The Energy Policy Act of 2005 and Its Impact on the U.S. Natural Gas Supply/Demand Imbalance

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American Gas Foundation

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Energy and Environmental Analysis, Inc.

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FOREWORD

Today and for the foreseeable future, high natural gas prices are negatively impacting all consumers in our nation. The impact includes high gas bills, the inability of companies to remain competitive, and the loss and/or overseas move of U.S. jobs. Even in light of this, government decision makers continue to support public policy and federal/state regulations that reduce, delay, or eliminate natural gas supplies that can ease the supply/demand imbalance that has directly contributed to high prices. This study:

- Reemphasizes the 2005 American Gas Foundation "Natural Gas Outlook to 2020" (AGF Outlook Study) study findings;
- Cross-references the Energy Policy Act of 2005 provisions and the draft provisions of proposed legislation against the "2020" study policy scenarios – identifying those areas addressed and those still in need of action; and
- Performs a "gap analysis" to identify the policies/regulations that directly impact natural gas supply and consumer prices and identify the actions that have been taken plus those actions that may resolve our Nation's natural gas supply/demand imbalance.

EEA performed the original modeling and projections published in the 2005 AGF Outlook Study. The AGF Outlook Study clearly identified the advantages for consumers and the nation of policies and legislation that move the natural gas market in the direction of the path described in the "Expanded Scenario" in terms of reduced residential and commercial gas costs and reduced pressure on the competitiveness of U.S. industry. For this study, EEA compared recent market trends and its current projection against the projections included in the AGF Outlook Study. That analysis concluded that recent events only heighten the importance of addressing the imbalance in the gas market. Further, EEA's analysis identifies those policy and legislative initiatives that if enacted and fully implemented, would increase the likelihood that the favorable "Expanded Scenario" would be achieved.

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I. EXECUTIVE SUMMARY

The purpose of this American Gas Foundation (AGF) report, "The Energy Policy Act of 2005 and Its Impact on the U.S. Natural Gas Supply/Demand Imbalance," is twofold. First, the report revisits the findings of a prior 2005 AGF study, "Natural Gas Outlook to 2020" (AGF Outlook Study), in light of recent market conditions. Second, and very importantly, the report performs a "gap analysis" that compares the policy scenarios outlined in the AGF Outlook Study to the potential impacts of the Energy Policy Act of 2005 (EPAct). This analysis measures the progress in implementing policies/regulations that could ease the natural gas supply/demand imbalance and lower energy costs for consumers.

The AGF Outlook Study, released in February 2005, analyzed the U.S. natural gas market to the year 2020 under three alternative public policy scenarios: "Existing, Expected, and Expanded." These scenarios were used to describe potential market conditions and to emphasize the key policy variables that will have an impact on markets through 2020. The results of the study pointed to the need for public policy makers and industry decision makers to immediately address critical issues that will have a significant impact on the availability and price of natural gas for decades to come.

Summary of Findings

The Energy Policy Act of 2005 represents a significant first step toward addressing some of the natural gas supply/demand issues facing our country. It took more than five years to develop, and was the first major piece of federal energy legislation since 1992. As such, Congress deserves significant credit for its efforts. Nevertheless, ***there remains a supply/demand imbalance, which is having a significant negative impact on the U.S. economy and consumers.***

While EPAct made some headway in key policy areas noted in the AGF Outlook Study, such as demand reduction, onshore supply access and liquefied natural gas (LNG) supplies, there are many more policy actions that still need to take place. Additionally, actions on other important issues such as moving forward with the Alaska Gas Pipeline have yet to be taken. Further, for many of the initiatives in the EPAct, Congress has not appropriated funds. At best, EPAct and other policy measures taken over the past year bring us about one third of the way toward achieving the potential market balance as outlined in the Expanded policy scenario of the AGF Outlook Study. The AGF Outlook Study estimated that if the U.S. followed the path of the Existing policy scenario, consumers could be facing as much as $1 trillion in additional natural gas cost. ***Without additional efforts beyond the measures taken over the past year, U.S. consumers will continue to bear the burden of high and volatile natural gas prices and can expect to face billions of dollars in additional cost over the next 14 years.***

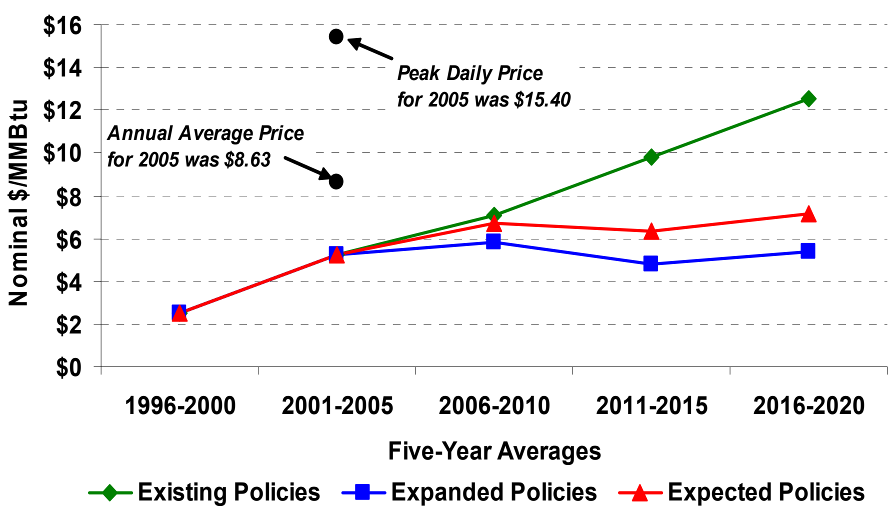
Although the supply/demand balance was much tighter than anticipated in 2005 due to such events as the record-breaking hurricane season, higher crude oil prices, and lower LNG imports, the long-term gas market projections made in the AGF Outlook Study remain the same:

- It is unlikely that the natural gas market will return to the over supply/low price environment of the 1980s and 1990s.
- Without significant policy changes, the North American natural gas market will remain in a tight supply/demand balance, with accompanying high prices, for the foreseeable future.
- The tightness of the supply/demand balance means that short-term supply disruptions can cause prices to rise dramatically.
- LNG imports will depend both on the ability to construct new import terminals and the ability to contract for LNG supplies.

Implications for the U.S. Economy and Natural Gas Consumers

Natural gas is a key commodity in the U.S. economy, used for applications as diverse as home heating fuel and industrial feedstock. The situation facing the U.S. economy in 2007 has certainly not changed significantly. As pointed out in the AGF Outlook Study, ample natural gas resources exist but supply access and infrastructure are being constrained. As demand continues to grow, prices have remained high and very volatile, and are obviously detrimental to the U.S. economy and consumers. In 2005, a U.S. Department of Commerce study estimated that higher natural gas prices between 2000 and 2004 led to lower GDP growth and a decrease in employment of almost 500,000 jobs.

Actual and Projected Natural Gas Prices at Henry Hub – AGF Outlook Study

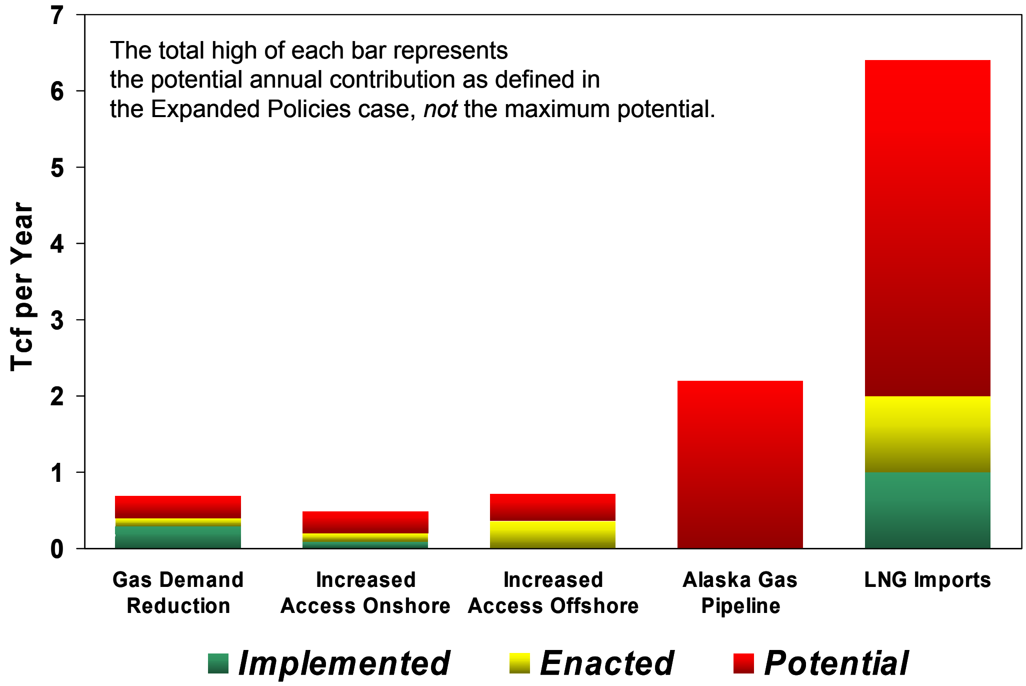


As pointed out in the AGF Outlook Study, natural gas prices in the Existing policies scenario averaged about $4.00 higher than the Expanded policies scenario – an increase of more than 40 percent. As a result, by the year 2020, consumer expenditures on natural gas are $200 billion higher in the Existing policies scenario. These increased costs would have a ripple effect throughout the economy, as increased expenditures on natural gas reduce disposable income, slow economic growth and reduce employment.

Progress Toward Addressing the Imbalance

The chart below provides a summary of how far the U.S. has moved over the past year toward the favorable market conditions as outlined in the Expanded policies scenario. An estimate of the progress made on the key variables as outlined in the AGF Outlook Study's Expanded scenario is provided. The progress is expressed in terms of the percent progress with policies that have been fully implemented ("Implemented"), or policies that have been enacted (i.e. EPAct) but not yet fully implemented ("Enacted"). The percentages were calculated by estimating the impact of enacted/implemented policies on gas supply or demand in Bcf per year, then dividing the impact by the potential supply identified in the AGF Outlook Study. The total height of each bar represents the potential annual contribution of that variable as identified in the Expanded policies scenario (although the maximum potential may actually be much higher).

Impacts of Policy Changes on Key Variables - Expanded Policies Potential



	Implemented *Impact of policies that have been fully implemented.*	**Enacted** *Impact of policies that have been enacted, but not yet implemented.*	**Potential** *Potential impact identified in AGF Outlook Study.*
Gas Demand Reduction	Currently implemented efficiency and conservation policies could reduce demand by about 300 Bcf per year.	Full implementation of all EPAct measures could reduce gas demand by another 100 Bcf per year.	The AGF Outlook Study identified potential reductions of 650 Bcf per year by decreasing gas demand in the power sector .
Increased Access Onshore	Policy to streamline the approval and permitting process may increase production by about 100 Bcf per year.	Full implementation of all EPAct measures could increase onshore supplies by another 100 Bcf per year.	Assuming only modest changes in onshore access policies, the Intermountain West could provide another 450 Bcf per year.
Increased Access Offshore	No new policies on OCS access have been implemented since the AGF Outlook Study.	In December, Congress passed legislation that will provide access to an additional 365 Bcf per year in the Eastern Gulf of Mexico.	Lifting the moritoria on exploration and production off the East and West Coasts could yield another 365 Bcf per year.
Alaska Gas Pipeline	No new policies have been implemented since the AGF Outlook Study.	The Alaskan Natural Gas Pipeline Act provides loan guarantees and other support, and the Alaskan legislature is currently considering an SGA agreement with the Producers Group.	An Alaskan Gas Pipeline could provide as much as 2.2 Tcf per year of additional gas supplies.
LNG Imports	Currently implemented policies that simplify the approval process for new terminals may increase LNG imports by about 1.0 Tcf per year.	Implementation of additional policies to promote long-term supply contracts could increase LNG imports by an additional 1.0 Tcf per year.	The AGF Outlook Study identified potential additional LNG imports of 6.4 Tcf per year.

Gas Demand Reduction

Enacted Score: 60%
Implemented Score: 40%
Potential Identified in AGF Outlook Study: 650 Bcf per Year

In some respects, EPAct goes beyond the Expanded policies scenario in that it includes additional measures to reduce natural gas demand, such as new building efficiency standards for government buildings. Although these additional measures toward demand reduction make a positive contribution toward improving the supply/demand balance, their collective impact is small relative to the potential impact of reducing the growth of gas demand for electricity generation. ***EPAct includes some critical measures to promote coal, nuclear, and renewable generating technologies, but cannot be met without further Congressional action to provide funding.***

Increased Access Onshore

Enacted Score: 40%
Implemented Score: 20%
Potential Identified in AGF Outlook Study: 450 Bcf per Year

EPAct made some progress toward improving access to federal onshore lands. Still, barriers remain to the approval and permitting of oil and gas exploration on these lands, particularly in the Intermountain West, which has some of the most promising resources in the Lower-48. A study by the Department of the Interior noted that there are nearly 1,000 different stipulations that can impede the development of oil and gas resources on federal lands. ***An integrated, all encompassing review of restrictions in the Intermountain West would coordinate and rationalize all the regulations governing land access. These regulations, which are often duplicative and overlapping in their scope, continue to be an impediment to increasing production in this area.***

Increased Access Offshore

Enacted Score: 50%
Implemented Score: 0%
Potential Identified in AGF Outlook Study: 730 Bcf per Year

Unfortunately, EPAct did not take any actions toward opening the Outer Continental Shelf (OCS) for oil and gas development. However, in December 2006, Congress did pass legislation that will open 8.3 million acres of federal waters in the eastern Gulf of Mexico to oil and gas drilling. While this was a significant step forward, exploration and production is still prohibited in all of the waters off the East and West Coasts. ***There are still abundant supplies in the OCS that remain off limits to development.***

Alaska Gas Pipeline

Enacted Score: N/A
Implemented Score: N/A
Potential Identified in AGF Outlook Study: 2.2 Tcf per Year

Unlike other policies, the Alaska Gas Pipeline is an "all or nothing" proposition; even though some policies to promote the project have been enacted, it will make no contribution to the U.S. natural gas market unless it is fully implemented. At present, it seems unlikely that an Alaska Gas Pipeline will become operational by the end of 2014. Most analysts agree that the earliest the pipeline could be operational would be in 2015 or 2016. For every year the project is delayed, the risk that it will be displaced by LNG imports increases. While the preliminary SGA contract is a positive development, it still must be approved by the Alaska state legislature before the pipeline project can move forward.

