system (the purpose of the expansion), but not to the delivery point of SoCalGas (Topock) since SoCalGas had the full rights at that point. FERC rejected this request, effectively abrogating our contract rights, and allowed new shippers to have the same level of service at that point.

Local distribution companies in California, as well as the CPUC, have opposed projects that threaten the reliability or economic viability of consumers' existing interstate pipeline rights. Federal regulators have consistently refused to consider these concerns. As a result, California consumers have endured substantial stranded costs, as well as a basic inability to utilize services even when paying maximum rates.

Noneconomic costs to consumers. INGAA's table claims that SoCalGas protested the Kern River 2001 emergency expansion "because it will not expand Wheeler Ridge capacity." In fact, SoCalGas stated the following in this case:

> "SoCalGas supports expansions that will provide more reliable and usable pipeline capacity. However, the expanded capacity needs to be rationalized and it must be constructed to facilitate deliveries to targeted markets, e.g., electric generation loads....the question presented by this filing is whether it is appropriately tailored to serve the intended markets."

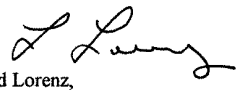
Our filing in this case went on to request that the Federal Energy Regulatory Commission convene a comprehensive conference (within 15 to 20 days of the filing) to collaborate among the market participants and the state and federal regulators. This is the essence of our concern with infrastructure development, there is no coordination among the regulatory bodies and there is no indication that infrastructure is being planned in a manner that reflects the anticipated actual needs of consumers.

As I indicated in my testimony, SoCalGas does not support blindly matching interstate capacity with intrastate capacity. Our intent is to ensure there is adequate capacity to meet the needs of consumers, with a healthy cushion of "slack capacity." Building beyond that level would simply straddle consumers with higher costs for empty pipes. While these pipelines might help the interstate pipeline companies have an extra outlet for excess natural gas when electric generation demand is lower, we do not feel that California consumers should be asked to pay for that flexibility.

Mr. Chairman, this is a difficult and contested issue. The Federal Energy Regulatory Commission has begun to take a more constructive role—hosting a public forum for all stakeholders on this issue. It is our hope that discussions like that, and like the unique

opportunity you provided in this hearing, will provide a clearer understanding of what natural gas infrastructure will be needed to satisfy future demand in California and throughout the west. Thank you again for providing us with the opportunity to provide the Committee with our testimony on this important subject.

Very truly yours,



Lad Lorenz,
Director, Capacity and Operational Planning
Southern California Gas Company