LNG Imports

Enacted Score: 30%
Implemented Score: 15%
Potential Identified in AGF Outlook Study: 6.4 Tcf per Year

Over the past year, the U.S. has added one new LNG import terminal and several more are currently under construction. While EPAct's Section 311 provision confirmed FERC's exclusive authority over the approval of LNG facilities, there are still issues over local opposition to new import terminals. The volume of LNG imports will also depend on the ability of terminal operators to secure long-term contracts. In the coming decade, many existing LNG contracts will expire and come up for renegotiation, and many new contracts will have to be negotiated for new import terminals. ***Even if more import terminals are built, the U.S. cannot be assured of dramatically increasing its LNG imports without securing LNG supply contracts.***

II. INTRODUCTION

Energy is the lifeblood of the U.S. economy, and natural gas contributes one-fourth of the nation's total primary energy supply. Natural gas is an important fuel in both the industrial and power sectors and is used to heat over half of the homes in the U.S. As a result of the critical role natural gas plays, higher natural gas prices can have ripple effects throughout the economy. These impacts include high natural gas bills, the inability of companies to remain competitive, and the loss and/or overseas move of U.S. jobs. These impacts in turn can lead to an increase in the trade deficit, a worsening of the balance of payments, and a decrease in the value of the dollar. Even in light of this, federal and state government decision makers continue to support public policies and regulations that reduce, delay, or eliminate natural gas supplies that can ease the supply/demand imbalance that has directly contributed to high prices.

In 2005, the American Gas Foundation issued the "Natural Gas Outlook to 2020" study, which analyzed the U.S. natural gas market to the year 2020 under three alternative public policy scenarios: "Existing, Expected, and Expanded." These scenarios were used to describe potential market conditions and to emphasize the key policy variables that will have an impact on markets through 2020. The results of the study pointed to the need for public policy makers and industry decision makers to immediately address critical issues that will have a significant impact on the availability and price of natural gas for decades to come. Under none of these scenarios did the natural gas market return to the conditions that prevailed in most of the 1980s and 1990s – surplus supply and relatively low, stable prices. The Energy Policy Act of 2005 (EPAct), which was signed into law by President Bush in August 2005, deals with the supply, delivery and use of fossil fuels (natural gas, coal and oil), nuclear power and renewable energy. While EPAct represented an important "first step" in bringing the natural gas market into balance, there are still some critical policy gaps that need to be addressed.

In the sections that follow, a review of the AGF Outlook Study findings, an examination of the impacts (if any) of recent market events on that study's findings, and the provisions of EPAct and other legislation that directly impact on natural gas supply or demand will be outlined. Further, the remainder of this study will assess the "gaps" and assess the progress made toward addressing the natural gas supply/demand imbalance facing our country.

III. IMPACT OF RECENT EVENTS

Supply and demand policy scenarios and the associated market conditions made in the AGF Outlook Study were based on a number of factors directly related to the U.S. gas market, such as recent trends in gas consumption and natural gas resource assessments. Other factors that influence the gas market were also taken into account, such as projections for oil prices and U.S. economic growth. Of course, it was not possible to accurately anticipate all the variables that would have an impact on the U.S. gas market in the near-term. Throughout most of 2005, the U.S. natural gas supply/demand balance was much tighter than anticipated in the AGF Outlook Study.

This section explores the impact of recent events on the long-term outlook for the U.S. natural gas market put forth in the AGF Outlook Study. It begins with a brief summary of the three sensitivity cases from the Study. Next, an examination of the events that caused recent gas market activity to differ from the Study's near-term market projections is presented. Lastly, impacts (if any) of these differences have on the Study's long-term projections are discussed.

<u>Summary of the AGF Outlook Study's Sensitivity Cases</u>

The AGF Outlook Study analyzed U.S. natural gas markets through 2020 under the three alternative policy-driven scenarios (Existing, Expected, and Expanded) by altering five key variables that may impact the U.S. natural gas market: natural gas production in the Lower-48 states, construction of a pipeline to transport natural gas from Alaska to the Lower-48 states, imports of Canadian gas, imports of LNG from outside North America, and the use of natural gas to generate electricity. Since these were policy-driven scenarios, key assumptions for variables such as economic growth and coal and oil prices were held constant in all three scenarios (Table 1). Growth in electricity demand, which is driven largely by GDP growth, was also assumed to be constant in all scenarios.

Table 1
Common Assumptions for All Scenarios in the 2005 AGF Outlook Study

Variable	**Assumption**
GDP Growth Rate	2.8% per year throughout the forecast
Industrial Production Growth Rate	2.3% per year throughout the forecast
Coal Prices	Increases at 1% per year in nominal terms throughout the forecast
Oil Prices	RACC declines to $28/bbl by 2010, and increases 2% per year nominally thereafter
Electricity Generating Capacity Additions	Short-term additions based on existing development plans, long-term assumes 1.9% annual growth rate in electricity output
Capacity utilization of Coal Generating Units	70% today, 73% in 2010, and 78% in 2020
Nuclear Generation	Capacity utilization continues at current level, no major retirements

The first scenario was the Existing policies scenario, which assumed that most projects to expand gas supply would be impeded, and that major policy modifications affecting gas demand would not be undertaken. Under the Existing policies scenario:

- No changes for in-place moratoria on offshore exploration and production.
- No changes for access in the Intermountain West.
- No Alaskan gas pipeline.
- The four currently operational LNG terminals expand, but no new terminals are built; total LNG imports reached only 5 Bcfd by 2020.
- Electricity generating capacity expands by roughly 150 gigawatts (GW), including 60 GW of gas-fired capacity, 50 GW of coal-fired capacity, and 40 GW of renewable capacity.

The Expected policies scenario, which assumed that future U.S. energy policy decisions would be relatively consistent with those that are being made today. Under the Expected policies scenario it was assumed that:

- Moratoria on exploration and production in the eastern Gulf of Mexico and off the East and West coasts continue.
- Drilling activity in the Intermountain West remains partially restricted.
- An Alaskan natural gas pipeline is operational by 2014 at 4 Bcfd, and expanded in 2017 to 6 Bcfd.
- Liquefied natural gas (LNG) imports reach 18 Bcfd by 2020.
- The electricity generating addition assumptions are the same as in the Existing policies scenario, including the addition of 60 GW of new gas-fired capacity.

The Expanded policies scenario employed a number of modifications to both natural gas supply- and demand-related assumptions that act to ease pressure in the gas market and reduce the cost of gas to the consumer. The Expanded policies scenario assumed:

- Drilling moratoria are lifted in the eastern Gulf of Mexico and off the East Coast, but not the West Coast.
- Less restrictive (but not unlimited) access in the Intermountain West.
- An Alaskan natural gas pipeline is operational by 2014 at 4 Bcfd, and expanded in 2017 to 6 Bcfd (same as Expected policies scenario).
- LNG imports increase to 23 Bcfd by 2020.
- Natural gas-based electricity generating capacity increases by 30 GW (only half as much as under the Existing and Expected policies scenarios), while coal, nuclear and renewable capacities are greater than in the Expected policies scenario.

In the Existing policies scenario, limited resource access, lower LNG imports, and the absence of the Alaska Pipeline lead to much higher gas prices and lower gas demand. In this case, annual gas prices average over $9 per MMBtu and peak at nearly $14 per MMBtu (Table 2 – on next page). Seasonal price volatility is also much greater than in either the Expected or Expanded policies scenarios.

In the Expected policies scenario, gas demand growth is led by the power generation sector. Industrial demand rebounds somewhat in the near-term, but overall growth is sluggish. Modest demand growth was projected for the residential and commercial sectors, which are driven primarily by demographic changes. Prices remain between $6 and $7 per MMBtu through most of the projection, about 30 percent lower than the Existing policies scenario. This price reduction represents a consumer cost saving of about $120 billion in 2020, versus the Existing policies scenario.

In the Expanded policies scenario, growth in power generation gas demand is lower than in the Expected policies scenario, due to the increased additions of coal, renewable, and nuclear capacity. The easing of supply access restrictions, along with greater imports of LNG lead, to gas prices that average between $5 and $6 per MMBtu, about 18 percent lower than the Expected policies scenario and over 40 percent lower than the Existing policies scenario. This price reduction represents a consumer cost savings of about $200 billion in 2020, versus the Existing policies scenario.

Table 2
Comparison of 2020 Projections from the AGF Outlook Study

	PROJECTED 2020		
CONSUMPTION (Bcfd)	Existing Policies	Expected Policies	Expanded Policies
Residential	5,899	6,142	6,230
Commercial	3,505	3,829	3,955
Industrial	6,522	7,514	8,027
Electric Generation	7,986	9,906	9,249
Pipeline Fuel	903	964	948
Lease & Plant	1,297	1,217	1,176
Total	26,113	29,572	29,584
SUPPLY (Bcfd)			
Lower-48 /1	20,069	18,414	17,791
Alaska	459	2,710	2,686
Canada /2	3,951	2,267	1,237
Mexico /2	-171	-171	-171
LNG /3	1,875	6,636	8,319
Total	26,183	29,856	29,863
PRICE ($/MMBtu, Henry Hub)			
Nominal	**$13.76**	**$8.15**	**$5.47**
Nominal Average (2004-2020)	**$9.43**	**$6.72**	**$5.50**

1. While increased access raised natural gas production in the Expected Policies scenario, other concurrent changes tended to reduce Lower-48 natural gas production in the Expanded Policies scenarios. However, increased access did help lower the cost of natural gas to consumers in the Expanded Policies scenario.
2. Net imports (positive) or exports (negative).
3. Net LNG imports (less Alaskan LNG exports).

The Impact of Recent Events on Near-term Market Projections

Since all three scenarios focused on policy changes that are implemented gradually over the forecast period, the U.S. supply, demand and price projections for the year 2005 varied from each other only slightly, as shown in Table 3. Yet there is a significant difference between the AGF Outlook Study's projections and what actually occurred in the gas market last year. While there were many variables that contributed to the short-term shift in the gas market, four of these factors had a significant impact:

- Hurricane-driven supply disruptions
- High oil prices
- High economic growth
- Lower LNG imports

The impact of each of these four variables on the 2005 gas market is discussed below.

Table 3
Comparison of 2005 Projections from the AGF Outlook Study

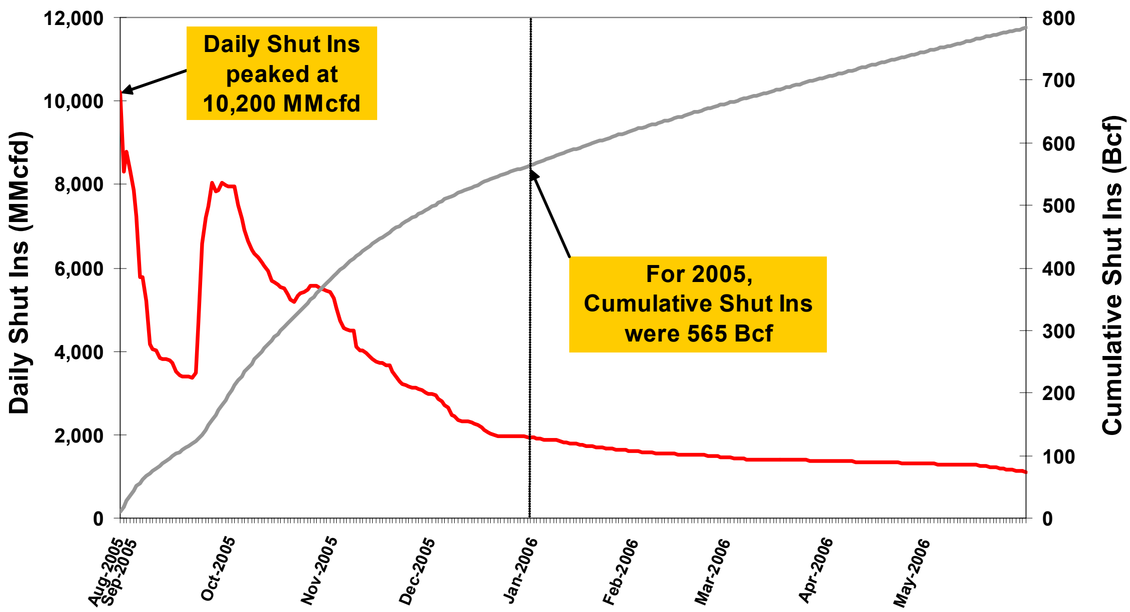
		PROJECTED 2005		
CONSUMPTION (Bcfd)	Actual 2005 /1	Existing Policies	Expected Policies	Expanded Policies
Residential	4,819	5,091	5,091	5,092
Commercial	3,007	3,170	3,170	3,172
Industrial	6,925	7,033	7,027	7,058
Electric Generation	4,809	4,858	4,856	4,812
Pipeline Fuel	712	735	729	729
Lease & Plant	1,235	1,206	1,206	1,206
Total	21,507	22,093	22,079	22,069
SUPPLY (Bcfd)				
Lower-48	17,730	17,970	17,963	17,996
Alaska	420	419	419	419
Canada /2	3,369	3,056	3,052	3,043
Mexico /2	-417	-511	-511	-511
LNG /3	559	1,047	1,047	1,047
Total	21,661	21,981	21,970	21,994
PRICE ($/MMBtu, Henry Hub)				
Nominal	**$8.78**	**$7.71**	**$7.74**	**$7.61**

1. EEA estimate.
2. Net imports (positive) or exports (negative).
3. Net LNG imports (less Alaskan exports).

The Impact of Hurricanes on U.S. Gas Supplies in 2005

Actual U.S. gas production was lower in 2005 than anticipated in the AGF Outlook Study, primarily because of supply disruptions caused by tropical storms and hurricanes in the 2005 hurricane season. The 2005 Atlantic hurricane season was the most active in recorded history, shattering previous records on repeated occasions. The season officially began on June 1, 2005, and lasted until November 30, although effectively the season persisted into January 2006 due to continued storm activity. A record twenty-eight tropical storms formed, of which fifteen became hurricanes. Of these fifteen hurricanes, Hurricanes Rita and Katrina had the greatest impact on U.S. gas production.

Figure 1
Gulf of Mexico Gas Supply Disruptions in 2005



At the peak of the hurricane supply disruptions, gas shut-ins totaled over 10 Bcfd (Figure 1). Cumulatively, there were 565 Bcf of gas shut-in in the last four months of 2005, an average of about 4.5 Bcfd. Some production in the Gulf remained offline well into 2006, with the U.S. Minerals Management Service (MMS) reporting 1099 MMcfd of production still shut-in as of June 1, 2006.

While the AGF Outlook Study emphasized the impact that sudden shifts in demand can have on price volatility, a sudden decrease in supply, such as that caused by hurricane shut-ins, can have the same effect. As noted in the AGF Outlook Study, U.S. gas production is at or very near the limit of productive capacity, and wellhead prices have generally been well above the variable cost of production. Due to these conditions, fluctuations in gas prices have very little impact on the amount of gas produced in the very near-term. If demand suddenly increases, such as during a very cold winter, supply has very little ability to respond, so the primary impact is on price. However, a supply disruption such as those caused by the hurricanes of 2005 can shut-in significant quantities of gas for months and also driving up gas prices.

The Impact of High Oil Prices on Gas Prices

While the AGF Outlook Study assumed that oil prices would continue to rise in 2005, it did not anticipate the magnitude of the increase. The AGF Outlook Study assumed that the price for West Texas Intermediate (WTI) crude oil would average about $47.50 per barrel in 2005. The actual average price in 2005 was nearly $56 per barrel, with prices peaking as high as $70 per barrel. As with gas prices, a major cause of the increasing oil prices was the impact of hurricanes on Gulf of Mexico production. For August through December of 2005, oil production shut-ins averaged 870,000 barrels per day. However, oil prices were climbing even before the hurricanes, so supply disruptions were not the only reason for higher prices. Other factors, such the growing demand for oil in China and continued political unrest in Nigeria and the Middle East, also had a significant impact on world oil prices over the past year.

Due to the ability of some U.S. gas consumers, primarily power generators, to switch between oil and natural gas, there is some correlation between the prices of the two fuels. Increases in oil prices will tend to cause those consumers that can switch between fuels to increase their use of natural gas, thereby increase gas prices. As mentioned in the AGF Outlook Study, the amount of switchable power generating capacity has been on the decline and is projected to continue to decrease in the future. However, for the near-term, the amount of switchable capacity is large enough that some relationship between oil and gas prices can be expected to persist.

The Impact of Economic Growth on Gas Demand

In 2005, U.S. economic growth was stronger than anticipated in the AGF Outlook Study. The U.S. GDP grew 3.2 percent in 2005, versus the projected rate of 2.8 percent. This strong pace of growth, despite rising energy costs, indicates that the U.S. economy is much more able to absorb the impact of higher oil and gas prices today than it was in the 1970s and 1980s. One indication of this is the level of industrial gas demand. Industrial gas demand in 2005 was only slightly lower than anticipated, despite high gas prices and hurricane damage to industrial facilities in the Gulf Coast area. In the AGF Outlook Study, industrial gas demand in 2005 was projected to be slightly over 7,000 Bcf, while actual demand was about 100 Bcf less, a difference of 1.4 percent. The pace of economic growth helped to strengthen industrial gas demand in 2005, preventing it from falling by more than it did.

Rising prices for industrial products have also played a role in reinforcing U.S. industrial gas demand. For example, it was anticipated that high gas prices would continue to reduce gas demand for ammonia production as it has over the past three years. However, the high cost of fertilizer worldwide encouraged U.S. ammonia producers to continue to operate even when gas prices reach $7 to $8 per MMBtu.

The Impact of LNG Imports on Gas Supply

The AGF Outlook Study cited LNG imports as one of the key variables affecting the future of the U.S. natural gas market. While the analysis focused on the long-term impact of additional LNG regasification facilities in the U.S. and increasing liquefaction capacity worldwide, the AGF Outlook Study also anticipated higher levels of U.S. LNG imports in 2005 at existing regasification facilities.

The primary reason the U.S. did not receive more LNG import in 2005 was the competition from consumers in other parts of the world, particularly Europe. While gas prices were high in the U.S., they were even higher in Europe due to cold winter weather. As a result, while the U.S. terminals continued to receive their firmly contracted deliveries of LNG, spot cargos of LNG were diverted to Europe. The AGF Outlook Study anticipated that U.S. LNG terminals would operate at or near their maximum capacity in 2005, increasing imports to over 1,000 Bcf. In reality, U.S. LNG imports were only 559 Bcf in 2005, almost 500 Bcf lower than projected.

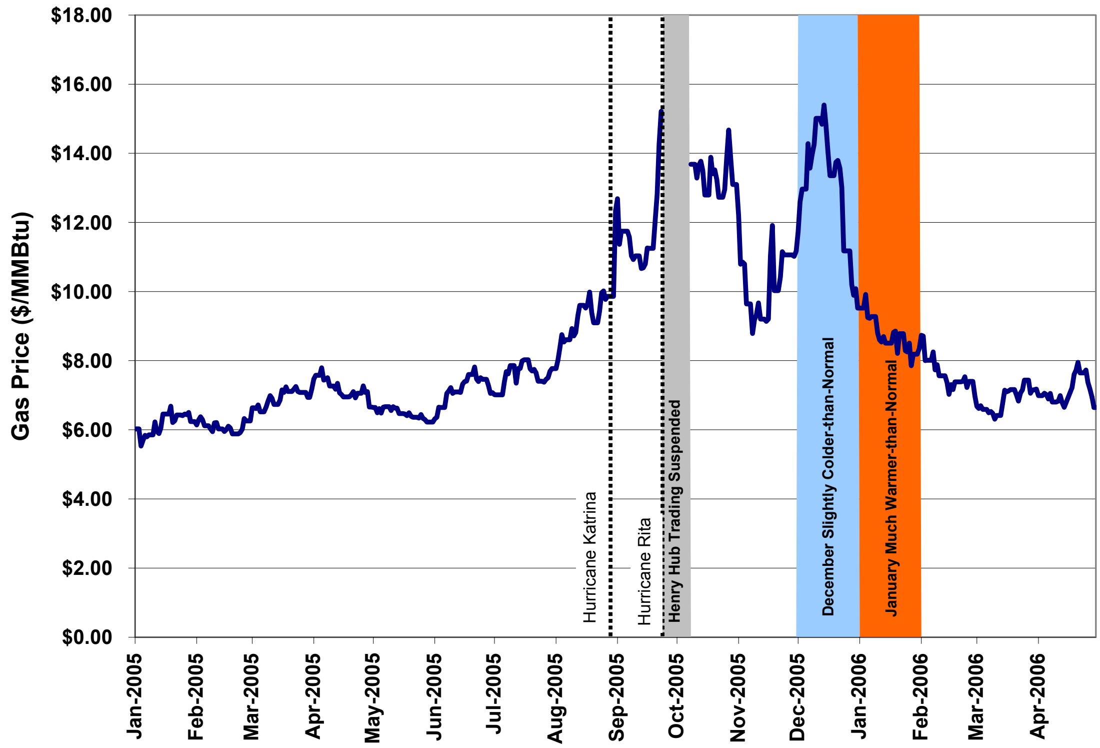
In the future, the U.S. will continue to compete with Europe and Asia for LNG imports. LNG supply contracts in Europe and Asia are usually based on crude oil prices, so any increase in the price of oil will have an impact on the price and quantity of LNG available to the U.S. market.

The Impact of Recent Events on Long-term Market Projections

The events described above combined to produce near-term gas prices that were much higher than anticipated in the AGF Outlook Study. However, these recent market events have not fundamentally changed the long-term outlook for the U.S. gas market. The tightness of the supply and demand balance means that short-term supply disruptions can cause prices to rise dramatically. However, as soon as the short-term event is over, the gas market can return to its prior supply/demand balance and prices will fall.

This is exactly what has occurred over the past year. Prior to the start of the 2005 Atlantic hurricane season, spot gas prices at Henry Hub ranged between \$6 to \$8 per MMBtu (Figure 2- on next page). After Hurricane Rita, the second major storm to hit the Gulf Coast in 2005, prices spiked to over \$15 per MMBtu. However, as the hurricane season slowly drew to a close and offshore production began to recover, prices started to decline. Prices rose again in December, as a brief period of cold winter weather caused demand to rise. However, January 2006 turned out to be the warmest January on record. Because of the warm weather, January gas demand averaged about 15 Bcfd below normal-weather levels, dwarfing the supply reductions caused by the hurricanes. By the end of winter, prices had returned to the range of \$6 to \$8 per MMBtu.

Figure 2
Daily Spot Gas Prices at Henry Hub, January 2005 through April 2006



Despite the much looser supply/demand balance caused by warm winter weather, gas prices remained relatively firm, and did not fall below their pre-hurricane levels until September 2006. While gas prices have exhibited a great deal of volatility in the upward direction when supply was constrained, there is a minimum, or "floor" on gas prices as the market balance loosens. This floor price for natural gas is influenced by both demand and supply side forces that affect the market in both the short-term and the long-term.

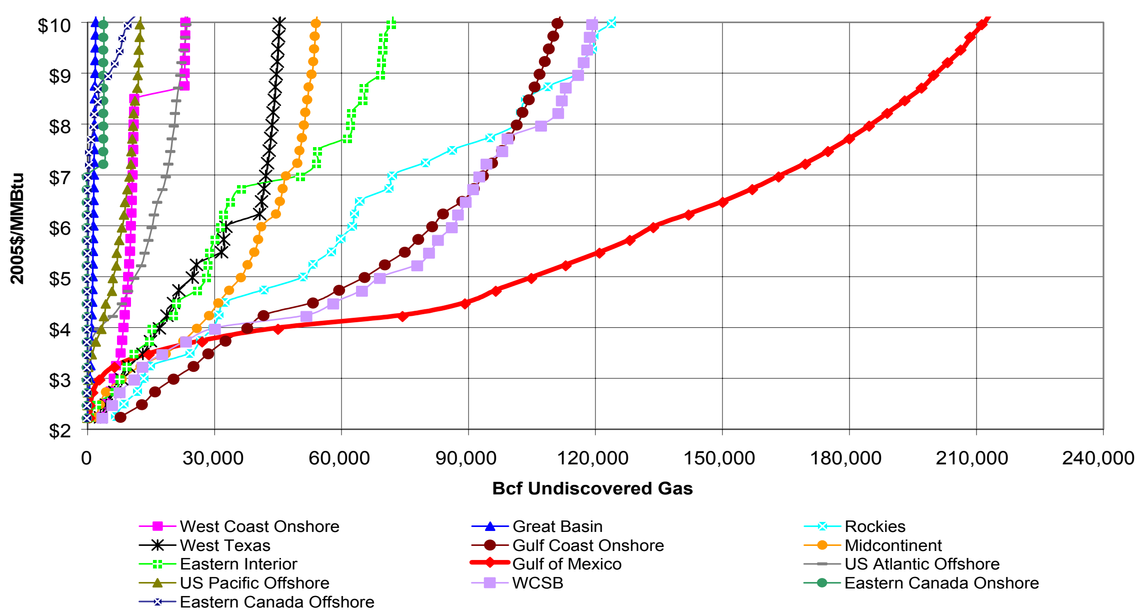
On the demand side, short-term gas consumption tends to increase as gas prices drop because of fuel switching, primarily in the electric power sector. The dispatch of electric power plants is based partly on their marginal costs, so as the price of natural gas declines gas consumption in the power sector increases. This increase in consumption tends to slow the rate at which gas prices decline.

In the long-term, the demand for natural gas is influenced by capital expenditures in the power sector. Decisions for the construction of new generating capacity are made based on the total cost of generation, considering both capital and variable operating costs. The capital cost of building a new coal plant can be more than twice that of constructing a gas-based combined cycle plant of a similar size. Despite their high capital costs, the cost of coal is much lower than natural gas, so the total cost of generation (including both fixed and variables costs) is lower for coal-fired plants than gas-based plants when gas prices are about $5.50 per MMBtu or greater. However, if gas prices were to drop below this level for a sustained period of time, power plant developers would tend to build more new gas-based plants, driving up gas demand in the future.

A decline in gas prices may cause producers to make decisions that affect gas supply in the short-term. Producers selling into the spot market may choose to withhold gas if the decline rates on their wells are relatively high and they believe they can get a higher price in the future by deferring production. A near-term decrease in gas prices can also cause drilling activity to fall. If drilling activity is not maintained, the decline of production at existing wells will gradually reduce gas supply and increase prices over the following 6 to 12 months.

By far, the greatest factor influencing the long-term floor on natural gas prices is the cost of developing new supply. Gas production from traditional basins in the U.S. generally is on the decline. Much of the production required to meet future demand will have to come from newer production areas, such as the deep water Gulf of Mexico and non-conventional gas. In general, these areas have much higher production costs than traditional basins, as shown in Figure 3. Also, the supply curves are highly elastic between \$4 and \$5 per MMBtu. As a result, the development of new gas resources will decline rapidly as gas prices fall below \$5.

Figure 3
North American Natural Gas Supply Curves



The market shifts caused by supply disruptions and weather variations over the past year demonstrate both the tightness of the market balance and the price volatility created by shifts in supply and demand. All indications are that, absent significant changes in policy, market volatility will continue in the future as the U.S. gas market relies heavily on the supplies from the Gulf of Mexico, which will be vulnerable to hurricane disruptions. While LNG imports will provide new supplies in the future, the U.S. is not the only potential market for these supplies. And, as demonstrated over the past year, industrial gas demand can remain robust even in times of high gas prices.

As it was put in the AGF Outlook Study, "The nature of supply and demand in the natural gas market makes it vulnerable to price volatility." The AGF Outlook Study concluded that without significant policy changes, the North American natural gas market would remain in a tight balance for the foreseeable future. If anything, the events of the past year reinforce that assessment.

IV. REVIEW OF POLICY CHANGES

Since the AGF Outlook Study was written, there have been several new legislative acts and proposals that could potentially have an impact on natural gas supply and demand. Most notable among these is the EPAct. In this section we will examine the provisions of EPAct and other legislation, describing those provisions that have a direct impact on natural gas supply or demand. Next, we will compare these policy initiatives to the policy scenarios of the AGF Outlook Study, with particular emphasis on those areas where the EPAct policy initiatives have fallen short in addressing the market conditions negatively impacting the natural gas supply/demand balance.

The EPAct has nearly one hundred sections that address, either directly or indirectly, the natural gas supply/demand balance. Additional legislative proposals over the past year have dealt with some of the same issues covered in EPAct, such as LNG imports, and other issues, such as the Alaska Gas Pipeline. These new policies and proposals can be divided into ten broad policy categories:

- Efficiency and Conservation Measures
- Increased Access to Onshore Resources
- Increased Access to Offshore Resources
- Production Incentives, Miscellaneous Production Issues
- New Supply Sources
- Liquefied Natural Gas
- Contract Issues for Pipelines, Storage and LNG
- Natural Gas Infrastructure and Markets
- Alaska Gas Pipeline
- Replacing Natural Gas for Electric Generation (Renewables, Coal, and Nuclear)

Efficiency and Conservation Measures

There are 34 sections in EPAct aimed at directly reducing energy demand, including the demand for natural gas, by promoting energy efficiency or conservation measures. These measures fall into a variety of categories, such as regulations that set energy efficiency standards for federal buildings, provide grants and tax credits to improve the efficiency of both state-owned and private buildings, and promote public education on energy efficiency and conservation measures.

Table 4
EPAct Energy Efficiency and Conservation Measures

Section	Action
102	Requires Federal buildings to reduce energy consumption by 2 percent in FY2006, increasing annually to 20 percent in FY2015.
104	Expands a provision in the National Energy Conservation Policy Act requiring Federal agencies to consider energy efficiency when procuring products.
106	Establishes a government / private sector voluntary program to reduce primary energy consumed for each unit of physical output.
109	Establishes a performance standard for new Federal buildings, stating that they must achieve 30 percent reduction in energy consumption over August 2005 energy consumption levels.
110	Extends daylight savings time in 2007.
111	Increases use of energy efficient technologies in Federal land management.
122	Provides assistance to states for state energy programs, weatherization, and energy efficient state buildings.
123	Promotes state energy conservation plans and state energy efficiency goals.
124	Provides funding for state-administered energy efficient appliance rebate programs, to encourage consumers to replace old appliances with Energy Star products.
125	Provides grants to states to assist local governments to improve energy efficiency of public buildings.
126	Establishes a low income community energy efficiency pilot program which will provide competitive grants to local governments, private, non-profit community development organizations, and Indian tribes.
128	Provides incentive funding to implement a plan to achieve and document 90 percent compliance with residential and commercial building energy efficiency codes.
131	Encourages consumer education to identify and promote energy efficient projects and buildings.
132	Directs DOE to educate homeowners and small business owners on HVAC maintenance issues.
134	Directs DOE to conduct a national advertising and media awareness campaign to promote practical, cost-effective measures to reduce consumption of natural gas, electricity, and gasoline.
135	Amends the Energy Policy and Conservation Act to include additional residential appliances.
136	Amends the Energy Policy and Conservation Act to include additional commercial equipment.
137	Directs the Federal Trade Commission (FTC) to commence a rulemaking by November 6, 2005 that considers the effectiveness of consumer products labeling in assisting consumers to make energy-efficient purchasing decisions, and considers changes to the labeling rules that could improve their effectiveness.
139	Directs the Secretary of Energy to conduct a study, in consultation with NARUC and NASEO, of state and regional policies that promote reduce energy consumption by regulated and non-regulated electric and natural gas utilities.
140	Authorizes DOE to establish pilot program to provide financial assistance to 3 to 7 states to adopt energy efficiency programs & reduce energy consumption by at least 0.75 percent.
151	Authorizes the use of the public housing capital funds to increase energy and water use efficiency in public housing.
316	Directs FERC, Regional Transmission Organizations (RTOs) and state utility commissions to facilitate adoption of market-based mechanisms and/or rate regimes (with meter and information technology) to provide market price signals to encourage efficient gas use.
503	Assists Indian tribes in development of energy resources.

Table 4 (continued)
EPAct Energy Efficiency and Conservation Measures

Section	Action
506	Directs the Secretary of Housing and Urban Development to improve energy efficiency and conservation in federally assisted housing on Indian land.
911	Authorizes programs for energy efficiency R&D, demonstration and commercial applications to increase energy efficiency of vehicles, buildings, industrial processes, and reduce U.S. energy demand, especially imported energy sources.
1252	Directs utilities to offer time-based rate schedules, meters, and training for all customer classes.
1253	Improves combined heat and power (CHP) and renewable energy (RE) purchase and sale requirements.
1254	Improves distributed generation (DG) and CHP interconnection standards.
1331	Provides for a tax deduction for new commercial buildings constructed between April 11, 2005 and December 31, 2007.
1332	Provides a credit for new energy efficient homes that reduce annual heating & cooling energy consumption at least 50 percent below comparable dwelling in new energy efficient homes.
1333	Provides a tax incentive to promote energy efficiency home improvements.
1334	Provides a tax credit to the manufacturers of energy efficient appliances.
1335	Provides a tax credit for residential energy efficient property in service before December 31, 2007.
1336	Provides a tax credit for business installation of fuel cells and stationary microturbine power plants, including gas turbine engine and other components, and applies to installations after December 31, 2005.
1802	Directs the DOE to commision a study by the National Science Foundation of full-fuel-cycle energy analysis within one year of EPAct's passage.

Most of the energy efficiency and conservation measures in EPAct impact the residential and commercial sectors. While all the scenarios in the AGF Outlook Study assumed continuing advances in residential and commercial energy efficiency, policies affecting demand in these sectors were not directly addressed in the AGF Outlook Study. There are two reasons for this. First, the projected gas demand growth in the residential and commercial sectors is fairly modest, ranging from 1.1 to 1.2 percent per year. In regard to policies affecting gas demand, the AGF Outlook Study focused on the electric power sector, since its projected growth is far greater than either the residential or commercial sectors. Second, there were many efficiency and conservation programs already in place prior to EPAct. These pre-existing programs contribute to the continued decline in natural gas consumption per customer anticipated in all the Study's scenarios. However, the rate at which consumption per customer declines is expected to slow over time, as trends such as an increase in the size of new homes tend to offset some of the gains from efficiency and conservation.

In 2005, the American Council for an Energy Efficient Economy (ACEEE) issued a study of the impact of energy efficiency measures included in EPAct.[1] In the study, ACEEE estimated that the tax credits, appliance standards, and other efficiency provisions in the energy bill could reduce natural gas use by as much as 1.3 Tcf by 2020.

[1] *The Federal Energy Policy Act of 2005 and its Implications for Energy Efficiency Program Efforts*, American Council for an Energy Efficient Economy, September 2005.

However, this estimate of total savings was based on the sum of estimated savings for each type of efficiency measure. Summing the individual impacts ignores interdependencies that may reduce the total, such as increasing insulation and HVAC efficiency in the same building. Also, the ACEEE estimate included several optimistic assumptions about the implementation of these measures, such as the level of new appliance efficiency standards. As a result, it is likely that ACEEE's savings estimates are significantly higher that the actual gas savings that will be achieved.

In summary, while the energy efficiency and conservation measures in EPAct make a positive contribution toward the improving gas market conditions, these measures alone cannot resolve the tight supply and demand balance.

<u>Increased Access to Onshore Resources</u>

The Energy Policy and Conservation Act Amendments of 2000 (EPCA) directed the Department of the Interior (DOI), in consultation with the Departments of Agriculture and Energy, to conduct an inventory of oil and natural gas resources beneath onshore federal lands. This inventory was intended to identify: 1) the estimated oil and gas resources underlying federal lands, and 2) the extent and nature of any restrictions or impediments to the development of these resources. Building upon EPCA, EPAct contains a number of provisions designed to improve access to oil and gas resources on federal lands and to streamline the permitting and approval of exploration and production operations on these lands. Specifically:

- Section 361 directs DOI to review current federal onshore oil and gas leasing and permitting practices, including processes for considering surface use plans and identifying stipulations and conditions of approval. As of August 2006, the Bureau of Land Management (BLM) reported that they have completed their review of oil and gas leasing and permitting practices and have prepared a report to Congress that is currently in final review.
- Section 362 directs DOI to improve timely action on leases and permits, identify best management practices, and improve enforcement. In response, the BLM has updated their "Surface Operating Standards and Guidelines for O&G Exploration and Development," and issued an Instruction Memorandum that established oil and gas process improvement teams in BLM Field Offices.
- Section 363 requires a Memorandum of Understanding between the Departments of Interior and Agriculture on oil and gas leasing policies and processes. The MOU was signed earlier this year.
- Section 364 amends the EPCA to require periodic assessment of economically recoverable resources on federal onshore lands. The BLM has completed the EPCA Phase II inventory of oil and gas resources and has prepared a report that is currently in final review.

- Section 365 establishes the Federal Permit Streamlining Project, as a mechanism for potentially streamlining and improving the permitting and approval process for oil and gas operations on federal lands. The BLM has signed an interagency MOU to establish roles, responsibilities and delegations of authority among federal agencies in seven newly established Oil and Gas Pilot Offices. The BLM has also contracted a private consulting firm to assist in the review and reporting of implementation and performance of the streamlining efforts in the Pilot Offices
- Section 366 requires that deadlines be established for acting on permits. The BLM has issued interim policy guidance on processing timeframes and published proposed regulations for public comment.
- Section 371 allows the Secretary of the Interior to reinstate any oil and gas lease that was terminated for failure to pay full rental by a designated date, under certain conditions. The BLM has published final regulations to extend time limit to file lease reinstatement petitions.
- Section 390 establishes the presumption that when managing public lands, the Secretary of the Interior (or the Secretary or Agriculture, if the land in question is part of the National Forest System) can make categorical exclusions under the National Environmental Policy Act (NEPA) for activities related to the exploration or development of oil or gas. The Department of the Interior has issued policy guidance to implement the NEPA categorical exclusion provisions.
- Section 1835 requires a review of the management of federal subsurface oil and gas development and its effect on privately owned surface. The BLM has completed a public review process and prepared a report to Congress that is currently in final review.
- Section 1836 requires a statutory review by DOI to resolve any conflict relating to development of Federal coal versus coal bed methane in the Powder River Basin. The BLM has completed a review and submitted a report to Congress.

Substantial progress has already been made in initiating and/or implementing many of these actions set forth in EPAct. However, the primary concern is the pace that these actions are pursued, which is in part related to the commitment of personnel and resources to these actions. For example, Section 390 does include some provisions to encourage the use of "categorical exclusions" to limit delays in implementing requirements under the NEPA. However, many in the oil and gas industry feel it did not go far enough in addressing the issue referred to as "NEPA creep," i.e., the application of NEPA to less significant federal actions.

<u>Increased Access to Offshore Resources</u>

There are no provisions in EPAct that directly address access to oil and gas reserves in the outer continental shelf (OCS). The Department of the Interior (DOI) has conducted a comprehensive inventory of OCS oil and natural gas resources, as required by EPAct Section 357. In the inventory, the DOI estimated there are 29.3 Tcf of natural gas reserves in the OCS, with 95 percent of the reserves being in the Gulf of Mexico. In the undiscovered resource category, the DOI estimated 420 Tcf of natural gas, 55 percent of which was in the Gulf of Mexico.

There are a variety of policy options and potential actions that are currently being considered by the MMS and in Congress. These actions include potential leasing in areas previously not included in the MMS five-year OCS leasing plans. In the near-term, MMS is focusing on the North Aleutian basin off the coast of Alaska, selected areas in the Eastern Gulf of Mexico, and leasing in the Mid-Atlantic off the coast of Virginia.

In the summer of 2006, separate bills addressing oil and gas development in the OCS were passed in both the House and Senate. The House bill, H.R. 4761, would have given states a variety of options they could have exercised over the use of federal outer continental shelf lands off of their coastlines. Existing moratoria bar oil-and-gas exploration out to 200 nautical miles (230 statute miles), which is the extent of the zone of economic interest controlled by the U.S. The House legislation, which was expressed in statute miles, would have removed the ban beyond 100 miles from the coastline. The bill would have reduced the area where drilling is prohibited to 50 miles from the coastline, but would have given coastal states the right to allow drilling closer to their shoreline. State legislatures could have also moved to bar drilling for natural gas within 100 miles of their coasts if they voted to oppose it within a year after the federal law is passed. States that allow drilling, however, could collect between 50 and 75 percent of royalty payments that would otherwise go to the federal government.

The Senate bill, S.3711, which was passed in December 2006 as part of the comprehensive year-end tax bill, is more narrowly focused than the one proposed earlier by the House. It allows drilling on 8.3 million acres in the eastern Gulf of Mexico, including nearly 2 million acres that were dropped from the federal government's OCS Lease Sale 181 in 2001 because of objections from Florida officials. The Senate bill includes a no-drilling zone within 125 miles of Florida's panhandle and within 230 miles of the state's Gulf Coast through 2022. The measure also includes a provision to share 37.5 percent of revenues derived from gas and oil produced from the newly opened acreage with four Gulf Coast states. However, it should be noted that this legislation does not add much beyond would have happened without congressional action. The area included in this Senate bill was already scheduled for opening by DOI the over the next five years. Further, it is estimated that it will take four to five years before the natural gas from this region will reach the market.

Once implemented, the immediate impact of the passed legislation will be to provide access to as much as 365 Bcf per year of additional gas supplies off the western coast of Florida. In the long run, the legislation may also help promote the development of resources in the Gulf of Mexico. Since the Gulf Coast states will receive a greater share of royalties from the new production, state governments will be more inclined to promote the development of oil and gas projection off their shores. Unfortunately, the legislation that was passed does nothing to address access to substantial natural gas resources off the East and West Coasts of the U.S.

<u>Production Incentives, Miscellaneous Production Issues</u>

Future development of U.S. natural gas resources will depend on the revenues derived from current production. These revenues provide the capital for additional drilling and resource development. Therefore, fiscal incentives are an effective means of ensuring predictable cash flow for producers, thereby facilitating the development of new natural gas supplies. EPAct contains a number of provisions to encourage natural gas production:

- Section 343 enacts a countercyclical marginal well tax credit and an extension of the net income limitation on percentage depletion for marginal wells, along with reducing federal royalty rates for marginal onshore and offshore natural gas production when Henry Hub spot prices are less than $2/MMBtu.
- Section 344 extends federal royalty relief incentives for deep natural gas wells drilled in shallow waters of the Gulf of Mexico.
- Section 345 provides federal royalty relief incentives for deep water production in the Gulf of Mexico.
- Section 1326 offers tax incentives for construction of gas gathering systems, applying to lines installed after April 11, 2005.
- Section 1329 allows for the 24-month amortization of geological and geophysical expenditures.

In June 2006, the Energy Information Administration's Office of Oil and Gas issued a report describing the changes to the offshore royalty relief program.[2]

New Supply Sources

There are several new natural gas supply sources within the U.S. that could be economic to develop with some advances in technology. Deep onshore and shallow water offshore formations, unconventional natural gas resources such as gas shales, tight gas, and coal bed methane, and deepwater natural gas resources are those likely to make the greatest near-term potential. Supplemental gas supplies can be gained by promoting coal and petroleum coke gasification technologies. In the longer-term, methane hydrates have the potential of providing a vast supply of energy, although much work still needs to be done to harness this resource. EPAct contains provisions that support technological advancements to increase both near and long-term sources of supply:

- Section 354 promotes enhanced oil and natural gas production from CO_2 injection on federal lands, both onshore and in the OCS. The MMS issued an advanced notice of proposed rulemaking (NOPR) in March 2006 on royalty reductions for production using enhanced recovery techniques. The final rulemaking is due by September 2006.
- Section 353 promotes natural gas hydrate production from OCS and federal lands in Alaska by providing royalty incentives.
- Section 968 expands R&D efforts on methane hydrates. In July 2006, DOE's Office of Fossil Energy published "An Interagency Roadmap for Methane Hydrate Research and Development" which addresses the goals of this section.
- Section 415 authorizes DOE to provide loan guarantees for at least five petroleum coke gasification projects; however, no funds have been appropriated for this specific purpose and no rules have issued.

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[2] *Overview of the Federal Offshore Royalty Relief Program*, Energy Information Administration Office of Oil and Gas, June 2006.

- Subtitle J creates a program to develop new technologies for the exploration and development of ultra-deepwater and unconventional natural gas resources, as well as examine the special technological changes for small producers. The National Energy Technology Laboratory (NETL) is currently soliciting offers to administer programmatic research and development activities pertaining to the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Program.
- Section 1321 extends tax credits for facilities producing coke and coke gas.

Liquefied Natural Gas

Liquefied natural gas (LNG) has become an increasingly viable supply option for the U.S. because of the large amount of low-cost natural gas resources around the world and the significant decline in the cost of developing and delivering these resources. The AGF Outlook Study cited LNG imports as a critical variable in determining the future U.S. gas supplies, and several sections of EPAct address this issue.

Section 311 requires the Federal Energy Regulatory Commission (FERC) to promulgate regulations on the NEPA pre-filing process for LNG projects. Section 311 also confirms FERC's exclusive and final authority to approve or deny siting, construction, expansion, or operations of an LNG import terminal located onshore or in state waters, authorizes FERC to set timely schedules for LNG permits, and requires other federal and state agencies to meet these schedules or face civil action. Additionally, this section directs FERC to complete a Memorandum of Understanding (MOU) with the Secretary of Defense to ensure coordination of LNG facilities that may affect an active military installation. To date, the regulations for the NEPA pre-filing process have been completed, and the process for establishing the MOU with the Secretary of Defense has been initiated.

Section 313 directs a number of procedural improvements designed to streamline the review of facilities including natural gas infrastructure and new LNG import facilities. This section establishes FERC as the "lead agency" and directs that certain reviews be completed in accordance with a schedule established by the Commission consistent with Federal law.
Section 317 of EPAct directs the Department of Energy, in consultation with the Department of Transportation, Department of Homeland Security, the Federal Energy Regulatory Commission, and the Governors of the Coastal States, to convene at least three forums on liquefied natural gas. The Forums are intended to educate and foster informed dialog among stakeholders in the development of LNG facilities, and to identify "best practices" associated with liquefied natural gas imports. To date, three forums have been held in Boston, Massachusetts, Eugene, Oregon, and Los Angeles, California. However, government officials expressed doubts that the forums had any impact reducing the "not-in-my-backyard" (NIMBY) opposition that has slowed terminal development.[3]

[3] *Officials: Forums did little to quiet LNG critics*, Gas Daily, July 18, 2006.

Contract Issues for Pipelines, Storage and LNG

In 2005 the National Association of Regulatory Utility Commissioners (NARUC) and the Interstate Oil and Gas Compact Commission (IOGCC) formed a Joint Task Force ("Joint Task Force") to offer policy recommendations "on the advisability of encouraging government support of long-term natural gas transportation and storage agreements as a way to increase investment in natural gas and LNG delivery infrastructure." The Joint Task Force focused on State regulation, particularly as it affects the incentives and ability of gas utilities to transact long-term contracts for delivery service. The Joint Task Force devoted particular attention to whether State regulation has erected barriers to long-term contracting that could jeopardize the future development of the gas-delivery infrastructure in the United States.

The Joint Task Force offered the following policy recommendations:

- State regulators should recognize the urgent need for additional gas-delivery infrastructure to moderate the level, as well as the volatility, of future natural gas prices.
- State regulators should consider long-term contracting as an appropriate mechanism to manage long-term price and volume risk within the confines of a gas utility's portfolio strategy.
- State regulators should recognize the special features of certain infrastructure projects, specifically the Alaskan gas pipeline and multiple LNG projects, that will require substantial revenue guarantees.
- State regulators should consider working with gas utilities to develop long-term strategies for pipeline capacity, gas storage and gas supply acquisitions, in the 10+ year range.
- FERC should revisit its policies for pricing different pipeline services, in addition to its other practices that may be stifling financing of, and contracting for, long-term gas-delivery services.
- State regulators, in addition to regional power operators, should recognize the benefits of electric generators holding firm, long-term capacity for pipeline transportation and storage.

Addressing some of the same issues, the Interstate Natural Gas Association of America (INGAA) and the Natural Gas Supply Association (NGSA), joined together to petition FERC to re-examine the parameters of blanket certificate authority and to make clear to the marketplace that shippers who make projects financially possible may enjoy preferential rates. The petitioners explained FERC should take these actions to make it easier for the industry to build new capacity, and thereby ensure the adequacy of pipeline infrastructure in the future.

In the petition, INGAA and NGSA sought changes in three areas. First, they asked FERC to allow blanket authorization of certain mainline expansions, storage enhancements, and liquefied natural gas takeaway facilities. Second, they sought adjustments in the dollar limits for blanket facilities, raising limits to reflect current project development costs. Third, they requested favorable rate treatment for anchor shippers or foundation shippers.

In a NORP released June 15, 2006, FERC addressed all three of these issues. FERC stated that it was making these changes because it agreed with the petitioners that gas project costs have increased faster than inflation, and that certain restrictions were no longer needed and might actually impede development of the gas pipeline infrastructure. The proposed rule also authorized a more favorable rate for "foundation shippers," shippers that commit to a project early and make it possible for a pipeline to secure financing for a proposed project.

Natural Gas Infrastructure and Markets

FERC Order 678/EPAct Section 312

One of the impediments to natural gas storage development has been the difficulty storage providers encountered in gaining FERC approval to charge market-based rates. In the past, FERC would not grant market-based rates to a storage provider that had market power, unless the storage provider adopted conditions that sufficiently mitigated its market power as measured by traditional criteria. And the criteria for showing lack of market power were sometimes difficult to meet, especially in areas where there are only a limited number of storage service providers. In June 2006, FERC issued Order No. 678, amending its regulations regarding the criteria for granting market-based rates for underground natural gas storage services. Among other things, FERC's new regulations significantly ease the burden for storage providers to obtain market-based rate treatment in order to encourage the development of new storage facilities.

FERC's Order No. 678 addressed these concerns in two ways. First, FERC modified its market power analysis requirements to allow storage providers to include non-traditional storage alternatives, such as local production, availability of LNG, and pipeline capacity in their market power analyses. Second, FERC implemented Section 312 of EPAct, which added Section 4(f) to the Natural Gas Act ("NGA"). The new Section 4(f) permits FERC to allow market-based rates for new storage facilities, even if the storage provider is unable to show that it lacks market power, if FERC finds that the market-based rates are in the public interest and necessary to encourage the construction of needed storage capacity and that customers are adequately protected. In its NOPR of December 22, 2005, FERC originally interpreted Section 4(f) as applying only to new storage facilities that were not in existence on August 8, 2005, the date EPAct 2005 was enacted. In Order No. 678, FERC reversed its course and interpreted Section 4(f) to apply to both greenfield storage facilities and expansions of existing facilities.

In another reversal of course, in Order No. 678 FERC removed the requirement that it proposed in the original notice of proposed rulemaking issued on December 22, 2005, subjecting those obtaining market-based rates after a market power determination had been conducted to periodic market power reviews to ensure that abuses do not develop. After considering the many comments filed by industry participants on this topic, FERC found that a generic periodic market power review is not necessary for market-based rates to be granted by FERC, because FERC can meet the periodic review requirement through regular monitoring and taking appropriate action under Section 5 of the NGA either on its own or in response to a complaint. However, FERC did retain the right to require storage providers with a market share greater than ten percent to submit to additional reporting requirements if the facts presented in the relevant case so warranted. The revisions to FERC's regulations will encourage storage expansions and greenfield projects by making it easier for developers to obtain market-based rates for storage service.

EPAct Section 313

In addition to its impact on LNG import terminals as outlined earlier, EPAct Section 313 also streamlines the review of other types of energy infrastructure, such as natural gas pipelines. Section 313 allows for creation of a consolidated federal record for court review of proceedings involving authorization of interstate natural gas pipelines, and stipulates that the U.S. court of appeals in the circuit in which a pipeline is proposed will have jurisdiction over petitions for review of the resulting consolidated federal record. These provisions are designed to reduce delays caused by numerous legal appeals.

EPAct Section 315

Besides promoting the construction of new infrastructure, EPAct also has provisions intended to strengthen natural gas markets. Specifically, Section 315 of EPAct bans market manipulation by "any entity." The FERC ruling on this section, issued January 19, 2006, states that it is unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas, gas transportation, electric energy, or transmission services subject to FERC's jurisdiction:

- To use or employ any device, scheme, or artifact to defraud.
- To make any untrue statement of a material fact or to omit to state a material fact.
- To engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity.

In its ruling, FERC stated that it will "police all forms of fraud and manipulation that affect natural gas and electric energy transactions and activities the Commission is charged with protecting."

EPAct Section 316

Section 316 directs FERC to facilitate price transparency in markets for the sale or transportation of natural gas in interstate commerce. FERC is allowed to proscribe such rules as the Commission deems necessary and appropriate to carry out this directive, including directing market participants to provide information about the availability and price of natural gas sold wholesale or in interstate commerce. In October 2006, FERC held a Technical Conference on this issue.

<u>Alaska Gas Pipeline</u>

There are three potential projects to bring natural gas from the North Slope of Alaska to markets in the Lower-48. The Alaska Natural Gas Transportation System (ANGTS), which is currently supported by TransCanada Corporation, is a proposed 48-inch pipeline that would parallel the Trans-Alaska Pipeline System (TAPS) from Prudhoe Bay to Delta Junction, then follow the

Alaska Highway to the Alaska-Yukon border and continue through Canada to the Alberta hub. The Trans-Alaska Gas System (TAGS) is an LNG export project currently promoted by the Alaska Gas Port Authority (AGPA).

The proposal calls for a 36-inch pipeline to parallel the TAPS from Prudhoe Bay to Anderson Bay near Valdez, Alaska, where an LNG liquefaction plant would be built to ship the LNG to worldwide markets. The TAGS project also includes a 24-inch "spur" gas pipeline from Glennallen to the greater Anchorage Bowl. The third potential project has been proposed by the Producer Group, comprising BP, ConocoPhillips and ExxonMobil. The Producer Group project consists of a 52-inch pipeline that would parallel the TAPS from Prudhoe Bay to Delta Junction, then follow the Alaska Highway to the Alaska-Yukon border and continue through Canada to the Alberta Hub, and ultimately to markets in the Lower-48 states. Currently, the State of Alaska's only active negotiations are with the Producer Group.

Alaska Natural Gas Pipeline Act

The Alaska Natural Gas Pipeline Act of 2002 (ANGPA) authorized the Department of Energy to issue loan guarantees for up to 80 percent of capital costs, subject to a maximum of $18 billion as adjusted for inflation. As Congress thought the benefits of an Alaska Gas Pipeline to consumers would be great enough to warrant government involvement, the Federal loan guarantee was designed to improve the commercial viability of the project. Even with the loan guarantee, lenders and equity participants will still require longer-term capacity commitments to support investment in a project of this size. Also, any additional pipeline capacity needed to move the gas out of Alberta to the U.S. markets will require long-term firm contracts. The long-term contracts will also help to support Congress' decision to provide the guarantees.

In June 2006, President George W. Bush nominated Drue Pearce to be Federal Coordinator for Alaska Natural Gas Transportation Projects. Established by ANGPA, the Federal Coordinator is responsible for coordinating the actions of all Federal agencies with respect to the Alaska Gas Pipeline and ensuring the compliance of Federal agencies with the provisions and deadlines of ANGPA.

Also in June 2006, the Federal Interagency Memorandum of Understanding (MOU) for the Alaska Natural Gas Transportation Project was fully signed and executed by senior executives and heads from 15 federal departments and agencies. The MOU establishes a project management framework for cooperation among participating federal agencies with responsibilities related to the approval of an Alaska natural gas transportation project. In particular, the MOU provides for early agency coordination in order to streamline regulatory reviews of applications for permits needed to construct and operate the project. The MOU also includes an agreement by the participating agencies to work within the pre-filing time frame set by FERC to identify issues and seek to resolve them at the earliest stages of project development. The Commission's pre-filing process, which is initiated by a request of the project sponsor, serves as a mechanism to meet requirements of NEPA while optimizing scheduling.

Alaska Stranded Gas Development Act

The Alaska Stranded Gas Development Act (SGA) permits Alaska's state government to negotiate terms regarding payments in lieu of taxes and royalty adjustments in order to encourage new investment to develop the state's stranded gas resources. However, potential investors have indicated that they will only begin to develop an application once they have successfully negotiated fiscal certainty under the SGA.

In February 2006 one of the first major hurdles to the project was cleared when it was announced that the State of Alaska and the Producer Group had reached agreement on the major components of an SGA fiscal contract. Under the terms of the draft agreement, the State of Alaska will own 20 percent of the primary project elements, including the gas treatment plant, the mainline in Alaska, and the Alaska-to-Alberta pipeline. The state will own other elements of the project in proportion to its share of the expected throughput in those elements. The state also will receive its royalty gas in kind and receive gas, not cash, in payment of the producers' production tax obligations.

In return for the state's participation in and financial support of the project, the producers will receive fiscal stability on their oil and gas obligations in Alaska for decades, as spelled out in the contract. In May 2006, Governor Murkowski provided the draft fiscal contract to the Alaska legislature for its review and to the public for comment and called the legislature into a special session. The special session was called to consider six subjects, all related to the natural gas pipeline.

EPAct Section 1810

Section 1810 of EPAct provides that within 180 days of the date of enactment, and every 180 days thereafter until the Alaska natural gas pipeline commences operation, FERC shall submit to Congress a report describing the progress made in licensing and constructing the pipeline and any impediments to its progress.

To date, FERC has issued two reports in response to the Section 1810 requirement. In its second 1810 report, FERC emphasized the risk of the Alaska Gas Pipeline being marginalized by the rapid growth of LNG imports. The report notes that a lack of progress on the Alaska Gas Pipeline encourages gas buyers in the Lower-48 to enter into long-term LNG contracts. The longer the pipeline is delayed, the more strength is gained by the proponents of LNG. This report also sites additional impediments, such as competition from the Mackenzie Delta gas pipeline project (planned to be in operation by 2011) for resources and labor that will be needed to complete the Alaska Gas Pipeline.

Replacing Natural Gas for Electric Generation

The increasing use of natural gas as a fuel for electricity generation has been the primary driver of growth in gas demand over the past 8 years, and is expected to continue to drive demand growth in the future. Since 1998, about 230 gigawatts of new gas-based capacity have been added in the U.S. To the extent that public policy can promote the use of other fuels to meet electricity demand, this will lessen the growth in gas demand. EPAct includes a number of provisions that promote the use of fuels other than natural gas for electric generation, thereby lessening the growth of demand for natural gas.

Coal Power

While coal is still the primary fuel for power generation in the U.S., the vast majority of new generating capacity build over the past decade has been gas-based. Environmental concerns have been the greatest barrier to expanding the use of coal in the electric power sector. EPAct addresses this issue by promoting clean coal technologies. Two provisions (Sections 411 and 414) promote the construction of new coal plans based on advanced integrated coal gasification combined cycle (IGCC) technology by providing loan guarantees. IGCC is a power generation system that produces a synthesis gas from coal, which is used as a fuel in a high-efficiency combined cycle turbine system. While still in the development phase, IGCC technology holds great promise because of its low emissions characteristics.

Title IV, Subtitle A establishes a Clean Coal Power Initiative, intended to promote IGCC as well as other technologies capable of reducing coal emissions. Section 1307 reinforces this initiative by establishing a tax credit for investment in clean coal facilities.

Nuclear Power

The Nuclear Power 2010 Program was established in 2002 as one means towards addressing the need for new power plants. The program is a joint government/industry cost-shared effort to identify sites for new nuclear power plants, develop and bring to market advanced nuclear plant technologies, evaluate the business case for building new nuclear power plants, and demonstrate untested regulatory processes. Three consortia responded in 2004 to the U.S. Department of Energy's solicitation under the Nuclear Power 2010 initiative and were awarded matching funds.

Building on this program, EPAct addresses several issues that are critical to the development of new nuclear plants in the U.S. under Title VI, Nuclear Matters. Subtitle A extends the Price-Anderson Nuclear Industries Indemnity Act through 2025, providing plant operators with continued protection from liability concerns. Subtitle B authorizes the Secretary of Energy to cover cost overruns due to regulatory delays, up to $500 million each for the first two new nuclear reactors, and half of the overruns due to such delays (up to $250 million each) for the next four reactors. This is an important consideration, since delays in construction due to vastly increased regulations were a primary cause of the high costs of some earlier plants. Subtitle C establishes the Next Generation Nuclear Plant Project, which provides for the research, development, design, construction, and operation of a prototype nuclear reactor to produce electricity and hydrogen.

Under Title XIII (Energy Policy Tax Credits), Section 1306 provides for a production tax credit of 1.8 cents per kilowatt-hour for the first 6,000 megawatt-hours from new nuclear power plants for the first eight years of their operation, subject to a $125 million annual limit.

Renewable Energy

Renewable energy (excluding hydroelectric generation) currently contributes only about 2 percent of the nation's total electricity supply. However, generation from renewable sources has been growing rapidly, increasing by almost 20 percent since 2001. EPAct builds on several existing polices that promote renewable energy in the electric power sector. Section 202 extends the renewable energy electricity production incentives originally established in the Energy Policy Act of 1992, and expands the program to cover more types of renewables, such as landfill gas. Additionally, Section 1301 extends the renewable energy production tax credit through 2008. Section 1251 requires that each electric utility develop a plan to minimize dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

Adding Oil Backup at Gas-based Facilities

The presence of oil backup capability at gas-based generating stations can reduce gas demand during peak demand periods, thereby relieving stress on natural gas transportation and storage infrastructure and reducing prices. Section 1812 directs the Secretary of Energy to conduct a study on the effects adding oil backup capability at gas-based power and industrial facilities. Specifically, the study is to address the costs and benefits of adding backup fuel, how Federal and state governments can encourage power and industrial gas consumers to add it, and how it will impact the supply and cost of natural gas.

V. POLICY IMPACTS AND GAPS

The AGF Outlook Study identified five important supply/demand variables that have an impact on the U.S. natural gas market: imports of Canadian gas, natural gas production in the Lower-48 states, construction of a pipeline to transport natural gas from Alaska to the Lower-48 states, reduction of gas demand (particularly from the electric power sector), and imports of LNG. This section assesses the relative impact each of these five variables have on achieving a better supply/demand balance in the future, as well as the impact of the recent policy changes described in Section 3 on each of these variables. Second, policy "gaps" regarding these variables are identified, i.e., important areas where policies have fallen short of achieving the favorable market conditions as described in the AGF Outlook Study.

Relative Impact of Supply/Demand Variables

While all five of the variables identified in the AGF Outlook Study are important to improving market conditions, they do not have an equal impact on the U.S. natural gas market. Below, we have evaluated the relative impact of each of the five variables on the market, a summary of which is in Figure 4.

Figure 4
Impact of Supply/Demand Variables on U.S. Gas Market

Canadian Imports

Independent of the effects of other key variables on Canadian gas production, U.S. policies have little direct impact on the level of natural gas imports from Canada. While imports from Canada are unlikely to make up a significant portion of the incremental increase needed to meet rising gas demand, they will continue to make an important contribution to U.S. supplies.

Gas production from conventional fields in western Canada, the main supply area for exports to the U.S., has been flat over the past few years and is expected to decline in the future. New resources, such as coal bed methane and gas from the Mackenzie Delta, are expected to be developed. However, Canadian gas demand will also continue to grow. The growth in gas-based power generation and the gas-use for the development of the western Canadian oil sands resource will limit the amount of gas available for export to the U.S.

The Grand Banks area of the Canadian Atlantic offshore contains approximately 6 Tcf of natural gas reserves that are not being marketed. While some of this gas is undeveloped, much of it is being recycled as part of crude oil extraction at the Hibernia, Terra Nova and White Rose fields. The owners of these natural gas reserves are considering ways of producing the natural gas and delivering it by pipeline or by ship as compressed natural gas (CNG) to initial points of delivery in the U.S. or Canada. To the extent that the method of shipping is CNG tankers to U.S. ports, new issues may arise regarding the regulatory jurisdiction and treatment of the CNG receipt terminals. It is most likely that the CNG terminals will be under FERC jurisdiction and will get the "Hackberry" exemption that now allows new LNG terminals to side step open access requirements and FERC filed and approved rates. However, the details on these issues still need to be worked out. There will also be a need to develop various Federal and state safety and operating rules for the new form of tankers and any onshore processing and storage facilities.

There has been one policy action that is meant to facilitate natural gas trade between Canada and the U.S. In May 2004, FERC and Canada's National Energy Board (NEB) signed a Memorandum of Understanding to enhance interagency coordination on cross-border natural gas pipelines. The FERC and NEB recognized that by coordinating their efforts on energy infrastructure projects they could promote the public interest through increased efficiency, expedited and coordinated action. The parties agreed that coordinated reviews may be considered in cases where related matters are pending before both agencies. They also agreed that they will, whenever practical, coordinate the timing of related decision making, including but not limited to coordinating the submission of evidence, the timing of developing findings of facts and conclusions of law, and the ultimate resolution of the related matters.

Lower-48 Production

As was noted in the AGF Outlook Study, while there is some uncertainty as to the ultimate volume of gas that can be recovered, virtually all estimates of the United States' natural gas resource are large. However, none of the three scenarios in the AGF Outlook Study anticipated any significant growth in Lower-48 production. Rather, Lower-48 production projections ranged from modest growth (in the Existing and Expected policies scenario) to essentially flat (in the Expanded policies scenario). While increased access to onshore and offshore resources raised natural gas production in the Expected policies scenario, other concurrent changes, such as the Alaska Gas Pipeline and increased LNG imports, tended to reduce Lower-48 natural gas production in the Expanded policies scenarios. However, the increased access policies in the Expanded policies scenario contributed to a more favorable natural gas market environment by decreasing production costs, thereby lowering the cost of natural gas to consumers.

While Lower-48 drilling rig activity has been increasing over the past several years, much of the activity has been focused in existing, mature production areas. But since the best prospects in the mature areas have already been developed, productivity per new well has been on the decline.

The net result is that producers have to drill an increasing number of wells every year just to maintain the current level of production, which has lead to increasing production costs. The development of unconventional resources (including tight gas sands, gas shales, and coal bed methane) and the Deepwater Gulf of Mexico have helped to stabilize Lower-48 production by adding additional supplies at lower costs. Still, oil and gas development in many areas with significant resource potential remains restricted.

In their 2003 study, NPC evaluated the effect of removing the OCS moratoria and of reducing the impact of conditions of approval (COA) in the Intermountain West by 50 percent over five years.[4] NPC found that these changes could potentially increase Lower-48 production by 3 Bcfd by 2020. However, there are no provisions in EPAct that directly address access to the OCS, and EPAct provisions addressing access in the Intermountain West are far more limited than the NPC's Gradual Increase Access case. At best, the EPAct provision addressing onshore access will increase natural gas production by only a small fraction of the potential increase identified in the NPC study.

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[4] *Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy*, National Petroleum Council, September 2003.

Demand Reduction

While the other key variables from the AGF Outlook Study address gas supply issues, the market balance can also be improved by decreasing the growth of demand for natural gas. As discussed above, EPAct has over 30 sections that promote the reduction of demand growth through efficiency and conservation measures. However, these measures alone cannot resolve the gas market imbalance. The majority of the efficiency and conservation measures address energy use in the residential and commercial sectors, where gas demand growth is expected to be relatively slow. A few sections address relatively small demand segments, such as energy use on Indian lands. There is also considerable overlap in the objectives of certain sections, such as those aimed at decreasing energy use in Federal buildings. So, while the efficiency and conservation measures in EPAct can make a positive contribution to the gas market balance, their projected impact is relatively small.

The key gas demand variable identified in the AGF Outlook Study was the increasing use of natural gas as a fuel for electricity generation. Policies that promote other options for generating electricity will help lower gas prices and decrease price volatility. In this regard, EPAct has addressed several important issues to promote the use of fuels other than natural gas for the generation of electricity. The U.S. has abundant supplies of coal, and the most significant impediment to expanding its use is concerns over the potential environmental impact. EPAct's advancement of clean coal technologies, particularly IGCC, could help coal to continue to contribute to the nation's electricity supply mix.

By reducing financial risks and providing support for additional research and development, EPAct also increases the possibility that new nuclear plants will be built. And by continuing the existing support for renewable energy, EPAct helps to ensure that these new technologies will continue to gain market share.

Alaska Gas Pipeline

Currently, Alaska is the third largest gas producing state, with wellhead production exceeding 9 Bcfd. The vast majority of the gas produced is currently re-injected due to the lack of infrastructure to deliver the gas to the Lower-48. While costly, an Alaskan gas pipeline could deliver a significant quantity of natural gas at competitive prices. Over the past few months there have been several important developments to move the Producer Group's project forward, including the negotiation of an SGA fiscal agreement between the State of Alaska and the Producer Group.

Despite this recent progress, the Alaska Gas Pipeline risks being eclipsed by an increasing number of LNG projects, as was emphasized in FERC's second report to Congress, issued July 2006. Many nations, in partnership with commercial entities, are developing LNG liquefaction facilities to supply a growing world market for natural gas. The U.S. natural gas market is changing rapidly, and is increasingly becoming part of an international market as dozens of new LNG import terminals are planned.

As LNG trade increases, Alaskan gas will face stiff competition from LNG exporting countries across the globe. While LNG is also an important contributor to future gas supplies, Alaskan gas is also needed to ensure that domestic gas production remains strong to ensure supply diversity.

Additionally, Alaskan oil and natural gas production tax reform (an issue which is linked to the Alaskan Gas Pipeline) has become a central issue in Alaska's gubernatorial election campaign. Governor Frank Murkowski, who negotiated the SGA contract with the Producers Group, has warned that failure to ratify the contract this summer would delay the project, raising costs and allowing imported LNG to capture markets that could be supplied with Alaska gas. As of the writing of this report, Alaskan legislators are in Juneau for the second special session of the summer, after failing earlier in May to pass a revised state oil production tax and enabling amendments to the SGA. The governor has said both these actions are necessary to conclude and sign the deal with the companies.

There is also a pending citizen ballot initiative appearing on the November state election ballot that would impose a $1 billion per year reserves tax on the producers. If the tax is approved by voters it would add $8 billion to $10 billion to the pipeline's cost, because producers would have to pay this tax for 10 years before the pipeline is operational and earning revenues, thereby making the project uneconomic. Legislative approval of the pending SGA contract would shield the project from the reserves tax, but to do that the contract must be in place before the election. Governor Murkowski has taken a lead role in negotiating and promoting the SGA contract with the Producers Group. His loss in the recent Alaskan primary election for Governor reduces the chances of a legislative agreement on the issue.

Some of Murkowski's political rivals have argued that he could have driven a better bargain with the producers. State Rep. Eric Croft, a Democrat from Anchorage who is running for governor in the November election, cites findings by a consulting firm working for the Legislature that the project is very profitable under the state's current tax regime, and that no special fiscal terms are needed.

LNG Imports

The vast majority of the world's natural gas reserves lie outside of North America. The development of new liquefaction facilities means there could be vast amounts of LNG available to the U.S. at relatively low prices, if policies allow for the growth of imports.

Since trade in LNG is developing into a world market, future imports of LNG will be in part determined by factors outside the control of U.S. policy makers, e.g., the construction of new liquefaction facilities. The most obvious issue that policy makers can have an effect on is the number and placement of LNG import terminals in the U.S. Many of proposed terminals have been faced with considerable opposition on the basis of security and environmental concerns.

As of July 2006, 16 new terminals have received regulatory approval from either FERC or the Maritime Administration and U.S. Coast Guard,[5] and two of the existing terminals have had plans to expand their import capacity approved. However, of all the new import terminals that

[5] The Maritime Administration and U.S. Coast Guard have jurisdiction over LNG terminals built offshore.

have been proposed, only one new U.S. import terminal – Gulf Gateway Energy Bridge, located in the Gulf of Mexico off the Louisiana coast – has been built so far. Construction on Shell's Altamira LNG regasification project in the Mexican state of Tamaulipas was recently completed, and it received its first shipment in August 2006.

While EPAct grants FERC "exclusive and final authority" to approve or deny citing of LNG import terminals, that provision only applies to federal agencies. Several terminals that have been approved by FERC are being delayed by opposition from state and local authorities.

Gaps in Existing Policies

Gas Demand Reduction

Additional measures should be taken to increase the use of fuels other than natural gas for power generation, both in the short-term and the long-term. One way to increase short-term fuel switching away from natural gas is to encourage more gas-based power generators to add oil backup capability. This type of modification is usually inexpensive and takes only a short time to complete. Adding oil backup capability allows power generators to switch to lower priced oil when natural gas is scarce and prices are high. This switching helps to reduce gas price volatility and increase electric reliability. While the absolute volume of switching from natural gas to oil may be small when oil prices are high, having the capability to switch can help reduce gas price volatility by reducing demand when gas prices are highest.

Environmental regulations (primarily the Clean Air Act) can sometimes be a barrier to adding oil backup capability, even when oil use is very limited. While it is often possible to meet environmental regulations by installing pollution control equipment, this can substantially increase costs, making the modification uneconomic.

In the long-term, policies to promote the use of technologies and processes using coal, nuclear, and renewables can help reduce demand for natural gas. In the power generation sector, this requires building new coal, nuclear and renewable power plants to replace gas-based plants. Changes such as these will take many years to achieve and require a substantial investment. Concerns over potential future changes to emissions regulations, particularly mercury and CO_2, have discouraged investment in new coal plants.

Another way to encourage the use of fuels other than natural gas for power generation would be to get power generators to enter into firm contracts for their gas service. The majority of power generators use interruptible transportation service, thereby avoiding contributing to the cost of building and maintaining gas pipelines. Exposing generators to the full cost of gas service would improve the comparative economics of non-gas generation, as well as increase investment in natural gas infrastructure.

At the state level, more can be done to promote the goals of energy efficiency and conservation. Traditional rate mechanisms may run counter to policies that promote energy efficiency. Most utility rates are designed on a volumetric basis, meaning that any effort to encourage efficiency and reduce consumption can result in financial harm to the utility. Recently, several states have adopted innovative rate structures that align the utility's economic interests with the goals of increased efficiency and conservation. In November 2005, NARUC adopted a resolution that encourages State commissions and other policy makers to consider whether they should implement changes to existing rate designs to encourage energy efficiency and conservation. The AGF issued a White Paper in July 2006 that summarized the recommendations discussed during the AGF/NARUC Foundation "Rethinking Natural Gas Utility Rate Design" held in May 2006 in Columbus, Ohio.

Additionally, energy policy makers can do more to make sure that each fuel is put to its most efficient use. In most instances, on a life cycle, full-fuel-cycle basis, natural gas is the most efficient fuel in direct flame applications, i.e., space heating, cooking, and water heating. Electricity is considerably less efficient for these uses. Section 1802 of EPAct directs DOE to contract the National Academy of Science to conduct a study of full-fuel-cycle energy analysis within one year of EPAct's passage. However, as of the writing of this report, DOE has not indicated any progress on getting this study underway. In October 2005, the AGF issued its report "Public Policy and Real Energy Efficiency," which illustrates the advances that could be made in energy efficiency if this analytic framework were used. Using this method of analysis would shift gas consumption toward direct flame applications and away from generating electricity, which would in turn result in a more efficient use of the nation's energy resources.

Another recent proposal on energy efficiency is the National Action Plan for Energy Efficiency, which was released on July 31, 2006. The plan was developed by the Action Plan Leadership Group, which was co-chaired by Diane Munns, Member of the Iowa Utilities Board and President of the National Association Regulatory Utility Commissioners, and Jim Rogers, President and Chief Executive Officer of Duke Energy and a member of the Alliance to Save Energy's Board of Directors. The U.S. Department of Energy and U.S. Environmental Protection Agency facilitated the work of the Leadership Group. The Leadership Group also includes the American Gas Association, as well as 23 electric and gas utilities, seven state utility regulators, two consumer advocacy agencies and more than 30 other organizations. The plan makes five broad recommendations to policy makers:

- Recognize energy efficiency as a high-priority energy resource.
- Make a strong, long-term commitment to implement cost-effective energy efficiency as a resource.
- Broadly communicate the benefits of and opportunities for energy efficiency.
- Promote sufficient, timely, and stable program funding to deliver energy efficiency where cost-effective.
- Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments.

Particularly noteworthy is the plan's recommendation to align utility incentives with the delivery of cost-effective energy efficiency programs. The plan, in further support of energy efficiency, encourages states to modify utility ratemaking practices in order to promote investments in energy efficiency technologies. Utilities that have implemented energy efficiency programs similar to ones described in the plan include NW Natural in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, Piedmont Natural Gas in North

Carolina and Cascade Natural Gas in Washington. Other companies have filed for permission to adopt such plans in additional states.

Increasing Access to Resources

While the recent legislation passed by Congress has opened up access to the Eastern Gulf of Mexico, all of the East Coast and West Coast OCS still remain off limits to development. Additionally, approximately 40 percent of the resource in the Intermountain West is either closed to development or subject to restrictions, based on estimates by the National Petroleum Council.[6] More progress is needed to improve access to resources both on and offshore to help maintain Lower-48 gas production in the future.

Increased access to onshore areas that are currently limited due to environmental concerns could significantly expand U.S. gas supplies. A major challenge to achieving increased access is the patchwork nature of the many statutes, regulations, executive orders, and policies that create these restrictions. Additionally, the interpretation of federal land use regulations is often inconsistent between and within various agencies with regulatory jurisdiction.
Increased production in these areas would require addressing land use and environmental issues, including concerns related to access to and restrictions associated with development on public lands, as well as managing produced water and air emissions.

There have been both positive and negative developments regarding access to offshore resources. On the positive side, legislation has finally passed to open the Eastern Gulf of Mexico to oil and gas exploration and development. This legislation included an increase in royalty shares for the Gulf Coast states to encourage their cooperation in the development of these resources. On the negative side, the Bush administration's budget proposal for 2007 omitted funding for EPAct's Subtitle J, which creates a program to develop new technologies for the exploration and development of ultra-deepwater and unconventional natural gas resources.

Encouraging Investment in Gas Infrastructure

Over the past twenty years, pipeline constraints have contributed to low and volatile natural gas prices in the Intermountain West, which in turn has reduced the growth of production. While the situation has begun to improve, improved access to pipelines remains critical to ensuring natural gas production in the region will continue to grow.

Regulated rates of return for interstate pipelines are not high enough to justify purely speculative construction of new pipeline capacity. Therefore, pipelines will not build new capacity without long-term contractual commitments. Long-term contracts are needed to assure these companies that they will recover the substantial investments required to build and maintain pipeline capacity. Long-term contracts also reduce the cost of borrowing for pipeline companies by improving their credit rating, ultimately lowering the cost of transportation to shippers.

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[6] National Petroleum Council, *op. cit.*

However, both regulated and unregulated shippers are increasingly reluctant to enter into new, firm long-term contracts for transportation service because of the significant financial commitment required in doing so. Such shippers rely on short-term, interruptible transportation service (IT) contracts or capacity-release contracts rather than long-term firm contracts, in an effort to obtain more advantageous pricing without firm commitment. As a result, without firm commitments on capacity, interstate pipelines are discouraged from pursuing new projects. Market complexities and existing regulations compound the problem. To solve this problem, policy makers must find ways to encourage contract mechanisms that ensure continued investment in infrastructure.

Increasing LNG Imports

Despite the policy advances in EPAct, LNG project sponsors still face multiple, often competing state and local reviews that lead to permitting delays. Greater coordination among federal, state, and local agencies, with FERC taking the lead, will reduce permitting lead-time. Agencies must coordinate and streamline their permitting activities and clarify positions on new terminals construction and operation. Similarly, streamlining the permitting process by sharing data and findings, holding concurrent reviews, and setting review deadlines would provide greater certainty to the overall permitting process.

The large number of terminal applications will require more government support at the federal, state, and local levels to process the applications and avoid delays. Regulatory agencies must be funded and staffed at levels necessary to meet permitting and regulatory needs in a timely manner. Additional funding and staffing will also be required once these new terminals become operational, particularly to support the large increase in LNG tanker traffic.

Standards for natural gas interchangeability in combustion equipment were established in the 1950s. Because of difference in the mix of hydrocarbons and Btu content of imported LNG, adding large volumes of regasified LNG into the U.S. supply mix will require a re-evaluation of these standards. FERC and DOE should advance new standards to allow a broader range of LNG imports and to ensure safety and reliability. This should be conducted with participation from LDCs, LNG purchasers, process gas users, and equipment manufacturers. DOE should fund research with these parties in support of this initiative.

In order to promote the highest safety and security standards and maintain the LNG industry's safety record established over the past forty years of operations, FERC, the Coast Guard, and the U.S. Department of Transportation should undertake the continuous review and adoption of industry standards for the design and construction of LNG facilities, using internationally proven technologies and best practices.

VI. IMPLICATIONS FOR THE U.S. ECONOMY AND NATURAL GAS CONSUMERS

This section examines the effects of recent policy changes on the U.S. economy as a whole and on natural gas consumers in particular. First, the findings of the AGF Outlook Study, summarizing the impacts of the each of the alternate policy scenarios on natural gas prices, consumer costs, and the overall effect on the economy are outlined. Second, progress made to date in achieving the favorable market conditions as outlined in the 2005 Report, including an estimate of how far policies have advanced toward achieving the prices impacts of the Expanded policies scenario, are assessed.

As discussed earlier, the three scenarios examined in the AGF Outlook Study were based on different policy stances for the five key variables examined in the study. The Existing policies scenario assumed energy policy would maintain the status quo prior to EPAct and other action taken in 2005. The Expected policy scenario assumed modest progress in moving polices forward. The Expanded policies scenario assumed additional policy advances that will bring natural gas supply and demand into better balance, producing lower and less volatile prices. Gas prices in the Expected policies scenario averaged about $2.70 lower than the Existing policies scenario, a reduction of nearly 20 percent. The Expanded policies scenario averaged almost $4.00 lower than the Existing policies scenario, a reduction of over 40 percent. By the year 2020, consumer savings are $120 billion per year in the Expected policies scenario, and $200 billion in the Expanded policies scenario, compared to the Existing policies scenario.

There have been two recent studies that examine the economic impact of higher natural gas prices. The first study, conducted by the Department of Commerce, tried to quantify the impacts of rising natural gas prices between 2000 and 2004 on the U.S. economy.[7] The study found that higher natural gas prices in the 2000 to 2004 period had a somewhat mildly depressing effect on GDP, but a more serious negative effect on employment. In 2000 and 2002, the study estimated that natural gas price increases reduced real GDP growth by 0.2 percentage points in each of these years. In terms of jobs, the study estimated that total civilian employment was lower by an average 489,000 jobs between 2000 and 2004. Manufacturing employment was lower by an average 79,000 jobs, or about 16 percent of the total civilian jobs lost. The study also found from 1999 to 2003, prices were increasing more quickly than in other countries so that by 2002/03, U.S. natural gas prices were generally higher than those overseas.

The second study was conducted by the consulting firm Global Insight for the California Natural Gas Advisory Group, comprised of the California Energy Commission, Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas and Electric Company.[8] The Global Insight study focused on the California economy, comparing the impacts of three different natural gas price scenarios on that state's economy from 2006 through 2016. The high and low price projections used in the Global

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[7] *Impacts of Rising Natural Gas Prices on the U.S. Economy and Industries*, Economics and Statistics Administration, U.S. Department of Commerce, July 29 2005.

[8] *The Impact of Natural Gas Prices on the California Economy*, prepared for The California Natural Gas Advisory Group by Global Insight, Inc., February 2006.

Insight study were similar to the price projections in the AGF Outlook Study's Existing and Expanded policies scenarios, respectively.

Examining the difference between the high and low price cases, the Global Insight study found that for California alone:

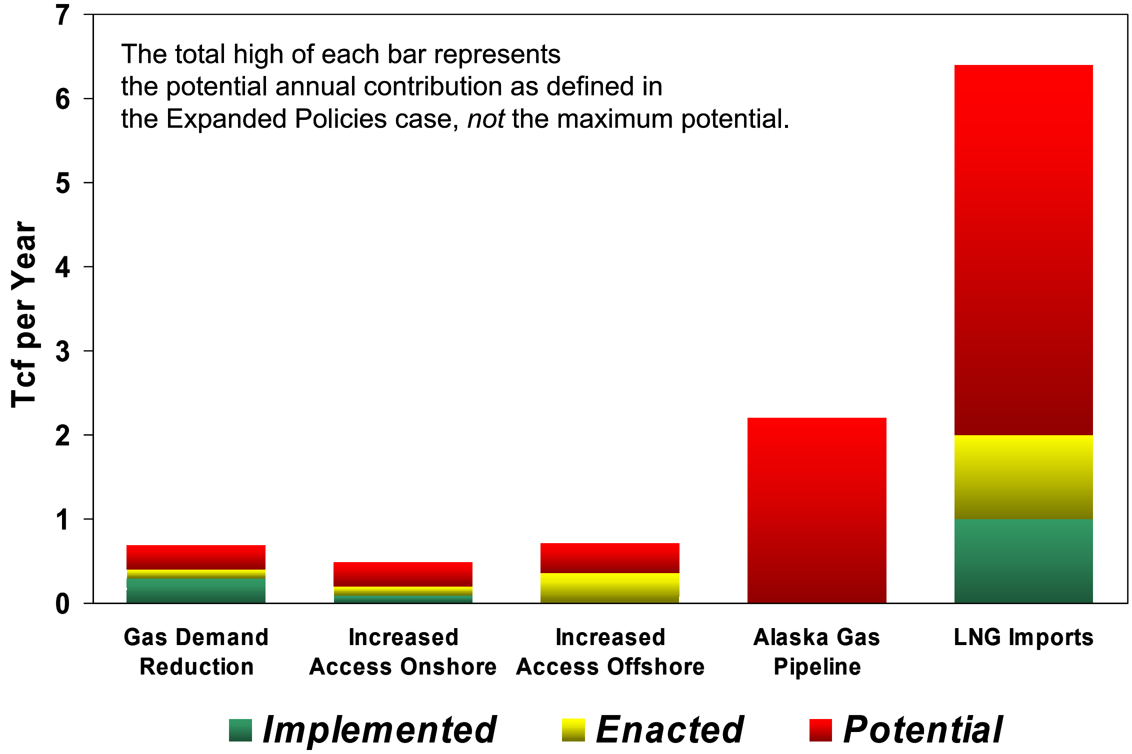
- Households would spend 22 percent more annually in 2016 for heating, cooking and electricity, and average real household income would be 1 percent lower.
- Manufacturing, which has already lost 321,000 jobs since 2000, would have 2.1 percent fewer jobs in 2016, and real gross state product (GSP) in the sector would decline by 3.3 percent, accounting for nearly 43 percent of the value of the decline in total GSP.
- The largest employment impact would be in the private services-providing sectors (i.e., 68 percent of California's total employment), which would feel higher prices in increased costs for office space and electricity, and would have 0.9 percent fewer jobs.
- Because nearly 50 percent of the state's electric power generation is fueled by natural gas, California's electric utilities would face natural gas bills that would be $8.3 billion, or 81 percent higher.

It is clear that natural gas prices have a broad impact throughout the economy. Higher prices reduce disposable incomes for residential consumers. Besides the direct impact, this reduction ripples through the economy as reduced spending on other goods and services. Higher natural gas prices also raise costs in the commercial sector, which ultimately get passed on to consumers in the form of higher prices for goods and services. In the industrial sector, higher prices increase production costs, particularly in gas-intensive industries such as nitrogenous fertilizer and petrochemicals. The increase in costs will either reduce profits or be passed on to consumers in the form of higher prices. Higher gas prices also increases the cost of gas-based electric generation, which in turn puts pressure on electricity prices.

Progress Toward Addressing the Imbalance

Figure 5 (on the next page) provides a summary of how far the U.S. has moved over the past year toward the favorable market conditions as outlined in the Expanded policies scenario. An estimate of the progress made on the key variables as outlined in the AGF Outlook Study's Expanded policies scenario is provided. The progress is expressed in terms of the percent progress with policies that have been fully implemented ("Implemented"), or policies that have been enacted (i.e. EPAct) but not yet fully implemented ("Enacted"). The total height of each bar represents the potential annual contribution of that variable as identified in Expanded policies scenario (although the maximum potential may actually be much higher). The Expanded policies scenario was not meant to present a "best case" for the U.S. natural gas market. Likewise, the estimated potential contributions in that scenario do not represent the maximum possible for each variable.

Figure 5
Impacts of Policy Changes on Key Variables - Expanded Policies Potential



	Implemented *Impact of policies that have been fully implemented.*	**Enacted** *Impact of policies that have been enacted, but not yet implemented.*	**Potential** *Potential impact identified in AGF Outlook Study.*
Gas Demand Reduction	Currently implemented efficiency and conservation policies could reduce demand by about 300 Bcf per year.	Full implementation of all EPAct measures could reduce gas demand by another 100 Bcf per year.	The AGF Outlook Study identified potential reductions of 650 Bcf per year by decreasing gas demand in the power sector .
Increased Access Onshore	Policy to streamline the approval and permitting process may increase production by about 100 Bcf per year.	Full implementation of all EPAct measures could increase onshore supplies by another 100 Bcf per year.	Assuming only modest changes in onshore access policies, the Intermountain West could provide another 450 Bcf per year.
Increased Access Offshore	No new policies on OCS access have been implemented since the AGF Outlook Study.	In December, Congress passed legislation that will provide access to an additional 365 Bcf per year in the Eastern Gulf of Mexico.	Lifting the moritoria on exploration and production off the East and West Coasts could yield another 365 Bcf per year.
Alaska Gas Pipeline	No new policies have been implemented since the AGF Outlook Study.	The Alaskan Natural Gas Pipeline Act provides loan guarantees and other support, and the Alaskan legislature is currently considering an SGA agreement with the Producers Group.	An Alaskan Gas Pipeline could provide as much as 2.2 Tcf per year of additional gas supplies.
LNG Imports	Currently implemented policies that simplify the approval process for new terminals may increase LNG imports by about 1.0 Tcf per year.	Implementation of additional policies to promote long-term supply contracts could increase LNG imports by an additional 1.0 Tcf per year.	The AGF Outlook Study identified potential additional LNG imports of 6.4 Tcf per year.

Gas Demand Reduction

Enacted Score: 60%
Implemented Score: 40%
Potential Identified in AGF Outlook Study: 650 Bcf per Year

The Expanded policies scenario assumes policies are enacted to encourage electricity generator to increase non-gas capacity in order to slow the growth of gas demand in the electric power sector. These policies reduced future additions of gas-based generating capacity by 30 GW, decreasing gas demand for electricity generation by approximately 650 Bcf per year by 2020.

In some respects, EPAct goes beyond the Expanded policies scenario in that it includes additional measures to reduce natural gas demand, such as new building efficiency standards for government buildings. Although these additional measures toward demand reduction make a positive contribution toward improving the supply/demand balance, their collective impact is small relative to the potential impact of reducing the growth of gas demand for electricity generation. EPAct includes some critical measures to promote coal, nuclear, and renewable generating technologies, but Congress must follow though with funding to ensure those measures are fully implemented.

Increased Access Onshore

Enacted Score: 40%
Implemented Score: 20%
Potential Identified in AGF Outlook Study: 450 Bcf per Year

The Expanded policies scenario assumes a modest increase in access to resources in the Intermountain West could provide up to 450 Bcf per year of additional supply by 2020.

EPAct made some progress toward improving access to federal onshore lands. Still, barriers remain to the approval and permitting of oil and gas exploration on these lands, particularly in the Intermountain West, which has some of the most promising resources in the Lower-48. A study by the Department of the Interior noted that there nearly 1,000 different stipulations that can impede the development of oil and gas resources on federal lands. An integrated, all encompassing review of restrictions in the Intermountain West is needed to coordinate and rationalize all the regulations governing land access. These regulations, which are often duplicative and overlapping in their scope, continue to be an impediment to increasing production in this area.

Increased Access Offshore

Enacted Score: 50%
Implemented Score: 0%
Potential Identified in AGF Outlook Study: 730 Bcf per Year

The Expanded policies scenario assumes that lifting restriction to exploration and production in the OCS could provide and additional 365 Bcf per year from areas off the East Coast, and another 365 Bcf per year from currently restricted portions of the Sale 181 lease block in the Gulf of Mexico.

While EPAct did not take any actions toward opening the OCS for oil and gas development, Congress recently passed legislation to open 8.3 million acres in Federal waters in the Eastern Gulf of Mexico to oil and gas exploration and development. In additional to providing an estimated 365 Bcf per year from formerly restricted areas, the new legislation will also promote greater development in the Gulf of Mexico by providing a larger share of oil and gas royalties to the coastal State governments. While this legislation was a significant step forward, other OCS areas off both the East and West Coasts remain off limits.

Alaska Gas Pipeline

Enacted Score: N/A
Implemented Score: N/A
Potential Identified in AGF Outlook Study: 2.2 Tcf per Year

The Expanded policies scenario assumes that an Alaska Gas Pipeline is complete in November 2014, with an initial capacity of 4 Bcfd. It also assumes that the pipeline is expanded to 6 Bcfd in 2017, providing a total of 2.2 Tcf per year. By 2020, Alaska natural gas production makes up almost 10 percent of U.S. supplies.

Unlike other policies, the Alaska Gas Pipeline is an "all or nothing" proposition; even though some policies to promote the project have been enacted, it will make no contribution to the U.S. natural gas market unless it is fully implemented. At present, it seems unlikely that an Alaska Gas Pipeline will become operational by the end of 2014. Assuming the SGA contract is approved by the state legislature, the State of Alaska estimates that the open season for capacity would be in 2007, project permitting would start in 2008, and actual construction would start in 2011. Most analysts agree that the earliest the pipeline could be operational would be in 2015 or 2016. For every year the project is delayed, the risk that it will be displaced by LNG imports increases. While the preliminary SGA contract is a positive development, it still must be approved by the Alaska state legislature before the pipeline project can move forward.

LNG Imports

Enacted Score: 30%
Implemented Score: 15%
Potential Identified in AGF Outlook Study: 6.4 Tcf per Year

The Expanded policies scenario assumes that LNG imports are 6.4 Tcf per year greater by 2020 that in the Existing policies scenario. By the end of the projection, LNG imports make up almost 29 percent of the U.S. natural gas supply.

Over the past year, the U.S. has added one new LNG import terminal and several more are currently under construction. While EPAct's Section 311 provision grants FERC exclusive authority over the approval of LNG facilities, there are still issues over local opposition to new import terminals. For example, FERC has approved the construction and operation of the proposed Weaver's Cove regasification terminal in Fall River, Massachusetts, conditioned upon implementation of mitigation measures to ensure safety, security and the environment in the project area. However, the project is in jeopardy due to opposition at the state and local level. The Massachusetts State Legislature recently passed a bill that would impose restrictions on the passage of LNG tankers under Massachusetts' bridges, effectively barring the Weaver's Cove facility. Massachusetts Governor Mitt Romney has also publicly apposed the Weaver's Cove facility. Other proposed regasification facilities, primarily on the East and West coasts, have met with similar opposition.

The volume of LNG imports will also depend on the ability of terminal operator to secure long-term contracts. In the coming decade, many existing LNG contracts will expire and come up for renegotiation, and many new contracts will have to be negotiated for new import terminals. A trend is developing toward more flexibility in the contracts, including less rigid pricing, shorter terms, more delivery flexibility, and less strict take-or-pay provisions. Already, more LNG is now being traded on a short-term basis and spot contract deals have occurred.

Importing LNG into the United States at uncertain gas market prices and volumes entails a level of risk that traditional LNG traders are not accustomed to. This risk varies geographically, with the Gulf Coast being relatively less risky than downstream markets on the East and West coasts. The downstream markets, such as New England, are smaller than the Gulf Coast market, and have limited access to the broader U.S. interstate pipeline system. When LNG enters these markets, local gas prices can become depressed relative to Henry Hub. Importers of LNG will make an effort to lay off the risks of their long-term upstream purchase and shipping contracts (including take or pay provisions) on large volume, credit-worthy buyers who can shoulder such risks, including regulated gas and electric utilities. Without long-term sales contracts or ready access to large consuming markets, terminals in the less-liquid market areas face more risk, and may be more difficult to develop and to finance. Even if these downstream terminals are developed without long-term sales contracts, spot LNG imports will not provide a secure supply, since spot cargos may end up in Europe and Asia if natural gas prices in those markets are higher.

Over 95 percent of the world's natural gas reserves lie outside of North America. As such, it is logical that the U.S. should increase LNG imports to help meet increasing demand. However, imported LNG entails certain risks. As the spot market sales grow to make up a greater share of the world LNG market, the U.S. would be exposed to volatility created by price changes in European and Asia markets. To avoid excessive exposure to these risks, the U.S. must not rely exclusive on LNG, but should instead take a balance approach by increasing access to domestic supplies and implementing meaningful demand reductions policies.